FORTIS BC™

Doug Slater
Director, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3874
Cell: (778) 214-3842
Fax: (604) 576-7074
Email: doug.slater@fortisbc.com
www.fortisbc.com

September 16, 2019

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC)

Project No. 1598996

Application for Approval of a Multi-Year Rate Plan for 2020 through 2024 (Application)

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 2

On March 11, 2019, FortisBC filed the Application referenced above. In accordance with BCUC Order G-156-19 setting out a further Regulatory Timetable for the review of the Application, FortisBC respectfully submits the attached response to BCUC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.
FORTISBC INC.

Original signed:

Doug Slater

Attachments

cc (email only): Registered Parties

Table of Contents **Page no.**

A. EVOLVING OPERATING ENVIRONMENT

154.0 Reference: EVOLVING OPERATING ENVIRONMENT

Exhibit B-10, BCUC IR 1.1

Customer Expectations

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 1.1, FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC) discussed the opportunities and challenges presented by rising customer expectations with respect to service, engagement channels and keeping pace with other service providers.

FortisBC further stated in response to BCUC IR 1.1: "Generally speaking, meeting customer expectations with respect to service, engagement channels and keeping pace with other service providers is expected to support increased customer engagement and may translate to increased demand for FortisBC's energy solutions and services."

154.1 Please indicate which service providers FortisBC is referring to in its response to BCUC IR 1.1 and the types of activities being undertaken by these service providers which FortisBC is aiming to keep pace with. Please clearly indicate if the service providers are electric or gas utilities (or both).

Response:

In response to BCUC IR 1.1.1, FortisBC's reference to "keeping pace with other service providers" generally refers to any other service provider that our customers are doing business with. This recognizes that the expectations of our customers are formed by their collective service experiences and are not confined to their interactions with gas or electric utilities. Accordingly, FortisBC's customers might compare their experience with FortisBC to their service experiences with companies like Amazon and Telus, as well as BC Hydro.

154.1.1 As part of the above response, please indicate if in the above-mentioned preamble "FortisBC's energy solutions and services" is intended to refer to FortisBC Energy Inc. (FEI), FortisBC Inc. (FBC) or both. Please also describe the specific energy solutions and services being referenced in this statement.

Response:

In the above preamble, "FortisBC" refers to both FEI and FBC. The statement, including reference to increased demand for FortisBC's energy solutions and services, was intended to refer broadly to all of FortisBC's service offerings.

FortisBC believes that its focus on meeting customer expectations will help drive greater customer engagement and maintain or increase demand for its products and services.

155.0 Reference: STAKEHOLDER ENGAGEMENT

Exhibit B-10, BCUC IR 3.4

Discussions with Stakeholders

In response to BCUC IR 3.4, FortisBC stated that it met with "representatives from the Ministry of Energy, Mines and Petroleum Resources and the BC Business Council as part of the MRP consultation process."

155.1 Please explain in detail the topics discussed with: (i) the Ministry of Energy, Mines and Petroleum Resources; and (ii) the BC Business Council.

Response:

Please refer to Appendix C3 in the Application for the presentation made to the two parties[1].

In general, the discussions gravitated towards areas of interest. For example, the Ministry of Energy, Mines and Petroleum Resources (MEMPR) was interested in issues that support the objectives of CleanBC such as the Clean Growth Innovation Fund, targeted incentives as well as stakeholder engagement and Indigenous relations. MEMPR indicated that CleanBC has policy implications that need to be considered in addition to the BCUC's traditional lens of an economic regulator. Similar to MEMPR, the topics discussed with BC Business Council (BCBC) gravitated towards areas of interest, including the economic and environmental benefits to British Columbia related to FortisBC's proposals.

In FortisBC's opinion, MEMPR indicated support for the objectives of the Innovation Fund and proposed targeted incentives, and the BCBC also indicated support. However, the BC Government, and other interveners, are best positioned to make their own views known. Consequently, the Companies encouraged MEMPR, and all stakeholders it consulted, to participate and make their views known through the MRP regulatory process.

While the discussions with MEMPR and BCBC focused on various elements of the MRPs, the discussions were high level in nature. FortisBC considered the general discussions it had with stakeholders, including MEMPR and BCBC, in its proposals in the Application.

155.2 Please provide any feedback given on the Multi-year Rate Plans (MRPs) by each of the Ministry of Energy, Mines and Petroleum Resources and the BC Business

[1] FortisBC Next Generation PBR, Stakeholder Discussion, October 2018.

Council and explain whether this feedback was incorporated into the MRP application proposals.

Response:

Please refer to the response to BCUC IR 2.155.1.

155.2.1 As part of the above response, please specifically explain whether the Ministry of Energy, Mines and Petroleum Resources provided any feedback on the proposed Innovation Fund or on the proposed Targeted Incentives.

Response:

Please refer to the response to BCUC IR 2.155.1.

B. EVALUATION OF THE CURRENT PBR PLANS

156.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-10, BCUC IR 6.3

Decoupling of Revenues and Costs

In response to BCUC IR 6.3, FortisBC stated the following:

> …both FEI and FBC achieved significant O&M [Operations and Maintenance] savings during their PBR terms. However, the incentives to achieve these savings are not derived from the inclusion or quantum of the productivity factor. Rather, they are derived from the decoupling between revenues and costs during the Plans' terms, the length of the rate period and the amount of the costs that are subject to an incentive framework…The X-Factor does ensure that part of the "expected" industry productivity growth during the Plans' terms is passed to customers regardless of the actual performance of the Utilities.

156.1 Please fully explain the statement in the above preamble that the incentives are "derived from the decoupling between revenues and costs during the Plans' terms." Please specifically refer to the design of FEI and FBC's Current Performance Based Ratemaking (PBR) Plans in this response.

Response:

The term "decoupling between revenues and cost during the Plan's terms" in the preamble, and as generally found in PBR literature, refers to the use of indexing formulas to break the link between the formula driven revenues or prices and incurred costs either on components of the revenue requirement or the entire revenue requirement.

As explained in Appendix C4-3 of the Application (Fundamentals of Rate Setting), FortisBC's Current PBR Plans can be described as a hybrid revenue cap model with a building block approach, while also containing cost of service elements. This is based on the following features:

- revenues are capped independent of the actual costs incurred for O&M and capital;
- the formulas for capital expenditures are separated from the formulas for O&M; and
- certain costs are treated using cost of service rate-setting methodologies.

Unlike the revenue cap plans in other jurisdictions, the Current PBR Plans escalate O&M and certain capital expenditures with separate formulas that are based on inflation, a growth factor, and a productivity factor. In this sense, the amount of FortisBC's capital and O&M expenditures recovered in rates is independent of the actual costs incurred. Subject to the earnings sharing mechanism, any variance between actual costs and formula driven costs for the entire PBR term will flow to the account of the shareholders which will incent the Utilities to strive to find cost efficiencies (without negatively affecting service quality) to spend less than formula driven amounts. Even without the existence of the productivity factor, the same incentive would exist.

For more information, please refer to Dr. Kaufmann's presentation titled "Multi-year rate plan and cost of service regulation" included in Appendix C-3 as well as to Appendix C4-3 of the Application.

156.2 Please explain if the decoupling described in the above preamble was also experienced by each of FEI and FBC under the cost of service rate-setting approaches in place prior to the Current PBR Plans due to the approved use of the Rate Stabilization Adjustment Mechanism deferral account (FEI) and the Revenue Variance deferral account (FBC).

Response:

What is commonly referred to as "revenue decoupling" is a different concept than the decoupling of rates/revenues and incurred costs in the context of MRP/PBR plans. FEI provides further clarity in the response below.

In regulatory literature, "revenue decoupling" ordinarily refers to a rate making mechanism that is designed to eliminate or reduce the dependence of a utility's revenues on system throughput (i.e., sales). It is adopted with the intent of removing the disincentive a utility has to administer and promote customer efforts to adopt demand side management initiatives or to install distributed generation to displace electricity delivered by the utility. Revenue decoupling is used under both cost of service and MRP/PBR rate setting frameworks. As noted in the question, FEI and FBC and many other North American utilities use revenue stabilization mechanisms to decouple the amount of energy sold and the actual (allowed) revenue collected by the utility.

In contrast, and as discussed in the response to BCUC IR 2.156.1, the decoupling of rates/revenues and incurred costs in the context of MRP/PBR plans typically refers to the use of indexing formulas to break the link between the allowed revenues/prices and incurred costs.

For more information, please refer to Dr. Kaufmann's presentation titled "*Multi-year Rate Plan and Cost of Service Regulation*" included in Appendix C-3 as well as to Appendix C4-3 of the Application.

157.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-10, BCUC IR 7.1

Compugen Contract Renewal

In response to BCUC IR 7.1, FEI stated that negotiations for another five-year term with Compugen are nearing completion and the new contract is "in line with the previous contract in regards to costs and services."

157.1 If the new contract with Compugen has now been completed, please provide a comparison of the costs under the new contract to the costs under the existing contract and highlight any differences.

Response:

The new contract is in the process of final approval, and is expected to be completed in September. The cost of the new contract will increase by 2.38 percent by the end of the contract in 2024 compared to 2019 costs.

158.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-10, BCUC IR 8.1, 8.8; Exhibit B-7, Commercial Energy Consumers Association of BC (CEC) IR 11.1, Exhibit B-1, p. B-34; Exhibit B-1-1, Appendix B8-1, p. 6

FEI Growth Capital

In response to BCUC IR 8.1, FEI provided the following scenario which compared the Actual Growth Capital during the Current PBR Plan to the Growth Capital amount which would have occurred under a scenario where actual service line additions (SLAs) were used (but the 0.5 multiplier was still applied to the growth factor):

Table 1: Forecast of Growth Factor with 50% multiplier included

Year	Actual	Formula	Variance
2014	24.231	26.009	1.778
2015	45.776	36.760	(9.016)
2016	47.500	36.827	(10.673)
2017	59.542	42.221	(17.321)
2018	82.884	43.474	(39.410)
2019P	63.328	40.257	(23.071)
Total	323.262	225.548	(97.713)

In response to CEC IR 11.1, FEI provided a revised Table C1-2 from the Application which shows the Growth Capital recalculated using actual SLAs:

Growth Capital $000	2014	2015	2016	2017	2018	Total
Approved Growth Capital using lagging growth	21,478	28,480	33,263	33,477	37,485	154,183
Growth Capital recalculated using Actual Additions	30,508	43,042	42,997	55,457	58,414	230,418
Difference	(9,031)	(14,563)	(9,734)	(21,979)	(20,929)	(76,236)
Total Growth Expenditures	34,677	45,776	47,500	59,543	82,884	270,380

158.1 Excluding the year 2014 in the table provided in response to CEC IR 11.1, which includes FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) amalgamated costs, please explain why years' 2015 through 2018 in the "Growth Capital recalculated using Actual Additions" row do not agree with the "Formula" column in the response to BCUC IR 8.1.

Response:

The "Growth Capital recalculated using Actual Additions" in the response to CEC IR 1.11.1 and the "Formula" column in the response to BCUC IR 1.8.1 are not equivalent. In response to BCUC IR 1.8.1, FEI substituted the actual growth factor in place of the lagging growth factor, leaving all other formulaic components as approved.

In the response to CEC IR 1.11.1, FEI also used the actual growth factor, but substituted it into the formula that FEI had proposed to use in the 2014-2018 PBR Application. The major difference between the two calculations is that the table provided in response to CEC IR 1.11.1 (which is an amended version of Table C1-2 from the Application) did not include the 50 percent multiplier (reduction) to the growth factor.

158.2 Please provide an additional scenario in the same format as was provided in response to BCUC IR 8.1 to show the annual formula amount which would have been provided if actual customer additions had been used instead of service line additions (but still including the 50% multiplier).

Response:

The following table produces the Formula Growth Capital using Actual Gross Customer Additions (not lagged) to produce the growth factor and includes the 50 percent multiplier on the growth factor.

Year	Actual	Formula	Variance
2014	24.231	24.299	0.068
2015	45.776	36.196	(9.580)
2016	47.500	37.541	(9.959)
2017	59.542	41.549	(17.993)
2018	82.884	43.419	(39.466)
2019P	63.328	40.206	(23.122)
Total	323.262	223.210	(100.052)

158.3 Please provide an additional scenario in the same format as was provided in response to BCUC IR 8.1 to show the annual formula amount which would have been provided if the Growth Capital proposals included in the Application were applied during the Current PBR Plan term (i.e. 0% X-Factor, 100% growth factor, actual customer additions). Please compare the resulting annual formula Growth Capital funding to the actual Growth Capital spending during the Current PBR Plan term.

Response:

The following table produces the Formula Growth Capital using Actual Gross Customer Additions (non-lagging) to produce the growth factor, 100 percent multiplier on the growth factor, and a 0 percent X-factor.

Year	Actual	Formula	Variance
2014	24.231	27.268	3.037
2015	45.776	43.414	(2.362)
2016	47.500	46.945	(0.555)
2017	59.542	57.442	(2.100)
2018	82.884	62.947	(19.937)
2019	63.328	53.316	(10.013)
Total	323.262	291.332	(31.930)

As can been seen in the table, when applying the proposals in the MRP retrospectively, FEI would still have been underfunded for Growth Capital, although the variance is significantly reduced. The other funding concerns for Growth Capital in the Current PBR Plan term have been addressed in this Application through means other than the growth factor and X-factor changes.

In response to BCUC IR 8.8, FEI stated the following:

> The annual actual New Customer Mains amounts in Table C3-1 of the Application do not agree with the annual actual New Customer Mains amounts in Table A:B8-1-3 of Appendix B8-1 due to Pension and OPEB [Other Post-Employment Benefits] expense. Both the actual and allowed New Customer Mains expenditures in Table A:B8-1-3 include Pension and OPEB adjustments whereas Table C3-1 of the Application excludes Pension & OPEB.

158.4 Please explain why FEI included the Pension and OPEB adjustments in Table A:B8-1-3 of Appendix B8-1 for New Customer Mains. Please also provide a revised Table A:B8-1-3 which excludes Pension and OPEB adjustments.

Response:

FEI included Pension and OPEB adjustments in Table A:B8-1-3 of Appendix B8-1 for New Customer Mains because the internal reporting for actual Growth Capital expenditures includes Pension and OPEB. FEI's projections for Growth Capital also include Pension and OPEB as part of the total estimated labour expenditures. It should be noted that the annual variance amount is unchanged whether the table includes or excludes Pension and OPEB adjustments as these adjustments flow through both the Actual/Projected and Allowed at the same amount.

A revised table of Table A:B8-13 which excludes Pension and OPEB adjustments is provided below:

Table A:B8-1-3: New Customer Mains ($ thousands) – excluding Pension & OPEB adjustments

New Customer Mains ($000's)	Actual/ Projected	Allowed	Variance	Var%
2014	5,272	6,521	(1,250)	-19%
2015	13,752	8,677	5,075	58%
2016	12,823	10,165	2,659	26%
2017	16,467	10,213	6,253	61%
2018	24,494	11,422	13,072	114%
Cumulative	72,808	46,998	25,810	55%

158.5 Please clarify if Table B2-4 on page B-34 of the Application includes Pension and OPEB adjustments.

Response:

Table B2-4 on page B-34 of the Application excludes Pension and OPEB adjustments.

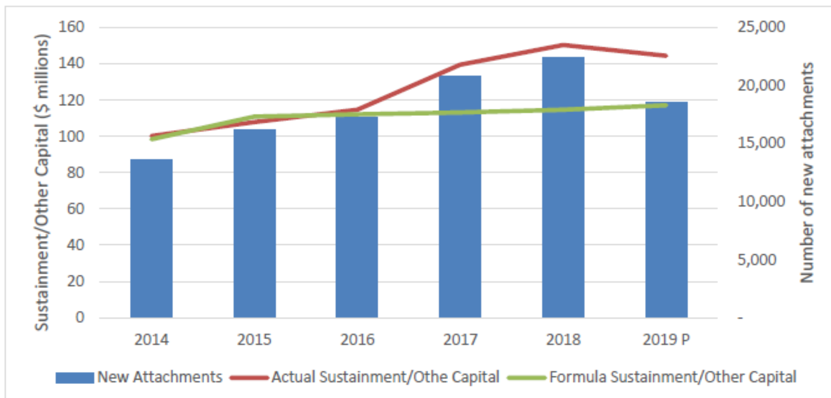
159.0 Reference: EVALUATION OF THE CURRENT PBR PLANS

Exhibit B-10, BCUC IR 8.1, 9.1

FEI Sustainment/Other Capital Correlation Analysis

In response to BCUC IR 9.1, FEI provided the following correlation analysis for Sustainment/Other Capital:

Figure 1: FEI Trend in New Attachments Compared with Actual and Formula-driven Sustainment/Other Capital



159.1 Please discuss whether, based on Figure 1, the correlation between 2019 projected new attachments and formula-driven Sustainment/Other Capital is trending more closely than the correlation between 2019 projected new attachments and actual/projected Sustainment/Other Capital.

<u>Response:</u>

The premise of the question seems to be incorrect. The correlation is not used to compare single data points (year 2019), but rather the trend in a set of data (for instance data for the 2014-2019 period).

In Figure 1 in response to BCUC IR 1.9.1, the actual sustainment line is trending more closely with the new attachment line. As the number of new attachments declines from 2018 to 2019 so too does the actual sustainment/other capital, whereas the formula amounts continue to increase.

Nevertheless, it is not appropriate to draw conclusions on any perceived correlation between Actual or Formula Sustainment/Other Capital and New Attachments for the following reasons:

1. As explained in the response to CEC IR 1.14.4, the first step before conducting any correlation analysis is to establish the causal relationship between variables. Formula Sustainment/Other Capital from 2014 to 2019 was based on a 2013 base with a growth factor related to the average number of customers from the preceding year. Any

correlation between Formula Sustainment/Other Capital and the 2019 projected New Attachments is not, itself, indicative of a causal relationship.

2. Sustainment/Other Capital is primarily made up of capital investments required to upgrade or refurbish the existing system. Although there are some capacity-related upgrades that are influenced by New Attachments that could explain, in part, the appearance of correlation, the majority of Sustainment/Other Capital is related to asset condition and equipment obsolescence which is independent of New Attachments. FEI notes that the higher expenditures experienced in 2018 are attributable mainly to the Whistler IP project. This is an example of a Sustainment project that is influenced by New Attachments, but not directly correlated because it takes a number of years of strong customer additions to necessitate a capacity upgrade of that magnitude. Thus, the fact that the actual expenditures decline in 2019 due to the Whistler IP project no longer being included is not due to a reduction in attachments. The appearance of a strong correlation between Actual expenditures and New Attachments in that year is mostly coincidental.

159.1.1 Please discuss the likely reasons for the projected trends in 2019.

Response:

Please refer to the response to BCUC IR 2.159.1.

In response to BCUC IR 8.1, FEI provided three tables based on three scenarios described in BCUC IR 8.1.

159.2 Please provide the same analysis for FEI's Sustainment/Other Capital using the applicable growth factor (i.e. average number of customers) and using actual average number of customers instead of forecast, similar to the response to BCUC IR 8.1.

Response:

FEI has produced the requested tables for Sustainment/Other Capital below.

Table 1: Forecast of Growth Factor with 50% multiplier included

Year	Actual	Formula	Variance
2014	100.168	98.785	(1.383)
2015	107.803	111.219	3.416
2016	114.641	112.608	(2.033)
2017	139.416	113.681	(25.735)
2018	150.329	115.452	(34.877)
2019P	144.359	117.577	(26.782)
Total	756.716	669.324	(87.392)

Table 2: Lagging Growth Factor with 50% multiplier excluded

Year	Actual	Formula	Variance
2014	100.168	98.602	(1.566)
2015	107.803	111.841	4.038
2016	114.641	113.639	(1.002)
2017	139.416	115.475	(23.941)
2018	150.329	117.830	(32.499)
2019	144.359	121.347	(23.012)
Total	756.716	678.734	(77.982)

Table 3: Forecast Growth Factor with 50% multiplier excluded

Year	Actual	Formula	Variance
2014	100.168	99.486	(0.682)
2015	107.803	112.481	4.678
2016	114.641	114.763	0.122
2017	139.416	116.652	(22.764)
2018	150.329	119.585	(30.744)
2019	144.359	122.300	(22.059)
Total	756.716	685.267	(71.449)

Similar to the analysis for Growth Capital, excluding the 50 percent multiplier and using a forecast growth factor would have resulted in the lowest variance as demonstrated in Table 3.

160.0 Reference: EVALUATION OF THE CURRENT PBR PLAN

Exhibit B-10, BCUC IR 8.1, 10.1, 10.2, 10.4; Exhibit B-1 , p. B-37

FBC Regular Capital

In Table B2-6 on page B-37 of the Application, FBC provides the capital expenditure variances during the Current PBR Plan term.

In response to BCUC IR 8.1, FortisBC provided three tables based on three scenarios described in BCUC IR 8.1.

160.1 Please provide the same analysis for FBC's total formula capital (i.e. the combined Growth/Sustainment/Other Capital) using the applicable growth factor for FBC (i.e. average number of customers) and using actual average number of customers instead of forecast, similar to the response to BCUC IR 8.1.

<u>Response:</u>

The requested analysis is provided in the tables below.

Table 1: <u>Forecast Customer Growth Factor</u> with 50% multiplier <u>included</u>

Year	Actual	Formula	Variance
		($ millions)	
2014	$ 42.665	$ 42.211	$ (0.454)
2015	44.791	42.570	(2.221)
2016	45.838	43.038	(2.800)
2017	59.053	43.494	(15.559)
2018	60.187	44.284	(15.903)
2019P	56.500	45.161	(11.339)
Total	$ 309.034	$ 260.759	$ (48.275)

Table 2: <u>Lagging Customer Growth Factor</u> with 50% multiplier <u>excluded</u>

Year	Actual	Formula	Variance
		($ millions)	
2014	$ 42.665	$ 42.332	$ (0.333)
2015	44.791	42.601	(2.190)
2016	45.838	43.356	(2.482)
2017	59.053	43.955	(15.098)
2018	60.187	44.807	(15.380)
2019P	56.500	46.278	(10.222)
Total	$ 309.034	$ 263.329	$ (45.705)

Table 3: <u>Forecast Customer Growth Factor</u> with 50% multiplier <u>excluded</u>

Year	Actual	Formula	Variance
		($ millions)	
2014	$ 42.665	$ 42.365	$ (0.300)
2015	44.791	42.970	(1.821)
2016	45.838	43.684	(2.154)
2017	59.053	44.439	(14.614)
2018	60.187	45.755	(14.432)
2019P	56.500	46.889	(9.611)
Total	$ 309.034	$ 266.103	$ (42.931)

160.2 Please provide an additional scenario for FBC in the same format as was provided in response to BCUC IR 8.1 to show the annual formula amount which would have been provided under the following assumptions: 0% X-Factor, 100% growth factor, actual average number of customers.

<u>Response:</u>

The requested analysis is provided in the table below.

Year	Actual	Formula	Variance
		($ millions)	
2014	$ 42.665	$ 42.800	$ 0.135
2015	44.791	43.856	(0.935)
2016	45.838	45.042	(0.796)
2017	59.053	46.290	(12.763)
2018	60.187	48.149	(12.038)
2019P	56.500	49.843	(6.657)
Total	$ 309.034	$ 275.980	$ (33.054)

In response to BCUC IR 10.1, FBC provided the following tables:

	Growth Capital				Sustainment/Other Capital			
	Actual	Formula	Variance	% Variance	Actual	Formula	Variance	% Variance
2014	15.283	17.944	2.661	14.8%	27.382	24.249	(3.133)	12.9%
2015	17.662	18.025	0.363	2.0%	27.128	24.359	(2.769)	11.4%
2016	12.937	18.233	5.296	29.0%	32.901	24.641	(8.260)	33.5%
2017	19.159	18.395	(0.764)	4.2%	39.894	24.859	(15.035)	60.5%
2018	20.634	18.631	(2.003)	10.7%	39.553	25.187	(14.366)	57.0%
2019P	15.051	18.870	3.819	20.2%	41.449	25.992	(15.457)	59.5%

FBC also stated in response to BCUC IR 10.1 that it does not have disaggregated capital spending envelopes or formula calculations and that "An arbitrary calculation of formulaic capital components reflects neither the determination of FortisBC's PBR formula capital, nor the internal allocation of the capital components."

In response to BCUC IR 10.4, FBC attributed $20.9 million of the $49.6 million formula versus actual capital variance to "system improvements to accommodate growth" which FBC confirmed in response to BCUC IR 10.2 is part of Growth Capital.

160.3 Please explain how FBC is able to determine the amount that "system improvements to accommodate growth" contributed to the capital spending pressures given FBC's statements in response to BCUC IR 10.1 that it does not have disaggregated information on formula capital spending.

Response:

As stated in the response to BCUC IR 1.10.1, FBC's formula capital is determined at the aggregate level, therefore the formula amounts provided in the response to that question are hypothetical and no meaningful analysis of the variances can be made.

FBC has several projects for system improvements to accommodate growth. These projects are New Connects, Small Growth, Unplanned Growth, and third party or customer funded growth projects which are planned and executed under Growth Capital. FBC compared actual spending in these projects with its internal forecasts (the components of which vary year to year due to the flexibility provided under the PBR mechanism) to determine the amount that these projects contributed to capital spending pressures.

In Table A: B8-3-1 in Appendix B8-3 of the Application the cumulative values are shown as follows:

Area	Variance Amount ($ million)
New connects, small growth, unplanned growth (system improvements to accommodate growth)	$16.705
Customer driven modifications at RG Anderson Terminal	$3.656

Area	Variance Amount ($ million)
Customer-funded projects	$0.552
Total	$20.913

160.4 Please clarify FBC's statements regarding the over-spending of "system improvements to accommodate growth" given the table provided in response to BCUC IR 10.1 which shows that actual Growth Capital was lower than formula Growth Capital in four out of the six years of the Current PBR Plan term.

Response:

Please refer to the response to BCUC IR 2.160.3.

C. PROPOSED RATE PLANS

161.0 Reference: X-FACTOR

Exhibit B-10, BCUC IR 13.2; Exhibit B-1, pp. B-25, B-44; FEI Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 proceeding, Exhibit B-1, p. 53; FBC Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 proceeding, Exhibit B-1, p. 44

O&M Savings and the X-Factor

In response to BCUC IR 13.2, FortisBC stated the following:

> The theory of the I-X mechanism defines the X-Factor value as an adjustment to the inflation factor (I-Factor) for the difference between the economy-wide inflation factors (used in the indexing formula) and the real cost [of] inflation of the utility…
>
> …The variance between [the] economy-wide inflation factor used in the formula and the utility's actual inflation depends on two factors: (i) the variance between the economy-wide inflation and the input cost inflation of the utility and (ii) the variance between the average productivity of the economy and the productivity of the utility.

In FEI's Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (FEI PBR Application) and FBC's Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (FBC PBR Application), both FEI and FBC requested approval of a 0.5 percent X-Factor (inclusive of any stretch factor).

As shown on page B-25 of the Application, the BCUC approved a 1.10 percent X-Factor for FEI and a 1.03 percent X-Factor for FBC for the Current PBR Plan terms.

On page 53 of the FEI PBR Application, FEI stated the following:

> The reasonableness of FEI's proposed X-Factor can be assessed by comparing the impact of the proposed X-Factor on forecast rate changes under a formula relative to forecasted rate changes under the cost of service model. As FEI explains in Section B7 of this Application, the rates arising from PBR formulas (the combination of proposed 0.5 per cent X-Factor and the proposed composite inflator) will lead to average delivery revenues that are 2.0 percent lower than the average rates under the cost of service model which indicates that the proposed

> X-Factor is an ambitious estimate of expected productivity gains and represents a considerable challenge to the Company.

On page B-44 of the Application, FortisBC states: “FEI’s and FBC’s O&M expenditure performance has been a success in almost every category – less than inflation, O&M per customer has declined, and strong performance relative to other utilities.”

161.1 Given that O&M savings were achieved for each of FEI and FBC in each year of the Current PBR Plan term beyond the productivity improvement factor (PIF) savings, please explain how these results may be interpreted from the perspective of each of the following: (i) FEI’s and FBC’s input cost inflation compared to the economy-wide inflation; and (ii) FEI’s and FBC’s productivity compared to the average productivity of the economy.

Response:

To clarify, the “productivity of the utility” in the preamble refers to the productivity of an average firm in the utility industry and not the specific productivity of FEI and FBC. Further, to be accurate the reference to the term “Input cost inflation” in the preamble and the question should be replaced with “input price inflation”. With these notes, FortisBC provides the following response.

The information requested in this question and in BCUC IR 2.161.2 can only be addressed by conducting a TFP growth study for the utility industry as well as separate TFP studies for FEI and FBC. Conducting a TFP study is a lengthy and expensive process that takes several months. FortisBC does not have internal expertise to conduct such a study and therefore is unable to respond to these questions.

For the reasons explained in response to BCUC IR 1.17.5, FortisBC has not conducted a TFP study and is proposing a judgement-based approach for X-Factor determination. Other inputs that can inform the BCUC’s decision were discussed in the response to BCUC IR 1.13.2.

Based on FortisBC’s review of expert TFP testimonies in other Canadian jurisdictions, the difference between utility industry input price inflation and the economy-wide inflation is often considered to be statistically insignificant and the X-Factor is not adjusted for this item. For instance, Dr. Makholm’s evidence in Union Gas’ and EGD’s amalgamated incentive rate-setting proceeding explains this issue as follows:

> Using the largest possible TFP data set for North American energy distribution companies, I have consistently never found a statistically significant difference in input prices for the energy distribution industry versus the economy as a whole. I confirm that same result here. That is, I have always found that there is no reason to conclude that the input price inflation faced by the energy utility

distribution sector differs from the input price inflation facing the rest of the economy.[2]

161.2 Please explain how FEI's and FBC's O&M expenditure performance during the Current PBR Plan term compares to each utility's expectations at the time of filing the FEI and FBC PBR Applications, where a 0.5 percent X-Factor was proposed. Specifically, please compare the O&M expenditure performance to FEI's and FBC's expectations regarding: (i) input cost inflation compared to the economy-wide inflation; and (ii) productivity compared to the average productivity of the economy.

Response:

Please refer to the response to BCUC IR 2.161.1.

161.3 Please confirm, or explain otherwise, that FEI and FBC have not performed a similar analysis as was described on page 53 of the FEI PBR Application – i.e. analysis of forecast rate changes under a cost of service model compared to forecast rate changes under the proposed indexed-based formula – to assess the reasonableness of the 0 percent X-Factor proposals.

Response:

Confirmed.

Comparisons similar to those provided in FEI and FBC's PBR Applications are not needed to assess the reasonableness of the X-Factor. FortisBC's proposal to not recommend an X-Factor in its O&M determination (which can also be expressed as an implied zero percent X-Factor) is reasonable and appropriate based on the evidence, including:

- the review of X-Factor related evidence and decisions in other jurisdictions, including the range of X-Factors calculated in recent TFP studies, the increased importance of judgement and rapidly declining industry productivity growth values in recent years;

[2] Dr.Makholm (2017); Expert Report and Direct Testimony pm behalf of Enbridge Gas Distribution and Union Gas Limited; page 32, Para A43.

- FEI's and FBC's history of being under performance based regulation, including efficiencies achieved during the Current PBR Plan period;
- the assessment of FEI and FBC's changing operating environment and O&M cost pressures during the proposed MRP period; and
- the results of Concentric's benchmarking study.

FortisBC's proposal to not recommend an X-Factor in its O&M determination will incent the Companies to keep controllable cost increases below the rate of inflation by finding additional efficiency opportunities while maintaining the current high levels of service quality.

Furthermore, although FortisBC undertook the comparisons described above in its 2014 PBR Applications[3], the BCUC 2014 PBR Decisions did not give the analysis any weight in its X-Factor determination[4]:

> **Comparison to COS Rates**. We do not consider an "illustrative revenue requirements forecast" to be a reasonable basis on which to make an X-Factor determination. The "illustrative forecast" has not been adequately tested and, as such, may be prone to error and bias. It cannot be viewed as a cost of service requirement for the next five years.

Considering the BCUC Panel's comments above, FortisBC does not believe it is useful to conduct a similar comparison in this Application. Further, considering that the majority of items in the MRPs will be set based on a cost of service methodology, only O&M (and Growth Capital for FEI) would be relevant to the comparison. FortisBC is not able to provide a reasonably accurate forecast of O&M (or Growth Capital) at a cost of service level of detail for a five year term.

For the upcoming year, 2020, FortisBC has no reason to believe its rates would be different under either cost of service or its proposal. For the remaining years of the MRP term, FortisBC is aware that there are cost pressures that are not reflected in the Base and that other cost pressures over the term of the MRP will arise. Therefore, FortisBC expects that the five year cost of service forecasts would be higher than the formula amounts, although FortisBC cannot accurately forecast by how much.

Nonetheless, due to the number of requests for similar information, the Companies have endeavoured to provide indicative revenue requirements and rate changes for at least the three-year period 2020 – 2022, based on the major assumptions set out in Table 1 below. These

[3] In the case of FBC, the rates under the proposed PBR formulas were virtually the same as those under the indicative cost of service model (FBC Exhibit B-1, page 49, lines 19-22.
[4] 2014 PBR Decisions, page 89 (FEI) and page 86 (FBC).

assumptions are likely to change in FortisBC's applications for interim rates to be filed in October 2019 and will change in subsequent years' rate filings once more information is available.

FortisBC reiterates that the revenue requirements and rates set out below are not at a level of accuracy that would allow rates to be set for 2020 to 2022 at this time.

Table 1: FEI and FBC Assumptions - Indicative Rates 2020 - 2022

	FEI	FBC
Inflation Factor	2%	2%
Customer Growth	Average 1%	Average 1%
O&M Expense	Cost of Service assumed equal to Indexed O&M plus Forecast O&M	Cost of Service assumed equal to Indexed O&M plus Forecast O&M
Base O&M	As set out in the response to BCUC IR 1.24.1	As set out in the response to BCUC IR 1.34.1
Growth Capital	Assuming 17,750 Gross Customer Additions per year	See Section C3.4
Sustainment and Other Capital	See Section C3.3	See Section C3.4
Major Projects	Previously approved: Lower Mainland IP System Upgrade	Previously approved: Corra Linn Spillway Gates, UBO Old Plants Refurbishment, Grand Forks Terminal Reliability
Depreciation Rates	See Section D2.2	See Section D2.3
Power Supply Costs	n/a	Based on average gross load increase of 1.1%, current contracts and expected future prices
Income Taxes	Existing rates	Existing rates

Table 2: FEI Indicative Revenue Requirement and Delivery Rates 2020 - 2022

	2020	2021	2022
	($ millions)		
Revenue			
Sales (2019 Rates)	$ 1,205,043	$ 1,262,468	$ 1,275,721
Deficiency (Surplus)	42,777	79,883	99,892
Total	1,247,820	1,342,351	1,375,613
Cost of Energy	364,305	369,577	374,564
Margin	883,515	972,774	1,001,049
Delivery Rate Increase	5.3%	4.5%	2.4%
Expenses			
O&M Expense (Net)	249,631	253,468	256,339
Depreciation & Amortization	242,159	294,037	300,656
Property Taxes	68,736	70,548	72,371
Other Revenue	(44,145)	(42,583)	(41,365)
Utility Income Before Income Taxes	367,134	397,303	413,048
Interest Expense	153,249	153,314	156,416
Income Taxes	43,137	27,602	33,833
Return on Common Equity	$ 170,748	$ 216,386	$ 222,799

Table 3: FBC Indicative Revenue Requirement and Rates 2020 – 2022

	2020	2021	2022
	($ millions)		
Revenue			
Sales (2019 Rates)	$ 373,274	$ 374,317	$ 374,606
Deficiency (Surplus)	14,863	32,757	50,930
Total	388,137	407,074	425,536
Rate Increase	4.0%	4.6%	4.5%
Expenses			
Cost of Energy	165,236	173,064	177,972
O&M Expense (Net)	51,653	55,508	57,156
Depreciation & Amortization	60,432	63,381	70,596
Property Taxes	16,880	17,163	18,183
Other Revenue	(8,056)	(8,056)	(8,056)
Utility Income Before Income Taxes	101,993	106,013	109,684
Interest Expense	42,177	44,522	44,077
Income Taxes	8,039	8,176	9,768
Return on Common Equity	$ 51,777	$ 53,315	$ 55,839

An excel spreadsheet is provided as Attachment 2.161.3.

161.3.1 If confirmed, please explain why this analysis was not considered necessary to support FEI's and FBC's proposals for the 0 percent X-Factor in the Application.

Response:

Please refer to the response to BCUC IR 2.161.3.

161.3.2 If confirmed, please perform the analysis described on page 53 of the FEI PBR Application for each of FEI and FBC to support each utility's 0 percent X-Factor proposal.

Response:

Please refer to the response to BCUC IR 2.161.3.

162.0 Reference: X-FACTOR

Exhibit B-10, BCUC IR 13.2, 22.1; Exhibit B-1, pp. C-16 – C-17; FEI PBR Application proceeding, Exhibit B-1, pp. 52-53

Expected Cost Pressures and the X-Factor

In response to BCUC IR 13.2, FortisBC described the cost pressures anticipated by FEI and FBC during the proposed MRP term and referenced pages C-16 and C-17 of the Application.

In response to BCUC IR 22.1, FortisBC provided the following table quantifying the cost pressures identified on pages C-16 and C-17 of the Application:

Company	Cost Pressures listed on pages C-16 and C-17	Department Affected	$ millions
FEI	Additional resources to enable continued investment	Operations	$ 0.80
FEI	Operations transition and succession planning	Operations	$ 0.70
FBC	Increased engineering and technology staffing	Operations and Engineering	$ 0.22
FEI and FBC	Increased general and administrative costs	Finance, HR, Procurement	$ 0.64
FEI and FBC	Increased costs in meeting evolving municipal regulations	Operations	$ 0.20
FEI and FBC	Increased environmental and safety programs	Safety	$ 0.20
	Total Cost Pressures listed		$ 2.76

162.1 Please provide an individual departmental analysis for each of FEI and FBC's O&M expenses which shows how each department's costs are expected to increase compared to inflation during the proposed MRP term.

Response:

Provided below are two tables which show the departmental breakdown of the proposed 2019 Base O&M, including the incremental funding requested, and applies the proposed inflation and growth factors to show each department's costs for 2020, the first year of the MRP term. Total O&M Expense will increase under the indexing formula by inflation plus customer growth (assumed to be 2 percent and 1 percent respectively as stated in the response to BCUC IR 2.161.3). FortisBC reiterates that the O&M Expense by department is subject to, and expected to, change from year to year as FEI and FBC utilize the flexibility of the indexing mechanism to meet their evolving requirements and therefore the Utilities cannot provide estimates by department beyond 2020.

FEI O&M by Department ($000's)	2019 Base O&M before adjustments	Total Adjustments	New funding for MRP term	2019 Base O&M	Inflation/ Growth	2020 Forecast based on Formula Factor
Operations	80,629	2,867	2,650	86,147	2,724	88,871
Customer Service	41,077	74		41,151	1,301	42,452
Energy Solutions & External Relations	21,847	(310)	5,608	27,145	858	28,003
Energy Supply & Resource Dev	4,234	46	950	5,230	165	5,395
Information Technology	23,893	230	808	24,931	788	25,719
Engineering Services & PM	14,822	115	400	15,338	485	15,823
Major Projects	1,342	2		1,344	42	1,386
Operations Support	11,441	70		11,511	364	11,875
Facilities	9,543	543		10,086	319	10,404
Environment Health & Safety	4,359	35		4,394	139	4,533
Finance & Regulatory Services	11,379	(429)		10,950	346	11,296
Human Resources	9,008	40		9,047	286	9,334
Governance	380	2,675		3,055	97	3,152
Corporate	(1,299)	7,121		5,822	184	6,006
Total Gross O&M	**232,654**	**13,080**	**10,416**	**256,150**	**8,100**	**264,250**

FBC O&M by Department ($000's)	2019 Base O&M before adjustments	Total Adjustments	New funding for MRP term	2019 Base O&M	Inflation/ Growth	2020 Forecast based on Formula Factor
Generation	2,577	51	232	2,860	95	2,955
Operations	20,169	(251)	272	20,189	673	20,862
Customer Service	8,320	(1,911)	99	6,508	217	6,725
Communications & External Relations	1,519	4	80	1,603	53	1,656
Energy Supply	1,284	3		1,287	43	1,330
Information Systems	3,457	1,267	80	4,805	160	4,965
Engineering	3,482	2,011		5,493	183	5,676
Operations Support	1,232	(341)		892	30	921
Facilities	2,790	91		2,881	96	2,977
Environment Health & Safety	1,158	4		1,162	39	1,200
Finance & Regulatory Services	3,237	318		3,555	118	3,673
Human Resources	1,865	6		1,871	62	1,933
Governance	887	896		1,783	59	1,843
Corporate	1,302	1,480		2,781	93	2,874
Total Gross O&M	**53,279**	**3,628**	**763**	**57,670**	**1,922**	**59,591**

162.1.1 As part of the above response, please discuss how the incremental O&M funding requested to be added to FEI's and FBC's proposed 2019 Base O&M can be used to assist with expected cost pressures.

Response:

The proposed incremental funding as outlined on pages C-29 and C-47 is required to address key issues and challenges in FortisBC's operating environment. For cost pressures like that listed in the table above, FortisBC expects to manage most of these types of cost pressures through its productivity focus of "doing more with the same" and with no incremental funding.

162.2 Please explain whether any of the cost pressures identified in the table in response to BCUC IR 22.1 or described in response to BCUC IR 13.2 were already anticipated during the Current PBR Plan term but the decision to take action on these pressures was deferred in order to achieve savings within the Current PBR Plan term.

Response:

Cost pressures such as those identified in the responses to BCUC IRs 1.22.1 and 1.13.2 exist at all times, including during the Current PBR Plan term and in the upcoming MRP term. As such, addressing these items has not been deferred as these challenges arise on an ongoing basis, although the extent of each individual challenge may vary over time. With the items listed, FortisBC was demonstrating that it will continue to manage these cost pressures within the funding provided by the index-based O&M by continuing its focus on productivity throughout the MRP term.

On pages 52 and 53 of the FEI PBR Application, FEI stated the following:

> B&V [Black & Veatch] and FEI are in agreement that B&V's TFP [Total Factor Productivity] Report produces a more negative TFP number than would be applicable to FEI by virtue of how TFP data has been provided for the sample companies in the TFP Report. The capital component in B&V's study is

> measured as the difference between operating revenue (excluding gas costs) and all other O&M expenditures, and which therefore includes all capital costs, whether pertaining to base capital or growth spending, as well as the infrastructure replacement programs that have been more prevalent in recent years. In contrast, in FEI's proposed PBR Plan, large capital projects approved as CPCNs are excluded from the (I-X) mechanism and are treated under a separate regulatory approval process…The effect of FEI's proposals to exclude CPCN type projects from capital expenditures subject to the I-X mechanism is to moderate the measured negative TFP value applicable to the industry as a whole.

In response to BCUC IR 13.2, FortisBC stated the following:

> FortisBC's proposal to not recommend an X-Factor value for the index-based O&M (implying a zero percent X-factor value) reflects its assessment that the economy-wide composite inflation index is expected to track the Companies' price inflation during the term of the MRPs and in some case, may even be insufficient to compensate the Companies' higher input cost growth required to prepare the Utilities for the rapid industry transition in the upcoming term of the MRPs.

162.3 Please confirm, or explain otherwise, whether a portion of the potential costs which may be required to prepare FEI and FBC for the "rapid industry transition" would fall under flow-through costs (e.g. Investments in a Clean Growth Future, incremental costs to comply with legislatively mandated federal, provincial and municipal climate policy).

Response:

Confirmed.

Due to the evolving nature of policies, regulations and requirements related to "rapid industry transition", there is considerable uncertainty as to the impact on FEI and FBC. As a result, depending on the circumstances as they arise, FEI and FBC may require additional funding during the term of the Proposed MRPs, which may be classified as flow through or as index-based O&M. If the costs qualify for exogenous factor treatment, then this may be the approach taken to funding. An example of this is the potential impact of the Clean Fuel Standard on the Companies' operations and costs. As mentioned in the Application (page B-4), the details of the Clean Fuel Standard are currently being developed and the specific impact to FortisBC and its customers is a significant unknown.

162.3.1 If confirmed, please confirm, or explain otherwise, that the costs identified in the response to BCUC IR 13.2 would likely not impact FEI or FBC's O&M formula spending.

Response:

Please refer to the response to BCUC IR 2.162.3.

162.4 Please fully explain whether the economy-wide composite inflation index described by FortisBC in response to BCUC IR 13.2 includes capital costs.

Response:

Yes, the composite inflation index includes the impact of capital cost inflation. The composite inflation index consists of:

AWE-BC (at 55 percent) reflecting inflation associated with labour; and

BC-CPI (at 45 percent) reflecting inflation of both labour and non-labour cost changes on the prices paid by BC consumers for a basket of goods and services.

Capital expenditures consist of both labour and non-labour components. The inflation for the labour portion of capital cost is reflected in BC-AWE. The BC-CPI, on the other hand, is a measure of output prince inflation as it reflects the changes in prices of a basket of goods and services consumed by BC consumers some of which are imported. BC-CPI acts as a proxy for inflation experienced by the non-labour component of O&M and capital costs.

162.4.1 If yes, please explain whether FortisBC adjusted its assessment of the proposed 0 percent X-Factor to reflect the fact that its proposed MRPs exclude the majority of capital from formula spending and, if so, please explain how these adjustments were incorporated in detail. If no adjustments were made, please explain why not.

Response:

An adjustment is already embedded in the proposed zero percent X-Factor and no additional adjustment would be necessary.

As presented in a table provided in response to BCUC IR 1.13.2, the majority of experts in the other jurisdictions have estimated negative industry productivity growth trends in recent years. FortisBC's proposed zero percent X-Factor exceeds these estimates and therefore offsets any impact on industry productivity growth resulting from the capital treated outside the MRP formula. Further, although not derived from formulas, most of FEI's and FBC's forecast capital expenditures are still subject to incentives as any variance between the forecast and actual incurred costs remain subject to the earnings sharing mechanism. This important property of the proposed MRPs can provide assurance that the Companies' will not solely focus on O&M efficiencies at the expense of capital.

162.5 Please explain if FEI and FBC included capital costs in the assessment of each utility's real cost of inflation.

Response:

FortisBC assumes that the question is asking whether consideration was given to adjusting the inflation factor for fewer capital costs being included in the indexing formulas.

FortisBC is proposing to use the same (FEI and FBC aggregated) inflation factor that the BCUC approved under the Current PBR Plans. FortisBC believes that there is no need to adjust the inflation factor as the Utilities' aggregate inflation for capital expenditures and O&M expenditures are not significantly different as they have comparable levels of labour and non-labour components. The share of labour and non-labour cost items for FortisBC's O&M expenses indicates that the composite inflation factor weightings for labour and non-labour used in the Current PBR Plan formulas continue to be appropriate for the MRP indexing formulas.

A breakdown of FEI's, FBC's, and the aggregate O&M expenses into labour and non-labour cost components is provided in the table below. As can be seen, FEI's average actual O&M expenditures between 2014 and 2018 period consists of 51 percent labour and 49 percent non-labour. For FBC, the average actual O&M expenditures between 2014 and 2018 consists of 60 percent labour and 40 percent non-labour. On an aggregate basis, the average is 53 percent labour and 40 percent non-labour, which is close to the proposed shares of 55 percent labour and 45 percent non-labour and not a significant enough departure to warrant a change to the weightings in light of the further discussion below.

Table 1: FortisBC Labour and Non-Labour O&M Expense, 2014-2018 ($ millions)

	2014	2015	2016	2017	2018	Cumulative 2014-2018
FEI Aggregate O&M Expense						
Labour	$ 138.332	$ 133.892	$ 128.610	$ 125.234	$ 142.244	$ 668.312
Non-Labour	119.456	126.142	130.849	134.397	129.468	640.312
Gross O&M	$ 257.788	$ 260.034	$ 259.459	$ 259.631	$ 271.712	$ 1,308.624
Labour	54%	51%	50%	48%	52%	51%
Non-Labour	46%	49%	50%	52%	48%	49%
Gross O&M	100%	100%	100%	100%	100%	100%
FBC Aggregate O&M Expense						
Labour	$ 38.032	$ 35.682	$ 32.959	$ 31.865	$ 34.556	$ 173.094
Non-Labour	21.690	22.103	22.650	23.956	22.799	113.198
Gross O&M	$ 59.722	$ 57.785	$ 55.609	$ 55.821	$ 57.355	$ 286.292
Labour	64%	62%	59%	57%	60%	60%
Non-Labour	36%	38%	41%	43%	40%	40%
Gross O&M	100%	100%	100%	100%	100%	100%
FortisBC Aggregate O&M Expense						
Labour	$ 176.364	$ 169.574	$ 161.569	$ 157.099	$ 176.800	$ 841.406
Non-Labour	141.146	148.245	153.499	158.353	152.267	753.510
Gross O&M	$ 317.510	$ 317.819	$ 315.068	$ 315.452	$ 329.067	$ 1,594.916
Labour	56%	53%	51%	50%	54%	53%
Non-Labour	44%	47%	49%	50%	46%	47%
Gross O&M	100%	100%	100%	100%	100%	100%

In 2018, FortisBC implemented direct intercompany cross charging (replacing the need to invoice between the utilities), with the result that intercompany labour is now included in labour expense instead of non-labour as was previously the case. This change, which is a more accurate reflection of total labour costs to each utility, will lead to an increase in the share of labour of approximately $7 million for the Utilities on a combined basis. Using 2018 O&M Expense as a proxy, an increase of $7 million in labour expense would result in an aggregate labour component of 56 percent for the year [($841.406 + 7.000)/$1.594.916 = 56%].

Considering the share of labour cost in O&M expenditures for FEI and FBC and the expected increases to the labour portion of O&M expenditures in 2019, the 55 percent labour and 45 percent non-labour weighting used in the composite inflation factor is reasonable and, if a change were to be made, an increase to the labour component would be appropriate. Comparison of historical and forecast BC-AWE numbers versus BC-CPI numbers indicates that BC-AWE is on average 30 basis points higher than BC-CPI. Therefore, all else equal, any adjustment to the composite inflation factor would tend to increase the inflation factor.

Further, as far as the forecast capital, the forecasts reflect the Companies' estimated capital cost inflation. As mentioned in the Application, the Companies may update their forecasts in year three of the MRPs for the last two years of the Plans to reflect any capital cost changes not anticipated in the initial forecasts. This will ensure that the Companies' capital expenditure forecasts will track their expected capital cost inflation.

162.5.1 If yes, please explain why the inclusion of capital costs for each of FEI and FBC is appropriate and please provide a revised assessment of each utility's real cost of inflation which excludes capital costs.

Response:

Please refer to the response to BCUC IR 2.162.5.

162.5.2 If no, please explain in detail how FEI and FBC derived the real cost of inflation for each utility. Please explain all inputs and assumptions in detail.

Response:

Please refer to the response to BCUC IR 2.162.5

162.6 Please explain how FEI and FBC's proposal to exclude the majority of capital spending from the proposed indexed formula might impact the determination of a productivity factor for each of FEI and FBC when compared to the Current PBR Plans.

Response:

The capital exclusion discussions in the 2014 PBR proceeding were mainly focused on the incremental capital requested through the CPCN process which is not subject to incentives or the earnings sharing mechanism.

A review of expert testimonies in FEI's and FBC's 2014 PBR proceedings, as well as in other jurisdictions, indicates that there is no established methodology for adjusting the TFP values for the exclusion of incremental capital, and further, that any such adjustment would require regulatory judgement. As such, regulators ordinarily consider the impact of capital exclusion in their overall X-Factor value determination without a specific percentage assigned to this issue.

In the 2014 PBR Decision, the BCUC decided that the issue of CPCN treatment and capital exclusion criteria under PBR would require a separate proceeding and deferred its decision for any calibration to the X-Factor value until that proceeding was completed[5]:

> Accordingly, the Panel will not apply any adjustments at this time, but directs that this issue be revisited when a further determination on the dollar threshold is made.

Ultimately after reviewing all the evidence in the capital exclusion criteria proceeding, BCUC determined that no adjustment is required[6]:

> There is no persuasive evidence before the Panel regarding what, if any, adjustment should be made to the X-factor for either company. Although ICG argues in favour of an upward calibration, it provides no recommendations supported by evidence as to how that calibration is to be made. The Panel concludes there is no reasonable basis on which it can rely to make an adjustment to the X-factor and therefore, declines to make any adjustment at this time.

FortisBC's review of X-Factor value decisions in other jurisdictions indicates that regulators did not identify any explicit adjustment value to be applied to the computed productivity growth values for excluded capital. Rather, the regulators' final X-Factor determinations were inclusive of any adjustments (including any adjustments needed for capital exclusion) that, in the regulators' judgement, were required.

In the proposed MRPs, unlike the CPCN-related incremental capital, forecast capital remains subject to incentives and the earnings sharing mechanism. Furthermore, under the proposed MRPs, more cost items are subject to incentives and the earnings sharing mechanism. As

---

5 BCUC Decision G-138-14, p.90.
6 BCUC Decision G-120-15, p.18.

discussed in response to BCUC IR 2.162.4.1, this and other factors mitigate the fact that the Proposed MRPs exclude more capital from the formulas compared to the Current PBR Plans.

163.0 Reference: X-FACTOR

Exhibit B-10, BCUC IR 13.2, 13.5, 17.3, 17.5; Exhibit B-1-1, Appendix C4-1; Decision 20414-D-01-2016 (Errata): 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, December 16, 2016

Jurisdictional Analysis

In response to BCUC IR 13.2, FortisBC stated that its "review of expert testimonies and regulators' decisions in other jurisdictions…provided two important insights regarding the X-Factor determination… i. Increased importance of regulatory judgement for X-Factor determination… ii. A downward trend in both utility and interveners' experts computed TFP growth numbers and the corresponding decline in approved X-Factor values."

In response to BCUC IR 13.2, FortisBC provided the following table:

Proceeding	Expert	Evidence date	Retained by	Productivity results	X-Factor proposed	X-Factor approved	Description
Union/EGD Amalco PBR	Dr.Lowry / PEG	May 2018	OEB staff	TFP= -0.23%	0.3%	0.3%	58 T&D NG utilities in U.S. / 1999-2016
	Dr.Makholm / NERA	Nov 2017	Utilities	TFP= 0.54% Adjusted= 0.35%	0.00%		65 utilities, Combination of NG &Elec / 1973-2016
Not Applicable	Dr.Lowry et al. / PEG	Jul 2017	Berkeley Lab/ DOE	TFP range: 0.22% to 0.45%	N/A	N/A	86 Elec and combination of NG& Elec utilities
Alberta 2nd Generation PBR	Dr.Meitzen / Christensen	March 2016	EPCOR	TFP=-1.11 %	-1.11%	0.3%	68-72 utilities, Updated NERA TFP, Avg. of 2000-2014 & 2005-2014
	Drs. Brown & Carpenter / Brattle	May 2016	Utilities	TFP= -0.79%	-0.79%		Updated NERA TFP, 67 utilities, 2000-2014
	Dr.Lowry / PEG	Jun 2016	CCA	TFP= 0.43% & 0.78%	0.63% & 0.98%		88 & 21 utilities, 1997-2014
Hydro Quebec Dist (HQD)	Dr.Lowry / PEG	Jan 2018	AQCIE-CIFQ	TFP range: 0.22% to 0.45%	0.3%	0.3%	Based on Berkeley Lab's study and expert's judgement
	Coyne / CEA	Jan 2018	HQD	-0.75%	-0.5%		The estimate was based on review of TFP results in other jurisdictions, not a standalone TFP study

FortisBC also provided in response to BCUC IR 13.2 the following passage from the Alberta Utilities Commission (AUC) Decision on the second generation PBR:

> The Commission has determined an X factor, using its judgement and expertise in weighing the evidence and in taking into account the multitude of considerations set out above, in particular evidence demonstrating that the TFP growth value cannot with certainty be identified as a single number, but rather, in view of the variability resulting from the assumptions employed, must be considered as falling within a reasonable range of values, between -0.79 and +0.75. The Commission finds that a reasonable X factor for the next generation PBR plans for electric and gas distribution utilities in Alberta, inclusive of a stretch factor, will be 0.3 per cent.

163.1 Please confirm, or explain otherwise, that in the examples provided in the above table, the regulatory bodies utilized some form of expert evidence when determining the approved X-Factors, as indicated by the list of studies provided by FortisBC in the last column of the above table.

Response:

Confirmed. The names of the experts and the type of evidence filed by these experts is provided in the table that is included in the preamble.

The information provided by experts in Quebec is similar to the evidence provided in FortisBC's Jurisdictional Comparison in Appendix C4-2, and generally in response to the first round of information requests in this proceeding. That is, the evidence was solely focused on the evaluation and review of industry TFP growth values and approved X-Factors in other jurisdictions.

163.2 Please explain for each of the jurisdictions provided in the above table if the calculation of the TFP includes capital costs. Please also explain for each jurisdiction if capital costs are subject to the I-X formula and, if so, to what extent.

Response:

Yes. The productivity growth values provided in the table above included both capital and O&M productivity.

As explained in Appendix C4-2 (Jurisdictional Comparison) and on page B-72 of the Application, most plans cover both O&M and capital expenditures while allowing for recovery of certain costs outside the formula as incremental capital expenditures, flow-through, or exogenous cost items. Ontario's custom IR Plan option, however, is often used by utilities with significantly large and highly variable capital plan profiles which are not suitable for formulas. Therefore, the capital expenditures under these plans are often forecast. Further, most plans include some form of incremental capital funding mechanism outside the I-X formulas to accommodate utilities' capital needs for lumpy and significant capital projects during the PBR term. The extent of capital cost subject to formula in these jurisdictions is often comparable to the type of capital expenditures subject to the earnings sharing mechanism in FEI and FBC's proposed MRPs.

In response to BCUC IR 17.5, FortisBC stated the following:

> The list of qualified and experienced productivity experts is limited with five or six experts having an almost total oligopoly on the TFP study market in Canada. If FortisBC had decided to conduct a TFP study, both utilities and interveners would have likely retained one of the experts that has recently filed TFP evidence in other jurisdictions and their evidence would have shown the same range of TFP results estimated by these experts in those jurisdictions.

163.3 Please provide the range of TFP results provided by each of the productivity experts who have recently provided TFP evidence in other jurisdictions and provide the supporting source references.

Response:

The range of TFP results was provided in the response to BCUC IR 1.13.2. For reference, FortisBC has reproduced the table below and added a separate column including the source references, and provided in Attachment 163.3.

Proceeding	Expert	Evidence date	Retained by	Productivity results	X-Factor proposed	X-Factor approved	Description	Source reference
Union/EGD Amalco PBR	Dr.Lowry / PEG	May 2018	OEB staff	TFP= -0.23%	0.3%	0.3%	58 T&D NG utilities in U.S. / 1999-2016	IRM Framework for the Proposed Merger of Enbridge and Union Gas, Revised May 4, 2018, Mark Newton Lowry
	Dr.Makholm/ NERA	Nov 2017	Utilities	TFP= 0.54% Adjusted= 0.35%	0.00%		65 utilities, Combination of NG &Elec / 1973-2016	EB-2017-0307, Expert Report and Direct Testimony Prepared by Jeff D. Makholm, PhD
Not Applicable	Dr.Lowry et al. / PEG	Jul 2017	Berkeley Lab/ DOE	TFP range: 0.22% to 0.45%	N/A	N/A	86 Elec and combination of NG& Elec utilities	State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities, July 2017, Lowry, Makos, Deason, and Schartz
Alberta 2nd Generation PBR	Dr.Meitzen / Christensen	March 2016	EPCOR	TFP=-1.11 %	-1.11%	0.3%	68-72 utilities, Updated NERA TFP, Avg. of 2000-2014 & 2005-2014	Determination of the Second-Generation X Factor for the UAC Price Cap Plan for Alberta Electric Distribution Companies, March 21, 2016, Mark E. Meitzen, PhD
	Drs. Brown & Carpenter / Brattle	May 2016	Utilities	TFP= -0.79%	-0.79%		Updated NERA TFP, 67 utilities, 2000-2014	Proceeding ID No. 20414, Written Reply Evidence of Brown, Carpenter, May 2016; TFP Calculation Live Spreadsheet
	Dr.Lowry / PEG	Jun 2016	CCA	TFP= 0.43% & 0.78%	0.63% & 0.98%		88 & 21 utilities, 1997-2014	PEG Reply Evidence, Revised June 22, 2016, Lowry, Hovde
Hydro Quebec Dist (HQD)	Dr.Lowry / PEG	Jan 2018	AQCIE-CIFQ	TFP range: 0.22% to 0.45%	0.3%	0.3%	Based on Berkeley Lab's study and expert's judgement	MRI Design for Hydro-Quebec Distribution, Errata January 11, 2018, Lowry, Makos
	Coyne / CEA	Jan 2018	HQD	-0.75%	-0.5%		The estimate was based on review of TFP results in other jurisdictions, not a standalone TFP study	Performance Based Regulation: Recommended X Factor, Hydro-Quebec Distribution, January 5, 2018, Concentric Energy Advisors

As part of the overall evidence and information requests filed in a proceeding, experts may provide various TFP values for different scenarios; however, the ranges provided in the table above are the final numbers computed and proposed by the experts in these jursdictions.

As can be seen, the TFP growth numbers calculated/proposed by experts range from negative productivity growth of -1.11 percent to positive productivity growth of +0.78 percent.

The AUC's final decision did not give any weight to Dr. Meitzen's -1.11 percent and Dr. Lowry's +0.78 percent TFP growth values. Excluding these numbers, the TFP growth values calculated and proposed by experts narrow down to -0.79 percent to +0.45 percent while the approved X-Factor values in all three jurisdictions are set at a uniform value of +0.3 percent for HQD, Union Gas/Enbridge Gas Distribution Amalco and Alberta's electric and natural gas utilities.

163.4 Please explain in detail whether FortisBC considers the range of TFP growth results generated by the experts in other jurisdictions, as described in the above preamble, to be reasonable. In particular, please explain whether FortisBC considers the TFP ranges to be a reasonable basis from which the BCUC may apply a judgement-based approach to determining an X-Factor for FEI and FBC.

Response:

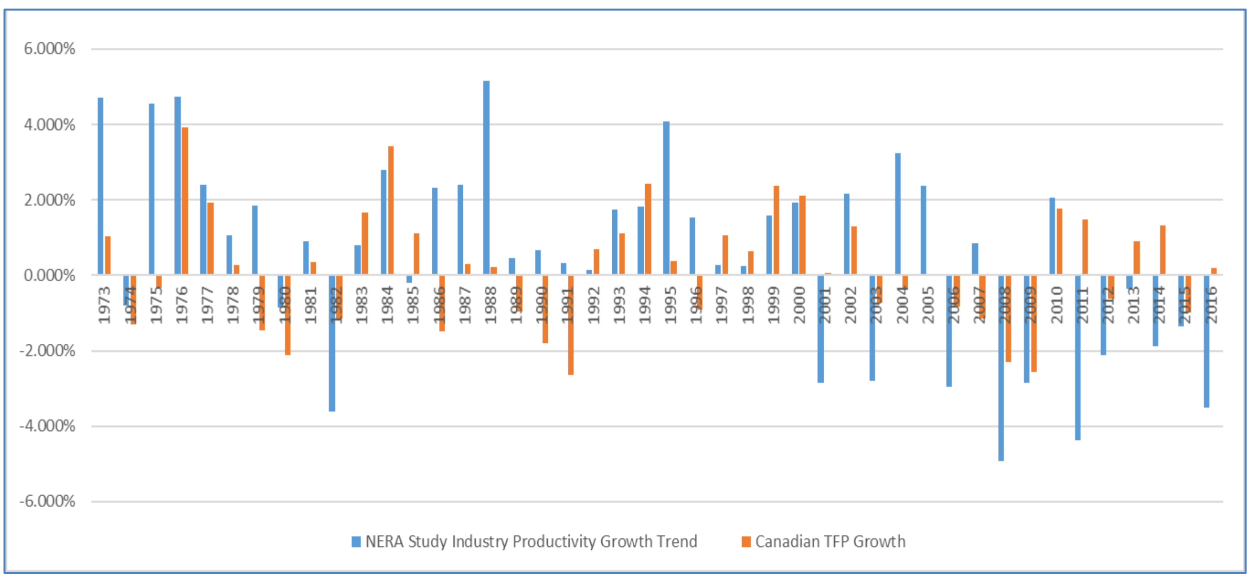
FortisBC believes that it would be reasonable for the BCUC to assume that if utilities and interveners had retained the services of productivity experts, the proposed TFP growth values by these experts would have been within the -1.11 percent to 0.78 percent range as provided in table in response to BCUC IR 13.2. However, FortisBC does not believe the upper bound of the range is reasonable due to the downward trend in productivity in recent years. Below FortisBC first discusses the the range adopted by the AUC in its 2016 PBR decision and then how the reasonable range for TFP factors is negative given the declining trend in industry productivity.

AUC's adopted range and reasoning

In the case of Alberta, the AUC considered a range of -0.79 percent and +0.75 percent. The -0.79 percent was based on the Brattle Group's proposed industry TFP growth value which was calculated based on an updated NERA model (Dr. Makholm's model that was developed in the AUC's first generation PBR proceeding) for 67 utilities for 2000-2014 period while the +0.75 percent was based on the same model for the longest period available (1972-2014) which gives less weight to the recent negative productivity trends. In its decision, the AUC acknowledged that "the only consistent time periods for comparison of all the TFP numbers is 15-17 years"[7]. However, since the longest available time period best reflects the long-term TFP growth, the AUC decided to apply "*some weight on the longest-term TFP growth results presented in evidence, namely, the approximately +0.75 value determined for the 1972-2014 period*"[8]. This was set as the upper limit of acceptable TFP results by the AUC.

In the Union Gas and Enbridge Gas Distribution incentive rate-setting proceeding, Dr. Makholm of NERA, the original creator of the AUC model that was used to calculate both of the above mentioned numbers, updated his model up to 2016. The updated model decreased the upper bound of the range to 0.54 percent[9].

The NERA study for the industry TFP values over the entire 44 years of data generates an average productivity growth value of +0.54 percent which, when adjusted for average Canadian economy-wide TFP growth of +0.19 over the same period, results in an X-Factor of +0.35 percent[10]. The figure below illustrates the calculated industry and Canadian economy-wide industry growth over the time.



Dr. Makholm explained this issue as follows[11]:

---

7 AUC Decision 20414-D01-2016, P.42, para 161.
8 AUC Decision 20414-D01-2016, P.42, para 161.
9 There are minor differences between Dr.Makholm's updated model in this study and the one updated in AUC's proceeding but the models are close enough to compare the results.
10 0.54% - 0.19%
11 NERA Study (Nov 2017); "Expert Report and Direct Testimony by Jeff Makholm", pp.32-33

> My recommendation rests on the rapidity of the falling measured TFP growth for that group of distribution utilities, since the last time I performed that analysis in 2010- supported by my analysis of consistent EGD and Union data.
>
> For the TFP growth study in that case, I computed average annual TFP growth for the entire population of US distribution companies to be 0.96 percent over the 37 years from 1973 to 2009. Lengthening the period by seven years to 2016, with no methodological changes, reduced the average TFP growth of 0.54 percent—or a growth rate relative to the Canadian economy of 0.35 percent—a precipitous drop that is evident in Figure 3. Because of that decline, where the past six years show negative TFP growth (as do 8 of the last 10 years), I cannot conclude that there is a prospect for any reliable positive TFP growth for that group in the next 10 years—either by themselves or in relation to the Canadian economy as a whole.

Therefore, FortisBC submits that the upper limit used by the AUC based on the updated Dr. Makhom model (updated up to 2014) has reduced to approximately 0.54[12] when updated up to 2016. However, as discussed below, this positive X-factor is not appropriate given the recent downward trend in industry productivity growth.

FortisBC's assessment of reasonable range for TFP numbers

The X-Factor is the "expected" industry productivity growth during the MRP term while industry productivity growth studies are backward looking in nature. Therefore, it is important to assess the extent to which the historical productivity trend can reflect the "expected" productivity trend during the MRP period. This issue is explained by Dr. Kaufmann[13] as follows:

> Any regulator evaluating an Inflation minus X proposal should want the TFP evidence it is considering to reflect current trends and developments, not ancient history. TFP evidence that incorporates ongoing, fundamental change in the electric utility industry is, therefore, necessary to satisfy regulators' "search for objectivity in RPI minus X regulation," not problematic.

FortisBC therefore examined the overall sensitivity of the TFP growth values to the negative industry productivity trend, using the updated NERA study for electric and a combination of electric and natural gas utilities (filed by Dr. Makholm) as well as PEG's TFP study for natural gas utilities (filed by Dr. Lowry) . These two studies have the most recent data (up to 2016) and were conducted by two of the most well-known and experienced productivity study experts

[12] There are minor differences between Dr.Makholm's model in this study and the one recreated in AUC's proceeding but the two models are close enough to compare the results.

[13] Kaufmann (2019); "The Past and Future of the X Factor in Performance-based Regulation"; Journal of Geopolitics of Energy, Vol 41, Issue 2

recently involved in Canadian regulatory proceedings. Both experts have filed evidence for Canadian regulators, utilities and intervener groups.

The table below provides the average industry productivity trends calculated by the two experts for three periods: 1999-2016 (the longest dataset available in PEG's study), 2005-2016, 2010-2016.

	NERA Study	PEG Study
1999-2016	-0.88%	-0.23%
2005-2016	-1.59%	-0.65%
2010-2016	-1.65%	-0.78%

As can be seen, the industry TFP growth values would range from -0.23 percent to -0.78 percent and -0.88 percent to -1.65 percent for the PEG and NERA studies, respectively. As explained in the response to BCUC IR 2.163.11, evidence suggests that the downward trend in productivity growth is likely to continue during the MRP period. As such, more weight should be given to the recent numbers.

Based on this analysis, FortisBC submits that a reasonable range for the expected industry productivity trend is between -0.23 percent and -1.65 percent with more weight given to the lower (more negative) bound of this range.

163.4.1 As part of the above response, please specifically discuss the reasonableness of the AUC's range of -0.79 to +0.75.

Response:

Please refer to the response to BCUC IR 2.163.4.

163.4.2 If FortisBC does not consider the above-mentioned ranges to be reasonable, please provide a revised range for each of FEI and FBC and provide a detailed rationale for why the proposed ranges are more appropriate.

Response:

Please refer to the response to BCUC IR 2.163.4.

In response to BCUC IR 17.3, FortisBC stated the following:

> FortisBC's proposal to not recommend an X-Factor value for its index-based formulas can be expressed as proposing an implied productivity factor of zero percent. A zero percent X-Factor is higher than what the majority of utility experts in other jurisdictions have proposed and is not at odds with what has been approved by regulators in other jurisdictions. This can be seen from the table provided in BCUC IR 1.13.2, which shows that the majority of utilities in Canada have proposed negative productivity factors. Further, the OEB has approved zero percent productivity factors with additional 0.0 to 0.6 percent stretch factors for the case of electric utilities and 0.3 percent stretch factor for Union Gas and Enbridge Gas Distribution amalgamated price cap plans.

163.5 Please confirm, or explain otherwise, that regulators in other jurisdictions have not approved the negative X-Factors proposed by the utility experts.

Response:

Despite the negative industry productivity growth results in recent years, Canadian regulators have been resistant to the idea of negative X-Factor values and have not approved X-Factor values lower than zero percent. However, outside Canada some regulators have approved negative X-Factors. One recent example relates to the 2017 Eversource Case in Massachusetts where the regulator approved a final X-Factor value of -1.56 percent (reduced to -1.31 percent when inflation goes above 2 percent). The TFP trends estimated by productivity experts and regulator's approved values in recent Massachusetts proceedings are provided in the table below.

Proceeding	Expert	Evidence date	Retained by	Productivity results	X-Factor proposed	X-Factor approved	Description

Proceeding	Expert	Evidence date	Retained by	Productivity results	X-Factor proposed	X-Factor approved	Description
Eversource Revenue Requirement (DPU 17-05)	Dr.Meitzen / Christensen	Jan 2017	Utility	TFP= -0.46% & -0.41% Adjusted TFPs[14] = -2.56% & -2.47%	- 2.56%	-1.56% (-1.31% when the inflation goes above 2 percent)	67 Electric Distributors and 17 NE Electric Distributors in U.S. / 2001-2015
Massachusetts Electric Revenue Requirement (DPU 18-150)	Dr.Lowry / PEG	Mar 2019	Attorney General	TFP= 0.33% Adjusted TFP = -0.71% --------- Kahn approach X-factor range: - 0.41% to - 1.13%	-0.6 % Adj TFP + 0.4 % Stretch factor = -0.2%	Waiting for decision	Dr.Lwory used two approaches: (i) TFP approach for electric distributors in U.S. (1997-2017) (ii) Kahn Approach[15] for 1997-2017, 2002-2017 and 2007-2017
	Dr.Meitzen / Christensen	Nov 2018	Utility	TFPs: - 0.30%, - 0.34%, -0.34 and - 0.69% Adjusted TFPs: -1.72%, -2.22%, -2.41% and -2.27%	-1.72% Adjusted TFP + 0.4% Stretch factor if inflation exceeds 2%		Sample of overall US Electric utilities and North East U.S. Utilities calculated using two different approaches (2002-2017)

14 In Massachusetts, the I-Factor is GDP-PI (an output price index) and the TFP results are adjusted for the variance between economy-wide inflation and industry input price and variance between industry productivity and economy-wide productivity. This is different from the approach in Canadian jurisdictions where the differential between industry input price and economy-wide inflation is often not considered.

15 The approach used by Dr.Overcast in the Companies' 2014 PBR proceeding

163.5.1 If confirmed, please discuss why these negative X-Factors were not approved by regulators in other jurisdictions, and why regulators chose to instead set an X-Factor at or above zero.

Response:

The following are the general reasons provided by Canadian regulators that did not adopt a negative X-Factor value:

Alberta

The AUC agreed with the utilities' experts that PBR incentives are not affected by the choice of a particular value of the X-Factor whether it is negative, zero, or positive and that the value of the X-Factor can be negative. However, the AUC also noted that a negative X-Factor amount decreases the appeal of a formula approach to customers and though any industry may experience periods of negative productivity (meaning periods in which more inputs are used to produce the same outputs or less output is produced using the same inputs), it is not clear why such an event should persist over time.

Ultimately based on the evidence and considering all the variability caused by different assumptions applied to the TFP studies, the AUC used its judgement to set an X-Factor of +0.3 percent, inclusive of any stretch factor, for both electric and natural gas utilities.

Ontario

As explained in the response to BCUC IR 1.13.2, the OEB's decision in the Enbridge Gas Distribution and Union Gas incentive rate-setting proceeding did not comment on the merits of the methodologies adopted by experts, but rather, accepted the applicants' proposal for a base productivity factor of zero percent since both experts proposed the same amount. Therefore, instead of explaining the OEB's reasoning, this section will discuss the experts' reasoning for not adopting their computed TFP numbers and instead proposing a zero percent productivity factor.

Dr. Makholm's TFP study for 1973-2016 produced a TFP growth number of 0.54 percent but he proposed a zero percent X-Factor. He explained his decision to do so as follows[16]:

> I do not recommend splitting the period of measurement. But the analysis since 2009, when I last performed such TFP computations, shows a definitive trend. Given the long term changes in the energy utility industry since the early 1970s, including the unbundling of distribution services and competition in energy supply, there may well be trends behind such TFP results, for the industry as a

[16] NERA Study (Nov 2017); "Expert Report and Direct Testimony by Jeff Makholm", pp 29-30.

> whole or for particular objective regions of the United States that disinterested researchers have not yet discovered. I do not hold the opinion that electricity restructuring, as such, necessarily led to a change in the TFP growth exhibited by the distribution portion of the industry. I also do not have an objective explanation for that apparent trend or knowledge of any scholarly analysis that would do so.
>
> But that trend does inform my conclusions in this case—which is to recommend a simple average TFP growth estimate as applicable to EGD and Union in this case would be unwise. The trend, in a type of analysis that has proven highly credible and has been relied upon in the past, is too apparent for that. Whereas any split in the data would produce a negative TFP growth figure, I determine that it is better to conclude that I cannot definitively reason that there is a prospect for any reliable positive TFP growth for that group of firms for the rebasing period applicable to EGD and Union.

On the other hand, Dr. Lowry's TFP study produced a -0.23 percent result, but he proposed a zero percent based productivity factor. He explained his decision to do so as follows[17]:

> Increased OM&A expenses and capex seem to have partly resulted from the distributors' response to regulations that were enacted by the US Pipeline and Hazardous Materials Safety Administration ("PHMSA") and by a high-profile gas transmission pipeline explosion in San Bruno, California. The new regulations mandated that distributors have and implement a Distribution Integrity Management Program ("DIMP") with a written integrity management plan by August 2, 2011.
>
> OM&A expenses of gas utilities increased due in part to the cost of developing and implementing the DIMP and addressing the findings of major incident investigations. Some of the increased OM&A expenses would be temporary. For example, in the aftermath of the San Bruno incident, Pacific Gas and Electric requested nearly $400 million for various activities related to upgrading their transmission pipeline records. OM&A expenses may also increase if a distributor finds that it needs to implement or alter its leak management program to meet the PHMSA's requirements.
>
> Capex increased in subsequent years, as distributors relied on the data compiled from implementing the DIMP and addressing the findings of major incident investigations to identify assets needing replacement due to a high risk of failure.

[17] PEG (May, 2018); "IRM Framework for the Proposed Merger of Enbridge and Union Gas", pp 40-42

Quebec

The Regie's final decision on X-Factor determination affirmed that the industry productivity growth is experiencing a downward trend in recent years and that in many jurisdictions, this issue has resulted in approval of lower X-Factor values. However, in the Regie's opinion this negative productivity trend does not necessarily require a negative X-Factor and that Concentric's approach of relying on a simple arithmetic average of recent productivity values without considering the regulators' decisions and the context of these studies is insufficient. In particular, the Regie affirmed that regulators' final decisions in these proceedings are essential for a credible recommendation as a regulator must examine all the evidence before reaching to its final X-Factor value determination.

The Regie's opinion was that, despite the recent downward trend in industry productivity of North American utilities, HQD is able to achieve additional efficiency gains. For these reasons, the Regie did not give any weight to Concentric's proposal for a negative X-Factor value.

163.5.2 If confirmed, please discuss to what extent the other jurisdictions' determinations that a positive X-Factor is appropriate should be factored into the BCUC's determination on the appropriate X-Factor for FEI and FBC.

Response:

FortisBC is proposing a zero percent X-Factor and not a negative X-Factor. Regulators in other jurisdictions have also approved the zero percent base productivity factor and the additional 0.3 percent stretch factor (either expressed separately or included as part of the X-Factor) which is the major reason behind positive X-factor values in other jurisdictions.

FortisBC believes that experts' computed TFP growth values, their proposed X-Factor values, and regulators' final approved X-Factor values can all be factored into the BCUC's determination on the appropriate X-Factor for FEI and FBC. However, as discussed in the response to BCUC IR 1.17.4, the BCUC should also consider the specific circumstances of utilities in other jurisdictions that may have warranted higher X-Factor values in those jurisdictions. This is particularly important for stretch factor determinations (whether determined inclusive of X-Factor value or determined separately) since they are more utility specific, unlike industry productivity growth.

163.6 Please discuss FortisBC's view on the inclusion of a separate stretch factor in those jurisdictions where a productivity factor of zero was approved.

Response:

As stated in the response to BCUC IR 1.17.4, the amalgamation of Enbridge Gas Distribution and Union Gas will provide the amalgamated utility with additional cost saving opportunities that are not available to either FEI or FBC. These additional opportunities may justify the higher 0.3 percent stretch factor for the amalgamated utility.

With regard to the OEB's stretch factor values for electric distributors, and as explained in response to BCOAPO IR 1.20.1, the OEB determined that distributors shall be assigned to one of the five cohorts based on their cost evaluation ranking. The stretch factor values are set based on the OEB's judgement. The stretch factor assignments, however, are based on the results of a statistical cost benchmarking study designed to make inferences on individual distributors' cost efficiency. These total cost benchmarking studies are updated each year and the distributors are assigned a stretch factor based on the results of the study in that year. As such, the stretch factor for each utility can change from year to year depending on the benchmarking study results.

The approach adopted by the OEB for electric utilities may be reasonable given the large number of similarly-situated distributors regulated by the same regulator in that jurisdiction, but cannot be applied to jurisdictions like BC. In contrast to Ontario, BC has a much lower number of utilities where BC Hydro and FEI serve the majority of the electric and natural gas customers, respectively. Nevertheless, and as explained in response to BCUC IR 1.16.1, Concentric's unit cost and service quality benchmarking analysis can be used by the BCUC to compare FEI's and FBC's relative efficiency against their peers. The benchmarking results indicate that an additional "efficiency factor" is not warranted.

163.7 Please discuss in detail the reasonableness of incorporating a stretch factor for each of FEI and FBC as part of each utility's X-Factor. If the BCUC were to determine a stretch factor should be included, what factors should the BCUC consider when determining the quantum of the stretch factor for each of FEI and FBC? Please discuss.

Response:

FortisBC does not believe that a stretch factor for either FEI or FBC would be reasonable.

The stretch factor value can be used to differentiate between the productivity opportunities that may exist for less efficient and more efficient firms. Some experts argue that the stretch factor shall ordinarily be applied to first generation MRPs or when a utility has been operating for a few years under cost of service regulation and is transitioning back to a multi-year rate plan. This view was advanced by Dr. Makholm and intervener groups in Alberta's first generation PBR and supported by AUC in its 2012-237 PBR decision[18]:

> The Commission agrees with the rationale for a stretch factor put forward by EPCOR, NERA, AltaGas, the UCA and Calgary. The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.

This rationale for a stretch factor does not apply to FEI and FBC given that they are not transitioning from cost of service regulation.

Other experts comment that irrespective of a company's historical experience with incentive rate-setting, the need for a stretch factor shall be determined based on some form of efficiency benchmarking analysis. In this context, Concentric's benchmarking analysis can be used by the BCUC to assess the need for any stretch factor. As discussed in response to BCUC IR 1.16.1, the benchmarking results indicate that a stretch factor is not warranted.

163.8 Under a hypothetical scenario where FEI and FBC were directed to include an X-Factor of 0.5 percent as part of each utility's I-X formula, please provide the annual and cumulative impact on formula O&M and formula growth capital (for FEI). Please provide all supporting calculations.

<u>Response:</u>

FortisBC has not produced a forecast of average customers nor gross customer additions for the term of the MRPs. The Application sets out the framework and mechanism by which inflation-indexed O&M and Growth Capital (for FEI only) will escalate Base O&M and Growth Capital over the term of the MRPs. The impact of a 0.5 percent X factor on O&M and FEI's Growth Capital will change based on the actual gross customer additions and actual number of average customers.

[18] AUC Decision 2012-237, p. 100

To be responsive, FortisBC has provided a hypothetical scenario using the customer growth and inflation factor assumptions outlined below.

Inflation Factor of 2 percent per year

Average Customer Growth of 1 percent per year

FEI Gross Customer Additions 17,750 per year

The following four tables set out O&M, and Growth Capital for FEI, with a zero percent X-Factor and with a 0.5 percent X-Factor and the difference between the hypothetical funding amounts over the term of the MRP. The first table is a summary of the three detailed tables.

Table 1: Summary of Funding Differences

Funding Difference from 0.5 % X-Factor ($000)						
	2020	2021	2022	2023	2024	Total
FEI O&M	(1,294)	(2,660)	(4,100)	(5,618)	(7,217)	(20,888)
FBC O&M	(291)	(599)	(923)	(1,265)	(1,624)	(4,702)
FEI Growth Capital	(338)	(688)	(1,051)	(1,425)	(1,813)	(5,315)

Table 2: FEI Gross O&M

Line	Particulars	Reference	Base	MRP years--> 2020	2021	2022	2023	2024	Total
	FEI - Zero percent X Factor - O&M								
1	I Factor	Assumption		2.00%	2.00%	2.00%	2.00%	2.00%	
2	X Factor			0.00%	0.00%	0.00%	0.00%	0.00%	
3	Net Inflation Factor	Line 1 - Line 2		2.00%	2.00%	2.00%	2.00%	2.00%	
4									
5	Average Customer Growth	Assumption		1.0%	1.0%	1.0%	1.0%	1.0%	
6									
7	O&M per customer	Prior Yr Line 7 x Line (1 + Line 3)	250	255	260	265	271	276	
8	Forecast of AC	Prior Yr Line 9 x Line (1 + Line 5)	1,024,962	1,035,212	1,045,564	1,056,019	1,066,580	1,077,245	
9									
10	*Gross O&M ($000)*	*Line 7 x Line 8 / 1000*		*263,979*	*271,951*	*280,164*	*288,625*	*297,341*	*1,402,061*
11									
12	**FEI - 0.5 percent X Factor - O&M**								
13	I Factor	Assumption		2.00%	2.00%	2.00%	2.00%	2.00%	
14	X Factor			0.50%	0.50%	0.50%	0.50%	0.50%	
15	Net Inflation Factor	Line 13 - Line 14		1.50%	1.50%	1.50%	1.50%	1.50%	
16									
17	Average Customer Growth	Assumption		1.0%	1.0%	1.0%	1.0%	1.0%	
18									
19	O&M per customer	Prior Yr Line 19 x Line (1 + Line 15)	250	254	258	261	265	269	
20	Forecast of AC	Prior Yr Line 21 x Line (1 + Line 17)	1,024,962	1,035,212	1,045,564	1,056,019	1,066,580	1,077,245	
21									
22	*Gross O&M ($000)*	*Line 19 x Line 20 / 1000*		*262,685*	*269,291*	*276,064*	*283,007*	*290,125*	*1,381,173*
23									
24	***Difference ($000)***	**Line 22 - Line 10**		***(1,294)***	***(2,660)***	***(4,100)***	***(5,618)***	***(7,217)***	***(20,888)***

Table 3: FBC Gross O&M

Line	Particulars	Reference	Base	MRP years--> 2020	2021	2022	2023	2024	Total
	FBC - Zero percent X Factor - O&M								
1	I Factor	Assumption		2.00%	2.00%	2.00%	2.00%	2.00%	
2	X Factor			0.00%	0.00%	0.00%	0.00%	0.00%	
3	Net Inflation Factor	Line 1 - Line 2		2.00%	2.00%	2.00%	2.00%	2.00%	
4									
5	Average Customer Growth	Assumption		1.0%	1.0%	1.0%	1.0%	1.0%	
6									
7	O&M per customer	Prior Yr Line 7 x Line (1 + Line 3)	416	424	433	441	450	459	
8	Forecast of AC	Prior Yr Line 9 x Line (1 + Line 5)	138,649	140,035	141,436	142,850	144,279	145,721	
9									
10	*Gross O&M ($000)*	*Line 7 x Line 8 / 1000*		*59,420*	*61,214*	*63,063*	*64,968*	*66,930*	*315,594*
11									
12	**FBC - 0.5 percent X Factor - O&M**								
13	I Factor	Assumption		2.00%	2.00%	2.00%	2.00%	2.00%	
14	X Factor			0.50%	0.50%	0.50%	0.50%	0.50%	
15	Net Inflation Factor	Line 13 - Line 14		1.50%	1.50%	1.50%	1.50%	1.50%	
16									
17	Average Customer Growth	Assumption		1.0%	1.0%	1.0%	1.0%	1.0%	
18									
19	O&M per customer	Prior Yr Line 19 x Line (1 + Line 15)	416	422	429	435	442	448	
20	Forecast of AC	Prior Yr Line 21 x Line (1 + Line 17)	138,649	140,035	141,436	142,850	144,279	145,721	
21									
22	*Gross O&M ($000)*	*Line 19 x Line 20 / 1000*		*59,129*	*60,616*	*62,140*	*63,703*	*65,305*	*310,892*
23									
24	***Difference ($000)***	**Line 22 - Line 10**		***(291)***	***(599)***	***(923)***	***(1,265)***	***(1,624)***	***(4,702)***

Table 4: FEI Growth Capital

Line	Particulars	Reference	Base	MRP years--> 2020	2021	2022	2023	2024	Total
	FEI - Zero percent X Factor - Growth Capital								
1	I Factor	Assumption		2.00%	2.00%	2.00%	2.00%	2.00%	
2	X Factor			0.00%	0.00%	0.00%	0.00%	0.00%	
3	Net Inflation Factor	Line 1 - Line 2		2.00%	2.00%	2.00%	2.00%	2.00%	
4									
5	Gross Customer Additions	Assumption		17,750	17,750	17,750	17,750	17,750	
6	Capital per GCA	Prior Yr Line 6 x Line (1 + Line 3)	3,811	3,887	3,965	4,044	4,125	4,208	
7									
8	*Growth Capital ($000)*	*Line 5 x Line 6 / 1000*		*68,998*	*70,378*	*71,786*	*73,221*	*74,686*	*359,069*
9									
10	**FEI - 0.5 percent X Factor - Growth Capital**								
11	I Factor	Assumption		2.00%	2.00%	2.00%	2.00%	2.00%	
12	X Factor			0.50%	0.50%	0.50%	0.50%	0.50%	
13	Net Inflation Factor	Line 11 - Line 12		1.50%	1.50%	1.50%	1.50%	1.50%	
14									
15	Gross Customer Additions	Assumption		17,750	17,750	17,750	17,750	17,750	
16	Capital per GCA	Prior Yr Line 16 x Line (1 + Line 13)	3,811	3,868	3,926	3,985	4,045	4,106	
17									
18	*Growth Capital ($000)*	*Line 15 x Line 16 / 1000*		*68,660*	*69,690*	*70,735*	*71,796*	*72,873*	*353,754*
19									
20	***Difference ($000)***	**Line 18 - Line 8**		***(338)***	***(688)***	***(1,051)***	***(1,425)***	***(1,813)***	***(5,315)***

In response to BCUC IR 13.5, FortisBC discussed the applicability of the article provided in Appendix C4-1 to the Application titled "The rise and decline of the X factor in performance-based electricity regulation," including the following:

> As part of the discussion around the changing nature of utility investments, the article points out that many new investments and operating expenses are non-revenue generating activities where increased costs do not lead to higher output levels…This issue is the main reason for declining industry productivity growth in the last 10 to 15 years…
>
> FBC, for instance, has incurred many of the same costs mentioned as examples in the article. FBC's investments in automated metering, cyber security, and information technology and data management platforms are all within this category.
>
> FEI also has many similar investment needs in areas such as cybersecurity or data management as well as the need for incremental expenditures related to safety and environmental regulations, customer and Indigenous engagement activities, and large sustainment projects that have no impact on FEI's traditional measured outputs.

163.9 Please explain to what extent the lack of capital inclusion in FEI (other than growth capital) and FBC's proposed formula spending impacts the relevancy of the article's discussions regarding the declining X-Factor.

Response:

FortisBC's proposal to forecast capital costs (other than FEI's Growth Capital) does not make the article any less relevant. Indeed, FortisBC's multi-faceted approach to the determination of capital and O&M expenditures is a response to the issues raised in this article which makes the article even more relevant. FortisBC further notes that, as per the preamble, the costs associated with non-revenue generating activities, where increased costs do not lead to higher output levels and therefore declining productivity growth values, also include operating expenses.

For further discussion of capital exclusions and the proposed X-Factor, please refer to the responses to BCUC IRs 2.162.4.1 and 2.162.6.

163.10 Please confirm, or explain otherwise, that a number of the investment needs identified in the above preamble, such as cybersecurity and customer and

Indigenous engagement activities, have been identified by FortisBC as requiring incremental O&M funding and approval of additional O&M amounts have been requested as part of the proposed Base 2019 O&M.

Response:

Confirmed.

163.10.1 Please explain to what extent the requested incremental funding to the Base O&M should be considered when assessing the appropriateness of FEI and FBC's requested 0 percent X-Factor.

Response:

The incremental funding to the Base O&M should not be considered when assessing the appropriateness of the X Factor.

As explained in the response to BCUC IR 1.13.2, the main purpose of the X-factor is to adjust the inflation factor so that the indexing formulas produce a reasonable level of anticipated cost growth. Thus, most indexing plans have approached the issue by comparing trends in specific inflation indices to the utility industry's total cost trends. This analysis identifies how the utility industry's costs have changed relative to inflation.

The base year is the starting point from which future productivity based revenue adjustment are applied and should reflect the current level of required resources. If the base year is underestimated, revenues at the outset of MRP are less than total cost. Since the MRP formula is designed to reflect expected cost growth it follows that the company revenues may be below the expected cost over the term of the MRP if the base year is underestimated.

In paragraph 167 of Decision 20414-D01-2016 (Errata), the AUC stated the following:

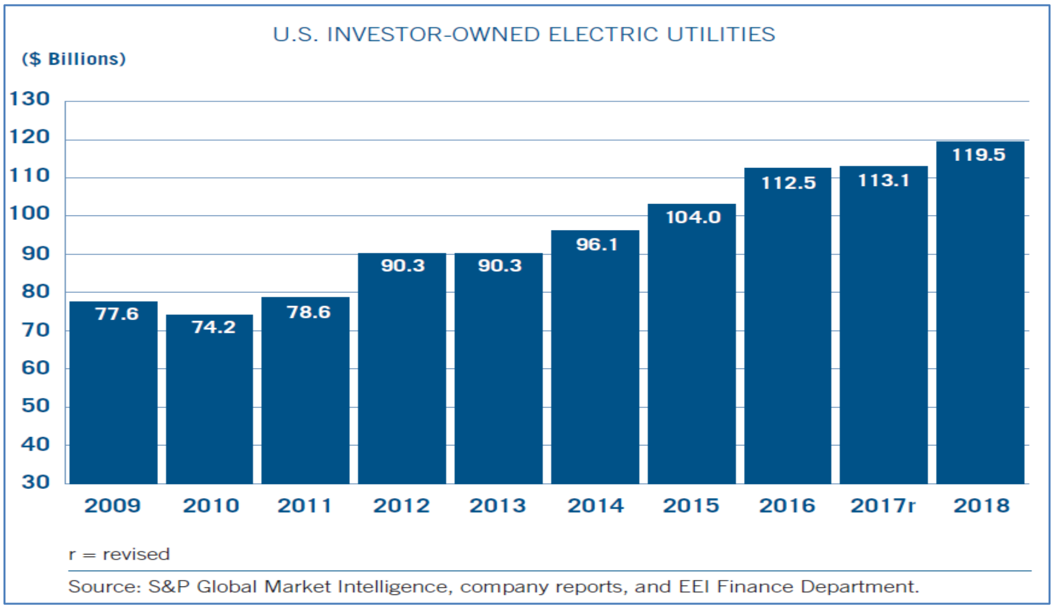
The Commission is aware that the value of the X factor can be negative, and there was considerable discussion of this issue in Decision 2012-237, as well as in this proceeding. However, given the manner in which TFP growth is calculated in the studies in evidence, negative values of TFP growth mean that more inputs are used to produce the same amount of output or that less output is produced using the same amounts of inputs. Any industry, including the electricity (and gas) distribution industry, may have periods when this phenomenon is observed, but it is not clear why such a phenomenon should persist over a long period. In the Brattle and Meitzen studies, TFP growth is negative in nine of the last 15 years, and more particularly, in seven of the last nine years. Yet, many of the utilities in the current proceeding went to great lengths to explain some of the efficiency-improving procedures (productivity improvements) they have adopted, and there is no reason to expect that at least some of this type of behaviour would not be observed in many of the U.S. firms in the sample used in the TFP growth calculations examined here. The findings suggest that there may be some concerns with the calculation of TFP growth using only volume as the measure of output, whatever the time period used, especially when combined with the particular data and input growth assumptions utilized in the Brattle and Meitzen studies, with the sample of U.S. electric distribution utilities. The evidence is not conclusive, but it does cause the Commission to be mindful of the extent to which the results differ with different choices of assumptions, including output measures.

163.11 Does FortisBC agree with the AUC that "…there is no reason to expect that at least some of this type of behaviour would not be observed in many of the U.S. firms in the sample used…"? Please explain why or why not.

Response:

FortisBC does not have any reason to believe that North American utilities would not strive to adopt some sort of efficiency-improvement procedures. However, that is not a reason to suggest that productivity levels will increase. The North American utility industry is in the midst of an unprecedented technological and climate policy driven transition that prompted utilities to invest record amounts in a broad spectrum of activities/projects. The following chart from Edison Electric Institute (EEI) provides the actual capital expenditures related to investor-owned U.S. based electric utilities between 2009 and 2018. As can be seen, the total capital funding has increased from $77 billion in 2009 to close to $120 billion in 2018. This significant funding trend coincides with the declining productivity growth values computed by experts.

Figure 1: Capital Funding by U.S. investor-owned electric utilities (2009-2018)[19]



EEI's description of the primary drivers of increasing transmission and distribution investments is as follows[20]:

> The survey shows that most of the projected investment will fund expansion of the transmission network and construction of new lines that connect new energy resources to the grid, enabling an evolving energy mix. The remainder is focused primarily on replacement of existing transmission lines and system improvements such as hardening, physical and cyber security measures and the adoption of smart technologies that improve and maintain the grid's resilience …
>
> Distribution investment is driven primarily by the continuous need to replace end-of-life assets, serve new load, preserve reliability, improve system resiliency and restoration capabilities, and increasingly, to accommodate distributed resources.

The following information has been redacted for the public version of these IR responses because it is part of a third-party copyrighted report and the provider has requested that the information be filed confidentially so it is not made available in the public domain. As such, FEI is requesting that this information be filed on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. Interveners may obtain a copy of the confidential information upon executing the BCUC's Confidentiality Declaration and Undertaking form.

[19] Edison Electric Institute; "2018 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry", page 14.
[20] Ibid, pp 52-53.

[redacted]

21 [redacted]
22

[redacted]

23 [redacted]
24

FortisBC acknowledges that this extraordinary investment cycle will eventually moderate at some time in the future; however, there is no evidence to suggest that this slow down will happen during the MRP term. There is ample evidence to suggest that utility industry transition will continue as more jurisdictions apply more stringent climate policies and as utilities continue to adopt technological solutions to address these and other challenges and opportunities.

Further, these investments may not lend themselves over time to additional sales/outputs growth for utilities. This is different from competitive industries which typically undertake new investment with the expectation that it will fund the output growth. In fact, public policy is often focused on further diminshing utility output at the same time that costs increase. Both of these factors affect the industry productivity growth and threrefore there is no reason to believe that this policy direction will change substanitally in the immediate future.

163.11.1 If FortisBC agrees with the above, please explain if the above findings from the AUC can be interpreted as the TFP growth factor for the US firms in the sample is expected to increase over time, and how FortisBC's proposed productivity factor of zero percent relates to these findings.

Response:

Please refer to the response to BCUC IR 2.163.11.

164.0 Reference: X-FACTOR

Exhibit B-10, BCUC IR 6.3.1, 13.2, 15.14.1, 22.1; Exhibit B-7, CEC IR 19.1; Exhibit B-5, British Columbia Old Age Pensioners' Organization et al. (BCOAPO) IR 17.1, 17.2; Exhibit B-1, pp. C-11 – C-12; Exhibit B-1-1, Appendix C2

Productivity Gains

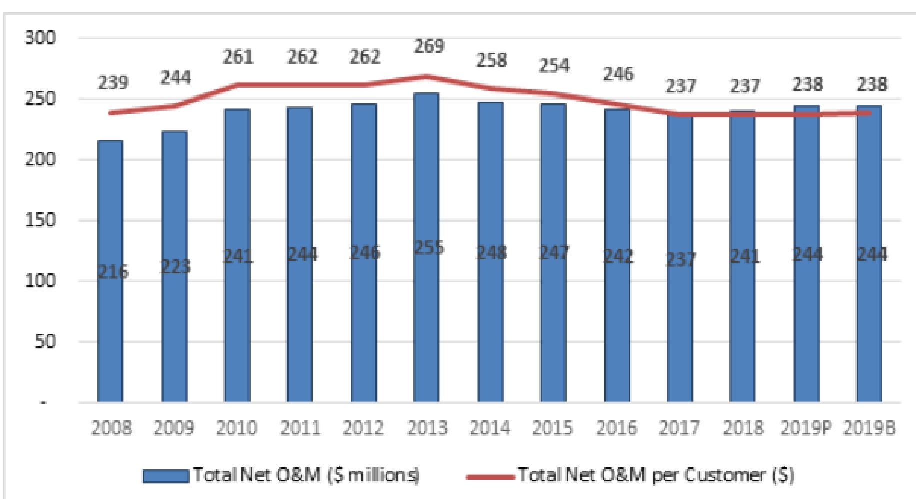
In response to BCUC IR 6.3.1, FortisBC stated: "The achieved O&M savings and the declining O&M unit costs, both on a standalone and on a relative basis, are an indication of effective management and reflect FEI's efforts to find new efficiencies and improve its operations during the PBR term."

In response to BCUC IR 13.2, FortisBC stated the following:

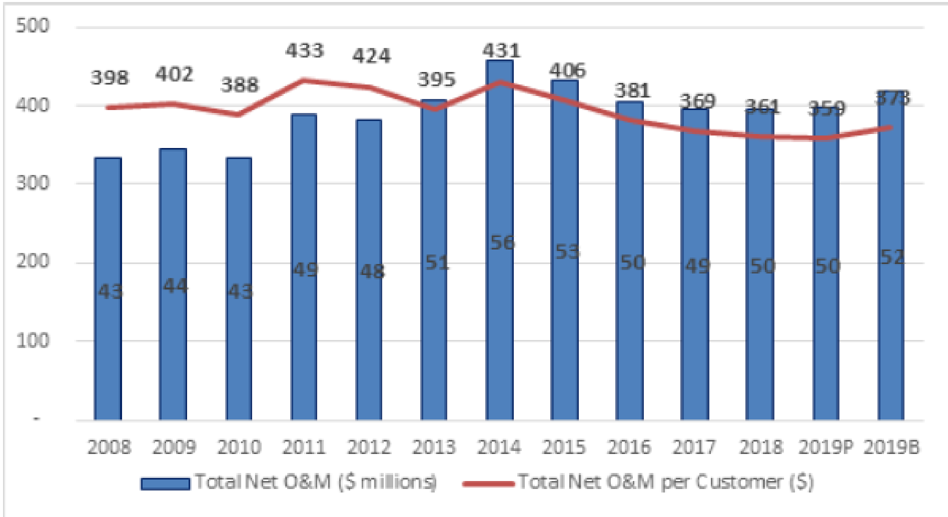
> As a result of years of O&M savings being achieved under successive PBR terms, the opportunities for additional O&M cost reductions have been steadily diminishing and there is now limited potential for future productivity gains. In other words, there is no low-hanging fruit left to pick.

In response to CEC IR 19.1, FortisBC provided the following historical graphs showing FEI and FBC's historical O&M:

FEI – Net O&M in Real Dollars:



FBC – Net O&M in Real Dollars:



164.1 Please clarify FortisBC's statement in response to BCUC IR 13.2 regarding the utilities being under "successive" PBR terms, given that both FEI and FBC were in a period of cost of service prior to the Current PBR Plans.

Response:

FortisBC's statement in the response to BCUC IR 1.13.2 relates to the Companies' proposed zero percent X-Factor value for the 2020-2024 MRP period and references that the 2014-2019 PBR period will be immediately followed by the 2020-2024 MRP.

FBC has been operating under some form of PBR framework for 20 of the last 24 years while FEI has operated under some form of PBR framework for 16 of the last 22 years. These facts clearly indicate that the central message of FortisBC's statement is valid and that, particularly in comparison to utilities that are relatively new to PBR, cost reduction opportunities are decreasing and this needs to be reflected in the X-Factor determination.

164.2 Please confirm, or explain otherwise, that the large increase in FEI's net O&M between 2010 and 2013 coincided with FEI entering into a period of cost of service.

Response:

Confirmed that from 2010 to 2013 FEI was under cost of service regulation, and that there were significant increases in O&M funding approved as part of the 2010-2011 Terasen Gas Inc. Revenue Requirements and the 2012-2013 FortisBC Utilities Revenue Requirements for additional resources to meet the Company's needs, including for code and regulations requirements and to provide for ongoing operations and activities.

164.3 Please explain whether, as a result of FEI's net O&M increasing from $223 million in 2009 to $255 million in 2013, as shown in the table provided in response to CEC IR 19.1, the opportunity for new "long-hanging fruit" productivity gains may have emerged.

Response:

In PBR literature, the term "low-hanging fruit" is sometimes used to define the opportunities that may exist when transitioning from cost of service regulation to higher incentive ratemaking frameworks. For instance, the AUC's decision in Alberta's first generation PBR proceeding referred to the term "low-hanging fruit" in this context[25]:

> Another EPCOR expert, Dr. Weisman, further elaborated on this reasoning and emphasized that the stretch factor is designed to ensure that consumers share in part of the efficiencies created by moving from the cost of service to the PBR regime:
>
> > DR. WEISMAN: The typical rationale, and one that I would agree with, is that when you move to a more high powered regulatory regime, such as price cap regulation, that this will fundamentally change the incentives of the firm, that it will be able to enhance its efficiencies, and the stretch factor is designed to ensure that consumers share in part of those efficiencies. So it basically bounces up our historical view of productivity growth to account for the change of the enhanced incentives that accompany price cap regulation relative to traditional cost-of-service regulation.
> >
> > Q. So it's good for that period of time when you move from cost of service into incentivebased regulation? Is that fair?

[25] AUC Decision 2012-237, pp.74,76-77

> A. DR. WEISMAN: Generally the focus is on the transition. You probably heard the so called low-hanging fruit argument, that the — in the initial transition the efficiency gains what we can change, how we can innovate are more obvious and apparent than they are later on …

The Commission agrees with Dr. Weisman that the transition from cost of service regulation to PBR provides an opportunity to realize more easily-achieved efficiency gains (the “low hanging fruit”) due to increased incentives.

The net O&M funding increase from $223 million in 2009 to $255 million in 2013 underwent a thorough review process conducted in two separate cost of service proceedings. The Company presented its reasons for the O&M increases and intervenors and the BCUC reviewed and asked questions to validate the appropriateness of the O&M funding increases. FortisBC believes the review process ensured that the funds approved were reasonable and appropriate for the Company to operate safely and reliably. Nevertheless, and as discussed in Dr.Weisman’s statement above, the Companies’ transition from cost of service in 2013 to a higher incentive PBR framework created an incentive environment that created opportunities for additional productivity gains early in the PBR term which may be characterized as “low-hanging fruit”. In contrast, the proposed MRPs follow six-year PBR plans and therefore there is no transitional productivity opportunity.

164.4 Please describe in detail the “low-hanging fruit” productivity gains which each of FEI and FBC achieved during the Current PBR Plan terms and why each of the described gains is considered to be “low-hanging fruit.”

Response:

As explained in the response to BCUC IR 2.164.3, in PBR literature the term “low-hanging fruit” is sometimes used as a general reference to the type of productivity opportunities that are derived when transitioning from cost of service to higher incentive ratemaking frameworks and that can be achieved early in the PBR term. However, FortisBC does not differentiate these opportunities from the rest of its achieved productivity and is not aware of any other jurisdiction or utility that does so either. Doing so would be a purely subjective practice.

On pages C-11 and C-12 of the Application, FortisBC describes its proposed Efficiency Carry-Over Mechanism (ECM) as follows:

> Under multi-year rate plans the utility's incentives to pursue efficiency gains declines over the plan's term. This is because the reward for a utility is greatest when the efficiency savings are made in the first year of the plan…In other words, the incentive properties of multi-year rate plans are time-dependent and there is an incentive imbalance between earlier and later plan years…
>
> …the evaluation of the Companies' performance in the Current PBR Plans indicate that annual savings above the formula level peaked in the third year of the plans. The proposed approach to consider the performance in the last two years of the Proposed MRPs is based on this observation.

164.5 Please explain to what extent the declining savings in the latter years of the Current PBR Plans are attributable to the design of the Current PBR Plans' ECM as opposed to FEI and FBC exhausting the opportunities for O&M cost reductions.

Response:

The Current PBR Plans do not have a pre-defined ECM. The lack of a pre-defined ECM can reduce the opportunities for cost savings in the later years of a plan's term. It is hard to estimate the extent of the impact this has had on declining cost reduction opportunities for the Current PBR Plans as this would require a counterfactual analysis of a hypothetical plan.

However, evidence and experience in other jurisdictions with ECM plans similar to the one proposed in this Application indicates that the existence of ECM has led to continued savings during the later years of their plans. For example, in Alberta an ECM that is similar to what is proposed in this Application exists. A review of savings achieved by utilities such as ATCO Gas and ATCO Electric indicates higher savings were achieved in the later years of the plans.

164.6 Please explain whether, if FortisBC's proposed ECM is approved as part of the MRPs, FEI and FBC will have a greater incentive to seek productivity savings beyond the "low-hanging fruit." If no, please explain why not.

Response:

As stated in the preamble, the ECM is designed to remove the imbalance between the earlier and later plan years with regard to the incentive to pursue efficiencies. Further, as explained in response to BCUC IR 2.164.4, the term "low-hanging fruit" is sometimes used to describe the type of productivity opportunities that are derived when transitioning from cost of service to higher incentive ratemaking frameworks and that can be achieved early in the PBR term.

FortisBC's proposed MRPs are following a six year PBR plan; therefore any savings achieved in the MRP period would be beyond the "low-hanging fruit", with or without an ECM.

164.7 Please discuss whether the proposed ECM supports the potential inclusion of a positive X-Factor as FEI and FBC will be incented to pursue efficiency gains over the entire length of the proposed MRP terms.

Response:

The premise of the question is incorrect in suggesting a relationship between the X-Factor and the ECM. The ECM and X-Factor are two PBR/MRP components with different functions. The function of the X-Factor is not related to the incentives created by ECM. As explained in response to BCUC IR 1.13.2, the X-Factor simply adjusts the composite inflation factor used in the indexing formula so that it more closely reflects the utility's expected cost changes. FortisBC is not aware of any expert testimony and/or regulatory decision in other jurisdictions with an ECM frameworks that adjusted the proposed or approved X-Factor values for the inclusion of an ECM.

164.8 Does FortisBC currently have any specific plans, initiatives or targeted programs to find further efficiencies in operations (e.g., planned cost optimization programs, efficiency programs)? If yes, please describe each of these programs in detail. If no, please explain why not.

Response:

Other than the continuation of a productivity focus, FortisBC cannot speculate on what efficiency initiatives may be undertaken in the upcoming MRPs.

For the proposed MRPs, FortisBC will be maintaining a productivity focus which has successfully resulted in the identification of efficiencies and cost savings shared with customers during the Current PBR Plan term. However, instead of a cost cutting focus, the Companies will be relying more on a productivity focus of "doing more with the same".

Additionally, as mentioned in the Application, FortisBC anticipates that finding new productivity opportunities will continue to be difficult, after having achieved a number of efficiencies resulting in cost savings over a number of years.

164.9 Please describe how FEI and FBC can each build off of productivity initiatives that were implemented during the Current PBR Plan terms to continue to find efficiencies in operations.

Response:

FortisBC's record of successfully implementing productivity initiatives during the Current PBR Plan terms, particularly major productivity initiatives that span across different departments and/or functions (i.e., Regionalization, Project Blue Pencil), demonstrates its ability to implement productivity initiatives. This demonstrated ability puts the Companies in a good position to pursue any identified productivity initiatives during the MRP term. However, FortisBC anticipates that finding new productivity opportunities will continue to be difficult, after having achieved a number of efficiencies resulting in cost savings over recent years.

164.10 Please explain why it is not reasonable to expect that FortisBC will continue to be able to use effective management practices to find new efficiencies and improve its operations if a positive X-Factor were to be put in place for the proposed MRP terms.

Response:

As part of its ongoing productivity focus, FortisBC will continue to look for new efficiencies to offset cost pressures and improve its operations during the proposed MRPs. This does not mean that a positive X-Factor should be used to determine funding.

Effective management is not limited to cost reductions. Effective management should also prepare the Companies for future challenges and opportunities and may involve increased focus on innovation and investment in projects and initiatives that would expand the business. These initiatives can increase certain costs in the short term, but are necessary for the long-term viability of the utility.

Please refer to the response to BCUC IR 1.13.2 for a discussion of why FortisBC is recommending that no X-Factor value be included for the proposed index-based O&M.

In response to BCUC IR 13.2, FortisBC stated that the benchmarking studies performed by Concentric (filed as Appendix C2 to the Application) can be used to inform the X-Factor determination decision and that the "benchmarking of O&M and capital expenditures for example can be used to estimate the relative cost efficiency of a utility compared to its peer group."

In response to BCUC IR 15.14.1, Concentric stated the following:

> …benchmarking provides a view into industry performance and provides perspective for regulators and stakeholders. Benchmarking does, however, have limitations, including its inability to quantify causal relationships between operating circumstances and costs, and between inputs and outputs.

164.11 Please explain how each of the limitations described by Concentric in the above preamble impact the applicability of the benchmarking studies' information when determining the appropriate X-Factors for FEI and FBC.

Response:

FortisBC notes that all benchmarking studies, whether done through econometric models or through unit cost approaches, have limitations and are subject to assumptions and simplifications.

The reference to "causal relationships between operating circumstances and costs and between inputs and outputs" is highlighting that benchmarking helps compare information and identify potential areas for further investigation, but that it is not able to identify the causal relationships (direct influence) between the costs incurred by a company and the operating circumstances the company faces. In other words, a benchmarking study does not help to understand why the results differ between companies. This is a reason why benchmarking a company's performance against itself over time may help address some of the limitations from comparing to the performance of other companies.

The costs a company incurs depend in part on the prices of its inputs (i.e., labour and materials costs) and the business conditions it faces (i.e., regulatory requirements, geographical location, etc.) and the size and scale of operations. The benchmarking study cannot help to explain the cause and effect relationship between its inputs (i.e., labour, materials, etc) and outputs (i.e., number of customers served, customer service levels, emergency response time, etc) for the company.

Further, the benchmarking study results will be influenced by such things as the capitalization policies followed by the companies, and by differences in how metrics are calculated between companies.

164.12 Please discuss if there are any other limitations to the benchmarking studies which should be considered when evaluating the relevancy of the benchmarking results in determining FEI and FBC's X-Factors.

Response:

Other than the items discussed, FortisBC is unaware of any other limitations that should be considered when evaluating the relevancy of the benchmarking results in determining FEI's and FBC's X-Factors.

In response to BCUC IR 13.2, FortisBC stated the following:

> The unit cost benchmarking results indicates that establishing an additional efficiency factor for O&M indexing formulas is not warranted as both FEI and FBC have been operating under PBR for a number of years and are relatively more efficient than the median of their peer companies in the majority of benchmarked metrics (and for all the O&M metrics).

In response to BCOAPO IR 17.1, Concentric provided the following table for FEI:

FEI Metric and Rank	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	1/5	1/5	1/5	1/5	1/5	2/5
Distribution O&M + Total A&G per TJ	3/5	2/5	3/5	3/5	2/5	3/5
Distribution O&M + Total A&G per Employee	1/4	1/5	1/5	1/5	1/5	1/5
Distribution O&M + Total A&G per km of Mains	3/4	2/5	2/5	2/5	2/5	2/5
Distribution Net Plant per Customer	4/6	4/6	4/6	4/6	4/6	3/6
Distribution Net Plant per Employee	3/5	4/6	4/6	4/6	4/6	3/6
Distribution Net Plant per Employee	3/5	3/6	3/6	3/6	3/6	3/6
Administrative and General Expense per Customer	2/5	2/5	2/5	2/5	2/5	2/5
Administrative and General Expense per TJ	3/5	3/5	3/5	3/5	3/5	3/5
Customer Care Expense per Customer	2/4	2/4	2/4	2/4	2/4	2/4
Customer Care Expense per TJ	3/4	3/4	3/4	3/4	3/4	3/4
Interest Expense per Customer	4/6	5/6	5/6	5/6	5/6	4/6
Emergency Response Time (within 1 hr)	2/5	2/6	4/6	3/6	3/6	3/6
Telephone Service Factor - Emergency	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non-Emergency	3/3	4/4	3/4	4/4	4/4	4/4
First Contact Resolution	NA	NA	NA	NA	NA	NA
Telephone Abandon Rate	2/5	1/5	1/5	2/5	3/5	2/5

164.13 Please clarify if, based on the rankings provided in the above table, FEI ranked at the median for “Distribution O&M + Total A&G per TJ” for three out of the four years occurring during the Current PBR Plan term and at the median for “Administrative and General Expense per TJ” for all four years during the Current PBR Plan term.

Response:

The colors in Figure 33 of Appendix C2-1 (FEI Benchmarking Study) can be used to understand which metric in which years ranked higher than, at, or below the median. FEI confirms that its performance for “Distribution O&M + Total A&G per TJ[26]” ranked 3/5 for 3 of the 4 years of the Current PBR Plan term and for “Administrative and General Expense per TJ[27]” ranked 3/5 for 4 of the 4 years during the Current PBR Plan term. As indicated in the response to BCOAPO IR 1.17.1, ‘1’ represents the best performance for the metric for the companies providing data.

As noted in the Application on page B-53, FEI’s O&M performance as highlighted by Concentric’s study was that in general FEI’s performance was more favorable when expressed on a per-customer basis, and less favorable when expressed on a per-volume basis. This can be explained by the fact that FEI has a high percentage of residential and commercial (i.e., lower volume) customers within its customer base,[28] thus explaining the difference between the results on the per-customer versus per-volume metrics.

For the metrics on an O&M per Customer basis, “Distribution O&M + Total A&G per Customer” and “Administrative and General Expense per Customer”, FEI’s performance was higher, ranking 1/5 for 3 of the 4 years and 2/5 for 4 of the 4 years of the Current PBR Plan term respectively. This benchmarking analysis indicates FEI’s relative efficiency for O&M per Customer metrics compared to its peers support that an additional “efficiency factor’ is not warranted for determining FEI’s O&M funding.

Please refer also to the response to BCUC IR 1.16.1 for discussion of how the results of the benchmarking studies for FEI and FBC provided support and helped to inform FortisBC’s proposal to not include a stretch factor in the proposed MRPs.

---

[26] Performed at median in 2014, 2015 and 2017 and better than median in 2016.
[27] Performed at median for all years studied.
[28] Referenced in the FEI Benchmarking study on page 11, “FEI does, however, have a high percentage of residential and commercial customers (88 percent combined in 2017) in its overall customer base, and as discussed herein, its relative performance compared to the peer groups is more favourable when expressed on a per-customer basis than when expressed on a per-unit-of-volume basis.”

164.13.1 Please explain why ranking at the median for the above-mentioned metrics would support not including an additional efficiency factor for FEI.

Response:

FEI interprets the median as representative of peer group performance for the different metrics, with the median providing an appropriate benchmark to assess FEI's relative efficiency to its peers. In addition to the position of FEI compared to median, the overall trend in the unit cost performance during the studied period, measured by the compound average growth rate (CAGR) values discussed in Concentric's report, is also important as it indicates the efforts to improve the efficiency compared to the peers. Performance rankings higher than the median and lower CAGR compared to the peer group would suggest FEI is relatively more efficient and that no stretch factor is warranted, while performance ranking lower than the median and higher CAGR suggest being less efficient and that a stretch factor may be warranted.

Based on the collective performance of FEI observed from 2014 to 2017 for the O&M metrics related to Distribution O&M + Total A&G, Administrative & General Expense, and Customer Care Expense, FEI's overall O&M performance has been at or better than the median. Further, although the O&M per TJ is at median level, FEI's per unit cost has experienced a steady decrease while the same O&M per TJ unit costs have increased for both Canadian and U.S. PNW peer groups.[29] Concentric states:

> On a distribution O&M and total A&G per TJ basis, FEI was at or below the Canadian peer group median (including FEI) over the study period, at or below the Canadian peer group median (excluding FEI) over the study period except for 2014, and below the Pacific Northwest U.S. peer group median. FEI's per unit costs have decreased over the period (nominal CAGR of (0.56)%). That is compared to nominal CAGRs of (0.56)%, 0.15% and 3.20% for the Canadian peer group median including FEI, the Canadian peer group median excluding FEI, and the Pacific Northwest U.S. peer group, respectively.

As a result, FEI is proposing no additional efficiency factor for its O&M indexing formula as it has been operating under PBR for a number of years and is relatively more efficient than the median of its peer companies in the majority of the O&M metrics.

Furthermore FEI notes that the proposed formulas are based on O&M per customer and not O&M per TJ. Therefore, O&M per customer performance is more important than per TJ unit costs since any stretch factor would apply to an O&M per customer base.

[29] Appendix C2, page 18.

In response to BCOAPO IR 17.2, Concentric provided the following table for FBC:

FBC Metric and Rank	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	4/8	2/8	4/9	3/9	4/9	3/8
Distribution O&M + Total A&G per MWh	4/9	3/9	3/9	3/9	3/9	2/9
Distribution O&M + Total A&G per Employee	1/9	1/9	1/9	1/9	1/9	1/9
Distribution O&M + Total A&G per km Distribution Line	2/7	2/7	3/7	3/7	3/7	3/7
Distribution Net Plant per Customer	9/10	9/10	9/10	9/10	9/10	8/9
Distribution Net Plant per Employee	7/10	9/10	9/10	8/10	7/10	5/9
Distribution Net Plant per km Distribution Line	7/8	7/8	7/8	7/8	6/8	5/7
Administrative and General Expense per Customer	4/8	4/8	4/9	4/9	5/9	5/8
Administrative and General Expense per MWh	4/8	3/8	5/9	4/9	4/9	4/8
Customer Care Expense per Customer	4/4	4/4	5/5	5/5	5/5	4/4
Customer Care Expense per MWh	4/4	4/4	5/5	5/5	5/5	4/4
Interest Expense per Customer	9/9	9/9	8/9	8/9	7/9	7/9
Emergency Response Time (within 2 hrs)	2/4	2/4	1/4	1/4	2/4	2/4
SAIDI	4/8	5/9	5/9	4/9	4/9	7/9
SAIFI	4/8	4/9	5/9	6/10	4/10	8/10
Generator Forced Outage Rate	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non Emergency	4/5	5/5	5/5	4/5	4/5	3/5
First Contact Resolution	NA	5/6	5/6	5/6	6/7	7/8
Telephone Abandon Rate	3/6	3/7	7/7	4/7	5/7	4/8

164.14 Please clarify if, based on the rankings provided in the above table, FBC ranked at the median for "Administrative and General Expense per Customer" and "Administrative and General Expense per MWh" for the majority of the years during the Current PBR Plan term.

Response:

The colors in Figure 36 of Appendix C2-2 (FBC Benchmarking Study) can be used to understand which metric in which years ranked higher, at, or below the median. FBC confirms that its performance for "Administrative and General Expense per Customer"[30] ranked 4/9 or 5/9 for the 4 years of the Current PBR Plan term and for "Administrative and General Expense per MWh[31]" ranked 4/9 for most years of the Current PBR Plan term. The table provided by Concentric included in the preamble was in response to BCOAPO IR 1.18.1. As indicated in the response to BCOAPO IR 1.18.1, '1' represents the best performance for the metric for the companies providing data.

Concentric's benchmarking study noted that FBC performed better than the median at the broadest expense analyzed (i.e., distribution O&M plus total A&G) on a per customer, per

30 Performed better than median in 2014 and 2015, at median for 2016 and worse than median in 2017.
31 Performed at median in 2014 and better than median in 2015, 2016 and 2017.

volume, per employee, and per kilometer of distribution line basis, as well at the A&G expense level on both a per-customer basis and per-volume basis. FBC's performance on the O&M metrics were better than the median in almost all the years studied.

For the overall O&M per Customer metric, "Distribution O&M + Total A&G per Customer", FBC's performance was consistently at or higher than the median indicating FBC's relative efficiency on an O&M per Customer basis compared to its peers and supporting that an additional "efficiency factor' is not warranted for determining FBC's O&M funding.

164.14.1 Please explain why ranking at the median for the above-mentioned metrics would support not including an additional efficiency factor for FBC.

Response:

FBC interprets the median as representative of peer group performance for the different metrics, with the median providing an appropriate benchmark to assess FBC's relative efficiency to its peers. In addition to the position of the company compared to median, the overall trend of the unit cost performance during the studied period, measured by the compound average growth rate (CAGR) values discussed in Concentric's report, is also important as it indicates the efforts to improve efficiency compared to peers. Performance rankings higher than the median and lower CAGR compared to the peer group would suggest FBC is relatively more efficient and that no stretch factor is warranted, while performance ranking lower than the median and higher CAGR suggest being less efficient and that a stretch factor may be warranted.

FBC's O&M and total A&G unit cost metrics performed better than the median in almost all the years studied. Further FBC's CAGR for O&M and total A&G unit cost metrics are generally comparable or better than its peer groups. Concentric states:[32]

> For the distribution O&M and total A&G-per-customer metric, FBC and the peer groups had similar five-year nominal CAGRs (i.e.¸(0.62)%, (0.66)%, (0.98%), and (0.60)% for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively). While the Pacific Northwest U.S. peer group has companies with distribution O&M and total A&G-per customer that fall below the Canadian peer group median, that group is less tightly clustered than the

[32] Appendix C2-2, Page 17

Canadian peer group, and there are two companies within the U.S. group that drive the median above the Canadian range and median.

The growth rates for distribution O&M and total A&G-per-MWh were 1.80%, 3.64%, 3.00%, and 3.19% for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively.

As a result, FBC is proposing no additional efficiency factor for its O&M indexing formula as it has been operating under PBR for a number of years and is relatively more efficient than the median of its peer companies in the majority of the O&M metrics.

164.15 Please explain, for the metrics where FEI and/or FBC rank below the median, if FortisBC factored in the results of these metrics when designing other components of the proposed MRPs.

Response:

FortisBC completed the benchmarking studies to provide the BCUC with information on the Utilities' efficiency relative to other utilities and to help inform the BCUC's decision on appropriate X-Factors. The benchmarking studies were not completed with the intent to use the information in designing other components of the proposed MRPs.

FortisBC provides the following discussion of the metrics with performance that ranked consistently below the median during the term of the Current PBR Plans to help understand the link between the results and other components of the proposed MRPs.

For FEI, the metrics with performance that ranked consistently below the median during the term of the Current PBR Plan were:

- Distribution O&M + Total A&G per TJ
- Administrative and General Expense per TJ
- Customer Care Expense per TJ
- Distribution Net Plant per Customer, per Employee, per km of Mains
- Interest Expense per Customer
- Telephone Service Factor – Non-Emergency

Following is discussion of the factors contributing to the lower than median performance of the metrics noted above.

The performance for the metrics Distribution O&M + Total A&G per TJ, Administrative and General Expense per TJ, and Customer Care Expense per TJ are discussed in the response to BCUC IR 2.164.13. Based on the collective performance on the O&M per Customer metrics for FEI observed from 2014 to 2017, FEI is relatively efficient compared to its peer group.

For the Distribution Net Plant metrics (per Customer, per Employee, per km of Mains), performance ranked at or below the median from 2014 to 2017. Contributing to the performance may be the elevated level of capital expenditures in recent years due to sustained growth in new customers and the related system improvements required to address capacity concerns. Funding for capital expenditures has been an area of concern during the Current PBR Plan impacted by high growth capital requirements. FEI's proposed approach to its capital expenditures during the MRP recognizes this concern. Recognizing this issue, FEI has proposed its unit cost approach to funding Growth Capital with expenditures allowed to vary based on customer growth while maintaining accountability for expenditures to attach new customers based on the unit cost. Additionally, FEI's other proposed Distribution capital over the term of the MRP is subject to review in this Application to ensure its appropriateness.

For Interest Expense per Customer, as noted by Concentric on page 27 of the FEI Benchmarking study in Appendix C2-1, interest expense is driven not only by a utility's cost of debt, but also by the relative portion of its rate base that is financed by debt (i.e., its capital structure). FEI notes that these factors make it difficult to compare performance amongst the peer companies for interest expense. Further, since the MRP is not the proceeding in which capital structure and financing strategies are reviewed, this metric would have no place in the MRP (this metric was added to the benchmarking study at the request of one of the interveners).

For the customer service metric, Telephone Service Factor – Non-Emergency, as mentioned by Concentric on page 30 of FEI Benchmarking study in Appendix C2-1, it is important to also view TSF (and other service quality indicators) in the context of what the target TSF rate is for the utility. In the case of FEI, the TSF target is 70 percent for non-emergency calls. FEI's TSF service levels have consistently met the target of 70 percent during the Current PBR Plan term.

For FBC, the metrics with performance that ranked consistently below the median during the term of the Current PBR Plan were:

- Distribution Net Plant per Customer, per Employee, per km Distribution line
- Customer Care Expense per Customer
- Customer Care Expense per MWh
- Interest Expense per Customer

SAIDI/SAIFI

Telephone Service Factor – Non Emergency

First Contact Resolution

Telephone Abandon Rate

For the Distribution Net Plant metrics (per Customer, per Employee, per km of Distribution line), performance ranked below the median from 2014 to 2017. Contributing to the performance is the elevated level of sustainment capital expenditures since approximately 2011 following the completion of numerous major system reinforcement (i.e., capacity) projects. Refer to the minutes from the meeting from the Benchmarking Study Workshop (Appendix C2-4 – page 6 of minutes). As noted by Concentric, FBC went through a period of significant capital expenditures from 2005 to 2012, resulting in an elevated level of gross plant that has not been significantly depreciated. Additionally, FBC's net plant on a per unit basis may also be impacted by its lack of scale compared to its peers.

The performance for the metrics Customer Care Expense per Customer and per MWh are discussed in the response to BCUC IR 2.164.14. Based on the overall O&M per Customer metric, "Distribution O&M + Total A&G per Customer", FBC's performance was consistently at or higher than the median indicating FBC's relative efficiency on an O&M per Customer basis compared to its peers.

For Interest Expense per Customer, as noted by Concentric on page 25 of FBC Benchmarking study in Appendix C2-2), interest is driven not only by a utility's cost of debt, but also by the relative portion of its rate base that is financed by debt (i.e., its capital structure). FBC notes that these factors make it difficult to compare performance amongst the peer companies for interest expense. Further, since the MRP is not the proceeding in which capital structure and financing strategies are reviewed, this metric would have no place in the MRP (this metric was added to the benchmarking study at the request of one of the interveners).

For SAIDI/SAIFI, as noted by Concentric on pages 29 and 30 of FBC Benchmarking study in Appendix C2-2, FBC results were negatively impacted by natural disasters in 2017 and by the implementation of the Outage Management System. As mentioned in the Application for the proposed Service Quality Indicators, FBC will be proposing an adjusted benchmark for its SAIDI/SAIFI once it has three full years of results reflecting the impact of the Outage Management System. Overall, as noted by Concentric, FBC's SAIDI and SAIFI results compared favourably to an industry wide measure as reported by the Canadian Electricity Association with the industry results being higher than FBC's.

For the Customer Service metrics, targeted service levels by a company may influence the performance observed. For Telephone Service Factor – Non Emergency, as mentioned by Concentric on page 33 of FBC Benchmarking study in Appendix C2-2, the TSF performance (and other service quality indicators) is best viewed in the context of the utility's target benchmark TSF. For FBC, the TSF – Non Emergency performance have been at or slightly above the target service level of 70 percent, with the exception of 2014 when FBC was recovering from a labour disruption.

For the First Contact Resolution metric, while service levels have been below the median for this study, FBC's performance have been better than the current target of 78 percent approved by the BCUC, a target that was set above the industry average for call centre performance.

For the Telephone Abandonment Rate metric, as noted by Concentric, FBC's performance was approximately that of the Canadian peer group in each year except for 2014 which was affected by the labour disruption in 2013. Additionally, as discussed in the Service Quality Indicator section of the Application (C7), FBC is proposing to replace the metric with a new metric, Average Speed of Answer.

164.15.1 If yes, please explain how the benchmarking study results were utilized in designing other components of FortisBC's proposed MRPs.

Response:

Please refer to the response to BCUC IR 2.164.15.

164.15.2 If no, please explain why not and explain why in the case of determining the X-Factor for O&M the benchmarking study results were considered relevant.

Response:

Please refer to the response to BCUC IR 2.164.15.

165.0 Reference: GROWTH FACTOR

Exhibit B-10, BCUC IR 8.4, 17.6, 17.7, 19.8

O&M and Growth Factor

In response to BCUC IR 17.7, FortisBC stated the following:

> As indicated in the response to BCUC IR 1.8.4 requesting the calculation of correlation coefficients for actual and formula O&M against the O&M formula cost driver (average number of customers), the results indicate a strong linear association between the cost driver and both actual and formula O&M. Given the nature of the O&M formula in the 2014-2019 PBR Plan, it is no surprise that formula-based O&M yields a strong linear relationship to customer numbers over the Current PBR Plan, but the linear relationship with customer numbers based on total actual O&M is also very strong.

In response to BCUC IR 8.4, FEI provided the correlation coefficients for actual and formula O&M which were 0.95 and 0.97, respectively.

165.1 Please discuss whether the correlation coefficient results for FEI's formula O&M compared to actual O&M indicate that formula O&M was more highly correlated to the average number of customers than actual O&M.

Response:

As stated in the preamble, the correlation coefficient for actual and formula O&M against the average number of customers were 0.95 and 0.97, respectively. These correlation coefficients are extremely close and therefore, although one is 0.02 higher than the other, statistically speaking they both indicate very strong linear relation with the cost driver and can be considered equally correlated to this variable.

As explained in the preamble, given the nature of the O&M formula in the 2014-2019 PBR Plan, it is no surprise that formula-based O&M yields a strong linear relationship to customer numbers over the Current PBR Plan. This is because the formula follows the trend in growth factor (it is indexed to I-X and the growth factor) and all else held constant, the correlation between the growth factor and the formula should be one. However, the use of a lagging growth factor and the impact of I-X on the formula can explain the variance from the correlation of 1.

165.1.1 If yes, please explain if this indicates that the 0.5 multiplier applied to the growth factor was reasonable.

Response:

For the reasons discussed below, the correlation coefficient results do not indicate that the 0.5 multipler applied to the growth factor was reasonable.

Why does the correlation between the formula results and the indexing factors not provide any information regarding the appropriateness of the 0.5 multiplier?

The existence of a 0.5, 0.75 or 1.0 multiplier has no impact on the correlation results and, therefore, a strong correlation does not indicate that the 0.5 multiplier was reasonable. As explained in the response to BCUC IR 2.165.1, the formula is indexed to the growth factor and therefore, all else equal, a very strong correlation is expected between the formula results and the indexing factor. As the growth factor increases and decreases, so too does the formula result. This would be the case regardless of which multiplier were applied.

However, a low correlation value between the formula results and the growth factor can be indicative of other problems. For instance, in the case of FEI's and FBC's growth capital formulas in the Current PBR Plans, the use of lagging actual growth and the volatility experienced from year to year were the main causes of the lower correlation values between the formula results and the growth factors.

Why did FortisBC conduct the correlation analysis in the Application?

As explained in Section C1.4.2 of the Application, in the 2014 PBR Decision, the "assumed" non-linear correlation between growth-related expenses and the proposed growth factors was described as one of the reasons to justify the judgement-based 50 percent reduction to the growth factors. As stated in response to CEC IR 1.14.5, FEI used the discussion of correlation coefficient and the values for this measure to rebut this assumption. Further, the strong correlation values between the actual O&M and capital expenditures and proposed growth factors indicate that proposed growth factors are appropriate cost drivers to be used in the formulas.

Why does FortisBC oppose the application of the 0.5 coefficient to the growth factor?

Section C1.1.4.2 of the Application provided three reasons to reject the reasoning provided in 2014 PBR Decision to approve the growth factor coefficient. These are listed below:

- There is a high correlation between growth factors and expenditures: As explained above, the correlation analysis rebuts the argument in the 2014 PBR decision[33] that the relationship between the growth factor and costs are non-linear.

[33] From 2014 BCUC Decision: "The Growth Term Fortis proposes for all formulas, except growth capital for FEI, is linear with a scale factor of 1 … However, growth related expenses may not be correlated in the manner suggested by the formula. Both capital and O&M growth related expenditures may be somewhat lumpy, causing

- The anecdotal evidence goes both ways: As explained in the Application, to support its assumption of non-linearity between growth factors and growth-related expenses, the Panel's 2014 PBR Decision provided isolated examples of instances when costs do not increase linearly but rather, only increase when a threshold in growth is reached. However, as explained on page C-9, the anecdotal evidence goes both ways (the addition of industrial customers was provided as an example).
- The 50 percent reduction to the growth factors is one of the reasons for persistent underfunding of formula capital amounts.

Based on the questions received in the two rounds of information requests and reviewing the 2014 PBR Decision, FortisBC realized that it may have overlooked another important reason: economies of scale and double counting issues.

The following excerpt from the 2014 PBR Decision describes the Panel's view on the impact of economies of scale on the scaling factor:

> A non-linearity may arise because of economies of scale. A utility that serves a million people may not incur 10 times the O&M spending as does a utility that serves 100,000. As the number of customers increases, the scale factor decreases. Potentially, many different scale factors could apply as the number of customers increases or decreases. Similar scaling issues may also apply to FEI's proposed growth capital Growth Term.

In the first and second round of information requests, FortisBC received a number of questions regarding its fixed and variable costs. This line of questioning examines the impact of economies of scale on costs (having fixed costs will lead to economies of scale since the incremental cost of adding one more unit will be less than the average cost).

Neither FEI nor FBC deny the impact of economies of scale on their costs (distribution utilities are widely known to have economies of scale). However, any impact from economies of scale is already factored in the formulas; therefore, additional adjustment in the form of a coefficient to the growth factor is not needed and would be equivalent to an additional productivity factor:

- First, as explained in response to BCUC IR 1.17.7, any economies of scale prior to the start of the MRP are already reflected in the proposed Base O&M per customer amount. In this context, the BCUC's statement regarding the difference in O&M spending for a utility with 1,000,000 and 100,000 customer is already reflected in the base unit costs.

---

spending requirements to increase in a step-wise manner. In this regard the Panel agrees with Mr. Bell's observation that costs only increase when a threshold in growth is reached."

Second, the impact of economies of scale on the Utilities' cost during the MRP term is already embedded in the expected industry productivity values and applying a multiplier to the growth factor would result in double counting.

Reviewing the regulatory decisions in other jurisdictions indicates that the topic of adjusting the growth factor for economies of scale is only discussed in two jurisdictions: BC and Quebec. While all of the PBR-type formulas have an implicit or explicit growth factor embedded in them, no other regulators in jurisdictions such as Alberta or Ontario adjusted the growth factor for this issue. FortisBC believes that the X-factor determination approach explains why this is the case. Productivity growth may come from various sources, ranging from technological improvements to economies of scale. Therefore, the productivity values calculated in productivity studies already reflect the impact of economies of scale for an average firm in the industry. For instance, Dr. Lowry's TFP evidence often refers to the economies of scale as a source of productivity growth for the utilities[34]:

> Economies of scale are a second source of productivity growth. These economies are available in the longer run if cost tends to grow more slowly than output. A company's potential to achieve incremental scale economies depends on the pace of its output growth. Incremental scale economies (and thus productivity growth) will typically be reduced when output growth slows.

In this context, applying a growth factor coefficient acts as an additional productivity factor, double counting the impact of economies of scale on the productivity growth values. FortisBC has not conducted a productivity study; however, it is proposing that the BCUC use the productivity results in other jurisdictions along with other inputs discussed in BCUC IR 1.13.2, to inform its judgement-based determination of the X-Factor value. As such, if the BCUC decides to adopt a growth factor coefficient, it should adjust the X-Factor value downward to avoid double-counting.

What conclusions can be derived from the regression analysis?

A strong correlation value, on its own, does not provide any useful information regarding the appropriateness of the growth factor coefficient. However, as explained in the response to CEC IR 1.14.4, a strong correlation provides necessary support to the regression analysis. FortisBC's response to BCOAPO IR 1.23.1 provides the results of its regression analysis for the cost items subject to formulas. As explained in that response, the slope of the O&M lines are 0.332 for FEI and 0.377 for FBC. This means that, according to the regression equation, FEI added $332 (0.332 x $1,000 because the dollar units are in $000s) for each additional FEI

[34] Lowry et al (2017); "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities", page B-10.

customer and FBC added $377 for each additional FBC customer. As explained in the response to BCUC IR 1.17.7, when combined with the regression line y-axis intercepts, with results near or below zero for both utilities, this analysis shows that O&M cost growth has been tracking with the growth in average customers.

While this regression analysis has its limitations (such as being limited to the PBR term), the comparison of regression lines' slopes with the proposed base unit costs can be used an another input to inform the BCUC's decision on this matter.

165.1.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.165.1.1.

165.2 Please provide the same correlation coefficient analysis for FBC's actual and formula O&M as was provided in response to BCUC IR 8.4 and provide an analysis of the results.

Response:

The tables below provide the correlation coefficient analysis for FBC's actual and formula O&M against the O&M formula cost driver (average number of customers).

The correlation coefficient between the cost driver and actual formula O&M is 0.90 while the correlation coefficient between the cost driver and formula O&M is higher at 0.97. Similar to FEI, the FBC results indicate a strong linear association between the cost driver and both actual and formula O&M.

Average Number of Customers vs Actual Formula O&M

Variables	2014	2015	2016	2017	2018	2019P	Correlation Coefficient
Avg number of customers	129,525	131,016	132,480	134,246	137,300	138,649	0.90
Actual formula O&M ($ thousands)	52,046	51,880	51,839	52,520	53,847	55,581	

Average Number of Customers vs Approved Formula O&M

Variables	2014	2015	2016	2017	2018	2019P	Correlation Coefficient
Avg number of customers	129,525	131,016	132,480	134,246	137,300	138,649	0.97
Formula O&M ($thousands)	52,745	52,984	53,596	54,071	54,776	56,081	

In response to BCUC IR 19.8, FortisBC provided a comparison of the risks/rewards/incentives and ease of understanding of the Current PBR Plans and the proposed MRPs.

With regard to formula O&M, FortisBC stated in response to BCUC IR 19.8: “The proposed changes…will improve the accuracy of the O&M formulas to estimate Utilities’ needed O&M during the MRP term…”

165.3 Please explain the basis for stating that the formula O&M under the proposed MRPs will be more accurate than the Current PBR Plans given the results of the Current PBR Plans.

Response:

The following proposed changes to the formulas are intended to improve the accuracy of formula results:

Change from the use of lagging actual indicators to forecast and true-up approach:

As explained in the Application, an approach based on forecasting formula elements, as opposed to a lagged actual approach, will lead to improved formula accuracy. This is because costs and revenues are both driven by the actual growth experienced in the year for which rates are being set.

Further, the use of a forecast growth factor is consistent with how FortisBC internally forecasts its costs. FortisBC acknowledges that the percentage change from year to year for the O&M formula elements is considerably less volatile than the percentage change for the growth factor used in FEI’s Growth Capital formula. Therefore, O&M formulas are less negatively impacted by this issue. Nevertheless, the use of the forecast and true-up approach will improve the accuracy of the O&M formulas as well.

Elimination of 0.5 multiplier to the growth factor:

By eliminating the 0.5 multiplier to the growth factor, O&M formulas will reflect the full O&M costs associated with each additional customer which will improve the ability of the formula to estimate the O&M costs.

In response to BCUC IR 17.7, FortisBC stated the following:

> In the short term, some of FortisBC's O&M costs are fixed (i.e. lease, rent), some are semi-variable (i.e. vehicle costs – insurance portion fixed while fuel costs variable based on vehicle usage) and some variable (i.e., customer billing and postage). FortisBC is unable, however, to provide an accurate estimate of what portion of its O&M costs are fixed, the portion of historical O&M costs for FEI and FBC that are reasonably impacted by the changes in the average number of customers, and specifically identify the O&M expenses which are impacted by changes in average customers.

165.4 Please further explain why FortisBC is not able to estimate the portion of FEI's and FBC's O&M costs that are fixed and the portion of historical O&M costs that are impacted by the changes in the average number of customers.

<u>Response:</u>

Please refer to the response to BCUC IR 2.165.5.

165.5 Please provide, to the best of FortisBC's ability, a breakdown of FEI's and FBC's O&M costs classified under the categories of "fixed," "semi-variable," and "variable." Please provide supporting rationale for each O&M cost classification.

<u>Response:</u>

FortisBC (FEI and FBC) provides the following discussion regarding its O&M costs and its relationship to the number of customers served.

Estimating the percentage of fixed costs versus variable costs is a complicated and contentious task and would require a significant amount of simplification, assumptions and judgement.

In the O&M formulas, the number of customers is a proxy for various types of costs drivers that affect O&M costs. While in the short-term certain costs may not change in line with changes in the number of customers, these costs may increase in line with other cost drivers that the number of customers is used as a proxy for. In other words, in the short-term, certain costs may be fixed relative to the number of customers, but may vary by other factors. For instance, certain O&M cost pressures can be related to increases in the size or complexity of the system or increases in regulations that are not directly related to the number of customers but for which the number of customers serves as a proxy.

Further, the analysis of fixed versus variable costs relative to the number of customers may require a multi-dimentional analysis that would consider not only the time dimension (considered in the tables below) but also other factors such as the location of changes during the MRP. For instance, the increase in number of customers or the load in certain geographical locations in a utility's service territory may require capacity upgrades that would result in additional O&M expenditures while the same number of customer additions and load increase distributed in various locations would not have resulted in the same cost pressures. In this example, the estimate for the percentage of fixed costs versus variable costs in a five-year period would also depend on the change in the number of customers and load in certain locations.

With these qualifications and to be responsive to the request for a breakdown of its O&M costs classified into "fixed", "semi-variable" and "variable", FortisBC completed a high level analysis, based on its judgement of its O&M costs by department. FortisBC completed the analysis using 2018 actuals by department provided in the responses to BCUC IRs 1.23.2 and 1.23.3, as the nature of the activities / functions within each department provide for a more intuitive explanation of the costs relative to the number of customers served than would analysis based on the type of resource (i.e., labour, materials, services, other, etc). Additionally, the departments' costs were grouped into major functions (Customer Service, Energy Solutions, External Relations, Communications, Administration and General, etc) to simplify the presentation and discussion.

Definition of Variable and Fixed Costs

For the purpose of this analysis, FortisBC's "fixed" O&M costs are those costs that are considered to remain constant for a period of time. Fixed costs from a department perspective include some costs typically in the Administration and General functions like Finance, HR and Regulatory where most costs are relatively constant for a period of time relative to the number of customers served.

"Variable" O&M costs are costs that vary with the number of customers served. Variable costs from a department perspective include those in the Customer Service and Energy Solutions, External Relations, Communications functions.

A "semi-variable" cost, also known as a mixed cost, is a cost composed of a mixture of both fixed and variable components. As FortisBC is providing the analysis at a functional level by "fixed" and "variable", the end result by function is a composite semi-variable cost. As a result, this classification is not necessary.

Time Period of Analysis

With respect to the fixed versus variable cost analysis, traditional economic theory suggests the classification of costs into fixed versus variable is dependent on the period of time considered. According to economic theory, in the short term (however long that may be) there are both fixed and variable costs. Conversely, in the long term, there are no fixed costs as all costs can be varied and a company is able to adjust its cost structure. The determination of why a cost that is fixed in the short term can become variable over the long term is dependent on the choice of the time period that is long enough for costs to be adjusted. This determination is a challenging and somewhat subjective exercise.

The analysis has been prepared in consideration of a five-year timeframe, the approximate term of FortisBC's Current PBR Plans and the term for the proposed MRPs.

Following the rationale described, FortisBC provides the following high-level analysis and the estimated breakdown of its 2018 actual O&M costs, classified into the categories fixed and variable.

Functions – Department Activities

FortisBC has grouped the departments into five broad functions representative of the similar nature of the departments' activities. The functions are:

- Customer Service;
- Energy Solutions, External Relations, Communications;
- Energy Supply;
- Operations, Generation, Engineering; and
- Administration and General.

FortisBC believes its Customer Service O&M costs have the strongest link to the number of customers. Energy Solutions, External Relations, Communications would be the next strongest link as this function includes departments focused on acquiring customers, engaging with stakeholders, enhancing existing services, providing ongoing support and communicating with customers and stakeholders. Energy Supply and Operations, Generation, Engineering O&M costs would have less of a link to the number of customers as their costs are more influenced by the size and age of the distribution system required to serve the number of customers. In the end, the number of customers does significantly influence the size of the distribution system required.

Recognizing that the differences in interpretation as to whether O&M costs are fixed or variable on a per customer basis is dependent on the time period, and recognizing the subjectivity of the interpretation and the estimated nature of the analysis, FortisBC has provided a range (X percent to Y percent) of the suggested percentage of variability of the O&M costs to the number of customers (i.e., low and high end range of the estimate provided) for each of the functions.

The ranges provided in the tables below are judgment based and start with the percentages for Customer Service, the function with O&M costs most closely linked to the number of customers.

FEI Analysis and Discussion

Classification of Functions	2018 Actuals	5 Year			
		% Variability with # of customers		$ Variability with # of customers	
		Low end of range	High end of range	Low end of range	High end of range
Customer Service	$ 39,475,000	100%	100%	$ 39,475,000	$ 39,475,000
Energy Solutions, External Relations, Communications	$ 28,004,000	80%	100%	$ 22,403,200	$ 28,004,000
Energy Supply	$ 4,453,000	40%	60%	$ 1,781,200	$ 2,671,800
Operations/Generation/Engineering	$ 111,160,000	40%	60%	$ 44,464,000	$ 66,696,000
Administration and General	$ 88,459,000	40%	60%	$ 35,383,600	$ 53,075,400
Total	$ 271,551,000	N/A	N/A	$ 143,507,000	$ 189,922,200
Percentage of total costs variable				53%	70%

In the five year timeframe, total O&M costs for FEI are estimated to be approximately 53 percent to 70 percent variable relative to the number of customers served, as this time period will allow FEI to adjust its costs to any significant change in the number of customers:

The Customer Service function is expected to have the most variability in its O&M costs related to the number of customers. Activities performed in the function include the contact centre, billing and bad debts management, which are directly affected by the number of customers served. As a result, FortisBC estimates a high degree of variability of the Customer Service O&M costs.

The function, Energy Solutions, External Relations and Communications O&M costs also has a high degree of variability relative to the number of customers served. Activities performed in this function include marketing and customer and stakeholder engagement that are influenced by the number of customers served, although likely not to the same degree as the Customer Service function. Core customer/stakeholder engagement activities that are performed somewhat independent of the size of the customer base include customer satisfaction survey/research, customer communications and stakeholder engagement.

The Energy Supply and Operations/Generation/Engineering functions' O&M costs are influenced by the number of customers but more so by the size and age of the distribution system and assets used to serve customers. As such, O&M costs are estimated to be more fixed than variable over a five year term, as the size of the system does not change in this time period.

Lastly for the Administration and General function, which includes the departments and activities IT, HR, Finance, Regulatory and Facilities, most of the O&M costs are fixed in the short run and likely follow a stepped cost pattern over a five year peroid, with costs fixed within certain boundaries, outside of which costs will change.

FBC Analysis and Discussion

Classification of Functions	2018 Actuals	5 Year			
		% Variability with # of customers		$ Variability with # of customers	
		Low end of range	High end of range	Low end of range	High end of range
Customer Service	$ 5,856,000	100%	100%	$ 5,856,000	$ 5,856,000
Energy Solutions, External Relations, Communications	$ 1,442,000	80%	100%	$ 1,153,600	$ 1,442,000
Energy Supply	$ 1,210,000	40%	60%	$ 484,000	$ 726,000
Operations/Generation/Engineering	$ 28,923,000	40%	60%	$ 11,569,200	$ 17,353,800
Administration and General	$ 19,922,000	40%	60%	$ 7,968,800	$ 11,953,200
Total	$ 57,353,000	N/A	N/A	$ 27,031,600	$ 37,331,000
Percentage of total costs variable				47%	65%

Similar to FEI, in the five year timeframe, total O&M costs for FBC are estimated to be approximately 47 percent to 65 percent variable relative to the number of customers served, as the longer time period will allow FBC to adjust its costs to any significant change in the number of customers. The rationale provided above in the context of FEI for the expected percentage variability of O&M costs to the number of customer applies also to FBC.

Summary

The above analysis suggests FortisBC's O&M costs relative to the number of customers served are more variable than fixed relative to the number of customers served over a five year time frame, and that from an economic perspective all costs in the long term are variable. As discussed though, the process of determining what portion of FortisBC's O&M costs is fixed and variable is dependent on the different considerations discussed, limiting the potential use of the analysis in informing the BCUC's decision on an appropriate growth factor in the proposed index-based O&M formula. FortisBC emphasizes that the estimated percentage of fixed costs in the above tables do not justify a growth factor coefficient as any impact of the fixed costs is already reflected in the base unit costs and the expected industry productivity growth.

Please refer also to the response to BCUC IR 2.165.1.1 providing a discussion of the factors regarding the appropriateness of the customer growth multiplier to use in the index-based O&M formula FortisBC is proposing.

In response to BCUC IR 17.6, FortisBC stated that Hydro Quebec Distribution applies a 0.75 multiplier to its growth factor.

165.6 Please provide a detailed description of Hydro Quebec Distribution's rationale for applying a 0.75 multiplier to its growth factor.

Response:

The following are the general reasons provided by the Regie for approval of the judgement-based 0.75 multiplier to Hydro Quebec's growth factor (number of customers)[35]:

> Since the Distributor's expenses have fixed and variable components, the Régie does not accept Distributor's proposal that a 1% increase in number of customers generates a 1% increase in distribution costs …
>
> The Régie considers that the present value of 0.75 included in the parametric formula for customers' growth must continue to be used in the context of the MRI for Factor G. This is to ensure a certain degree of harmonization between the existing ratemaking regulation and the MRI that will be put in place, which is generally recommended by the Distributor. Moreover, according to the distributor's expert (Concentric), growth factor must take into consideration the realization of economies of scale.
>
> The Régie therefore considers that setting this value at 0.75 for Factor G for the full term of the MRI will ensure the simplicity sought in the application of the MRI.

[35] The exact French version of the text is as follows and can be found on page 102 of Regie's decision D-2017-043: *Puisque les charges du Distributeur ont des composantes fixes et variables, la Régie ne retient pas la proposition du Distributeur à l'effet qu'une hausse de 1 % des abonnements génère une hausse de 1 % des coûts de distribution …*
La Régie considère que la valeur actuelle de 0,75 incluse dans la formule paramétrique pour la croissance des abonnements doit continuer à être utilisée dans le cadre du MRI à titre de Facteur G. Il s'agit d'assurer une certaine harmonisation entre la réglementation actuelle et le MRI qui sera mis en place, comme le préconise d'ailleurs, de manière générale, le Distributeur. De plus, aux dires mêmes des experts du Distributeur, le Facteur G doit prendre en considération la réalisation d'économies d'échelle.
La Régie juge par ailleurs que la fixation de cette valeur de 0,75 pour le Facteur G pour tout le terme du MRI permettra d'assurer la simplicité recherchée dans l'application d'un MRI.

165.7 Please compare and contrast FEI and FBC to the utilities regulated by Hydro Quebec Distribution in terms of similarities and differences in O&M.

Response:

FortisBC assumes that the question is asking for the similarities and differences between FEI's and FBC's O&M profile (fixed vs variable, labour vs. non-labour) and Hydro Quebec Distribution's O&M profile. FortisBC is unable to answer this question, as it does not have a detailed knowledge of Hydro Quebec Distribution's O&M profile.

Similar to FEI and FBC, Hydro Quebec Distribution has been unable to provide a detailed breakdown of fixed, semi-variable and variable costs. In a response to an information request, Hydro Quebec Distribution explained that its accounting standards and systems do not categorize costs based on fixed and variable categories (the distinction between fixed and variable costs cannot be done accurately without proper accounting capability) and that in the long term all cost are variable[36]:

> The Distributor's position is that it is not possible to determine economies of scale through a distinction between fixed and variable costs. On the one hand, this distinction of fixed and variable costs is not recorded in the accounting systems and on the other hand, it is not useful to do so since the fixed costs become variable after a certain volume of activity. Fixed costs change incrementally and overall continuously in response to customer growth. In addition, following the examination of the cost items, the presence of economies of scale in the development of the Distributor's operating expenses has not been demonstrated.

[36] The exact French version of HQD's response to FCEI IR 5.4 in R-3776-2011 proceeding is as follows : "*La position du Distributeur est qu'il n'est pas possible de déterminer les économies d'échelle par le biais d'une distinction des frais fixes et des frais variables. D'une part, cette distinction des coûts n'est pas enregistrée dans les systèmes comptables et d'autre part, il n'est pas utile de le faire puisque les coûts fixes deviennent variables à partir d'un certain volume d'activité. Les coûts fixes évoluent par paliers et dans l'ensemble de façon continue en réaction à la croissance des abonnements. De plus, suite à l'examen des postes de dépenses, la présence même d'économies d'échelle dans l'évolution des charges d'exploitation du Distributeur n'a pas été démontrée*".

166.0 Reference: PERFORMANCE INCENTIVE FRAMEWORKS

Exhibit B-10, BCUC IR 17.8, 64.2; Exhibit B-8, Industrial Customers Group (ICG) IR 9.1; Exhibit B-2, Workshop Materials, p. 5; Exhibit B-1, pp. B-70 – B-71; Exhibit B-1-1, Appendix C1

Expenditures Subject to Incentives

In response to BCUC IR 17.8, FortisBC stated the following:

> The more costs that are subject to incentives, the higher the risk and reward, and the higher the incentives for efficiency gains. Compared to the proposed MRPs and the MRPs in other Canadian jurisdictions, FEI's and FBC's Current PBR Plans had less costs subject to formulas (i.e., subject to incentives) as big cost items such as depreciation expenses were not subject to an incentive framework. Compared with the Current PBR Plans, the proposed MRPs include a larger set of cost items under an incentive framework as cost items such as depreciation expense are now subject to the sharing mechanism…All plans also exclude non-controllable costs items from the incentive frameworks such as commodity related costs.

In response to ICG IR 9.1, FBC provided an analysis of the expenses and revenues subject to deferral account treatment (i.e. not subject to incentives) under the Current PBR Plan compared to the proposed MRP.

166.1 Please provide the same analysis for FEI as was provided for FBC in response to ICG IR 9.1.

Response:

FEI provides the requested information in the tables below. FEI used 2019 Approved revenue requirement amounts per BCUC Orders G-237-18 and G-10-19 for comparison purposes, as detailed 2020 forecast revenue requirement amounts are not available.

Table 1: Current PBR Plan Deferral Account Treatment

	2019	Covered by Flowthrough or Specific Deferrals			Covered by Earnings Sharing Deferral	
Existing Approved Deferrals	Approved ($000s)	$000s	%	Applicable Deferrals	$000s	%
Cost of Energy	$ 369,282	$ 369,282	100.0%	Flowthrough, MCRA, CCRA	$ -	0.0%
O&M	246,088	29,679	12.1%	Pension & OPEB Variance, BCUC Fees Variance, Flowthrough	216,409	87.9%
Depreciation & Amortization	230,699	230,699	100.0%	Flowthrough	-	0.0%
Property Taxes	67,559	67,559	100.0%	Flowthrough	-	0.0%
Other Revenue	(44,893)	(44,893)	100.0%	Flowthrough	-	0.0%
Income Taxes	52,972	52,972	100.0%	Flowthrough	-	0.0%
Interest	140,241	140,241	100.0%	Flowthrough	-	0.0%
Equity Return	151,491	151,491	100.0%	N/A - No variance	-	0.0%
Total Expenses	$ 1,213,439	$ 997,030	82.2%		$ 216,409	17.8%
Revenue	$ 1,213,439	$ 1,213,439	100.0%	Flowthrough, RSAM	$ -	0.0%

Table 2: Proposed MRP Deferral Account Treatment

MRP Proposed Approved Deferrals	2019 Approved ($000s)	Covered by Flowthrough or Specific Deferrals $000s	%	Applicable Deferrals	Covered by MRP Incentives (Sharing) Deferral $000s	%
Cost of Energy	$ 369,282	$ 369,282	100.0%	Flowthrough, MCRA, CCRA	$ -	0.0%
O&M [1]	246,088	31,967	13.0%	Pension & OPEB Variance, BCUC Fees Variance, Flowthrough	214,121	87.0%
Depreciation & Amortization	230,699	42,172	18.3%	No variance for amortization, Flowthrough for Clean Growth Projects	188,527	81.7%
Property Taxes	67,559	67,559	100.0%	Flowthrough	-	0.0%
Other Revenue	(44,893)	(39,778)	88.6%	Flowthrough for Clean Growth Projects and SCP Third Party Revenue	(5,115)	11.4%
Income Taxes [2]	52,972	-	0.0%	Flowthrough for Clean Growth Projects, Tax Rate Variances	52,972	100.0%
Interest [2]	140,241	-	0.0%	Flowthrough for Clean Growth Projects, Interest Rate Variances	140,241	100.0%
Equity Return	151,491	151,491	100.0%	N/A - No variance	-	0.0%
Total Expenses	$ 1,213,439	$ 622,693	51.3%		$ 590,746	48.7%
Revenue	$ 1,213,439	$ 1,213,439	100.0%	Flowthrough, RSAM	$ -	0.0%

Notes:
[1] - Gross O&M expense adjusted for the addition of integrity digs of $2.6 million as shown in Table C2-1 in the Application
[2] - Given the base amounts used are approved amounts, no rate variances for interest or taxes are assumed

In table B2-9 on pages B-70 and B-71 of the Application, FortisBC provides a jurisdictional comparison of the MRPs utilized in Alberta, Ontario and Quebec.

166.2 Using FEI's approved 2019 revenue requirement for gas utilities and FBC's approved 2019 revenue requirement for electric utilities, please provide the same analysis as was provided in response to ICG IR 9.1 to show the amount (dollar and percentage) of costs and revenues which would be subject to deferral account treatment under each of the MRPs described in Table B2-9 of the Application.

Response:

The Companies are unable to provide the requested information as it is not possible for FEI and FBC to restate their revenue requirement components and accounting practices to be on a consistent basis with the utilities included in the jurisdictional comparison. The jurisdictional comparison included in Section B2.6 and Table B2-9 of the Application provides a comparison of the various MRP/PBR frameworks employed in North America. The comparison includes various mechanisms used for setting rates, inflating[37] costs or prices, sharing earnings, efficiency carryovers, off-ramps and reopeners. The information available to allow the Companies to make these comparisons is public. However, the information required to respond to this question is beyond the scope of the jurisdictional comparison included in Section B2.6 and requires a deeper knowledge of each utility in these jurisdictions, how the aforementioned

[37] Including X, Y and Z Factors

mechanisms affect each utility's revenue requirement and detailed knowledge of the accounting practices and regulatory decisions affecting each line of these utilities' revenue requirements.

166.3 Please explain whether, and to what extent, depreciation expense is subject to incentives in each of the Canadian jurisdictions listed in Table B2-9 of the Application.

Response:

Yes. Depreciation expense is subject to incentives in all three jurisdictions. Exceptions may exist for the OEB's custom incentive-ratemaking plans. The extent of the incentives for depreciation expense is similar to other cost items subject to formulas and depends on whether the plans include an earnings sharing mechanism and their approved sharing ratios.

166.4 Please compare the number and overall balance of FEI's and FBC's deferral accounts as of 2019 to the number and overall balances of the deferral accounts in the Canadian jurisdictions included in Table B2-9 of the Application.

Response:

Although utilities in the same jurisdictions may share many of the same deferral accounts, each individual utility may have various deferral accounts that are unique to their specific circumstances. As such, a comprehensive response to this question would require a detailed review of individual utilities' financial reports and regulatory filings which was outside the scope of the MRP/PBR related jurisdictional study. Nevertheless, FortisBC used the consolidated data readily available on regulators' websites to create the following table.

	FEI[1]	FBC[2]	Alberta Natural Gas Utilities	Alberta Electric Utilities	Union Gas/Enbridge Gas Amalco IR Plans[3, 4]	Ontario Electric Utilities[3]	Hydro Quebec[5]
Deferral Account Balance ($ million)	$ 36	$ 16	n/a	n/a	$ 78	$ (400)	$ 3,149
Number of Deferral Accounts	45	34	n/a	n/a	58	n/a	n/a
Year	2019 Forecast	2019 Forecast	n/a	n/a	2018	2018	2018

Reference:

1. 2019 Forecast as approved under BCUC Order G-30-19
2. 2019 Forecast as approved under BCUC Order G-246-18
3. https://www.oeb.ca/utility-performance-and-monitoring/natural-gas-and-electricity-utility-yearbooks
4. https://www.uniongas.com/-/media/about-us/regulatory/other-regulatory-proceedings/eb-2017-0307-rate-setting-mechanism/UNION_EGD_APPL_Rate-Setting-Mechanism_20171123.pdf?la=en&hash=5488A8F35C019347B68CC9B47112C2EF55807F33
5. http://www.hydroquebec.com/about/financial-results/annual-report.html

Notes to the table:

For the Alberta natural gas utilities and Alberta electric utilities, FortisBC is not able to provide the consolidated information as it involves 16 utilities (gas and electric) and consolidated reports are not readily available from the AUC.

For the Ontario electric utilities, the OEB provides annual consolidated financial reports for its regulated utilities; however, FortisBC is not able to obtain the number of deferral accounts as it involves 63 local distribution electric utilities and such information is not available from the OEB's annual consolidated financial reports.

For Hydro Quebec, FortisBC is not able to obtain the number of deferral accounts.

166.4.1 Please explain how FEI and FBC's deferral account usage compared to other Canadian jurisdictions may impact the potential risks and rewards and the promotion of an efficiency focus.

Response:

Generally speaking, FortisBC does not believe that the differences in deferral account usage between utilities, either in the same jurisdiction or between utilities in different Canadian jurisdictions, are significant enough to change the balance of risk and rewards or impact the promotion of an efficiency focus between these utilities. Further, it would be inappropriate to make any conclusion regarding the plans' risks and rewards based on the number of deferral accounts or their current balance. Rather, the focus should be on the type of costs subject to deferral account treatment.

All PBR/MRP related decisions studied in the Jurisdictional Comparison Appendix (C4-2) include many similar deferral and variance accounts that are treated outside the indexing formulas. These include both commodity related and non-commodity related deferral accounts. The common major categories subject to Y-Factor treatment in these jurisdictions include, but are not limited to, cost of gas and upstream transportation (or power purchases and transmission related costs for electric utilities), demand side management costs, pension and OPEB and some form of revenue adjustment mechanism. Individual utilities may also have a number of deferral accounts that are specific to their needs. For instance, in Union Gas and Enbridge Gas' incentive rate-setting proceeding, the OEB approved the following Y-Factors that are subject to deferral account treatment:

- Cost of gas and upstream transportation (in accordance with current QRAM treatment)
- Demand Side Management (DSM) costs (in accordance with current DSM treatment)
- Lost Revenue Adjustment Mechanism (for the contract market)
- Normalized Average Consumption/Average Use (the Applicants propose to continue to adjust rates annually to reflect the declining trend in use)
- Capital investments that qualify for ICM treatment

In addition, the utilities have a number of other deferral accounts. The full list of the amalgamated Union Gas and Enbridge Gas Distribution deferral accounts is provided below:

179.00_ Deferred Rebate Account

179.02_ Transition Impact of Accounting Change Deferral Account

179.04_ Demand Side Management Cost-efficiency Incentive Deferral Account

179.06_ Demand Side Management Variance Account

179.08_ Ex-franchise Third Party Billing Services Deferral Account

179.10_ Lost Revenue Adjustment Mechanism

179.20_ Gas Distribution Access Rule Impact Deferral Account

179.26_ Demand Side Management Incentive Deferral Account

179.30_ Manufactured Gas Plant Deferral Account

179.32_ Greenhouse Gas Emissions Impact Deferral Account

179.36_ Pension and OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account

179.40_ Dawn Access Costs Deferral Account

179.48_ Open Bill Revenue Variance Account

179.60_ Electric Program Earnings Sharing Deferral Account

179.66_ Average use True-up Variance Account

179.70_ Purchased Gas Variance Account

179.80_ Transactional Services Deferral Account

179.82_ Greenhouse Gas Emissions Compliance Obligation - Customer Related Variance Account

179.84_ Greenhouse Gas Emissions Compliance Obligation - Facility Related Variance Account

179.86_ Unaccounted for Gas Variance Account

179.88_ Storage & Transportation Deferral Account

179.94_ OEB Cost Assessment Variance Account

179-070_ Short-term Storage and Other Balancing Services

179-075_ Lost Revenue Adjustment Mechanism

179-100_ Transportation Tolls and Fuel - Northern and Eastern Operations Area

179-103_ Unbundled Services Unauthorized Storage Overrun

179-105_ North Purchase Gas Variance Account

179-106_ South Purchase Gas Variance Account

179-107_ Spot Gas Variance Account

179-108_ Unabsorbed Demand Cost (UDC) Variance Account

179-109_ Inventory Revaluation Account

179-111_ Demand Side Management Variance Account

179-112_ Gas Distribution Access Rule (GDAR) Costs

179-123_ Conservation Demand Management

179-126_ Demand Side Management Incentive

179-131_ Upstream Transportation Optimization

179-132_ Deferral Clearing Variance Account

179-133_ Normalized Average Consumption (NAC) Account

179-135_ Unaccounted for Gas (UFG) Volume Variance Account

179-136_ Parkway West Project Costs

179-137_ Brantford-Kirkwall/Parkway D Project Costs

179-138_ Parkway Obligation Rate Variance

179-141_ Unaccounted for Gas (UFG) Price Variance Account

179-142_ Lobo C Compressor/Hamilton to Milton Pipeline Project Costs

179-143_ Unauthorized Overrun Non-Compliance Account

179-144_ Dawn H/LoboD/Bright C Compressor Project Costs

179-145_ Transportation Tolls and Fuel – Union North West Operations Area

<u>Amalco: List of Deferral Accounts to be Continued During Deferred Rebasing Period</u>

179-146_ Transportation Tolls and Fuel – Union North East Operations Area

179-147_ Union North West Purchase Gas Variance Account

179-148_ Union North East Purchase Gas Variance Account

179-149_ Burlington Oakville Pipeline Project

179-150_ DSM Cost-Efficiency Incentive Deferral Account

179-151_ OEB Cost Assessment Variance Account

179-152_ Greenhouse Gas Emissions Impact Deferral Account

179-153_ Base Service North T-Service TransCanada Capacity Deferral Account

179-154_ Greenhouse Gas Emissions Compliance Obligation - Customer-Related

179-155_ Greenhouse Gas Emissions Compliance Obligation - Facility-Related

179-156_ Panhandle Reinforcement Project Costs

Similar to Union Gas and Enbridge Gas Distribution, other utilities in other jurisdictions use deferral accounts, many of them specific to their individual needs. As can be seen from the list above, the number of deferral accounts does not indicate anything in particular. For instance, Union Gas has one purchase gas variance account for its North West territory and one for North East. Without detailed forensic analysis of each deferral account, the balance of the deferral accounts also provides no useful information.

In Appendix C1 to the Application, FortisBC provides the pre-2014 PBR experience for FEI and FBC.

166.5 Please clarify for each of the pre-2014 PBR plans, if FEI's and FBC's depreciation expenses were subject to earnings sharing.

Response:

In both FEI's 1998 and 2004 – 2009 PBR plans, depreciation expense was subject to earnings sharing as a component of the ROE variance, which was shared 50 percent with customers.

FBC's depreciation expense was subject to flow-through treatment in its 1996 PBR Plan. In FBC's 2007 – 2011 PBR Plan, depreciation expense was subject to earnings sharing as a component of the ROE variance, which was shared 50 percent with customers; however, the treatment of capital expenditures and rate base in FBC's PBR plans differed from that of FEI, as explained below.

FBC's capital expenditures were not set by formula during the term of the 2007 – 2011 PBR Plan. FBC's capital expenditures were approved through one or two-year capital expenditure plans during the PBR term; FBC did not have a "going-in" forecast for capital expenditures during the PBR term. Rate base, and hence depreciation, was reforecast annually based on actual and projected expenditures.

166.6 If FEI's depreciation expense was subject to earnings sharing under the PBR plan previous to the Current PBR Plan (i.e. the 2004-2009 PBR plan), please explain in detail the results of this approach, including the following:

1.0 • The total variance between formula and actual regular capital at the conclusion of the PBR plan term;

2.0 • The total variance between formula and actual depreciation expense at the conclusion of the PBR plan term;

3.0 • The impact to the 2010 revenue requirement and rates of including the cumulative variance between formula and actual net capital into ratebase at the conclusion of the PBR plan term; and

4.0 • FEI's assessment of the success or lack of success of including regular capital depreciation expense variances in the incentive mechanism during the 2004-2009 PBR plan term, as well as any lessons learned.

Response:

At the end of 2009, the difference between TGI's (FEI's) approved and actual amounts for the requested information is provided in the table below. FEI did not distinguish between regular capital and major capital in the 2004-2009 PBR plan and has not attempted to reclassify previous expenditures in that manner or to re-calculate depreciation expense to identify the amounts that would relate to those categories.

$ million	Approved (formula)	Actual	Difference
Gross Plant in Service	$3,441	$3,301	$140
Net Plant in Service	$2,471	$2,403	$68
Depreciation Expense	$90	$80	$10

The following information was included in TGIs 2010-2011 Revenue Requirements Application:

> The impact of the formula plant on the 2009 rate base is a decrease of approximately $69 million which translates to a decreased revenue requirement of approximately $5.0 million. In addition, embedded in the 2009 revenue requirement was $8.0 million of formula versus forecast O&M (net $6.7 million including capitalized overheads) and $10.0 million of formula versus forecast depreciation expense which together translate into an $21.0 million decrease in revenue requirement when comparing formula to forecast (the depreciation impact is grossed up for taxes).

The paragraph above identifies a $15 million reduction in TGI's 2010 revenue requirement from rebasing capital, comprised of a $5 million reduction due to a lower rate base and $10 million reduction from lower depreciation expense.

FEI's capital spending results during the 2004 – 2009 PBR term contributed to lower depreciation expense which was shared to the benefit of customers and shareholders. Including regular capital depreciation as a component of earnings sharing creates a greater incentive for FEI to find capital efficiencies, which can result in a lower overall rate base exiting a multi-year (formula) plan. Upon rebasing, customers receive the entire benefit of these long lasting efficiencies for the remaining lives of the assets.

166.6.1 If FBC's depreciation expense was subject to earnings sharing under the PBR plan previous to the Current PBR Plan, please provide the same analysis as is requested for FEI.

Response:

FortisBC explains in the response to BCUC IR 2.166.5 that FBC's experience with formula capital and sharing of depreciation expense in the previous PBR term is not fully comparable to that of FEI. An analysis of capital expenditure variances is not meaningful because FBC's cumulative "forecast" includes annual reforecasts of capital expenditures, such that FBC's variance to actual is the sum of annual variances and is not representative of the differences in spending for multi-year projects or programs as in the case of FEI.

Nevertheless, FBC has calculated capital expenditure and depreciation expense variances as requested. The variances below represent FBC's total capital expenditures for the period. FBC did not distinguish between regular capital and major capital in the 2007-2011 PBR plan and has not attempted to reclassify previous expenditures in that manner or to re-calculate depreciation expense to identify the amounts that would relate to those categories.

The information requested for FEI in BCUC IR 2.166.6 is provided for FBC's 2007-2011 PBR plan below:

The total variance between formula and actual regular capital at the conclusion of the PBR plan term: Actual expenditures were lower than the cumulative forecasts for 2007-2011 by $47.7 million (total capital expenditures including major projects), subject to the explanation above.

The total variance between formula and actual depreciation expense at the conclusion of the PBR plan term: Actual depreciation expense was lower than the cumulative forecast depreciation expense by $0.538 million over the term of the PBR plan, an average of $0.108 million annually.

The impact to the post-PBR revenue requirement and rates of including the cumulative variance between formula and actual net capital into rate base at the conclusion of the

PBR plan term: As stated above, there was no true-up of cumulative capital expenditure variances at the conclusion of the PBR plan term because rate base was reforecast or "trued up" annually.

FBC's assessment of the success or lack of success of including regular capital depreciation expense variances in the incentive mechanism during the 2004-2009 PBR plan term, as well as any lessons learned: For the reasons mentioned above and since FBC is not proposing annual reforecasts of its capital, FBC's experience with the 2007-2011 PBR plan does not provide any meaningful insights for its proposed treatment in its MRP Application.

166.7 Please provide a detailed discussion as to the impact that FortisBC's proposal to include depreciation expense on regular capital expenditures in the earnings sharing mechanism (ESM) has on the level of risk for ratepayers of the proposed MRPs compared to the Current PBR Plans.

Response:

As explained in the response to BCUC IR 1.17.8, the more costs that are subject to incentives, the higher the risk and rewards, and the higher the incentives for efficiency gains. As a large cost item, subjecting depreciation expense to earnings sharing will increase the risk and rewards equally for both ratepayers and shareholders as any variance would be shared 50:50.

166.8 Please provide a quantitative example of the cumulative impact of the proposed change to the treatment of depreciation expense during the proposed MRP term compared to the treatment under the Current PBR Plan term and explain all inputs and assumptions.

Response:

In the response to BCUC IR 1.63.5, FortisBC illustrated the effect of applying the proposed treatment of variances to the Current PBR Plan and presented the related impact to achieved ROE, earnings sharing and customer rates. Embedded in that response was the variance in depreciation and its effect on achieved ROE, earnings sharing and customer rates.

For this response, since actual depreciation for the MRP period is not yet known, FortisBC has isolated the impact of variances in depreciation on achieved ROE, earnings sharing and customer rates by zeroing out all other variances from BCUC IR 1.63.5. To simplify the calculation even further, FortisBC removed all rate base variances between approved and actual (except for the variance in accumulated depreciation created by the depreciation expense variance) to fully isolate the impacts of depreciation, and any impacts to interest and income tax resulting from changes in depreciation and rate base have been excluded.

The following tables and detailed calculations include the annual impact on achieved ROE, earnings sharing and customer rates of variances in depreciation based on the approved method in the Current PBR Plans and the proposed method in the Application. A negative earnings sharing amount indicates an amount being returned to customers, whereas positive indicates an amount being recovered from customers. A negative difference in rates indicates a rate decrease; conversely a positive indicates a rate increase.

Despite some variations in the results when looking at historical periods due to the differing asset classes impacted and the simplifying assumptions used in this example, FortisBC notes that its proposal is designed to incent further efficiencies in capital spending that, all else equal, would result in lower depreciation expense than forecast, leading to greater earnings sharing with customers and lower rates overall.

Table 1: FEI Summary

	2014			2015			2016		
FEI	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference
Achieved ROE	8.75%	8.74%	-0.01%	8.75%	8.78%	0.03%	8.75%	8.80%	0.05%
Earnings Sharing	-	148	148	-	(433)	(433)	-	(704)	(704)
Change in Rates Including Energy						0.0%			0.0%
Change in Rates Excluding Energy						0.0%			0.1%

	2017			2018			2019		
FEI	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference	Current Approach	Proposed Approach	Difference
Achieved ROE	8.75%	8.81%	0.06%	8.75%	8.76%	0.01%			
Earnings Sharing	-	(793)	(793)	-	(221)	(221)			
Change in Rates Including Energy			0.1%			0.1%			0.1%
Change in Rates Excluding Energy			0.1%			0.1%			0.1%

Table 2: FBC Summary

FBC	2014 Current Approach	2014 Proposed Approach	2014 Difference	2015 Current Approach	2015 Proposed Approach	2015 Difference	2016 Current Approach	2016 Proposed Approach	2016 Difference
Achieved ROE	9.15%	9.15%	0.00%	9.15%	8.82%	-0.33%	9.15%	9.22%	0.07%
Earnings Sharing	-	-	-	-	1,623	1,623	-	(374)	(374)
Change in Rates Including Energy						0.0%			-0.5%
Change in Rates Excluding Energy						0.0%			-0.9%

FBC	2017 Current Approach	2017 Proposed Approach	2017 Difference	2018 Current Approach	2018 Proposed Approach	2018 Difference	2019 Current Approach	2019 Proposed Approach	2019 Difference
Achieved ROE	9.15%	9.18%	0.03%	9.15%	9.14%	-0.01%			
Earnings Sharing	-	(166)	(166)	-	56	56			
Change in Rates Including Energy			0.0%			0.0%			-0.1%
Change in Rates Excluding Energy			0.0%			0.0%			-0.2%

Table 3: FEI Detail

Line	FEI ($000s)	2014			2015			2016			2017			2018			2019			
No.		Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Approved	Actual	Variance	Reference
1	Depreciation	124,667	124,977	310	163,962	163,084	(878)	170,348	168,824	(1,524)	168,190	166,339	(1,851)	189,829	175,686	(14,143)				Variance = Actual - Approved
2	Less: Tilbury Expansion Depreciation embedded in rates	-	-	-	-	-	-	-	-	-	-	-	-	12,737	-	(12,737)				
3	Depreciation on all Plant but Tilbury Expansion	124,667	124,977	310	163,962	163,084	(878)	170,348	168,824	(1,524)	168,190	166,339	(1,851)	177,092	175,686	(1,406)				Line 1 - Line 2
4																				
5	Variances that flow to earnings			(310)			878			1,524			1,851			1,406				- Line 3
6	Approved equity earnings			93,140			123,343			124,398			124,801			147,235				
7	Total			92,830			124,221			125,922			126,652			148,641				Line 5 + Line 6
8	Approved Equity Portion of Rate Base + Cumulative actual rate base change			1,064,302			1,409,762			1,423,018			1,429,312			1,693,697				
9	Achieved before sharing ROE			8.72%			8.81%			8.85%			8.86%			8.78%				Line 7 / Line 8
10	Allowed ROE			8.75%			8.75%			8.75%			8.75%			8.75%				
11	Surplus ROE			-0.03%			0.06%			0.10%			0.11%			0.03%				Line 8 - Line 9
12																				
13	Surplus Earnings			(296)			867			1,408			1,587			442				Line 8 x Line 11
14	Customers Portion			50%			50%			50%			50%			50%				
15	Shared with Customers			148			(433)			(704)			(793)			(221)				Line 13 x Line 14
16																				
17	Achieved ROE after Sharing - Proposed method			8.74%			8.78%			8.80%			8.81%			8.76%				(Line 7 + Line 15) / Line 8
18	Achieved ROE after Sharing - Current Method			8.75%			8.75%			8.75%			8.75%			8.75%				
19	Difference in Achieved ROE			-0.01%			0.03%			0.05%			0.06%			0.01%				Line 17 - Line 18
20																				
21																				
22	Change in Flow Through						(162)			445			820			1,058			1,185	Prior Year (Line 5 + Line 15)
23	Approved Revenue						1,393,222			1,237,537			1,070,118			1,246,308			1,246,308	
24	Rate Impact						0.0%			0.0%			0.1%			0.1%			0.1%	Line 22 / Line 23
25																				
26	Approved Revenues less Energy Costs						752,736			759,823			774,715			822,033			822,033	
27	Rate Impact						0.0%			0.1%			0.1%			0.1%			0.1%	Line 22 / Line 26

Table 4: FBC Detail

Line No.	FBC ($000s)	2014 Approved	2014 Actual	2014 Variance	2015 Approved	2015 Actual	2015 Variance	2016 Approved	2016 Actual	2016 Variance	2017 Approved	2017 Actual	2017 Variance	2018 Approved	2018 Actual	2018 Variance	2019 Approved	2019 Actual	2019 Variance	Reference
1	Depreciation	49,682	49,682	-	52,151	55,552	3,401	54,353	53,896	(457)	56,046	55,980	(66)	58,408	58,802	394				Variance = Actual - Approved
2				-			-			-			-			-				
3	Depreciation	49,682	49,682	-	52,151	55,552	3,401	54,353	53,896	(457)	56,046	55,980	(66)	58,408	58,802	394				Line 1 - Line 2
4																				
5	Variances that flow to earnings			-			(3,401)			457			66			(394)				- Line 3
6	Approved equity earnings			44,065			45,713			47,060			47,046			48,357				
7	Total			44,065			42,312			47,517			47,112			47,963				Line 5 + Line 6
8	Approved Equity Portion of Rate Base + Cumulative actual rate base change			481,585			497,891			511,140			511,252			525,412				
9	Achieved before sharing ROE			9.15%			8.50%			9.30%			9.22%			9.13%				Line 7 / Line 8
10	Allowed ROE			9.15%			9.15%			9.15%			9.15%			9.15%				
11	Surplus ROE			0.00%			-0.65%			0.15%			0.07%			-0.02%				Line 8 - Line 9
12																				
13	Surplus Earnings			-			(3,245)			747			332			(113)				Line 8 x Line 11
14	Customers Portion			50%			50%			50%			50%			50%				
15	Shared with Customers			-			1,623			(374)			(166)			56				Line 13 x Line 14
16																				
17	Achieved ROE after Sharing - Proposed method			9.15%			8.82%			9.22%			9.18%			9.14%				(Line 7 + Line 15) / Line 8
18	Achieved ROE after Sharing - Current Method			9.15%			9.15%			9.15%			9.15%			9.15%				
19	Difference in Achieved ROE			0.00%			-0.33%			0.07%			0.03%			-0.01%				Line 17 - Line 18
20																				
21																				
22	Change in Flow Through						-			(1,778)			83			(100)			(338)	Prior Year (Line 5 + Line 15)
23	Approved Revenue						334,531			350,593			362,128			356,340			370,534	
24	Rate Impact						0.0%			-0.5%			0.0%			0.0%			-0.1%	Line 22 / Line 23
25																				
26	Approved Revenues less Energy Costs						234,100			201,631			210,656			207,890			209,769	
27	Rate Impact						0.0%			-0.9%			0.0%			0.0%			-0.2%	Line 22 / Line 26

In response to BCUC IR 64.2, FortisBC stated the following:

> …on page 33 line 26 to page 34 line 16 of Transcript Volume 1, from the Workshop on May 1, 2019, FortisBC mistakenly indicated that there would be a true-up for actual capital expenditures within the term of the MRP. To clarify, FortisBC is not proposing a true-up of rate base for actual regular capital spending over the term of the MRP. The approved forecast of capital will be embedded in rates over the term of the MRP with no adjustment for actuals until after the end of the term.

In the Workshop Materials filed as Exhibit B-2, FortisBC provided the following example regarding the calculation of variances in regular capital spending:

Line	Particulars	Forecast	Actual	Difference	Reference
1	Capital Spending	$100,000	$ 95,000	(5,000)	
2	Mid-Year add to Rate Base	$ 50,000	$ 47,500		
3					
4	Depreciation Rate	3.0%	3.0%		No depreciation impact in first year
5	Depreciation Expense	3,000	2,850		however, included in this calculation
6					
7	Debt Ratio	60%	60%		
8	Interest Rate	5.5%	5.5%		
9	Interest Expense	1,650	1,568		Line 2 x Line 7 x Line 8
10					
11	Income Tax Rate	27.0%	27.0%		
12	Income Tax Expense	666	632		Complex calc, therefore estimate
13					
14	**Sum of Depreciation, Interest and Income Tax Expense**	**5,316**	**5,050**	**(266)**	*** Line 5 + Line 9 + Line 12**

* Lower actual expenses than forecast, shown in the Difference column, will result in an increase to the earnings and, correspondingly, an increase in the achieved ROE.

166.9 Using the above example provided as part of the Workshop Materials, and assuming that the above example occurred in year 1 of the proposed MRP term, please provide example calculations and descriptions for how forecast versus actual capital spending will be treated during each year of the proposed MRP term, including how the lack of "true-up" of ratebase will impact the calculations of expenses.

<u>Response:</u>

For clarity, similar to the Current PBR Plan, there is no true-up of rate base for differences in actual and forecast expenditures during the term of the MRPs[38]. The main difference between the two plans with respect to regular capital expenditure variances is how the related variances

[38] With the exception of capital spending above the 10% deadband in the Current PBR plans.

in depreciation expense, interest expense and income tax expense are treated. In the Application, FortisBC has proposed to let variances in these expenses be subject to earnings sharing[39] and not be accounted for in the flow-through deferral account.

The following calculation illustrates how a regular capital expenditure variance in year 1 of the MRP will affect the following years of the MRP. In this illustrative example the difference in depreciation, interest and income tax expense from a lower actual capital expenditure than forecast will increase achieved ROE and be shared 50:50 with customers[40]. As can be seen, the manner in which variances in regular capital expenditures affect subsequent MRP years provides an increased incentive for FortisBC to find capital efficiencies. Once the MRP term ends, the benefit of capital efficiencies are passed onto customers through rebasing of rate base and continue on through the lives of the related assets.

[39] Section C4 of the Application. Summary in Table C4-1.
[40] All else equal, half of the variance will be returned to or recovered from customers through the proposed ESM.

Line	Particulars	Year 1	Year 2	Year 3	Year 4	Year 5	Reference
1	Capital Spending						
2	Forecast	$ 100,000					
3	Actual	$ 95,000					
4							
5	Forecast Rate Base - for rate setting purposes						
6	**Gross Plant**						
7	Opening	$ -	$ 100,000	$ 100,000	$ 100,000	$ 100,000	Prior Year Line 9
8	Additions	$ 100,000	$ -	$ -	$ -	$ -	Line 2
9	Closing	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	Line 7 + Line 8
10							
11	**Accumulated Depreciation**						
12	Depreciation Rate	3.0%	3.0%	3.0%	3.0%	3.0%	Assumed
13	Opening	$ -	$ -	$ (3,000)	$ (6,000)	$ (9,000)	Prior Year Line 15
14	Depreciation	$ -	$ (3,000)	$ (3,000)	$ (3,000)	$ (3,000)	- Line 12 x Line 7
15	Closing	$ -	$ (3,000)	$ (6,000)	$ (9,000)	$ (12,000)	Line 13 + Line 14
16							
17	Actual Rate Base						
18	**Gross Plant**						
19	Opening	$ -	$ 95,000	$ 95,000	$ 95,000	$ 95,000	Prior Year Line 21
20	Additions	$ 95,000	$ -	$ -	$ -	$ -	Line 3
21	Closing	$ 95,000	$ 95,000	$ 95,000	$ 95,000	$ 95,000	Line 19 + Line 20
22							
23	**Accumulated Depreciation**						
24	Depreciation Rate	3.0%	3.0%	3.0%	3.0%	3.0%	Line 12
25	Opening	$ -	$ -	$ (2,850)	$ (5,700)	$ (8,550)	Prior Year Line 27
26	Depreciation	$ -	$ (2,850)	$ (2,850)	$ (2,850)	$ (2,850)	- Line 24 x Line 19
27	Closing	$ -	$ (2,850)	$ (5,700)	$ (8,550)	$ (11,400)	Line 25 + Line 26
28							
29	For Rate Setting Purposes						
30	Mid-Year Rate Base	$ 50,000	$ 98,500	$ 95,500	$ 92,500	$ 89,500	(Line 7 + Line 9 + Line 13 + Line 15) / 2
31							
32	Depreciation Expense	-	3,000	3,000	3,000	3,000	- Line 14
33							
34	Debt Ratio	60%	60%	60%	60%	60%	Assumed
35	Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	Assumed
36	Interest Expense	1,650	3,251	3,152	3,053	2,954	Line 30 x Line 34 x Line 35
37							
38	Income Tax Rate	27.0%	27.0%	27.0%	27.0%	27.0%	Assumed
39	Income Tax Expense	666	1,312	1,272	1,232	1,192	Line 30 x 40% Equity x 9% ROE / (1 - Line 38) x Line 38
40							
41	**Sum of Depreciation, Interest and Income Tax Expense**	**2,316**	**7,562**	**7,423**	**7,284**	**7,145**	Line 32 + Line 36 + Line 39
42							
43	Actuals						
44	Mid-Year Rate Base	$ 47,500	$ 93,575	$ 90,725	$ 87,875	$ 85,025	(Line 19 + Line 21 + Line 25 + Line 27) / 2
45							
46	Depreciation Expense	-	2,850	2,850	2,850	2,850	- Line 26
47							
48	Debt Ratio	60%	60%	60%	60%	60%	Assumed
49	Interest Rate	5.5%	5.5%	5.5%	5.5%	5.5%	Assumed
50	Interest Expense	1,568	3,088	2,994	2,900	2,806	Line 44 x Line 48 x Line 49
51							
52	Income Tax Rate	27.0%	27.0%	27.0%	27.0%	27.0%	Assumed
53	Income Tax Expense	632	1,246	1,208	1,170	1,132	Line 44 x 40% Equity x 9% ROE / (1 - Line 52) x Line 52
54							
55	**Sum of Depreciation, Interest and Income Tax Expense**	**2,200**	**7,184**	**7,052**	**6,920**	**6,788**	Line 46 + Line 50 + Line 53
56							
57	**Difference in Depn Interest and Income Tax Expense ****	**(116)**	**(378)**	**(371)**	**(364)**	**(357)**	Line 55 - Line 41

** Increases achieved ROE and is shared with customers

166.9.1 As part of the above response, please clearly show the inputs and calculation of the forecast depreciation expense in each year of the proposed MRP (i.e. please show the basis upon which depreciation expense would be forecast in each annual review).

Response:

Please refer to the response to BCUC IR 2.166.9.

166.10 Please provide the annual forecast depreciation expense related to regular capital expenditures for each of FEI and FBC for each year of the proposed MRP term based on the forecasts of regular capital provided in the Application (excluding growth capital for FEI).

Response:

Depreciation expense for the MRP term will be calculated in each Annual Review filing based on the opening rate base, which includes the previous year's approved forecast regular capital expenditures as set out in this Application (updated with any approved changes for 2023 and 2024), and the previous year's approved calculated formula Growth Capital expenditures for FEI. Depreciation expense amounts included in revenue requirements during the term of the MRP will not be adjusted for any variances in actual capital expenditures from the approved forecast/formula.

To provide an understanding of the order of magnitude of annual depreciation expense, the Utilities provide in the tables below estimates of depreciation expense based on (proposed) composite depreciation rates by expenditure category and the regular capital expenditures as forecast in the Application, and the subsequent errata filed May 9, 2019.

1 **Table 1: FEI Estimate of Depreciation Expense from Regular Capital Expenditures ($000s)**

	2019	2020	2021	2022	2023	2024
Regular Capital Expenditures						
Transmission & Distribution	$109,187	$111,530	$112,944	$117,106	$119,663	$124,533
Other Capital	44,693	49,770	49,916	46,474	46,403	45,351
Total Regular Capital Expenditures	153,880	161,300	162,860	163,580	166,066	169,884
Composite Depreciation Rates						
Transmission & Distribution	2.32%	2.32%	2.32%	2.32%	2.32%	2.32%
Other Capital	7.87%	7.87%	7.87%	7.87%	7.87%	7.87%
Depreciation Expense						
Transmission & Distribution		$ 2,533	$ 5,120	$ 7,741	$ 10,458	$ 13,234
Other Capital		3,516	7,432	11,360	15,016	18,667
Total Depreciation Expense		**$ 6,049**	**$ 12,553**	**$ 19,100**	**$ 25,474**	**$ 31,901**

2

3 **Table 2: FBC Estimate of Depreciation Expense from Regular Capital Expenditures ($000s)**

	2019	2020	2021	2022	2023	2024
Regular Capital Expenditures						
Generation	$ 3,476	$ 6,697	$ 6,766	$ 6,309	$ 7,008	$ 6,514
Transmission & Distribution	47,270	71,076	66,374	61,139	63,931	70,557
Other Capital	15,225	15,752	14,712	14,756	15,281	15,134
Total Regular Capital Expenditures	65,971	93,524	87,853	82,205	86,220	92,204
Composite Depreciation Rates						
Generation	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
Transmission & Distribution	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
Other Capital	6.37%	6.37%	6.37%	6.37%	6.37%	6.37%
Depreciation Expense						
Generation		$ 73	$ 213	$ 355	$ 487	$ 634
Transmission & Distribution		1,245	3,117	4,864	6,474	8,158
Other Capital		970	1,973	2,910	3,850	4,824
Total Depreciation Expense		**$ 2,288**	**$ 5,303**	**$ 8,130**	**$ 10,812**	**$ 13,616**

4
5
6
7

8 166.10.1 Please explain if the forecasts provided in the above IR response will
9 remain unchanged during the proposed MRP term or if the depreciation
10 expense related to regular capital expenditures would be re-forecast
11 during the annual reviews to incorporate the impacts of actual regular
12 capital additions.
13
14 **Response:**

15 Please refer to the response to BCUC IR 2.166.10.

166.11 Please clarify if, as part of the proposed annual review process during the MRP term, FortisBC considers it reasonable for variances between forecast and actual/projected regular capital expenditures to be reviewed in detail.

Response:

Yes, FortisBC considers that variances in the levels of actual to forecast regular capital expenditures would be within the scope of the Annual Review proceedings. As always, for regulatory efficiency, FortisBC expects that the materiality of the capital expenditures and the associated variances will guide the level of detail that is explored.

166.11.1 If no, please explain why not. As part of this response, please specifically address whether a more detailed review of regular capital expenditures compared to the level of review of formula capital spending under the Current PBR Plan would serve to mitigate some of the increased risk of including depreciation expense as part of the proposed MRP incentive framework.

Response:

Please refer to the response to BCUC IR 2.166.11.

167.0 Reference: COMPARISON OF PERFORMANCE INCENTIVE FRAMEWORKS

Exhibit B-10, BCUC IR 19.1

AUC Five Principles

In response to BCUC IR 19.1, FortisBC provided the AUC's approved PBR principles. Principle 1 states: "A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality."

167.1 Please describe the specific components of the AUC's currently approved PBR plan which support Principle 1.

<u>Response:</u>

Consistent with FEI's response to BCPSO IR 1.11.3 in the FEI 2014 PBR proceeding, FortisBC continues to consider the emulation of incentive forces under competitive market conditions to improve efficiencies as more of a result of a comprehensive MRP/PBR plan than a principle. An MRP/PBR framework effectively decouples prices/revenues from the cost of service and therefore creates the intended incentives for utilities to optimize the various inputs of production to operate efficiently, similar to firms in competitive markets. However, certain regulatory safeguard mechanisms that are essential to multi-year rate plans, (such as deferrals, SQIs and off-ramps), do not conform to competitive market behavior. Therefore, FortisBC believes that emulating efficiency incentives such as those experienced in competitive markets, to the greatest extent possible, is implicit in a comprehensive PBR plan.

A PBR/MRP's alignment with AUC's PBR principle 1 depends on the strength of the incentives properties of the plan and the magnitude of safeguard mechanisms applied. As a plan's incentive properties increase and the magnitude of its safeguard mechanisms diminishes, its alignment with AUC PBR principle 1 increases. FortisBC's response to BCUC IR 1.17.8 provides an assessment of the items that affect the risk and reward balance and the associated incentives of MRP/PBR plans. These include items such as the plan's term, safeguards and ECM mechanism as well the amount of costs subject to incentives. In this context, the proposed MRPs have fewer safeguard mechanisms (FortisBC is proposing to discontinue the capital dead-band mechanism). However, this is partly offset by the Companies' proposal to update the capital expenditures forecast in the third year of the MRP period. Further, under the proposed MRPs and compared to the current PBR plans, more cost items are subject to incentives (depreciation expense will be subject to the earnings sharing mechanism), although less capital costs will be subject to indexing formulas. Overall, FortisBC considers that the two plans' incentive properties are comparable, although the proposed MRPs are slightly more aligned with AUC's Principle 1.

Further, the type of costs subject to the incentives as well as the term, safeguards, and ECM mechanism in the proposed MRPs are similar in comparison to the Alberta PBR plans.

FortisBC's MRPs include Targeted Incentives that increase the potential rewards to the utility, balanced by the benefits to customers and the public interest of achieving the targets. However, compared to Alberta PBR plans, the potential risks/rewards of FortisBC's proposed MRPs are tempered by the inclusion of a symmetrical 50/50 earning sharing mechanism. As such, FortisBC considers the Alberta PBR plans to be slightly more aligned with the AUC's PBR principle 1 than the proposed MRPs.

This assessment, however, does not necessarily mean that Alberta PBR plans are superior or inferior to the proposed MRPs. As explained by FortisBC's consultant, B&V, as part of a response to BCPSO IR 1.28.1 in FEI's 2014 PBR proceeding, the AUC's principle 1 need to be balanced against other PBR principles:

> The AUC correctly recognizes that even a comprehensive PBR Plan cannot match the efficiency of a competitive market. Having recognized that goal, B&V believes that the principle offers a reasonable basis for assessment of the plan elements but care must be taken to strike a balance with other plan objectives such as Principle 2[41].

AUC principle 5, for instance, indicates that the customer and the regulated companies should share the benefits of a PBR plan. In this context, FortisBC's proposed MRPs are more aligned with AUC principles than Alberta PBR plans.

167.2 Please compare each of FEI's and FBC's Current PBR Plans to the proposed MRPs in terms of the plans' alignment with Principle 1. Please explain in detail how each of the proposed changes to the MRPs from the Current PBR Plans improves or detracts from Principle 1.

Response:

Please refer to the response to the BCUC IR 2.167.1.

[41] Principle 2: A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

167.2.1 As part of the above response, please explain if overall FortisBC considers the proposed MRPs or the Current PBR Plans to be better aligned with the AUC's Principle 1.

Response:

Please refer to the response to the BCUC IR 2.167.1.

167.3 Please discuss the reasonableness of including a Targeted Incentive related to the achievement of efficiency gains in a specific area or areas of FEI and FBC's businesses (e.g. IT, operations, etc.). How might such an incentive be designed? Please discuss in detail.

Response:

FortisBC does not believe it is reasonable to add targeted incentives related to the achievement of efficiency gains in a specific area.

First, FEI's and FBC's proposed MRPs already include incentive for the Companies to achieve efficiency gains. Specifically, through the proposed Traditional Incentives and Earnings Sharing Mechanism, FortisBC will have incentive to:

- Contain annual index-based O&M expenditures to a level at or below that calculated under the gross O&M per customer amount; and
- Contain Regular Capital spending at the approved level or, in the case of FEI's Growth Capital, at or below the amount set through the index-based unit cost.[42]

Adding targeted incentives aimed at achieving efficiency gains in specific areas would serve to duplicate these objectives.

Second, adding targeted incentives related to efficiency gains for a specific department would reduce the flexibility that is inherent in the proposed MRPs that allows for resources to be allocated towards addressing the priorities that emerge during the 5-year term.

Third, the remaining (non-formula based) revenue requirements do not lend themselves to targeted incentive approaches due to their uncontrollable nature, or because they drive incremental revenues that are also afforded flow-through treatment.[43]

---

[42] Exhibit B-1. Section C-8.2, Page C-157.

D. O&M BASE

168.0 Reference: COST PRESSURES

Exhibit B-10, BCUC IR 22.4, 22.5

Retirements

In response to BCUC IR 22.4 and 22.5, FEI stated that approximately 370 employees are estimated to retire during the proposed MRP term and that of those 370 employees, 200 retirements are estimated in the Operations department.

168.1 Please provide the estimated number of retirements expected for FBC during the proposed MRP term and the estimated number of retirements specifically related to the Operations department.

Response:

FBC estimates that approximately 60 employees will retire during the proposed MRP term, and of those 60 employees, 40 retirements are expected to occur within the Operations department.

168.2 Please provide the total number of retirements for each of FEI and FBC which occurred during the Current PBR Plan term and the number of retirements attributable to each utility's Operations department.

Response:

The total number of retirements for FBC and FEI, and the number of retirements attributable to each utility's Operations departments during the Current PBR Plan term are as follows:

Table 1: Total FBC and FEI Retirements

Business Areas	2014	2015	2016	2017	2018	2019*
Total FBC	6	8	16	10	15	7
Total FEI	31	39	31	34	41	26
Combined Total	37	47	47	44	56	33

*as of July 31, 2019

[43] Exhibit B-1. Section C-4.4, Page C-110.

Table 2: Total FBC & FEI (Operations) Retirements

Business Areas	2014	2015	2016	2017	2018	2019*
FBC Operations	4	3	11	10	10	4
FEI Operations	15	26	21	28	28	8
Combined Total	19	29	32	38	38	12

*as of July 31, 2019

168.3 Please explain how FEI (and FBC if applicable) managed the employee turnover and succession planning during the period of high customer growth experienced during the Current PBR Plan.

Response:

The Companies have managed and mitigated the risks associated with employee turnover through proactive workforce planning. This includes addressing recruiting, training, transition planning, and knowledge transfer across the Companies, and on a more specific basis by department. Workforce planning related to retirements has been on-going for the past several years using various assessment factors including forecasting of eligible retirements, retirement probability projections based on actual retirements rates, and assessing the risk related to the retirement of highly-specialized skillsets against the market-availability of suitable candidates.

168.4 Please explain why high customer growth would be expected to create greater cost pressures for FEI during the proposed MRP than during the Current PBR Plan.

Response:

FEI did not state that high customer growth would create greater cost pressures during the MRP term than the Current PBR Plan term. FEI said that "the need for a successful transition is even more pronounced due to the recent period of high customer growth and associated higher employee base."

The cost pressures noted on page C-16 of the Application, including the one related to the growth of the distribution system, were presented as cost pressures for which FEI is not requesting incremental O&M and that FEI will instead manage by relying more on a productivity focus of "doing more with the same".

FEI notes that high customer growth has created O&M cost pressures for FEI during the Current PBR Plan and those pressures are expected to continue into the proposed MRP term. In past Annual Reviews (e.g., FEI Annual Review for 2019 Rates, BCUC IR 1.1.1), FEI discussed its increased O&M requirements related to its growing asset base. It identified that, as new customers are added to the distribution system, there is an increased need for O&M resources. Growth related cost pressures are expected to be sustained and may even increase in future years of the MRP depending on activity and personnel levels.

169.0 Reference: O&M EXPENSES

Exhibit B-10, BCUC IR 4.2, 4.3, 4.6, 22.14, 23.2, 23.3, 23.4; Exhibit B-1-3 (Errata dated June 21, 2019), pp. C-19, C-44; Order G-156-19, Appendix B, p. 7

Projected and Base 2019 O&M and Forecast 2020 O&M

In BCUC IR 22.14, FEI and FBC were asked to provide departmental O&M forecasts for each year of the proposed MRP term. In response, FEI and FBC stated that they are "proposing an Index-Based formula approach based on total O&M per customer to determine overall O&M funding for the MRP period. As a result, FortisBC has not prepared a forecast of O&M over the term of the proposed MRPs."

On page 7 of the reasons for decision attached to Order G-156-19, the BCUC stated the following:

> The examination of alternative rate-setting approaches, including cost of service, is an issue which can, and is, being explored in the current proceeding. The Panel expects that parties will continue to pursue these issues in IR no. 2…All parties are welcome to pursue any information necessary to assist the Panel in making determinations regarding a potential re-basing of certain costs and an appropriate approach to rate-setting.

In response to BCUC IR 23.2 and 23.3, FortisBC provided the following historical O&M departmental information for FEI and FBC, respectively:

O&M by Department	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Operations [2]	76,169	80,224	83,463	85,682	85,894	94,603
Customer Service [1]	40,912	45,493	40,121	38,481	39,715	39,475
Energy Solutions & External Relations [3]	21,376	21,935	24,974	25,190	26,081	28,004
Energy Supply & Resource Dev	4,031	4,196	4,513	4,590	4,624	4,453
Information Technology	25,331	26,296	28,229	26,529	24,521	25,240
Engineering Services & PM	15,814	15,383	16,379	16,382	15,496	16,556
Operations Support	11,917	13,459	13,446	13,197	12,503	12,749
Facilities	9,739	9,719	9,537	9,836	10,383	10,028
Environment Health & Safety	2,680	2,910	3,159	3,669	4,217	4,527
Finance & Regulatory Services	13,363	14,080	13,599	13,534	13,391	13,788
Human Resources	8,305	9,285	9,109	9,015	9,049	9,483
Governance	9,044	9,457	9,204	8,743	8,179	8,328
Corporate	11,715	5,351	4,301	4,611	5,579	4,316
Total Gross O&M	**250,396**	**257,788**	**260,034**	**259,459**	**259,631**	**271,551**

1 Excludes $14.5m deferred Customer Service O&M for 2013 Actual

Includes the following O&M tracked outside of Formula	2013	2014	2015	2016	2017	2018
2 LNG O&M		550	624	1,438	2,944	6,547
3 NGT Stations O&M		484	1,009	1,205	1,508	2,099
3 Bio-methane O&M		417	1,085	1,154	1,567	2,634

FBC O&M by Department ($000's)	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Generation [3]	2,513	2,954	3,166	3,092	3,050	3,075
Operations [1]	20,830	20,952	20,080	19,897	20,078	20,549
Customer Service [1]	7,630	8,366	7,243	5,712	5,914	5,856
Communications & External Relations	1,426	1,507	1,433	1,343	1,423	1,442
Energy Supply	1,083	1,225	1,233	1,274	1,170	1,210
Information Systems [1]	2,806	4,388	5,112	5,379	5,006	5,022
Engineering [1,2]	2,737	3,765	4,027	4,073	4,142	5,299
Operations Support [1]	1,308	1,166	1,074	792	750	800
Facilities	3,493	2,607	2,475	2,704	2,741	2,988
Environment Health & Safety	877	900	877	1,032	898	914
Finance & Regulatory Services	4,050	4,162	3,668	3,623	3,695	3,752
Human Resources	1,835	1,915	1,855	1,731	1,695	1,878
Governance	2,658	2,543	2,513	2,364	2,796	2,772
Corporate	3,448	3,273	3,028	2,595	2,463	1,796
Total Gross O&M	**56,696**	**59,723**	**57,785**	**55,610**	**55,821**	**57,353**

	Includes the following O&M tracked outside of Formula	2013	2014	2015	2016	2017	2018
1	Advance Metering Infrastructure Costs/Savings		431	272	(1,391)	(1,246)	(1,203)
2	Mandatory Reliability Standards			375	464	53	1,024
3	Upper Bonnington Unit 3 Annual Inspection					(40)	(40)

In response to BCUC IR 4.2 and 4.3, FEI stated that the Major Projects group was established in February 2018 and that it is a separate department for O&M purposes.

In response to BCUC IR 4.6, FEI stated that since it is proposing an index-based formula approach to determine overall O&M funding for the MRP period, it does not have a specific O&M forecast amount for the Major Projects department over the proposed MRP period.

169.1 Please add a column to the above tables for Projected 2019 O&M for FEI and FBC and indicate the number of months of actual results which have been included in the Projected 2019 O&M amounts.

Response:

The following updated tables include the Projected 2019 O&M for FEI and FBC estimated by department including seven months of actual results to July 2019. Total Gross O&M provided includes both formula and flow-through amounts. Additionally, the 2019 forecast flow-through amounts included are the same as the Approved 2019 Forecast flow-through amounts from the 2019 Annual Reviews.

FEI

FEI O&M by Department (in $000's)	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projected
Operations [2]	76,169	80,224	83,463	85,682	85,894	94,603	96,264
Customer Service [1]	40,912	45,493	40,121	38,481	39,715	39,475	42,789
Energy Solutions & External Relations [3]	21,376	21,935	24,974	25,190	26,081	28,004	27,820
Energy Supply & Resource Dev	4,031	4,196	4,513	4,590	4,624	4,453	5,238
Information Technology	25,331	26,296	28,229	26,529	24,521	25,240	25,720
Engineering Services & PM	15,814	15,383	16,379	16,382	15,496	16,008	17,291
Major Project						548	1,440
Operations Support	11,917	13,459	13,446	13,197	12,503	12,749	13,464
Facilities	9,739	9,719	9,537	9,836	10,383	10,028	10,400
Environment Health & Safety	2,680	2,910	3,159	3,669	4,217	4,527	5,232
Finance & Regulatory Services	13,363	14,080	13,599	13,534	13,391	13,788	14,471
Human Resources	8,305	9,285	9,109	9,015	9,049	9,483	10,202
Governance	9,044	9,457	9,204	8,743	8,179	8,328	8,737
Corporate	11,715	5,351	4,301	4,611	5,579	4,316	82
Total Gross O&M	**250,396**	**257,788**	**260,034**	**259,459**	**259,631**	**271,551**	**279,148**

1 Excludes $14.5m deferred Customer Service O&M for 2013 Actual

Includes the following O&M tracked outside of Formula	2013	2014	2015	2016	2017	2018	2019
2 LNG O&M		550	624	1,438	2,944	6,547	7,432
3 NGT Stations O&M		484	1,009	1,205	1,508	2,099	2,339
3 Bio-methane O&M		417	1,085	1,154	1,567	2,634	1,369

The updated table for FEI includes a new line for the Major Projects group with a Projected 2019 O&M of $1.440 million. In 2018, Major Projects O&M costs were $548 thousand which rolled up to Engineering Services & PM as indicated in the response to BCUC IR 1.23.1. In the Corporate area, for the 2019 Projected, the lower forecast amount includes a credit of approximately $5.6 million for the non-service portion of pension/OPEB flow through costs, resulting from a change in accounting treatment (ASU 2017-07) related to pension/OPEB discussed in the Annual Review for 2018 Rates. Total pension/OPEB costs, which are treated as flow through for FEI, however, remain the same.

Consistent with that filed in the Application, FEI is projecting overall formula O&M savings of $2 million in 2019.

FBC

FBC O&M by Department ($000's)	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projected
Generation [3]	2,513	2,954	3,166	3,092	3,050	3,075	3,327
Operations [1]	20,830	20,952	20,080	19,897	20,078	20,549	20,867
Customer Service [1]	7,630	8,366	7,243	5,712	5,914	5,856	6,591
Communications & External Relations	1,426	1,507	1,433	1,343	1,423	1,442	1,477
Energy Supply	1,083	1,225	1,233	1,274	1,170	1,210	1,335
Information Systems [1]	2,806	4,388	5,112	5,379	5,006	5,022	4,924
Engineering [1,2]	2,737	3,765	4,027	4,073	4,142	5,299	5,359
Operations Support [1]	1,308	1,166	1,074	792	750	800	914
Facilities	3,493	2,607	2,475	2,704	2,741	2,988	2,814
Environment Health & Safety	877	900	877	1,032	898	914	1,111
Finance & Regulatory Services	4,050	4,162	3,668	3,623	3,695	3,752	3,857
Human Resources	1,835	1,915	1,855	1,731	1,695	1,878	1,861
Governance	2,658	2,543	2,513	2,364	2,796	2,772	3,115
Corporate	3,448	3,273	3,028	2,595	2,463	1,796	1,149
Total Gross O&M	**56,696**	**59,723**	**57,785**	**55,610**	**55,821**	**57,353**	**58,701**

	Includes the following O&M tracked outside of Formula	2013	2014	2015	2016	2017	2018	2019
1	Advance Metering Infrastructure Costs/Savings		431	272	(1,391)	(1,246)	(1,203)	(1,161)
2	Mandatory Reliability Standards			375	464	53	1,024	940
3	Upper Bonnington Unit 3 Annual Inspection					(40)	(40)	(42)

Consistent with that filed in the Application, FBC is projecting overall formula O&M savings of $0.5 million in 2019.

169.1.1 With regard to FEI, please include the new department related to the Major Projects group and provide the Projected 2019 O&M attributable to the Major Projects group.

Response:

Please refer to the response to BCUC IR 2.169.1.

169.2 In the same format as the above tables, for each of FEI and FBC, please provide a departmental breakdown of the proposed 2019 Base O&M. Please specifically identify in which department each of the adjustments shown in the revised Tables C2-1 and C2-14 of the Application (Exhibit B-1-3) are recorded and separately identify where each incremental O&M funding item is recorded.

Response:

Provided below are two tables which show the departmental breakdown of the proposed 2019 Base O&M. The FEI table includes a separate line for the Major Projects group.

The 2019 Base O&M of $256.150 million for FEI and $57.670 million shown in the tables below reconcile to the 2019 Base O&M for FEI and FBC in the revised tables C2-1 and C2-14 provided in the responses to BCUC IRs 1.24.1 and 1.34.1.

1

FEI O&M by Department ($000's)		Exogenous Factor		Deferrals		Flow Through Treatment						
	2019 Base O&M before adjustments	2019 Z factor (EHT net of MSP)	FAES ovehead	BCUC levies	NGIF funding	Integrity Digs	LNG Plant O&M	2019 Normalized Forecast FHI Management Fee	FHI Corporate Services charged only to FEI	Total Adjustments	New funding for MRP term	2019 Base O&M
Operations	80,629	366				(2,600)	5,101			2,867	2,650	86,147
Customer Service	41,077	74								74		41,151
Energy Solutions & External Relations	21,847	99			(409)					(310)	5,608	27,145
Energy Supply & Resource Dev	4,234	46								46	950	5,230
Information Technology	23,893	62						168		230	808	24,931
Engineering Services & PM	14,822	115								115	400	15,338
Major Projects	1,342	2								2		1,344
Operations Support	11,441	70								70		11,511
Facilities	9,543	13						530		543		10,086
Environment Health & Safety	4,359	35								35		4,394
Finance & Regulatory Services	11,379	43		(2,839)				1,980	387	(429)		10,950
Human Resources	9,008	40								40		9,047
Governance	380							2,675		2,675		3,055
Corporate	(1,299)	6	786					6,329		7,121		5,822
Total Base O&M	**232,654**	**972**	**786**	**(2,839)**	**(409)**	**(2,600)**	**5,101**	**11,682**	**387**	**13,080**	**10,416**	**256,150**

		Exogenous Factors		Deferrals	Flow Through treatment						
FBC O&M by Department ($000's)	2019 Base O&M before adjustments	2019 Z factor (EHT net of MSP)	2019 Z factor (MRS)	Manual meter read	AMI Project cost reductions	BCUC levies	2019 Normalized Forecast FHI Management Fee	FBC Costs included in FHI Corporate Services	Total Adjustments	New funding for MRP term	2019 Base O&M
Generation	2,577	51							51	232	2,860
Operations	20,169	77		180	(508)				(251)	272	20,189
Customer Service	8,320	19			(1,931)				(1,911)	99	6,508
Communications & External Relations	1,519	4							4	80	1,603
Energy Supply	1,284	3							3		1,287
Information Systems	3,457	18			1,186		62		1,267	80	4,805
Engineering	3,482	32	1,540		439				2,011		5,493
Operations Support	1,232	7			(348)				(341)		892
Facilities	2,790	2					187	(98)	91		2,881
Environment Health & Safety	1,158	4							4		1,162
Finance & Regulatory Services	3,237	12				(237)	572	(29)	318		3,555
Human Resources	1,865	6							6		1,871
Governance	887	2					1,075	(181)	896		1,783
Corporate	1,302	3					1,477		1,480		2,781
Total Base O&M	**53,279**	**240**	**1,540**	**180**	**(1,161)**	**(237)**	**3,374**	**(308)**	**3,628**	**763**	**57,670**

169.2.1 With regard to FEI, please include the new department related to the Major Projects group and provide the Base 2019 O&M attributable to the Major Projects group.

Response:

Please refer to the response to BCUC IR 2.169.2.

169.3 In the same format as the above tables, for each of FEI and FBC, please provide a departmental breakdown of the Forecast 2020 O&M under a cost of service-based rate-setting approach. Please clearly identify and explain all differences between the 2019 Base departmental O&M and the Forecast 2020 departmental O&M (excluding inflationary increases).

Response:

The O&M requirements for 2020 under a cost of service based rate-setting framework would generally be similar to that determined under the proposed Index-based formula approach, as they both represent the O&M requirements to operate the Companies for the first year (2020) of the proposed MRP term. FortisBC has provided estimates of FEI's and FBC's 2020 O&M Expense based on the proposed MRPs in response to BCUC IR 2.162.1.

169.3.1 With regard to FEI, please include the new department related to the Major Projects group and provide the Forecast 2020 O&M attributable to the Major Projects group.

Response:

Please refer to the response to BCUC IR 2.169.3.

170.0 Reference: O&M EXPENSES

Exhibit B-10, BCUC IR 23.2, 23.4

Historical Actual and Projected O&M and FTEs

Based on the information provided in the table in response to BCUC IR 23.2, FEI's historical Operations O&M expenses, excluding Liquefied Natural Gas (LNG), were as follows:

- 2014 - $79,674
- 2015 - $82,839
- 2016 - $84,244
- 2017 - $82,950
- 2018 - $88,056

In response to BCUC IR 23.4, FEI stated: "In Operations, the Regionalization initiative (Phase 1 and 2) contributed to reductions [in FTEs] during the same period. These decreases were offset by increased staffing in the Operations and Engineering area to meet operational and capital work requirements."

170.1 Please provide a detailed description of the factors contributing to the six percent increase in Operations O&M in 2018 (this increase excludes the impact of LNG).

Response:

In 2018, FEI's total Operations O&M increased by $5.1 million or approximately 6 percent over 2017 expenses due to labour inflation and benefits (particularly pension and OPEB costs), increased headcount, vehicle fuel and insurance, municipal fees and expenses, and increased operating activities. The increased activities include preventative and corrective maintenance activities related to FEI's pipeline and distribution system. Operations also incurred costs for remediation activities related to erosion, landslides, forest fires and flood response.

Please refer to FEI's response to BCUC IR 1.1.1 in the FEI Annual Review for 2019 Rate proceeding, copied below, where FEI provided a detailed description of the factors contributing to 2018 cost pressures.

1.1 Please describe the new cost pressures FEI is experiencing in 2018 and expects to experience in 2019 with respect to O&M inside the formula.

This response also addresses BCUC IRs 1.1.1.1, 1.1.1.2 and 1.1.1.3.

FEI provides the following discussion of the formula and Productivity Improvement Factor (PIF) related O&M savings to enhance clarity and interpretation of the information. Formula savings are calculated by taking the difference between the actual O&M spending and the allowed O&M as provided using the formula approach (i.e., inflation, growth and productivity). Any savings calculated may be considered as one-time or permanent (sustainable), depending on the nature of the variance (i.e., temporary vacancy savings are considered one-time savings whereas a permanent headcount reduction would be considered permanent savings). On the other hand, the PIF related savings are determined based on the approved PIF factor (1.1 percent) applied to the O&M Base. The PIF related savings are imbedded as part of the formula and reduce the O&M Base funding by approximately $2.7 million each year. However, the savings cannot clearly be identified as permanent, as permanent savings are typically determined by comparing actual O&M spending to the allowed O&M funding available, instead of by reducing broadly the allowed funding available as the PIF does.

Formula savings can decrease as a result of cost pressures that increase actual spending compared to the allowed funding. Additionally, the impact of the PIF reduces the O&M Base funding that would otherwise be available. Without sufficient productivity related savings to offset the decreased allowed funding resulting from the annual PIF challenge, all else equal, the resulting formula savings will be lower.

For 2018, factors contributing to the forecast decrease in formula O&M savings from the recent year's result (i.e., $7.9 million savings in 2017 compared to forecast $5.0 million savings in 2018) include the ongoing impact of the PIF factor, the increasingly difficult challenge of finding new productivity opportunities with significant incremental savings, and cost pressures the Company is experiencing. Considering the increasingly difficult challenge of finding new productivity opportunities with significant incremental savings, the ongoing impact of the PIF factor itself reduces the allowed O&M funding each year by approximately $2.7 million. The PIF influence coupled with the cost pressures discussed below are expected to contribute to the forecasted decline in annual formula savings.

In order to respond to the evolving risks of changing cyber security landscape, O&M costs for cyber security are expected to increase by up to approximately $0.5 million in 2018. This pressure was discussed in the 2018 Annual Review Application, section 1.4.1, page 5. In 2019, this incremental funding will be required again to sustain the activities and may increase in the future.

Additional cost pressures the Company is managing are related to the growth and aging of the Company's pipeline and distribution system, estimated to total to approximately $1 million incremental in 2018. The Company continues to grow its asset base as new customers are attached to the distribution system, with new mains and service installations at high levels in recent years. In addition to the initial capital investment to install the necessary infrastructure required, the new assets also require supporting O&M resources to process and to operate and maintain them. These associated O&M costs are not directly charged to the capital activities and as a result are adding to the O&M costs pressures. The associated O&M costs are for support staff to process the higher number of capital jobs (i.e. employees to process new service orders) and for employee administration and training costs for staff (i.e. Planners, Engineers, Quality Assurance personnel, Construction crews, Trades Trainers) required to support the higher capital work. These cost pressures are expected to be sustained and may increase in future years depending on activity and personnel levels. Similarly, as the existing infrastructure continues to age, more resources are required to support activities to maintain the system. These growth and aging infrastructure related cost pressures are expected to continue and may increase in the future.

Other cost pressures the Company is managing are related to vehicle fuel and insurance costs and municipal fees. Vehicle fuel and insurance expenses have been rising with the average increase for 2018 and 2019 expected to be approximately $200 thousand incremental per year to O&M expenses. Additionally, fees paid to municipalities and other expenses to meet municipal regulations and allow the Company to obtain the necessary permits are expected to increase on average $100 to $200 thousand per year in 2018 and 2019.

Remediation activities related to erosion, landslides and fires in the spring and summer of 2018 in the Interior regions are also expected to reduce 2018 formula O&M savings by approximately $750 thousand. It is reasonable to expect these type of related cost pressures will continue into the future.

For 2018, the incremental cost pressures discussed above total to approximately $2.6 million and are expected to contribute to the forecast decline in formula O&M savings.

To offset some of these cost pressures, FEI has been continuing its ongoing productivity focus, including a broad-based Company-wide effort to seek alternate solutions to the filling and pursuing initiatives that result in savings that are shared with customers while maintaining service levels.

The cost pressures discussed above have related FTE/Headcount impact and have been considered in the 2018 Projected FTE/Headcount by FEI. However, FEI has not specifically identified FTE/Headcount with each cost pressure and instead has forecast staffing requirements at a general department level only.

Based on the information provided in the table in response to BCUC IR 23.2, FEI's historical Engineering Services & PM O&M expenses were as follows:

5.0 • 2014 - $15,383

6.0 • 2015 - $16,379

7.0 • 2016 - $16,382

8.0 • 2017 - $15,496

9.0 • 2018 - $16,556

Based on the information provided in the table in response to BCUC IR 23.4, FEI's historical Engineering Services & PM O&M FTEs were as follows:

10.0 • 2014 - 115

11.0 • 2015 - 115

12.0 • 2016 – 121

13.0 • 2017 – 121

14.0 • 2018 – 128

170.2 Please explain why the Engineering Service & PM O&M decreased in 2017 and then increased in 2018.

Response:

To explain the changes in O&M during the years noted, FEI provides the following table that shows (in $ thousands) a breakdown of Engineering Services & PMO O&M expenses into labour and non-labour.

Engineering Services & PM	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
Labour	10,870	11,780	11,681	10,857	12,218
Non-Labour	4,513	4,599	4,701	4,639	4,338
Total O&M	**15,383**	**16,379**	**16,382**	**15,496**	**16,556**

Contributing to the fluctuations in O&M costs observed are flow-through pension and OPEB costs changes that are not tied to the number of FTEs. As a result, changes in O&M spending have not correlated well with the changes in FTEs observed, particularly the change between 2016 and 2017. In 2016, pension and OPEB costs decreased slightly from 2015; however, in 2017, it decreased significantly. In 2017, the $886 thousand, or approximately five percent, decrease observed in labour was attributable to lower flow-through pension and OPEB costs allocated to the Engineering Services & PMO department. In 2017, the total O&M portion of pension and OPEB costs for FEI declined by approximately $8.4 million, or about 34 percent, with the Engineering Services & PMO's share of the decrease totalling to approximately $900 thousand.

In 2018, total O&M increased by $1.06 million or approximately 7 percent. The increase is attributed to higher labour costs resulting from increased headcount to meet operational requirements and as well as new headcount for the Major Projects group, a new department created in 2018. Pension and OPEB costs also increased in 2018.

170.2.1 Please explain why the above-mentioned changes in O&M do not correlate with the changes in FTEs during that time frame, particularly the change between 2016 and 2017.

<u>Response:</u>

Please refer to the response to BCUC IR 2.170.2.

Based on the information provided in the table in response to BCUC IR 23.3, FBC's historical Facilities O&M expenses were as follows:

15.0 • 2014 - $2,607

16.0 • 2015 - $2,475

17.0 • 2016 - $2,704

18.0 • 2017 - $2,741

19.0 • 2018 - $2,988

170.3 Please provide a detailed description of the factors contributing to the continuing increase in Facilities O&M expenses between 2015 and 2018. As part of this response, please explain in detail why Facilities O&M increased in 2016 and then again in 2018.

Response:

Facilities O&M increases are primarily due to operating and maintenance contract cost increases for FBC buildings and/or sites. Service and lease contracts are competitively tendered or negotiated over a fixed term. Upon expiry, contract increases have been experienced.

More specifically:

- In 2016, Facilities' costs relating to janitorial, site security, landscaping, and snow removal increased by approximately $170 thousand. The remaining increase related to labour expenses for pre-retirement training overlap and higher charges from FEI. FEI cross charges increased due to labour costs related to a preventative maintenance program for buildings.
- In 2017, the small O&M expense increases were caused by lease contract increases (buildings).
- In 2018, O&M expenses increased by $247 thousand from the previous year. This was driven by the introduction of the Kootenay Operations Centre (KOC). BCUC Order C-2-16 approved the new building construction and the associated operating costs for the facility which was completed in late 2017. This amount included an internal reallocation of $215 thousand from another department that was transferred to Facilities' expenses related to the operating and maintenance cost of the KOC; however, there was no impact to the overall FBC O&M. Finally, other increases for 2018 relate to internal labour expenses.

With regard to FBC, FortisBC stated in response to BCUC IR 23.4 that "FTEs increased slightly particularly in Operations and Engineering & PMO to support the AMI [Advanced Metering Infrastructure] system and new processes and as well as new headcount related to Mandatory Reliability Standards."

170.4 Please explain the increase in FTEs in the Energy Management department between 2014 and 2015 and then the further increase in 2016.

Response:

FBC clarifies the the reference in this question to the increases observed is to the table containing the Capital FTEs including Deferrals.

With the approved DSM spending budget increase from $3.0 million in 2014 to $7.3 million in 2015, FBC added two FTEs to increase the scope of its program offerings and capacity to process customer rebate applications. As program activity increased in 2016, along with an approved budget of $7.5 million, a further FTE was added partway through the year.

170.5 Please indicate which department(s) the new headcount related to Mandatory Reliability Standards (MRS) was added to.

Response:

The MRS group rolled up to the Engineering & PMO department in FBC's O&M and FTE breakdown by department tables, and the increase in headcount related to Mandatory Reliability Standards was added to the same department.

171.0 Reference: FEI BASE O&M

Exhibit B-10, BCUC IR 25.2, 25.3, 25.6, 25.7, 35.2; Exhibit B-1, pp. C-19 – C-20

Temporary Savings

On page C-19 of the Application, FEI proposes to add back temporary savings to FEI's 2018 Actual Base O&M of $1.677 million, which are comprised of $0.770 million for meter reading and $0.900 million for bad debts.

On page C-20 of the Application, FEI states the following:

> <u>In 2018, Olameter paid a penalty of $0.070 million based on 2017 performance</u>. In addition, they were not able to complete all of the readings as set out in the contract, which resulted in FEI reducing payments to Olameter by approximately $0.700 million. [Emphasis added]

FEI further states on page C-20 that it "considers these savings as not being sustainable, as we expect Olameter to meet their obligations under the contract in the future."

In response to BCUC IR 25.2, FEI stated: "In the Current PBR Plan term, Olameter paid a performance penalty in 2017 ($70 thousand) and in 2018 ($80 thousand)."

171.1 Please clarify based on FEI's response to BCUC IR 25.2 whether the 2018 penalty payment, which is proposed to be added back to the Actual 2018 Base O&M, is $0.070 million or $0.080 million.

<u>Response:</u>

The penalty payment proposed to be added back to the Actual 2018 Base O&M is $0.070 million.

FEI confirms that the penalty payment based on Olameter's performance in 2018 was $0.080 million; however, the penalties are finalized in the first Quarter of the subsequent year, which results in a timing lag. Thus, it is the 2017 penalty amount that is reflected in the 2018 O&M and accordingly the amount that must be added back to the Base O&M.

171.2 Please further explain the basis for FEI's statement that it expects Olameter to meet their obligations in the future, including a description of the actions which have been taken.

Response:

In the response to BCUC IR 1.25.1, FortisBC discussed the steps FEI has taken to work with Olameter to address the factors contributing to their performance and to meet their contractual obligations. FEI has seen improvement in Olameter's performance in 2019 in all areas of service delivery. Although the two most recent years of the contract have resulted in minor penalties relative to the overall contract costs, FEI believes these penalties are not reflective of the expected service level results going forward and as such, previous penalties should be considered temporary in nature.

171.2.1 As part of the above response, please also explain why two consecutive years of penalty payments would reasonably be considered temporary.

Response:

Please refer to the response to BCUC IR 2.171.2.

171.3 Please explain if FEI experienced a reduction in payments to Olameter in any other years of the Current PBR Plan term similar to the $0.700 million reduced payments experienced in 2018. If yes, please provide the amount in each applicable year.

Response:

There has been a variance between the cost of expected reads and the payments for actual reads in each year of the contract. In 2015, the actual reads were higher by approximately $0.100 million, resulting in higher payments than expected, and in all other years, the actual reads were lower and range from a variance in 2014 of $0.400 million to $0.700 million in 2016 through 2018.

As discussed in the responses to BCUC IR 1.25.1, 1.86.1 and 2.171.2, over the last few years, FEI has worked closely with Olameter to ensure they meet their contractual obligations. As a result, FEI has seen improvement in Olameter's performance in 2019 in all areas of service delivery. Therefore, FEI expects that the temporary savings created by reduced payments to Olameter in recent years will not continue and are appropriately reflected as temporary savings.

In response to BCUC IR 25.6, FEI stated the following:

> The meter reading costs embedded in the Base O&M take into account the reduced costs associated with meters that are not read due to access issues. This is because the contract accounts for a certain level of meters that may not be read each month due to the operational realities that include weather conditions.
>
> The impact of extreme events, such as prolonged and extreme winter conditions and wildfires, are not reflected.

171.4 Please explain the difference between the reduced costs associated with meters that are not read due to access issues which FEI stated are already embedded in the Base O&M and the $0.700 million related to reduced payments from Olameter's lack of meter reading completion.

Response:

The Base O&M for meter reading is calculated on a per read basis and is not based on 100 percent of meters being read. Instead, it is based on the achievement of the required performance standards which are contained within the contract. As a result, missed reads for any reason (including access issues) are embedded in the Base O&M up to the point of the performance standards required in the contract. If missed reads are higher and performance standards are missed, then there could be savings as a result. It is important also to note that there is no restriction on the vendor to read only at the performance standards. So, to the extent that the vendor reads more meters than required to achieve performance standards, costs would be higher than what is contained within the Base O&M.

FEI believes that holding the vendor accountable for achieving the performance standards within the contract is important as accurate and timely meter reads are a key component of customer satisfaction. FEI has been actively working with the vendor and expects them to meet their performance standards over the remaining term of the contract. Further, FEI believes that embedding meter reading costs that reflect the performance standards and expectations of the contract are necessary to ensure that performance expectations are met. That is, if the embedded funds in O&M do not sufficiently reflect the cost of meeting performance standards and the services identified within the contract, the ability to meet performance standards may be compromised.

Finally, with respect to future expected costs, the contract with Olameter has been extended for one year through to the end of 2020; however, Olameter has indicated that the existing low price inflation within the contract may not be sustainable beyond the one year extension, creating cost uncertainty regarding meter reading costs within the MRP term.

171.4.1 If the reduced costs referred to in the Application and in FEI's response to BCUC IR 25.6 are the same, please explain why the $0.700 million "temporary savings" should be added back to Base O&M.

Response:

Please refer to the response to BCUC IR 2.171.3.

In response to BCUC IR 25.3, FEI stated the following:

> FEI and Olameter entered into an amending agreement prior to the first renewal which revised the end of the term of the agreement to December 31, 2019. The amending agreement included pricing that was limited to one-half of the CPI…
>
> Under the Amending Agreement, the term may be extended for one additional year (January 1 to December 31, 2020) with a price increase limited to adjustments for CPI only. FEI will be providing notice to Olameter of its intent to extend the contract on these terms prior to June 30, 2019, but has not done so to date.

171.5 Please provide an update on FEI's notice of intent to extend the contract with Olameter. As part of this response, please provide the updated pricing and compare the updated pricing to the existing pricing.

Response:

FEI has completed an extension of its current contract with Olameter for a one-year term from January 1 to December 31, 2020. The extension continues all terms of the current agreement, with the renewal term costs inflated by one half (1/2) of the consumer price index (CPI).

171.5.1 If the contract has not yet been finalized, please explain whether, as part of the one-year extension from January 1 to December 31, 2020, FEI may be able to negotiate the same pricing as the existing pricing (i.e. one-half of CPI).

Response:

Please refer to the response to BCUC IR 2.171.5.

In response to BCUC IR 25.7, FEI provided the following table:

	2014	2015	2016	2017	2018	2019P
Bad Debt Expense	3,253,196	1,649,848	1,157,216	1,874,084	891,464	1,800,000

In response to BCUC IR 35.2, FBC provided the following table:

	2014	2015	2016	2017	2018	2019
Bad Debt Expense[42] ($)	1,217,093	1,276,247	877,490	1,037,224	471,147	1,000,000

171.6 Please explain why FEI's bad debt expense in 2014 was significantly higher than in the other years of the Current PBR Plan term.

Response:

The Companies believe that a five-year period (2014-2018) as reflected in the Application provides a representative timeframe for the high and low variation in bad debts expense that could occur due to changes in factors such as the overall economy strength and revenue levels, industrial bad debt and for one-time adjustments such as taxes (i.e. HST, carbon) related to customer bills. Over the course of the PBR term, high and low variations in bad debt expense were experienced in 2014 (high) and 2018 (low), demonstrating that variations will likely occur over a longer time period.

<u>2014</u>

While difficult to determine with certainty, in addition to changes in the economy, FEI's rates, and weather/consumption, the decrease in bad debt expense in 2015 compared to 2014 coincides with FEI's efforts in 2014 and subsequent years to improve operational efficiencies in collection processes, and a focus on working with customers to find reasonable and sustainable payment solutions. As a result, FEI believes it efforts contributed to the decrease in bad debt expense. Additionally, in 2014 bad debt expense was higher, affected by adjustments for tax recoveries and for prior year balances.

2018

FortisBC believes that the lower bad debt expense experienced in 2018 is attributable to several factors, including lower bad debt expense for industrial gas customers, as well as a combination of weather (and consumption), the overall strong economy experienced in British Columbia, and the continued focus of FortisBC to work with customers to find reasonable payment solutions. Customers in both service territories experienced warmer-than-normal temperatures during the winter of 2017/18, reducing consumption as compared to normal conditions, which resulted in lower bills in 2018 and correspondingly, potentially less bill-related challenges for some customers. Communications with customers regarding the need for reduced consumption in the latter months of 2018 (due to the Enbridge incident) may have also been a contributing factor to lower consumption and revenue amounts. In addition, British Columbia experienced a lower unemployment rate in 2018 as compared to previous years, which may have generally reduced the number of our customers experiencing difficulty paying their bills.[44]

In summary, as discussed above, bad debt expense can fluctuate from year to year due to a number of factors, some of which affect only a particular year's results. Each year's results can only be evaluated based on a longer time period where the annual fluctuations are averaged (i.e. smoothed), providing a more representative basis for comparison.

171.7 Please discuss the likely reasons why both FEI and FBC experienced significantly lower bad debt expenses in 2018.

Response:

Please refer to the response to BCUC IR 2.171.6.

171.8 Please explain why it would not be more appropriate to use FEI's and FBC's three-year 2016 through 2018 average bad debt expense to arrive at the appropriate adjustment for 2018 Base O&M.

Response:

[44] Province of BC Labour Force Statistics (July 2019); https://www2.gov.bc.ca/gov/content/data/statistics/employment-labour/labour-market-statistics; Data Tables- Table 2 BC Monthly Labour Force Data. Comparison of figure of 4.7 percent unemployment for 2018 as compared to 5.1 percent in 2017, 6.0 percent in 2016, 6.2 percent in 2015 and 6.1 percent in 2014.

FortisBC notes that the reference to "2018 Base O&M" in the question should likely be to "2019 Base O&M", consistent with the reference used in the MRP Application.

Using a three-year (2016 through 2018) average bad debt expense to arrive at the appropriate adjustment for the 2019 Base O&M would assume that all of the factors that impacted customers' ability to pay in those years remain static and are given equal weight. This includes the varying impacts of one-time adjustments (i.e as discussed in the response to BCUC IR 2.171.6), the overall economy, rates, weather and consumption. This approach to forecasting bad debt expense is not appropriate because it does not consider future potential changes in any of the factors and the particular three-year period considered reflects limited variation in economic circumstances and as such, it is unlikely to be more accurate than the proposed approach.

The Companies believe that a five-year average (2014-2018) as reflected in the Application will be more representative than a three-year average because a five-year period reflects recent experience while also considering high and low variations in overall economic strength and revenue levels. As such, this should be more indicative of the variations that may be experienced over the MRP term which will also span five years and is also projected to have higher rate increases than the current PBR term.

172.0 Reference: FEI BASE O&M

Exhibit B-10, BCUC IR 27.3, 32.6, 32.10; Exhibit B-1-3, p. C-19; Exhibit B-1, pp. C-22 –

C-24, C-38; FEI Certificate of Public Convenience and Necessity (CPCN) Application for the Inland Gas Upgrade (IGU) Project proceeding, Exhibit B-1

Adjustments – Integrity Digs

On page C-22 of the Application, FEI states the following:

> Integrity digs are determined based on FEI's analysis of in-line inspection data (for piggable pipelines) or above-ground coating and cathodic protection survey data (for non-piggable pipelines) once they are completed.

On page C-38 of the Application, FEI states the following:

> Not included in this category are the costs of the <u>integrity digs resulting from running ILI tools</u>. As there is uncertainty regarding the impact of the ILI results on the extent of integrity digs required during the Proposed MRP, FEI proposes to treat the costs of integrity digs as a flow through item, outside of formula O&M as discussed above in Section C2.4.2.2.3. [Emphasis added]

In response to BCUC IR 32.10, FEI stated: "As noted on page C-38 of the Application, FEI <u>proposes to treat the costs of all integrity digs as a flow through item</u>, outside of formula O&M as discussed above in Section C2.4.2.2.3." [Emphasis added]

172.1 Please clarify whether FEI proposes to treat all integrity dig costs as flow-through items or if FEI proposes to treat only the costs of integrity digs that result from running In-line Inspection (ILI) tools as flow-through items.

<u>Response:</u>

Consistent with the integrity dig costs reduction ($2.6 million) identified in Table C2-1 on Page C-19 of the Application, FEI proposes to treat all integrity dig costs resulting from any integrity assessment including in-line inspections as flow-through costs.

172.2 Please provide the forecast number and cost of integrity digs FEI plans to conduct on pipelines that cannot be inspected using ILI technology during the proposed MRP term.

Response:

FEI does not typically develop integrity dig forecasts given the degree of uncertainty in required dig numbers from year to year. Many factors influence FEI's annual integrity digs, as listed in FEI's response to BCUC IR 2.42.3 in the FEI IGU CPCN Application (which has been included in response to BCUC IR 1.32.9). These factors, as well as FEI's ongoing analysis of data from pipelines not currently inspected using ILI technology, impact the number and timing of digs on these pipelines.

FEI is anticipating an increase in integrity dig activity and associated costs over the proposed MRP term, including for pipelines not currently inspected using ILI technology. As stated on page B-20, lines 22-24, of the Application, as the average age of FEI's system continues to increase, the number of integrity digs is expected to increase. Further, FEI expects that industry practice will continue to evolve during the proposed MRP term, and that integrity digs on pipelines not currently inspected using ILI technology will have increasing priority and therefore increase the number of required integrity digs.

172.3 Please explain whether FEI is aware of any other Canadian natural gas utilities under multi-year rate plans that currently treat integrity digs as a flow-through item.

Response:

FEI is unaware of any other Canadian natural gas utilities that are currently under a multi-year rate plan and treat integrity digs as a flow-through item.

For the research, an informal survey of natural gas utilities was conducted by the Canadian Gas Association of its members for FEI. Three firms responded indicating no integrity digs were being done; 2 firms were under PBR and treated integrity dig costs as part of their Base O&M; and 1 firm treated integrity digs costs as capital and flow through and was under a cost of service structure.

FEI believes the choice in the treatment of integrity digs costs (formula O&M vs. flow through) will vary from jurisdiction to jurisdiction depending on the specific circumstances. While FEI does not have a specific example to refer to where another natural gas utility under a PBR plan treats integrity digs costs as a flow through item, FEI believes a key factor influencing the treatment of integrity dig costs is the uncertainty related to the scope, cost, timing, and volume of expected digs, and the uncontrollable nature of the expenditures. Please refer to the response to BCUC IR 2.172.5 for discussion of the factors that support FEI's proposed flow through treatment.

172.3.1 If yes, please provide the rationale given by the applicable regulatory body for approving the flow-through treatment.

<u>Response:</u>

Please refer to the response to BCUC IR 2.172.3.

172.3.2 If no, please explain the likely reasons why other natural gas utilities under MRPs would include the costs of integrity digs within formula O&M.

<u>Response:</u>

Please refer to the response to BCUC IR 2.172.3.

In response to BCUC IR 32.6, FEI provided the following table:

	Number of Digs per Year								
Reason for digs	2011	2012	2013	2014	2015	2016	2017	2018	2019 YEF
Dent digs (includes dig selections that were influenced by the strain-based criteria)	0	6	26*	12	11*	30*	21	15	30
Circumferential magnetic flux leakage in-line inspection digs	0	0	0	27	20	10*	44	36*	10
Other ILI digs	45	24	20*	19	33*	34*	25	34*	45
Non-ILI digs	9	8	4	4	2	0	8	1	5
Total Integrity Digs	**54**	**38**	**50***	**62**	**66***	**74***	**98**	**86***	**90**
Total Expenditures ($000's)	$1,600	$1,800	$1,400	$2,300	$2,300	$2,500	$3,200	$2,500	$3,100+
Cost per dig ($000's)	$30	$47	$28	$37	$35	$34	$33	$29	$34+

* *Note: Variances in dig numbers from past reporting has resulted from ongoing efforts in collecting and verifying historical dig data.*

\+ *The 2019 YEF is subject to change based on field conditions and necessary repairs. FEI notes that dig scope and costs can vary significantly.*

On page C-23 of the Application, FEI states: "For the period 2014 to 2019, expenditures for Integrity digs have varied between a low of $2.3 million to a high of $3.2 million, with the costs incurred dependent on the required scope of work and the number of integrity digs."

In the revised Table C2-1 on page C-19 of the Application, FEI shows a reduction to 2019 Base O&M of $2.6 million for integrity digs. The total 2019 Base O&M after adjustments is $256.15 million.

172.4 Please clarify, with reference to the integrity dig expenditures provided in the table in response to BCUC IR 32.6, how the reduction of $2.6 million to 2019 Base O&M was determined.

Response:

The integrity costs reduction to 2019 Base O&M of $2.6 million in the Application represents 2018 actuals inflated by the formula and was confirmed by estimating the number of integrity digs (100) and multiplying by an estimated cost of $26,000 per dig. As noted in the response to BCUC IR 1.32.6, "The 2019 YEF is subject to change based on field conditions and necessary repairs. FEI notes that dig costs can vary significantly."

The dig cost forecast for 2019 in the response to BCUC IR 1.32.6 is based on 90 digs at $34,000 per dig. The integrity digs planned for 2019 include instream work, environmental sensitivities, vegetation clearing, and danger tree removal which were not included in the estimate used to adjust 2019 Base O&M which explains why the total cost of integrity digs in the 2019 Base O&M ($2.6 million) is lower than that in the 2019 YEF ($3.1 million).

172.5 In consideration of FEI's total proposed Base O&M funding of $256.15 million, please explain why it is not reasonable to manage the variability of integrity dig expenditures, which historically have varied up to $900,000 annually, within the formula O&M spending envelope.

Response:

The proposal to forecast integrity dig costs annually as flow-through expenditures was based on the considerable uncertainty related to the scope, volume, timing, and resulting cost of digs during the MRP term. Further considerations that affect integrity dig variability, which are not reflected in the historical results, are the impacts of running new ILI technology and the IGU Project, if approved.

The historical annual variability of $900 thousand is not a good measure of the potential impact on the index-based O&M. As can be seen in the table provided in response to BCUC IR 1.32.6, costs upon entering the Current PBR Plan term were at $1.4 million and have more than doubled to $3.1 million by the end of the term, with the potential to further increase significantly over the upcoming term of the proposed MRP. Instead of FEI incorporating an adjustment in the Base O&M to reflect the level of uncertainty for the entire term of the MRP (refer to the response to BCUC IR 2.172.7), an adjustment that may turn out be too high or too low, the proposed flow-through treatment offers an appropriate funding mechanism that does not unfairly reward or penalize the Company or customers for volatility in the spending for integrity digs. This volatility and potential for significant increase is evident in the spending for integrity digs since the start of the Current PBR Plan term.

The proposed treatment is consistent with other uncontrollable costs described in Section C4.4.1 of the Application, some of which can vary to a lesser degree than integrity digs. Further, as noted on page C-22 of the Application, this treatment also relieves the constraints of index-based O&M on addressing pipeline safety issues.

172.5.1 As part of the above response, please explain the range of variability in O&M costs which FEI considers may be reasonably managed within the formula O&M spending envelope.

Response:

Please refer to the response to BCUC IR 2.172.5.

172.6 Please discuss how FEI budgeted for and managed expenditures related to integrity digs during the Current PBR Plan term and discuss any issues FEI has experienced.

Response:

FEI budgets for integrity digs in the Current PBR Plan term on an annual basis for the following year using ILI data and other available information.

The number of integrity digs planned and conducted annually is established at the time of budgeting based on priority and in consideration of many factors, including location, proximity to geographic features, resource availability, landowner impact, and cost effectiveness. Other factors such as subsurface conditions and nature of actual work required to repair the imperfection are unknown until resources are mobilized and the pipe is exposed.

FEI managed the expenditures of integrity digs during the Current PBR Plan term through prioritization based on ongoing engineering analysis. As ongoing analysis is performed, higher priority digs may be added and lower priority digs may be deferred. However, the variability in the number of integrity digs is generally uncontrollable. FEI has planned and conducted all required integrity digs over the Current PBR Plan term.

As stated on Page C-23 of the Application, the costs of integrity digs can vary significantly and range from $0.010 million to $0.150 million per dig. In addition to the specific issues described in BCUC IR 1.27.3, FEI has experienced other impacts to its integrity digs including the 2018 Enbridge rupture which impacted FEI's ability to perform certain integrity digs, and challenges digging in wetlands and stream crossings.

172.6.1 As part of the above response, please explain how FEI was able to manage the variability in integrity dig costs during the Current PBR Plan term and explain if, as a result of the variability, FEI did not perform all of its planned digs due to O&M funding pressures.

Response:

Please refer to the response to BCUC IR 2.172.6.

172.7 Under a scenario where FEI was directed to include integrity digs in the index-based O&M for the proposed MRP term, please discuss how FEI would budget for the expenditures relating to integrity digs and detail any adjustments FEI would make to the method used during the Current PBR Plan term.

Response:

Under a scenario where FEI was directed to include integrity digs in the index based O&M, FEI would need to significantly increase the $2.6 million Base O&M flow-through adjustment in Table C2-1 on Page C-19 of the Application (the table was revised in the response to BCUC IR 1.24.1, but the $2.6 million did not change). The increase would be required to account for the currently unknown number of additional integrity digs resulting from IGU and TIMC projects as well as other integrity assessments. Given the current lack of information, and no historical information to use for a comparator, any estimate for the increased work will be speculative. Consequently, FEI would need to adjust the Base O&M to reflect the level of uncertainty related to integrity digs including changes which may occur in regard to work scope, cost, timing and volume of expected digs. If FEI were directed to include an estimate for these digs in adjusted Base O&M, the Company would suggest increasing Base O&M to at least $5 million (an approximate doubling of current costs) as a representative forward-looking amount to appropriately reflect the uncertainties associated with the use of new ILI technologies and inspections of previously uninspected pipelines.

However, as stated in the Application and in response to BCUC IR 2.172.5, FEI believes including integrity digs as a flow-through expenditure based on its uncontrollable nature is a more effective solution.

172.7.1 As part of the above response, please explain if FEI would propose to include $2.6 million in the Base 2019 O&M related to integrity digs (i.e. the reduction proposed in Table C2-1 of the Application) or some other amount. Please provide a detailed explanation for the amount proposed.

Response:

Please refer to the response to BCUC IR 2.172.7.

On page C-24 of the Application, FEI states the following:

> The IGU project is expected to result in an increase in the number and associated costs of integrity digs starting in 2022…
>
> …If the IGU project results in increases in O&M costs related to integrity digs, then the alternatives would be to either re-base the index-based O&M or flow the additional costs of the integrity digs outside of the Base O&M. To provide greater transparency, FEI believes the preferred alternative is to flow all of the integrity dig costs outside of Base O&M.

In response to BCUC IR 27.3, FEI stated the following:

FEI is proposing to provide in-line inspection capability to 11 laterals as part of the Inland Gas Upgrade Project, and expects that it will propose to provide crack-detection in-line inspection capabilities for a number of larger diameter mainline pipelines as part of the Transmission Integrity Management Capabilities Project (TIMC). As part of the TIMC Project development, FEI will be piloting the use of crack-detection in-line inspection tools in its system as early as 2019.

172.8 Please estimate, based on the number of laterals proposed to be made ILI capable in the FEI IGU CPCN application, and based on the proposed IGU project timeline, the increased number of integrity digs resulting from approval of the IGU CPCN application in each year commencing in 2022 and the associated increase in costs.

Response:

FEI is unable to provide with any certainty an estimate of the increased number of integrity digs resulting from approval of the IGU Project. When running in-line inspection tool technology in a pipeline for the first time, predictions of the potential number of digs required are highly uncertain. Please refer to FEI's response to BCUC IR 1.32.8 for reasons why the number of in-line inspections, the length of pipe inspected (km), and the number of annual integrity digs do not correlate.

172.9 Please estimate the additional annual costs during the proposed MRP term of using the crack-detection in-line inspection tools.

Response:

FEI's costs associated with using crack-detection in-line inspection tools, excluding dig costs, will be identified within its TIMC Project CPCN application. As the TIMC Project is currently under development, including the scope and timeframe of the Project, FEI does not currently have estimates for additional annual costs that may result during the proposed MRP term.

173.0 Reference: FEI BASE O&M

Exhibit B-10, BCUC IR 28.1, 28.2, 28.3, 28.9; Exhibit B-1, p. C-28

Adjustments – LNG O&M Costs

FEI provided the following table in response to BCUC IR 28.1:

Actual Formula	2014 Actual		2015 Actual		2016 Actual		2017 Actual		2018 Actual		2019 Projected	
In $000's	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Labour	4,081		3,948		3,822		3,456		3,969		4,329	
Employee Expenses	71		90		71		106		287		267	
Vehicles	41		45		37		42		56		49	
Materials	427		481		586		562		562		385	
Contractors	384		965		928		1,147		738		715	
Fees & Admin	349		33		80		123		108		90	
Facilities	110		94		115		159		146		146	
Recoveries	(25)		(42)		(40)		(27)		(9)		(50)	
Electricity		778		587		631		598		435		706
Total	5,439	778	5,613	587	5,601	631	5,569	598	5,857	435	5,931	706

173.1 Please explain why employee expenses increased significantly commencing in 2017.

Response:

The increase in employee expenses commencing in 2017 to 2018 is the result of additional headcount to support Tilbury 1A operations and relocation and accommodation expenses related to the additional staffing required for the Tilbury 1A start up.

173.2 Please explain in detail why labour costs decreased annually between 2014 and 2017 and then began increasing as of 2018.

Response:

A factor that contributes to the variation in labour charges in Base O&M annually is the allocation of labour costs between Base and Rate Schedule 46 O&M. For LNG operations, FEI employees perform both Base and Rate Schedule 46 activities, providing for flexibility in utilization of resources and contributing to a productivity focus of "doing more with the same". This use of common labour resources for Base and Rate Schedule 46, however, can contribute to fluctuations in the allocation of labour costs from year to year, depending on the division of activities between Base and Rate Schedule 46. Additionally, labour costs can also vary from year to year in Base O&M due to normally occurring factors like the timing of hires and filling of vacancies, incurrence of overtime costs when required and work on capital activities.

Labour costs for Base O&M have been relatively consistent between 2014 and 2016 with a slight decline observed over the period reflective of the requirements for the existing Tilbury and

Mt. Hayes plants' operations and an increasing trend of a higher share of labour costs for Rate Schedule 46 activities. Starting in 2017, in support of the continued increase in activities for Rate Schedule 46 and the commissioning of Tilbury 1A Expansion, additional labour resources were allocated from Base O&M, contributing to the decline in labour costs in Base O&M. In addition, vacancies due to employee turnover (i.e., transfers within the Company) and retirements contributed to lower labour costs in Base O&M. For 2018 and onwards, with the startup of the Tilbury 1A Expansion, additional labour resources including overtime were and are required in support of Base O&M.

173.3 Please explain if the trend in labour costs described in the above IR is correlated to the changes in contractor costs during the same years.

Response:

No, there is no direct correlation between the trend in labour costs described and the changes in contractor costs during the same years. Drivers of the trend in contractor costs between 2014 and 2019 were mainly for upgrades, repair and maintenance to the plants. During the same period, the trend for labour costs in formula O&M was affected by fluctuations in Rate Schedule 46 requirements as described in the response to BCUC IR 1.173.2.

Contractor expenses increased between 2015 and 2017 due to upgrades, repairs and maintenance of the LNG plants, technical support and training of the staff. Increases in repair costs were related to the compressor at the Tilbury base plant. Contractor expenses declined 2018 and onwards as upgrades and repairs were completed in previous years and only regular plant maintenance activities were undertaken for 2018 and 2019. Please refer to BCUC IR 1.23.6 and 1.23.7 for further details of the maintenance activities.

173.3.1 If yes, please explain why the use of contractors increased between 2015 and 2017 and then declined commencing in 2018.

Response:

Please refer to the response to BCUC IR 2.173.3.

173.3.2 If no, please explain the drivers of the trend in contractor costs between 2014 and 2019.

Response:

Please refer to the response to BCUC IR 2.173.3.

In response to BCUC IR 28.2, FEI provided the forecast versus actual/projected LNG O&M costs for the costs which are treated as flow-through under the Current PBR Plan.

Flow-through	2014 Forecast		2015 Forecast		2016 Forecast		2017 Forecast		2018 Forecast		2019 Forecast	
In 000's	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Labour	77	54	224	80	176	105	1,352	176	2,414	182	2,670	283
Employee Expenses												
Vehicles												
Materials	17		49		41		156		91		130	
Contractors	25		73		60		345		732		773	
Office												
Computer												
Fees & Admin							120		160		160	
Facilities	15		42		40		166		135		144	
Electricity		188		467		448		2,660		2,936		3,272
Total	**134**	**242**	**388**	**547**	**317**	**553**	**2,139**	**2,836**	**3,532**	**3,118**	**3,877**	**3,555**

Flow-through	2014 Actual		2015 Actual		2016 Actual		2017 Actual		2018 Actual		2019 Projected	
In 000's	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Labour	194	67	136	98	361	112	1,473	160	2,717	354	2,908	406
Employee Expenses	0				19		45		36			
Vehicles	0		0		1		0		1			
Materials	32		46		59		52		202	310	130	411
Contractors	12		9		291		644		603		1,891	
Fees & Admin					1		22		25		160	
Facilities	16				30		142		28			
Electricity		228		334		565		404		2,271		3,981
Total	**255**	**295**	**193**	**432**	**762**	**676**	**2,379**	**564**	**3,612**	**2,935**	**5,089**	**4,798**

173.4 Please provide a description of the fixed and variable labour components of the LNG O&M. Please also explain how FEI determines whether labour is fixed or variable.

Response:

Fixed costs are costs to operate the LNG plant regardless of its use (i.e., for peak shaving storage or LNG production for sales). Variable costs are for the production of LNG (i.e., liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers to load LNG). Labour costs for employees' time to perform the activities identified as Variable (truck loading, shunting) are allocated to to Variable using timesheets.

The table below provides definitions of the fixed and variable cost components of LNG O&M used to categorize the types of costs shown (i.e., labour, materials, etc) in the response to BCUC IR 1.28.2 into Fixed and Variable.

Type of LNG O&M Costs	Fixed Costs related to operation of the plant regardless of its use.	Variable Costs related to production of LNG, whether for peak shaving or for LNG sales.
Labour	Labour cost for the operation of plant except for the truck loading and shunting activities.	Labour cost related to truck loading and shunting of LNG.
Materials	All materials except that used for freight / shipping of LNG.	Materials used for freight for shipping of LNG (i.e., ISO containers).
Contractor	Maintenance and disposal services (i.e., waste removal).	Contractor services used for truck loading. Services for sewer water treatment related to production of LNG.
Power (i.e., electricity)		All power (i.e., electricity) costs including that to operate the LNG facility but not related to LNG production, because the significance of the amount to operate the plant is considered immaterial for purposes of allocation.
Employee Expenses	Employee expenses are considered fixed except for charges related to truck loading labour.	Related to truck loading labour.
Vehicles	All vehicle costs (ie. vehicles used for maintenance) are considered fixed except for vehicles used for shunting and shipping of LNG.	Shunting trucks.
Other	Costs such as for permits and licenses are considered fixed as costs will be incurred regardless of production of LNG.	

173.5 Please describe the nature of the employee expenses which were incurred in years' 2016 through 2018.

Response:

Employee expenses incurred from 2016 to 2018 consisted of course fees, travel, meals, living out allowance, mileage and accommodation. Also included were expenses for the training of additional employees required in preparation for startup of the Tilbury 1A plant for Rate Schedule 46 activities.

173.5.1 Please explain why FEI has not forecast the incurrence of employee expenses in any of the years after 2016 (i.e. after the first year the employee expenses were incurred).

Response:

At the time when the forecasts were prepared for 2017 and onwards, given that historical employee expenses were not significant (i.e., $19 thousand in 2016), FEI did not specifically forecast employee expenses as a separate line item and instead included an allowance as part of Fees & Admin.

173.6 Please explain why, commencing in 2018, FEI has classified some materials costs as variable. As part of this response, please provide a description of the variable and fixed materials costs.

Response:

Some material costs that were classified as variable in 2018 were related to freight for shipping LNG (i.e., ISO Containers). Fixed costs for materials include all material costs incurred at the plants except for freight and shipping of LNG and some process chemicals which fluctuate with production volumes. Variable costs include freight costs related to LNG shipping and process chemicals whose volumes fluctuate with production volumes (i.e., refrigerants).

Please refer to the response to BCUC IR 1.173.4 for descriptions of the fixed and variable components of the LNG O&M.

In Table C2-6 on page C-28 of the Application, FEI provides the proposed Adjusted O&M Base amount related to LNG of $9.677 million and the proposed incremental Base O&M amount of $1.853 million, which results in a proposed 2019 Base amount of $11.530 million.

FEI also states the following on page C-28 of the Application:

> The $0.856 million for labour costs includes the hiring of two additional maintenance employees at an approximate cost of $0.274 million and $0.582 million for full year funding for positions hired part way through 2018. In 2018, six new positions were added part way through the year at an approximate cost of $0.353 million. An additional $0.582 million is required in the Base O&M representing the full year cost for the positions.

In response to BCUC IR 28.9, FEI stated the following:

> The job title of the two new positions that will be added is “LNG Millwright.”…The two additional millwright positions were identified as being needed after completing a detailed assessment of the equipment maintenance requirements as part of the start up of Tilbury Expansion.
>
> The six positions added part way through the year…related to operator positions approved as part of the FEI 2018 Annual Review.

In response to BCUC IR 28.1, FEI provided the 2019 Projected Fixed O&M currently included in the O&M formula of $5.931 million.

In response to BCUC IR 28.2, FEI provided the 2019 Forecast Fixed O&M and 2019 Projected Fixed O&M currently classified as Flow-through of $3.877 million and $5.089 million, respectively.

Based on FEI’s responses to BCUC IR 28.1 and 28.2, the 2019 Projected Fixed O&M which would be considered formula O&M under the proposed treatment for the MRP is $11.020 million.

173.7 Please explain when the need for the additional two millwright positions was identified.

Response:

The requirement for the additional millwrights was determined upon completion of a Reliability Centred Maintenance review by Asset Management and Operations in early 2019. Reliability Centred Maintenance refers to an established process within industry of reviewing the equipment vendor information and reconciling with previous experience to establish the annual maintenance program for the equipment. The process ultimately provides all the required maintenance activities to meet annual availability targets and therefore provides annual maintenance FTE requirements.

173.7.1 As part of the above response, please explain if the additional millwright positions were included in the 2019 Forecast for fixed LNG costs. If yes, please indicate where these increased costs were recorded based on the table provided in response to BCUC IR 28.2. If no, please explain why not.

Response:

The additional millwright positions were not originally included in the 2019 Forecast for fixed LNG costs as the Reliability Centered Maintenance review was not completed until early 2019. These positions are included in the 2019 Projected LNG fixed costs in the table provided in the response to BCUC IR 1.28.2 under the Labour column as part of the $2,908 thousand indicated.

173.8 Please explain whether the six additional operator positions were included in the Forecast 2019 Fixed LNG costs. If yes, please indicate where these increased costs were recorded based on the table provided in response to BCUC IR 28.2. If no, please explain why not.

Response:

Yes, the six additional positions were positions included on the Forecast 2019 Fixed LNG costs. These increased costs were recorded as part of the labour costs in the table provided in the response to BCUC IR 1.28.2.

173.9 Please confirm, or explain otherwise, that the Projected 2019 Fixed Flow-through LNG O&M costs provided in response to BCUC IR 28.2 include the incremental Base O&M costs described on page C-28 of the Application.

Response:

Confirmed.

The reason why there is a higher proposed 2019 Base O&M amount of $11.53 million compared to the Projected 2019 Fixed LNG costs of $11.02 million is a difference in timing because of when the two cost estimates were prepared. The $11.02 million 2019 Projection was prepared based on actual experience so far in 2019 and reflects more closely the expectation for the year, including any timing differences of spending for items identified as for incremental spending included in the 2019 Base O&M.

For the proposed MRP, as discussed in the response to BCUC IR 1.28.3, the 2019 Base O&M of $11.53 million is an accurate representation of a normal year's operation for the Tilbury Expansion and of the fixed annual operating costs that will be incurred over the MRP term, recognizing that the costs will be subject to inflation for services and materials or changes in regulation that may occur during the term of the proposed MRP.

173.9.1 If confirmed, please explain why the proposed 2019 Base O&M amount for LNG costs of $11.530 million is higher than the combined Projected 2019 Fixed LNG costs provided in response to BCUC IR 28.1 and 28.2 of $11.020 million.

Response:

Please refer to the response to BCUC IR 2.173.9.

173.9.2 If not confirmed, please provide a cost breakdown similar to the 2019 Projected Fixed O&M amounts provided in response to BCUC IR 28.1 and 28.2 which explains the need for the additional $510,000 (i.e. $11.530 million proposed Base O&M less $11.020 million Projected Fixed O&M). Please clearly identify which incremental costs described on page C-28 of the Application are already incorporated in the 2019 Projected Fixed O&M amounts provided in response to BCUC IR 28.1 and 28.2 and which incremental costs described on page C-28 of the Application are not included.

Response:

Please refer to the response to BCUC IR 2.173.9.

173.10 Please provide updated Projected 2019 O&M amounts (fixed and variable) in the same level of detail as was provided in the tables in response to BCUC IR 28.1 and 28.2 to reflect the additional months of actual O&M results. Please explain any significant variances in the updated Projected 2019 O&M amounts.

Response:

The Projected 2019 O&M (Fixed and Variable) for both the Base and Rate Schedule 46 are still projected to be substantially the same as that provided in the BCUC IRs 1.28.1 (Base) and 1.28.2 (Rate Schedule 46).

	Projected (BCUC IR 1.28.1)		Projected (BCUC IR 1.173.10)	
	Fixed	Variable	Fixed	Variable
Base	5,931	706	6,001	542
RS 46	5,089	4,798	5,014	4,848
Total	11,020	5,504	11,015	5,390

There are variations within the line items from the responses to BCUC IR 1.28.1 and 1.28.2. Within Fixed O&M, there has been a decrease by approximately $500 thousand in labour which is offset by increases in contractor and materials expenses. Within Variable O&M, increases in labour and materials costs are offset by approximately $1.2 million in lower electricity costs as a result of the transition to the BC Hydro Industrial rate tariff, from $80/Mwh to $50/Mwh, starting September 2019.

FEI notes that the Tilbury 1A plant has yet to be transferred over to FEI and therefore temporary 2019 Rate Schedule 46 flow-through O&M is still subject to variances from the 2019 Projected provided here since these amounts are not indicative of normal course operations. However, given the transition and commercial operation activities that occurred during 2019, certain of these related costs are not expected to affect the projected 2019 Base O&M to establish for the MRP.

173.10.1 If the updated 2019 Projected Fixed O&M amounts are still significantly less than the proposed 2019 Base O&M amount of $11.530 million, please explain in detail why it would not be more appropriate to reduce the Base 2019 O&M amount to reflect an amount closer to the Projected 2019 amount.

Response:

The updated 2019 Projected Fixed O&M amount as provided in the response to BCUC IR 2.173.10 including the Base ($6,001 thousand) and Rate Schedule 46 ($5,014 thousand) totals to $11.02 million, the same as previously projected ($11.02 million) and less than the 2019 Base O&M amount of $11.53 million. Contributing to the temporary lower spending in 2019 compared to the 2019 Base O&M is the timing of the hiring of additional positions to support the Tilbury 1A operations. Additionally, any projected underspend in 2019 costs compared to the proposed 2019 Base O&M is not an indication of the need going forward, but more a reflection of the first year startup of Tilbury 1A plant in 2019 as well as the timing of incremental costs expected for 2020.

For the proposed MRP, as discussed in the response to BCUC IR 1.28.3, the 2019 Base O&M of $11.53 million is an accurate representation of the Tilbury Expansion's annual operating costs, recognizing that the costs will be subject to inflation for services and materials or changes in regulation that are expected to occur during the term of the proposed MRP.

In response to BCUC IR 28.3, FEI stated: "While there is expected to be some variation in operational costs as FEI gains experience maintaining the equipment within the Tilbury Expansion facility, FEI has taken steps to minimize the potential for significant variances in the O&M expenditures proposed."

173.11 In consideration of the large increase in contractor costs between 2018 and 2019 and the large variance in contractor costs between 2019 forecast and 2019 projected, as shown in the tables in response to BCUC IR 28.2, please further explain the likelihood of large fluctuations in contractor costs during the proposed MRP term and the factors/events which could lead to large fluctuations.

Response:

The large variance in contractor costs for 2019 is related to a one time exercise to develop and deliver an operator competency program for the Tilbury 1A operators.

The likelihood of large fluctuations in contractor costs during the MRP term is low as the contractor support required is relatively well understood for routine operations. Factors or events that could lead to large fluctuations would be dependent on the performance of the equipment in both the Base Plant and the new Tilbury 1A plant. Unexpected outages or equipment breakdowns could result in a higher than forecast contractor spend. Other factors that could drive contractor costs during the MRP term include any regulatory changes which may require activities to ensure ongoing compliance.

In response to BCUC IR 28.10, FEI stated the following:

> The additional funding required for contractor support at the Tilbury site relates to the estimated annual cost for external service agreements that FEI needs to retain in order to maintain complex equipment that requires specialized expertise. These services were previously provided by Bechtel, the prime contractor for the Tilbury Expansion, but beginning in 2019 the responsibility for these services was transferred to FEI.

173.12 Please explain why Bechtel is no longer providing the services described in response to BCUC IR 28.10.

Response:

Bechtel provided these services to FortisBC through the commissioning and handover phases in the original contracted scope of work as part of the Tilbury 1A LNG Expansion Design Build contract. In May 2019, Bechtel completed the contractual requirements at which time FortisBC assumed full responsibilities for operation of the Tilbury 1A facility. As a result, Bechtel's contractual obligation to continue to provide these services has expired.

173.13 Please compare the cost charged by Bechtel for providing the services described in response to BCUC IR 28.10 to the costs charged by the new contractor(s).

Response:

FortisBC is currently in negotiations with various service providers for the services required at the site. It is difficult to compare directly the cost of these services as the scope of services may be different based on the period the services were provided. For example, specialized services for fugitive emissions monitoring will be more expensive under a full production environment than in the construction and commissioning phase. Similarly, security expenses should be lower during steady state operations than during the construction phases. As a general statement, and for equivalent scopes of work, services procured directly by FortisBC should be more cost competitive as there will be no contractor mark-up added to the service contract.

173.13.1 As part of the above response, please indicate the number of contractors being utilized for these services and explain why these services could not be provided by a single contractor, similar to FEI's previous arrangement with Bechtel.

Response:

The total number of contractors utilized for these services cannot be determined until all service contracts are in place. As noted in the response to BCUC IR 1.28.10, third party support will be required for specialized expertise such as security, fire and gas detection systems, process safety valve recertification, distributed control system, fugitive monitoring, corrosion monitoring, and specialized maintenance support for the compressors, liquefiers and pre-treatment equipment. The external service agreements will be structured to ensure that when required, these specialized services are available and the appropriate companies can provide support services to Tilbury without delay to ensure no interruptions to production.

Service agreements as described above are commonplace in the gas processing industry. Utilization of a single contractor to manage all the various service agreements adds cost and complexity to accessing the services required.

174.0 Reference: FEI BASE O&M

Exhibit B-10, BCUC IR 2.1, 30.2, 30.5, 30.8, 30.18.1, 30.26

New Funding for MRP Term – Customer Expectations

In response to BCUC IR 30.2, FEI provided the following table regarding FEI's historical Customer Expectations O&M spending:

Expenditures (in $ millions)	**2014**	**2015**	**2016**	**2017**	**2018**
Connect to Gas					
Natural Gas Appliance Incentives (incl. Stakeholder Engagement)	$0.890	$1.341	$1.338	$1.030	$1.711
Advertising - New Customer Additions & Conversions	$0.087	$0.759	$0.889	$1.082	$0.565
Total Connect to Gas	**$0.977**	**$2.100**	**$2.227**	**$2.112**	**$2.276**
In-house Resources to Address Customer Preferences					
In-house Resources (digital communications)	$0.051	$0.072	$0.125	$0.271	$0.271

In response to BCUC IR 30.2, FEI also stated: "Historically, FEI has spent little on providing workshops, education sessions and other types of stakeholder engagement with builders, developers, and manufacturers for the purpose of advancing gas technology, adoption and use."

174.1 Please explain in detail the increased spending on the Natural Gas Appliance Incentives in 2018 compared to previous years.

Response:

The increased spending on Natural Gas Appliance Incentives in 2018 was due to multiple factors including:

- FEI experienced an increase in overall participation in the incentive program. A total of 1,471 customers applied for incentives in 2018 compared to 956 in 2017, driving higher than historical spending.
- FEI expanded appliance incentive offerings to respond to the market. This included a new top-up incentive for water heating (increasing the incentive from $1,300 for just space heating to $1,700 for space and water heating). The top-up incentive was developed to encourage customers to consider upgrading their home heating system holistically at the construction stage, and address natural gas space and water heating solutions simultaneously. FEI also expanded natural gas appliance incentives to cover new natural gas equipment solutions such as wall furnaces and combi-system units. These are newer technologies in the market and provide compact natural gas appliance

solutions in a market where the average square footage in new home construction is declining and space is limited.

174.1.1 As part of the above response, please indicate if a contributing factor to the increased spending was increased stakeholder engagement activities.

Response:

FEI confirms that, as part of the increased participation in the Natural Gas Incentives program discussed in the response to BCUC IR 2.174.1, FEI's engagement and interaction with stakeholders such as contractors, builders, developers and equipment manufacturers increased. However, as FEI discussed in the response to BCUC IR 1.30.2, the engagement activities that occur as part of this program are not tracked separately and have been informal.

174.2 Please explain in detail why the spending on Advertising – New Customer Additions & Conversions was significantly lower in 2018 compared to 2017.

Response:

As noted in the response to BCUC IR 1.30.3.1, FEI may need to adjust its focus and/or shift funds between activities within its Connect to Gas umbrella to respond to the market landscape. As such, in 2018 FEI shifted investments towards the Natural Gas Appliance Incentives program and away from Advertising, to focus more on providing incentives to the market to increase the adoption of natural gas appliance solutions. This flexibility allows FEI to invest in areas with the highest impact in its efforts to add and retain customers.

174.3 Please explain why FEI has not historically undertaken the types of stakeholder engagement with builders, developers and manufacturers described in the above preamble.

Response:

The need to undertake this type of engagement with builders, developers and manufacturers during the MRP term has been precipitated by the changing market landscape, including climate policy directions which restrict the use of natural gas. In order to continue to add and retain customers, FEI has proposed to increase its effort and engagement activities within the stakeholder community, including activities seeking to educate stakeholders on the benefits of natural gas and the use of emerging natural gas technologies.

174.3.1 As part of the above response, please explain the types of interactions which FEI has had with builders, developers and manufacturers historically.

Response:

As discussed in the response to BCUC IR 2.174.1.1, FEI's engagement and interaction with this group of stakeholders conducted under the umbrella of the Natural Gas Incentive program has been more informal in nature, where FEI discusses various incentives and promotes natural gas as a safe, affordable and versatile energy solution.

FEI has a diverse group of stakeholders it engages with to encourage the adoption of natural gas solutions. As noted in FEI's response to BCUC IR 1.30.19, these interactions can range from individual discussions with and education of stakeholders such as builders, developers and contractors about the applicability and integration of natural gas in their projects, to undertaking collaborative initiatives that pilot new natural gas equipment solutions.

174.4 Please explain what precipitated FEI identifying the above-described engagement gap and why FEI considers it important going forward to address this gap.

Response:

A number of the factors that led to the identification of an engagement gap, and why it is important to address going forward, are discussed below:

FEI identified a lack of market knowledge of new natural gas equipment solutions, particularly those that are not yet considered mainstream such as wall furnaces and comb-units. To continue to add and retain customers, FEI needs to proactively promote the adoption of these energy solutions within its stakeholder community to inform and educate them on the benefits and applicability of the technology for their projects.

FEI identified that other competing heating solutions, such as electric air source heat pumps, are being increasingly promoted. In order to maintain market share, FEI needs to engage with stakeholders to ensure comparable natural gas equipment solutions such as gas-fired heat pumps, which are an emerging technology, are considered.

FEI identified that energy literacy related to natural gas is declining as discussed in the response to BCUC IR 1.30.10. Therefore, FEI needs to ramp up engagement activities to help address knowledge gaps and educate customers on their heating options so they are able to make fully informed decisions.

Finally, FEI identified that the evolving market landscape has become more complex. Climate policy aimed at reducing GHG emissions often overlooks the role that natural gas can play in reducing emissions, making it less likely that customers and stakeholders will integrate natural gas in their projects. FEI needs to engage closely with its stakeholders to navigate through policies, such as the BC Energy Step Code, and promote the benefits of natural gas for their projects.

In response to BCUC IR 2.1, FEI stated that climate action plans, including the CleanBC Plan, the BC Energy Step code and local government actions to strengthen their climate action initiatives, will constrain the outlook for FEI's traditional natural gas services. FEI further identified the following climate action plans that affect buildings and thus demand for natural gas in homes and businesses:

- BC Energy Step Code
- CleanBC's Impact on the Step Code
- CleanBC's Impact on Energy Efficiency and Electrification
- City of Vancouver Climate Emergency
- Other Municipalities

In response to BCUC IR 2.1, FEI also stated the following:

> The CleanBC Plan also calls for measures to expand energy efficiency improvements and electrification of buildings by fuel switching from natural gas appliances to electric heat pumps. CleanBC states that 70 thousand homes and 10 million m2 of commercial space will be retrofitted with electric heating, and that by 2030, 60 percent of homes and 40 percent of commercial buildings will

> use clean electricity, whereas today the majority of those homes and businesses are heated with natural gas.

In response to BCUC IR 30.5, FEI stated the following:

> …the 2019 Base O&M funds will not be sufficient for FEI to address the challenges it faces over the MRP term. FEI has therefore requested an additional $1.2 million to enable it to compete in the BC energy market space and address the challenges FEI faces in retaining and growing its customer base.

174.5 Please explain how increased spending on Customer Engagement activities such as Connect to Gas and Advertising will assist FEI in retaining and growing its customer base within the residential and building sectors if the climate action plans described in response to BCUC IR 2.1 are mandated.

Response:

FEI does not see a conflict between the proposed increased spending on Customer Engagement activities and the achievement of climate action plans. Rather, as stated in the response to BCUC IR 1.2.4, FortisBC believes its assets will play a critical role in the transition towards a lower carbon economy. FEI's focus on developing alternative energy products and services that reduce emissions while also leveraging its existing assets is supportive of climate objectives. Attracting and retaining customers expands FEI's ability to deliver clean, safe, reliable and cost effective energy to its customers and is aligned with climate action objectives.

In the response to BCUC IR 1.1.1, FEI identified that, with lower than desired levels of public awareness and involvement in energy decisions, there is an opportunity for FortisBC to provide leadership and education on how natural gas and electric distribution systems can play an active role in shifting BC to a lower carbon economy. Increasing spending on Customer Engagement not only supports the attraction and retention of customers, but also promotes the increased adoption of energy solutions that are aligned with climate objectives. This was highlighted in the response to BCUC IR 1.3.6:

> FEI intends to continue to add and retain customers while also serving the new and emerging energy needs of its customers.
>
> …
>
> As noted in the Application, FEI provides a range of energy solutions that are aligned with Provincial Government direction and mandates around reducing emissions. For example, FortisBC's programs help convert customers to cleaner sources of energy in transportation and buildings, provide renewable energy options for new and existing customers, and reduce emissions through its DSM programs by increasing efficiencies.

In summary, the proposed MRPs, including the increased spending on Customer Engagement, helps position FortisBC to continue to provide service to customers as the economy transitions towards a lower carbon future.

174.5.1 With separate reference to each of the three incremental funding categories (i.e. Advertising, Natural Gas Appliance Incentives, and Stakeholder Engagement), please explain how, in light of the climate action initiatives described in response to BCUC IR 2.1, the incremental funding will assist with: (i) attracting new natural gas connections; (ii) achieving conversions to natural gas; and (iii) retaining existing natural gas customers.

Response:

From research, and conversations and engagement with customers, builders, developers, contractors and stakeholders, FEI is aware that the general knowledge of gas is low in relation to options for customers, pricing, advantages and benefits. The following three components are designed to address and improve gas knowledge and understanding and lead to greater attraction and retention of customers.

Natural Gas Appliance Incentives

FEI offers incentives such as those to encourage customers to switch from other fuels such as oil or propane to natural gas. These incentives are popular with customers and FEI has seen increasing uptake as the incentives help to offset the upfront cost associated with the installation of natural gas heating appliances.

Conversions are often new natural gas customers as a large proportion do not previously have a natural gas service line and so connecting to natural gas and appliance installation costs are often higher than for new construction. Furthermore, natural gas appliances typically have a higher up-front cost as compared to other fuels such as electricity. Offering these incentives can help customers with these added costs. Over the course of the term of the MRP, FEI will continue to evolve its incentive program based on the market challenges it faces and the opportunities available both to attract new construction and conversion customers.

Advertising

While FEI has not pre-determined all of its advertising activities over the entire MRP term, for 2020 FEI plans to allocate the increased funding to include a Cooking with Gas campaign which will promote the use and versatility of natural gas for cooking to retain existing customers, and also an energy literacy campaign to attract new customers. The energy literacy campaign will focus on educating customers on the benefits of natural gas such as comfort, convenience and affordability as well as how natural gas is an important driver of the BC economy.

FEI had contracted the services of Innovative Research Group in 2018 to conduct research on customer preferences to understand the attitudes and knowledge of natural gas. This survey revealed that 48 percent of respondents thought that natural gas was the same price or more than electricity, reinforcing that customers are uninformed about their energy costs and that there is significantly more work that can be done in this area to increase awareness.

In addition, FEI has planned to promote awareness of the Connect to Gas program, which predominantly focusses on builders, developers, architects, engineers, equipment manufacturers, and contractors to promote the adoption of natural gas solutions. The Connect to Gas audience is largely technology focused and influences natural gas equipment selection within the building environment. As such, the messaging to this group is more specific and focused on the goal of adding and retaining customers by promoting familiarity and the adoption of natural gas and natural gas appliances.

Stakeholder Engagement

FEI recognizes that key stakeholders in the attraction and retention of customers includes customers themselves, builders, developers, HVAC contractors, manufacturers, distributors, municipal staff and other industry stakeholders that play a large role in energy choices both for new construction and existing buildings. Increased spending in this area will focus on increased dialogue and sessions to educate on the role gas will continue to play in the low carbon economy and the many natural gas solutions and technologies available to meet their energy needs. This activity will assist with all areas of attracting new natural gas connections, achieving conversions to natural gas, and retaining existing natural gas customers.

Over the term of the MRP, FEI will continue to focus on growing and retaining its customer base despite the more challenging operating environment. These activities will play a key role in helping mitigate some of the emerging pressure on FEI's ability to attract and retain customers as a result of climate policies.

In response to BCUC IR 30.18.1, FEI stated the following:

> FEI is also able to influence the market to adopt certain equipment or technologies. For instance, over the Current PBR Plan period, FEI worked with builders and developers to adopt natural gas heating equipment in their projects and provided incentives for equipment like combi-units and wall furnaces. These

incentives proved to be effective and the developer community has started to embrace this equipment.

In addition, FEI's Energy Solutions team works very closely with key stakeholder groups such as builders, developers, architects, engineers and contractors to keep them abreast of natural gas solutions and benefits.

174.6 Please explain how the activities described in response to BCUC IR 30.18.1 are different from the stakeholder engagement activities described in response to BCUC IR 30.2.

Response:

The activities described in response to BCUC IR 1.30.18.1 are the same as the activities described in response to BCUC IR 1.30.2. For added clarity:

- In the response to BCUC IR 1.30.2, FEI is providing a description and breakdown of expenses associated with the Connect to Gas umbrella.
- In the response to BCUC IR 1.30.18.1, FEI describes the factors that FEI is able to influence and how the Energy Solutions team works with builders, developers, and other stakeholders to promote the adoption of natural gas solutions under the Connect to Gas program.

In response to BCUC IR 30.8, FEI provided the following table:

FEI Advertising Expenditure ($ millions)					
2014	2015	2016	2017	2018	Total
$3.400	$4.102	$4.264	$3.351	$6.776	$21.894

FEI further stated the following in response to BCUC IR 30.8:

> These expenses include advertising for multiple areas and initiatives within FEI such as safety, conservation and energy management, natural gas for transportation, renewable natural gas, energy solutions (connect to gas initiatives), and capital projects. Not all of these amounts are included in O&M.

174.7 Please clarify FEI's statement that not all of the advertising expenditures are included in O&M.

Response:

FEI clarifies that advertising expenditures relating to Conservation & Energy Management (C&EM) are not included in O&M and are instead part of the DSM program expenditures.

The table below provides a breakdown of advertising expenditures attributable to O&M and C&EM which form the "other" category. The table has been expanded to include the 2019 projected expenditure amounts.

FEI Advertising Expense							
($ millions)	2014	2015	2016	2017	2018	Projected 2019	Total
O&M	$ 2.413	$ 3.273	$ 3.572	$ 2.503	$ 5.369	$ 2.843	$ 19.973
CE&M	$ 0.987	$ 0.829	$ 0.692	$ 0.848	$ 1.407	$ 2.384	$ 7.147
Total	$ 3.400	$ 4.102	$ 4.264	$ 3.351	$ 6.776	$ 5.227	$ 27.120

174.7.1 As part of the above response, please further break down the table provided in response to BCUC IR 30.8 to show how much of the annual expenditures are attributable to O&M and how much are attributable to other (and specify the other). Please also expand the table to include Projected 2019 amounts.

Response:

Please refer to the response to BCUC IR 2.174.7.

174.8 Please provide the total amount of Advertising expenses which are proposed to be included in FEI's Base 2019 O&M. As part of this response, please identify and describe each category of advertising costs.

Response:

The table below provides the total amount of advertising expenses that are proposed to be included in FEI's Base 2019 O&M[45].

[45] Excludes advertising activities related to capital (i.e., DSM and Capital Projects).

FEI O&M Advertsing Expenditures ($ millions)	Projected 2019
Safety	$1.688
NGT	$0.120
Energy Solutions(Connect to Gas)	$0.785
General Communication	$0.250
Total	**$2.843**

Please see below for a brief description of these advertising categories:

Safety: Focuses on educating the public on key natural gas safety messages, including "Call before you dig", Gas Odour, and Emergency preparedness. Includes various mass media mediums such as radio, digital, social media, events, bill inserts.

Natural Gas for Transportation (NGT): Educates industry, business and government on the benefits of using CNG or LNG, including for marine, transit, fleet vehicles. Channels include industry specific publications, digital and social media.

Energy Solutions: Focuses on the benefits of natural gas for space and water heating, through the Connect to Gas campaign primarily in Vancouver Island, Squamish, Whistler and the Lower Mainland. Channels used include print, digital, radio, social, bill inserts.

General Communications: This includes building and sharing awareness of the services and products FortisBC provides to British Columbians. Local Chambers, Board of Trades, Indigenous Relations publications, industry associations etc. are examples of some of the channels used to reach a broad audience.

In response to BCUC IR 30.26, FEI stated the following:

> The Digital Advisor, Communications Writer/ Researcher and Digital Communications Advisor requests relate to three incremental positions. This was initially contracted out to consultants to help manage work peaks, but with increased requirements, FEI plans to add incremental resources and bring this expertise in-house at the same time in order manage the workflow.

In response to BCUC IR 30.2, FEI provided the following details of the changes from year to year related to In-house Resources (digital communications) to Address Customer Preferences:

- In 2014 and 2015, the cost includes one contract writer, and not full-time capacity;
- In 2016 and 2017, FEI experienced an increase in demand for communications services and used two writers almost at full-time capacity;
- In 2018, FEI had three writers at full-time capacity; and
- The 2019 proposed incremental funding of $0.160 million supports the additional of a Digital Advisor and a Communications Writer / Researcher to continue to meet the growing demand for digital communications with our customers.

174.9 Please explain if, commencing in 2016, the writers FEI referred to in the above preamble were consultants or were in-house employees.

Response:

FEI confirms that the writers referred to in the above preamble were consultants. FEI used the term "In-House Resources" to highlight that the proposed incremental funding is for in-house resources, but recognizes that for the years 2014 through Base 2019, the resources were not in fact "in-house".

174.10 Please clarify if the historical In-house Resources (digital communications) O&M provided in response to BCUC IR 30.2 (i.e. $0.051 million, $0.072 million, $0.125 million, $0.271 million and $0.271 million for years 2014 through 2018, respectively) includes the consultant costs.

Response:

FEI confirms that the costs noted in the preamble are inclusive of 100 percent of the costs for consultants to perform the work. Until 2019, all of the work was performed by consultants.

In-house Resources (digital communications)	2014	2015	2016	2017	2018
Consultants	$0.051	$0.072	$0.125	$0.271	$0.271

174.10.1 If yes, please provide the amount for each year which was attributable to consultants and the amount that was attributable to other costs, such as FEI employees or non-labour costs.

Response:

Please refer to the response to BCUC IR 2.174.10.

174.10.2 If no, please explain in detail what the historical amounts were related to and please provide the annual costs related to consultants for the services described in response to BCUC IR 30.2 (as provided in the above preamble).

Response:

Please refer to the response to BCUC IR 2.174.10.

175.0 Reference: FEI BASE O&M

Exhibit B-10, BCUC IR 30.9, 31.3, 31.4; Exhibit B-1, pp. C-30 – C-31, C-33

New Funding for MRP Term – Engagement

On pages C-30 and C-31 of the Application, FEI describes its incremental funding request of $0.600 million for advertising under the Connect to Gas program.

On page C-33 of the Application, FEI describes its incremental funding request of $2 million for "Raising Awareness for Consumers in a Lower Carbon Future."

In response to BCUC IR 31.3, FEI stated the following:

> …the Connect to Gas initiative includes the range of activities that FEI undertakes to attract and retain its customers, whereas the incremental funding request for increasing awareness of the role of natural gas within a lower carbon economy supports communication of a much broader message to the public similar to public safety and energy efficiency messages. These messages speak to the benefits of natural gas in today's competitive, low carbon economy, including its contribution to lowering costs and emissions through applications like natural gas for transportation, renewable natural gas, liquefied natural gas, compressed natural gas, as well as for home heating.

In response to BCUC IR 31.4, FEI further stated that "these are two different programs and are targeted at different audiences. Therefore, the two programs require the development of separate content, separate communications streams, events, workshops, sponsorships and advertising targeted at different audiences."

In response to BCUC IR 30.9, FEI described the planned Connect to Gas advertising, including the following three campaigns: (i) Cooking with Gas, (ii) Energy Literacy, and (iii) Conversion. FEI also stated that it "plans to take a broader provincial approach to promoting natural gas, and as part of that, expand to channels such as TV to reach a broader audience."

175.1 Please explain in detail the different audiences that the Connect to Gas advertising and the Raising Awareness for Consumers in a Lower Carbon Future advertising are targeting.

<u>Response:</u>

Connect to Gas advertising predominantly focusses on builders, developers, architects, engineers, equipment manufacturers, and contractors to promote the adoption of natural gas appliances and solutions in homes and businesses.

In contrast, Raising Awareness in a Low Carbon Future advertising targets British Columbians in general within FEI's entire service territory, and relates to an integrated, mass communications approach. This includes homeowners, businesses, industry, government officials, and current and potential new customers. The communication channels chosen will depend upon the approved funding; however, the goal is to develop a creative concept that will be conveyed through the use of multiple channels including TV, social media, web, print (newspapers, direct mail), radio, out of home (e.g., billboards) and digital.

175.2 Please explain why it is not reasonable to expect that through the expansion of advertising channels in both areas of advertising there would be an overlap in messaging to customers.

Response:

FEI believes that overlap between the two programs will be minimal as the targeted audience for Connect to Gas is specific as is the messaging. The Connect to Gas audience is largely technology focused and influences natural gas equipment selection within the building environment. As such, the messaging to this group is more specific and focused on the goal of adding and retaining customers by promoting familiarity and the adoption of natural gas and natural gas appliances.

In contrast, Raising Awareness in a Low Carbon Future will be about raising public awareness of the role of natural gas and natural gas infrastructure in a lower carbon environment. FortisBC has a significant role to play in helping the Province deliver on its climate and energy goals. Our goal is to provide leadership in delivering safe, reliable and cost-effective energy while providing innovative solutions to climate change challenges. To show how natural gas advances climate goals and that natural gas can effectively, sustainably and affordably reduce carbon emissions. This will include sharing information about how FortisBC is committed to climate action: RNG, NGT, LNG and seeking new innovative technologies. The aim is to establish greater recognition amongst British Columbians about the benefits of natural gas as an energy source and its many roles economically, socially and environmentally that are beyond messaging for benefits for cooking and heating with natural gas.

While there could be potential for spillover in certain respects, advertising related to Raising Awareness of a Lower Carbon Future will be complementary. FEI intends to manage the potential for duplication by ensuring the programs do not speak to the same message and that they remain separate and focused on meeting their objectives.

175.3 Please explain why FEI is not able to combine some of the advertising efforts in the areas of Connect to Gas and Raising Awareness for Consumers in a Lower Carbon Future in order to reduce the incremental advertising costs.

Response:

FEI does not believe it is feasible to combine these advertising initiatives because, as noted in the responses to BCUC IRs 2.175.1 and 2.175.2, the target audience and messaging for both advertising initiatives are distinct and there is minimal overlap expected given their distinct purposes.

175.4 In a level of detail similar to FEI's response to BCUC IR 30.9, please provide a breakdown and description of the planned advertising activities for Raising Awareness for Consumers in a Lower Carbon Future for, at minimum, the upcoming 2020 year.

Response:

FEI has not yet determined all the planned advertising activities for the Raising Awareness for Consumers in a Lower Carbon Future campaign as channels chosen will depend on the approved funding. The Raising Awareness in a Low Carbon Future Campaign will be an integrated mass communications approach in order to reach British Columbians, specifically within our entire service territory. As discussed previously, the goal of this initiative is to help British Columbians understand the role of natural gas in a lower carbon economy, as opposed to educating British Columbian's about specific natural gas applications such as cooking and heating. The urgency to define the role of the gas system in a low-carbon future has intensified with a growing trend of municipalities, and even now the government of Canada, making declarations of a climate emergency and pledging to take more drastic action to reduce carbon emissions. As such, it is crucial that we show how natural gas advances climate goals and that natural gas can effectively, sustainably and affordably reduce carbon emissions.

For the MRP term, targeted audiences will include homeowners, business and industry, government officials, potential customers as well as current natural gas customers. The goal will be to develop a creative concept that will be conveyed through the use of TV, social media, web, print (newspapers, direct mail), radio, out of home (ie., billboards) and digital.

176.0 Reference: FBC BASE O&M

Exhibit B-10, BCUC IR 29.1; Exhibit B-1-3, p. C-44

New Funding for MRP Term

In response to BCUC IR 29.1, FortisBC provided the following analysis for FEI:

Line	Particulars	Reference	Base 2019	MRP years--> 2020	2021	2022	2023	2024
1	**Formula Cost Drivers**							
2	CPI/AWE	Assumed		2.00%	2.00%	2.00%	2.00%	2.00%
3	Productivity Factor	Approved		-1.10%	-1.10%	-1.10%	-1.10%	-1.10%
4	Net Inflation Factor for Costs	Line 2 + Line 3		0.90%	0.90%	0.90%	0.90%	0.90%
5								
6	Customer Growth Factor	Assumed		1.00%	1.00%	1.00%	1.00%	1.00%
7	50% reduction	Approved		-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
8	Net Growth Factor	Line 6 + Line 7		0.50%	0.50%	0.50%	0.50%	0.50%
9								
10	Inflation Factor for O&M	(1 + Line 4) x (1 + Line 8)		101.40%	101.40%	101.40%	101.40%	101.40%
11								
12	**Current PBR method**							
13	*Gross O&M ($000)*	*Prior Yr Line 13 x Line 10*	*246,269*	*249,728*	*253,235*	*256,792*	*260,399*	*264,056*
14								
15	**Proposed Method**							
16	Gross O&M Base ($000)	Assumption from IR	246,269					
17	AC	2019 projected	1,024,962					
18	O&M per customer	Prior Yr Line 18 x Line 2	240	245	250	255	260	265
19								
20	Forecast of AC	Prior Yr Line 20 x Line 6	1,024,962	1,035,212	1,045,564	1,056,019	1,066,580	1,077,245
21	*Gross O&M ($000)*	*Line 18 x Line 20*	*246,269*	*253,706*	*261,368*	*269,262*	*277,393*	*285,771*
22								
23	*Difference*	*Line 21 - Line 13*		*3,978*	*8,133*	*12,470*	*16,995*	*21,715*

176.1 Please provide the same analysis for FBC using a 2019 Base O&M of $56.907 million (i.e. the proposed 2019 Base O&M provided in the June 21, 2019 Errata but excluding the proposed incremental funding of $0.763 million).

Response:

FortisBC has not produced a forecast of average customer growth and inflation for years 2020 through 2024 for this Application; however, for the purpose of this question, FBC has assumed:

1 percent growth in average customers; and

An Inflation factor of 2 percent for years 2020 through 2024.

Since this analysis is prepared on a forecast basis, FBC cannot differentiate between actual and forecast customer growth so FBC has assumed that they are the same under both scenarios (Current PBR Plan and Proposed MRP funding mechanisms). Therefore, the only differences between the two scenarios below are the elimination of the X-factor of 1.03 percent and the elimination of the 50 percent reduction in the growth factor. FBC has provided the requested analysis below:

			Base	MRP years-->				
Line	Particulars	Reference	2019	2020	2021	2022	2023	2024
1	**Formula Cost Drivers**							
2	CPI/AWE	Assumed		2.00%	2.00%	2.00%	2.00%	2.00%
3	Productivity Factor	Approved		-1.03%	-1.03%	-1.03%	-1.03%	-1.03%
4	Net Inflation Factor for Costs	Line 2 + Line 3		0.97%	0.97%	0.97%	0.97%	0.97%
5								
6	Customer Growth Factor	Assumed		1.00%	1.00%	1.00%	1.00%	1.00%
7	50% reduction	Approved		-0.50%	-0.50%	-0.50%	-0.50%	-0.50%
8	Net Growth Factor	Line 6 + Line 7		0.50%	0.50%	0.50%	0.50%	0.50%
9								
10	Inflation Factor for O&M	(1 + Line 4) x (1 + Line 8)		101.47%	101.47%	101.47%	101.47%	101.47%
11								
12	**Current PBR method**							
13	*Gross O&M ($000)*	*Prior Yr Line 13 x Line 10*	*56,907*	*57,746*	*58,598*	*59,462*	*60,339*	*61,229*
14								
15	**Proposed Method**							
16	Gross O&M Base ($000)	Assumption from IR	56,907					
17	AC	2019 projected	138,649					
18	O&M per customer	Prior Yr Line 18 x Line 2	410	419	427	436	444	453
19								
20	Forecast of AC	Prior Yr Line 20 x Line 6	138,649	140,035	141,436	142,850	144,279	145,721
21	*Gross O&M ($000)*	*Line 18 x Line 20*	*56,907*	*58,626*	*60,396*	*62,220*	*64,099*	*66,035*
22								
23	*Difference ($000)*	*Line 21 - Line 13*		*879*	*1,798*	*2,758*	*3,760*	*4,806*

177.0 Reference: FBC BASE O&M

Exhibit B-7, CEC IR 43.4; FBC Application for a CPCN for the Grand Forks Terminal Station Reliability Project, Order C2-19 and Decision dated July 25, 2019

Grand Forks Terminal Station Reliability Project CPCN

In response to CEC IR 43.4, FBC confirmed that subsequent to the approval of the Grand Forks Terminal Station Reliability Project CPCN application, it would reduce FBC's Base O&M by $0.089 million (in $2021).

On July 25, 2019, the BCUC issued its decision and Order C-2-19 approving the Grand Forks Terminal Station Reliability Project CPCN application.

177.1 Please confirm, or explain otherwise, that FBC intends to file an evidentiary update which will reduce FBC's Base O&M as described in response to CEC IR 43.4. If confirmed, please explain when this update will be filed.

Response:

FBC believes that an evidentiary update is not required at this time. The Application will determine Base O&M for 2020 and the future escalation of the 2020 Base. As identified in the response to CEC IR 1.43.4, the reduction in Base O&M due to the salvage of the transmission lines is expected to occur beginning in 2021. FBC intends to include the reduction to Base O&M in its annual review materials for 2021 rates.

178.0 Reference: FBC BASE O&M

Exhibit B-10, BCUC IR 36.2, 36.4, 36.5, 36.8

Adjustments – Mandatory Reliability Standards (MRS)

In response to BCUC IR 36.2, FBC provided the following breakdown and description of actual MRS O&M (excluding incremental and Z-Factor O&M):

	2014	2015	2016	2017	2018	2019P
Base O&M						
Labour	$ 1,684	$ 1,460	$ 1,439	$ 1,566	$ 1,706	$ 1,863
Non-Labour	471	535	533	457	391	302
Total	2,156	1,995	1,972	2,023	2,097	2,165

Labour includes FortisBC employee wages while Non-Labour includes costs related to contractors, consultants, staff expenses, etc.

178.1 Please provide the number of FTEs included in each year's labour O&M shown in the above table and provide a detailed description of the titles and positions that make up the annual labour. Please also provide a detailed description of the activities performed by each FTE.

Response:

The MRS budget captures FBC's effort to comply with MRS standards beyond what was required prior to their introduction as explained and approved in previous proceedings. The work required spans eleven different departments to varying degrees. FBC has set up a model which fosters a culture of compliance and, in turn, ensures the reliability of the system. Further, the activities are completed by the resources available at the time so activities cannot always be delineated by specific FTE roles. Finally, changes in standards occur through the annual Assessment Review process, leading to changes in activities.

However, the following is a list of positions in the MRS department grouped by standards they support. The other departments are Engineering, System Planning, System Control Centre, Construction & Maintenance, Station Maintenance, Generation, Vegetation Management, Human Resources, Facilities, Security and Information Systems. These departments engage in activities to support the standards which vary in activity and level of effort.

Year	Critical Infrastructure & Protection Standards	Operations & Planning Standards	MRS Support
2014	• Compliance Manager (2) • Technical Analyst • Systems Analyst	• Senior Engineer, Compliance • Engineer, Operations • Engineer, Protection & Control • Supervisor, SCC Training & Compliance	• Manager, Assets & Compliance • Project Manager, Reliability and Compliance • Compliance Analyst • Compliance Coordinator

Year	Critical Infrastructure & Protection Standards	Operations & Planning Standards	MRS Support
2015	• Compliance Manager (2) • Technical Analyst • Systems Analyst	• Senior Engineer, Compliance • Engineer, Operations • Engineer, Protection & Control • Supervisor, SCC Training & Compliance	• Manager, Assets & Compliance • Project Manager, Reliability and Compliance • Compliance Analyst • Compliance Coordinator
2016	• Compliance Manager (2) • Technical Analyst • Systems Analyst	• Senior Engineer, Compliance • Engineer, Operations • Engineer, Protection & Control • Supervisor, Operations Support & Compliance	• Manager, Assets & Compliance • Project Manager, Reliability and Compliance • Compliance Analyst • Compliance Coordinator
2017	• Compliance Manager • Compliance Process Specialist • Technical Analyst • Systems Analyst	• Senior Engineer, Compliance • Engineer, Operations • Engineer, Protection & Control • Supervisor, Operations Support & Compliance	• Manager, Assets & Compliance • Project Manager, Reliability and Compliance • Compliance Analyst • Compliance Coordinator
2018	• Compliance Manager • Compliance Process Specialist • Technical Analyst • Systems Analyst	• Senior Engineer, Compliance • Engineer, Operations • Engineer, Protection & Control • Supervisor, Operations Support & Compliance	• Manager, Assets & Compliance • Project Manager, Reliability and Compliance • Compliance Analyst • Compliance Coordinator
2019F	• Compliance Manager • Compliance Process Specialist • Technical Analyst • Systems Analyst	• Senior Engineer Compliance • Engineer, Operations • Engineer, Protection & Control • Supervisor, Operations Support & Compliance	• Manager, Assets & Compliance • Project Manager, Reliability and Compliance • Compliance Analyst • Compliance Coordinator

Critical Infrastructure & Protection (CIP) standards focus on physical and cyber security, protection of information, control and logging as well as monitoring systems. This group also supports the Operations & Planning group as well as other department for non-MRS related activities.

Operations & Planning standards focus on non-CIP standards and address areas such as emergency operations, real time operations, protection and control, planning, maintenance, generation, communications, interaction with other entity interactions, personnel training, etc. This group also supports the CIP group as well as other department for non-MRS related activities.

MRS Support function provides oversight and support for the various groups activities related to MRS. This group also supports other department for non-MRS related activities.

The average FTE equivalent for each year's labour O&M identified is as per below.

Year	2014	2015	2016	2017	2018	2019P
Ave. FTE	10	9	9	9	10	10

178.2 For each year in the above table, please provide the number of contractors and consultants utilized and describe the activities performed by each contractor and consultant in detail.

<u>Response:</u>

Below is a table identifying the approximate number of contractors/consultants utilized each year.

Contractors/Consultants per Year

2014	2015	2016	2017	2018	2019P
9	13	14	9	15	9

The work performed by these groups varies each year depending on the type of work required and availability of internal resources. However, contractors/consultants typically provide legal support, technical expertise on specific standards, support in gathering of evidence, support of training programs, risk assessments and vendor support.

In response to BCUC IR 36.4, FBC provided the following tables:

Table 1: FBC Incremental MRS O&M Expense 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Forecast O&M - Compliance Audits						
Forecast	$ -	$ 350	$ -	$ -	$ 350	$ -
Actual	-	375	-	-	341	-
Z-Factor - Assessment Report No. 8						
Forecast	-	-	455	50	540	540
Actual	-	-	464	53	532	540
Z-Factor - Assessment Report No. 10						
Forecast	-	-	-	-	180	400
Actual	-	-	-	-	151	400

Table 2: FBC Incremental MRS Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Z-Factor - Assessment Report No. 8						
Forecast	$ -	$ -	$ -	$ 1,350	$ 50	$ 80
Actual	-	-	-	1,371	72	80
Z-Factor - Assessment Report No. 10						
Forecast	-	-	-	-	-	2,700
Actual	-	-	-	-	-	2,700

In response to BCUC IR 36.5, FBC provided the following table showing the forecast capital expenditures associated with Assessment Report No. 8 (AR8) and Assessment Report No. 10 (AR10) over the period 2020-2024:

	2020	2021	2022	2023	2024
Z-Factor - Assessment Report No. 8	$ 108	$ 109	$ 768	$ 55	$ 87
Z-Factor - Assessment Report No. 10	97	98	99	99	544
Total	$ 205	$ 207	$ 867	$ 154	$ 631

Expenditures are higher in 2022 for AR8 and in 2024 for AR10 because of infrastructure replacement which occurs at five-year intervals, similar to other IS systems.

178.3 With regard to the Actual Compliance Audit O&M incurred in 2015 and 2018 (as shown in Table 1 of BCUC IR 36.4), please provide a detailed explanation and breakdown of these costs.

Response:

FBC incremental costs related to triennial audits are included in forecast O&M Expense (i.e., outside of formula O&M). For clarity, these costs do not include internal labour costs (regular labour) embedded in Base O&M. Rather, only incremental labour costs arising from paid overtime, backfilling of positions, and positions normally charged to capital projects or capital loading pools is included in these audit costs. Incremental non-labour costs include contractors, consultants, and other incremental expenses.

The breakdown of the audit costs for 2015 and 2018 are:

Audit Year ($ thousands)		
	2015	2018
Labour	$ 320	$ 264
Non-Labour	$ 55	$ 77
Total	$ 375	$ 341

178.3.1 As part of the above response, please explain if the work performed related to the audits was done by existing FBC employees or contractors/consultants (or a combination). If some or all of the work was performed by existing FBC employees, please explain why the O&M costs were considered "incremental".

Response:

Please refer to the response to BCUC IR 2.178.3.

178.4 Please provide the frequency of MRS Compliance Audits and how many audits FBC anticipates during the proposed MRP term.

Response:

The compliance audit cycles are defined by Section 2.1 of the Compliance Auditing Program (Appendix 2 to the Rules of Procedure for Reliability Standards in British Columbia). FBC's audit cycle is every three years per Section 2.1.2. The next scheduled audits will occur in 2021 and 2024.

178.5 With regard to the AR8 costs provided in the above tables, please provide the following information:

20.0 • A detailed breakdown and explanation of the one-time O&M costs incurred in 2016 and 2017;

21.0 • A detailed breakdown and explanation of the one-time Capital costs incurred in 2017;

22.0 • A detailed breakdown and explanation of the ongoing O&M costs incurred in 2018 and 2019, including a detailed explanation as to why these incremental costs are required on a go-forward basis; and

23.0 • A detailed breakdown and explanation of the ongoing Capital costs incurred in 2018 and 2019, including a detailed explanation as to why these incremental costs are required on a go-forward basis.

Response:

The requested information regarding AR8 costs is provided below:

AR8 O&M Expense

	One-Time		Ongoing	
	($ thousands)			
	2016	2017	2018	2109P
Labour	$ 157	$ 10	$ 375	$ 469
Non-Labour	307	43	157	71
Total	$ 464	$ 53	$ 532	$ 540

Labour includes incremental employee wages. Non-Labour includes costs related to contractors, consultants, and incremental expenses.

One-time O&M Expenses were related to FBC's evaluation and implementation of additions/changes to procedures and processes to comply with the standards that came into effect in 2016. This included changes such as modifying the protection testing and maintenance program, training documents, and updating processes/procedures as required. In addition, FBC assessed and determined the detailed scope and strategy required to implement additions/changes to meet the effective dates of all the standards defined by Order R-38-15 in order to meet the timelines required. The work was primarily focused on version 5 of the CIP (CIP v5) standards and included evaluating such things as physical and cyber security controls, continuous monitoring, change management and vulnerability assessments. It also included reviewing industry practices, assessing available market solutions and determining the appropriate solutions to meet the requirements for FBC assets.

Ongoing annual costs include ongoing efforts to support and maintain processes and systems that address physical and cyber security controls, continuous monitoring, change management, patch management and vulnerability assessments. The effort is primarily labour and annual licensing fees required to maintain compliance with CIP v5.

AR8 Capital Expenditures

	One-Time		Ongoing	
	($ thousands)			
	2016	2017	2018	2109P
Labour	$ -	$ 276	$ 5	$ 10
Non-Labour	-	1,095	67	70
Total	$ -	$ 1,371	$ 72	$ 80

Labour includes incremental employee wages. Non-Labour includes costs related to contractors, consultants, and incremental expenses.

One-time capital expenditures in 2017 included adding hardware and software systems to current infrastructure. These expenditures were necessary to meet requirements of the new standards and are related to tasks such as continuous monitoring, change management, vulnerability assessment and cyber security controls.

Ongoing capital costs are required to support the infrastructure that was required for CIP v5 such as annual software upgrades for maintaining support and avoiding potential security, productivity and reliability issues. It also includes leveraging new functionality and features available that the vendors have developed through continued investment in their products.

178.6 With regard to the AR10 costs provided in the above table, please provide the following information:

24.0 • A detailed breakdown and explanation of the one-time O&M costs incurred in 2018 and 2019 (projected);

25.0 • A detailed breakdown and explanation of the one-time Capital costs incurred in 2019 (projected);

26.0 • A detailed breakdown and explanation of the anticipated ongoing O&M costs starting in 2020, including a detailed explanation as to why these incremental costs are required on a go-forward basis; and

27.0 • A detailed breakdown and explanation of the anticipated ongoing Capital costs starting in 2020, including a detailed explanation as to why these incremental costs are required on a go-forward basis.

Response:

The requested information regarding AR10 costs is provided below:

AR10 O&M Expense

	One-Time		Ongoing
	($ thousands)		
	2018	2019P	2020F
Labour	$ 72	$ 350	$ 750
Non-Labour	79	50	250
Total	$ 151	$ 400	$ 1,000

Labour includes incremental employee wages. Non-Labour includes costs related to contractors, consultants, and incremental expenses.

The one-time O&M costs for 2018 were primarily required for assessing and determining the strategy and detailed scope to comply with the revised standards, which includes: performing real-time pre- and post-contingency assessments every 30 minutes, meeting outage coordination requirements, implementing outage scheduling timelines and next day studies, and development of an operating plan to address all the above tasks. It also included fault level and breaker rating studies as well as testing of pressure relief devices and breaker close functionality.

The one-time O&M costs for 2019 are primarily for resource additions in System Operations that will be required to ensure full compliance by October 1, 2020. The resources require significant development and training to be fully functional in performing real-time pre- and post-contingency assessments every 30 minutes, meeting outage coordination requirements, and implementing outage scheduling timelines and next day studies by the effective date.

Ongoing annual costs include ongoing efforts to support and maintain processes and systems that address Real Time Contingency Analysis (RTCA) software, outage coordination tool to comply with Reliability Coordinator (RC) processes, operational planning analysis and (daily) assessments. The infrastructure will be required to be within the boundaries of and integrated with the SCADA network, so all Critical Infrastructure and Protection standards apply.

AR10 Capital Expenditures

	One-Time		Ongoing
	($ thousands)		
	2019P	2020F	2020F
Labour	$ 530	$ -	$ 10
Non-Labour	2,170	-	87
Total	$ 2,700	$ -	$ 97

Labour includes incremental employee wages. Non-Labour includes costs related to contractors, consultants, and incremental expenses.

One-time capital expenditures are required to purchase and install the necessary hardware and software systems (including backup) and resources to meet the requirements of AR10. This includes RTCA software, outage coordination tool to comply with RC processes, operational planning analysis and (daily) assessments. The infrastructure will be required to be within the boundaries of and integrated with the SCADA network.

Ongoing capital costs are to support of the infrastructure that was required for AR10 such as annual software upgrades for maintaining support and avoiding potential security, productivity and reliability issues. It also includes leveraging new functionality and features available that the vendors have developed through continued investment in their products.

178.7 Please provide a detailed discussion as to why the MRS Assessment Reports result in additional O&M and Capital cost requirements for FBC.

Response:

Assessment reports identify a new standard, retirement of a standard or changes to a standard that have occurred from the previous year. Pursuant to the UCA section 125.2 and the Mandatory Reliability Standards Regulation (BC Reg. 32/2009), BC Hydro is required to provide to the BCUC a report assessing new MRS for adoption in BC within a year of their adoption in the USA. Once accepted by the BCUC for adoption in the province, compliance is mandatory.

Additions or changes to standards have required additional effort to meet the requirements. For example, new or modified standards, depending on their nature, can result in the need to implement new systems and processes requiring capital investment and increased resources to support those investments and processes. Assessment Reports No. 8 and No. 10 have both resulted in increased capital and operating expenditures.

Retirement of standards are typically administrative changes and occur because they have been combined with other standards and do not result in any reduction of effort.

Since the beginning of the MRS Program in BC, the number of standards, and the effort to meet the requirements, has increased. Please also refer to the response to BCUC IRs 2.178.5 and 2.178.6 which describe the incremental efforts and costs associated with Assessment Reports No. 8 and 10. FBC also incurred incremental costs resulting from the adoption of other MRS, which were absorbed in its formula O&M Expense and did not result in incremental revenue requirements under the Current PBR Plan.

In response to BCUC IR 36.8, FBC stated the following:

> The costs of complying with existing MRS are not subject to uncertainty or variability to the same degree as the costs of integrity digs; therefore, there is no reason to exclude these costs from index-based O&M Expense…For clarity,

> FortisBC is proposing to forecast annually any incremental O&M and capital costs it incurs in complying with new or amended MRS requirements…

…Excluding portions of O&M from the indexing mechanism weakens the Utilities' ability and incentives to efficient management of expenses and also reduces the amount of indexed O&M Expense eligible for earnings sharing to the benefit of customers.

178.8 Please discuss whether allowing flow-through treatment of a portion of MRS-related costs (i.e. the costs to comply with new or amended MRS requirements) while including the remainder of costs in the index-based formula expenses might weaken FBC's incentives to efficiently manage its costs. For instance, please discuss whether, as a result of FBC being approved to treat new or amended MRS requirement costs as flow-through, when such new or amended requirements arise, FBC would not have an incentive to first assess whether the costs could be managed within formula O&M through increased efficiency efforts.

Response:

No, the proposed treatment does not weaken FBC's incentives to efficiently manage its MRS-related costs. The inclusion of compliance with existing MRS standards within index-based O&M expense incents the utility to find efficiencies for the majority of its MRS-related expense. Requiring FBC to forecast and include in Base O&M the unknown future costs of new and amended standards which could not reasonably have been known or quantified when setting the Base O&M Expense would be unfair and counter to the framework of the proposed MRP. Further, FBC as a matter of course evaluates all new O&M cost pressures, including non-MRS costs, to determine whether those costs can be managed within the indexed O&M envelope. The BCUC also has an opportunity to evaluate the costs to comply with new or amended MRS requirements in the Annual Review.

Incremental MRS compliance costs arising from new or amended standards are consistent with exogenous factor treatment although FBC is not proposing to apply for exogenous treatment in each case, as explained in the response to BCUC IR 1.36.6:

Incremental MRS compliance costs are triggered by BCUC orders adopting new, or amending, MRS for BC. Since the procedure for adoption of new standards is well established and well understood, FBC does not believe it is necessary to revisit the appropriateness of the flow-through treatment on each occasion by applying for exogenous factor treatment.

178.8.1 As part of the above response, please discuss whether the incentive properties of the proposed indexed-based O&M would be increased if

FBC were required to manage all of its MRS-related costs within the approved formula, including any incremental costs which may arise from new or amended MRS requirements.

Response:

Please refer to the response to BCUC IR 2.178.8.

179.0 Reference: FBC BASE O&M

Exhibit B-10, BCUC IR 37.1; Exhibit B-1, p. C-46

Deferrals – Manual Meter Reading Costs

On page C-46 of the Application, FBC states that it proposes to include the cost of manual meter reading in the 2019 Base O&M and that the revenue from the manual meter read fees will be recorded in Other Revenues.

In response to BCUC IR 37.1, FBC provided the following table:

AMI Radio-off Expense and Revenue, 2014-2019P ($000s)

	2015	2016	2017	2018	2019P
Expense	$ 40	$ 327	$ 315	$ 252	$ 180
Revenue	(42)	(273)	(247)	(230)	(180)
Net Expense (Revenue)	$ (2)	$ 53	$ 68	$ 22	$ -

179.1 Please explain why FBC does not propose to include the net manual meter reading expense in the 2019 Base O&M (i.e. an amount of 0) as opposed to recording the expense portion in the 2019 Base O&M and forecasting the revenue portion annually as part of Other Revenue.

Response:

The one-time radio-off charge, as well as the per-read fee charged to customers for manual meter reading, are tariff revenues which are classified as revenue under accepted regulatory practices for electric utilities (and for gas utilities). This is the same classification as late payment charges and connection fees.

Additionally, the expenses incurred by FBC that are associated with manual meter reading are better included as part of the 2019 Base O&M, subject to indexing, whereas the revenues collected from radio-off customers are reviewed and approved in rate design or other tariff-setting applications. Service-related tariff items, such as connection and reconnection charges, meter testing, etc., are not subject to annual rate changes. It would therefore be incorrect to escalate meter read fees annually by including them in indexed O&M Expense.

E. CAPITAL EXPENDITURES

180.0 Reference: CAPITAL EXPENDITURES

Exhibit B-1, Section C3

Capital Expenditures Overview

180.1 Please provide a table, in a similar format to the table below, comparing FEI's actual capital expenditures for each capital category during the Current PBR Plan and the forecast capital expenditures for the proposed MRP.

	Current PBR						Proposed MRP				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
GROWTH CAPITAL											
New Customer Mains											
New Customer Services											
New Customer Meters											
CIAC											
[Include categories as required]											
Growth Capital Total											
SUSTAINMENT CAPITAL											
Customer Measurement											
Transmission System Reliability & Integrity											
Distribution System Reliability											
Distribution System Integrity											
System Improvements (DP)											
CIAC											
[Include categories as required]											
Sustainment Capital Total											
OTHER CAPITAL											
Equipment											
Facilities											
Information Systems											
[Include categories as required]											

	Current PBR						Proposed MRP				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Other Capital Total											
MAJOR PROJECTS											
[Include categories as required]											
Major Projects Capital Total											
Annual Total											
Term Total											

Response:

Please refer to the table below, comparing FEI's actual capital expenditures for each capital category during the Current PBR Plan and the forecast capital expenditures for the Proposed MRP. Since FEI does not have a Growth Capital forecast or a forecast of customer additions for the MRP period, for the purposes of generating a Growth Capital expenditure forecast, FEI started with the 2019 proposed Base amounts for each of the Growth Capital categories and assumed a 2 percent inflation and a fixed high level estimate of annual Gross Customer Additions.

	CURRENT PBR						PROPOSED MRP					
Growth Capital	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Projection	2019 Unit Cost Base	2020	2021	2022	2023	2024
New Customer Mains	8,420	13,752	12,823	16,467	24,494	31,247	1,016	18,395	18,763	19,138	19,521	19,911
New Customer Services	24,675	30,064	31,246	39,149	53,993	44,752	2,486	45,015	45,915	46,834	47,770	48,726
New Customer Meters	1,583	1,960	3,430	3,927	4,397	4,215	230	4,157	4,240	4,325	4,411	4,499
System Improvements (DP)							214	3,868	3,945	4,024	4,104	4,187
CIAC	(3,757)	(2,805)	(2,505)	(2,770)	(2,529)	(2,742)	(135)	(2,445)	(2,494)	(2,544)	(2,595)	(2,647)
Total Growth (Net)	30,920	42,971	44,994	56,773	80,354	77,472	3,811	68,989	70,369	71,776	73,212	74,676
Base Growth Unit Cost (Net)							3,811	3,887	3,965	4,044	4,125	4,208
Gross Customer Additions								17,750	17,750	17,750	17,750	17,750
Sustainment Capital												
Customer Measurement	24,375	28,516	30,140	31,485	33,271	30,837		30,559	31,328	31,781	32,461	32,979
Transmission System Reliability & Integrity	22,043	30,409	31,738	37,596	39,095	42,301		42,213	37,599	41,021	45,792	47,355
Distribution System Reliability	11,195	12,622	11,260	14,667	13,253	10,295		14,539	12,402	19,224	12,486	22,031
Distribution System Integrity	29,635	15,676	17,378	20,722	25,158	22,960		24,219	31,615	25,080	28,924	22,168
System Improvements (DP)	2,439	5,723	2,953	3,566	4,433	2,793						
Sustainment CIAC	(1,882)	(3,530)	(3,799)	(3,844)	(4,077)	(4,118)		(3,902)	(3,902)	(3,902)	(3,902)	(3,902)
Total Sustainment Capital	87,806	89,417	89,669	104,192	111,132	105,069		107,628	109,042	113,205	115,761	120,631
Other Capital												
Equipment	8,242	7,319	7,706	12,611	15,990	13,156		15,106	13,378	12,288	12,100	12,110
Facilities	4,062	2,473	3,632	5,023	5,254	5,020		6,356	7,977	5,760	6,803	5,636
Information Systems	23,366	14,639	17,638	22,585	22,753	26,517		28,308	28,561	28,426	27,500	27,605
Total Other Capital	35,670	24,430	28,977	40,219	43,997	44,693		49,770	49,916	46,474	46,403	45,351
Major Projects												
CPCN Huntingdon Control Station		5,777	628									
Tilbury 1B Expansion (OIC)					1,448	10,797		36,667	64,563	1,003	1,062	1,124
Tilbury LNG Plant (OIC)	141,839	181,233	80,772	50,504	5,691	8,376		109	17,382			
Lower Mainland System Upgrade (OIC)	1,699	8,449	19,453	115,667	18,568	1,843						
CPCN LMIPSU		1,269	9,074	29,523	165,534	222,850		27,500				
Inland Gas Upgrades						6,641		62,217	99,311	93,483	67,377	31,164
Transmission Integrity Management Capability								-	25,736	155,933	154,810	155,094
Okanagan Capacity Upgrade						1,028		4,384	41,909	107,173	7,778	
Pattullo Bridge Gas Line Replacement						1,000		8,200	18,600	-	-	-
Southern Crossing Class Location Upgrades								200	1,500	16,000	200	-
Eagle Mountain. - Woodfibre Gas Pipeline Project											347,731	
Total Major Projects	143,538	196,728	109,927	195,695	191,241	252,535		139,277	269,000	373,593	578,958	187,382
Annual Total	297,935	353,546	273,567	396,878	426,725	479,769		365,664	498,327	605,047	814,334	428,040
Term Total			2,228,421							2,711,413		

1

180.2 Please provide a table, in a similar format to the table below, comparing FBC's actual capital expenditures for each capital category during the Current PBR Plan and the forecast capital expenditures for the proposed MRP.

	Current PBR						Proposed MRP				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
GROWTH CAPITAL											
Transmission Growth											
Distribution Growth											
New Connects											
CIAC											
[Include categories as required]											
Growth Capital Total											
SUSTAINMENT CAPITAL											
Generation											
Transmission Sustainment											
Stations Sustainment											
Distribution Sustainment											
Telecommunications											
CIAC											
[Include categories as required]											
Sustainment											

	Current PBR						Proposed MRP				
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Capital Total											
OTHER CAPITAL											
Equipment											
Facilities											
Information Systems											
[Include categories as required]											
Other Capital Total											
MAJOR PROJECTS											
[Include categories as required]											
Major Projects Capital Total											
Annual Total											
Term Total											

<u>Response:</u>

Please refer to the table below.

1

	Current PBR						Proposed MRP				
	2014	2015	2016	2017	2018	2019P	2020	2021	2022	2023	2024
Growth Capital											
Transmission Growth	377	4,224	62	2,939	945	833	5,172	2,063	2,740	5,195	1,086
Distribution Growth	3,027	1,105	500	1,795	1,153	747	3,716	1,876	1,807	1,899	1,921
New Connects	15,416	15,938	14,895	17,599	21,906	15,939	18,141	19,104	19,792	19,188	20,163
CIAC	(7,618)	(6,562)	(6,840)	(12,143)	(11,960)	(7,862)	(9,831)	(10,205)	(10,421)	(10,218)	(10,771)
Subtotal, Growth Capital	11,203	14,705	8,616	10,190	12,043	9,657	17,198	12,837	13,918	16,065	12,399
Sustainment Capital											
Generation	5,728	2,262	2,105	3,310	3,637	3,476	6,697	6,766	6,309	7,008	6,514
Transmission Sustainment	12,540	6,416	4,973	4,266	4,749	5,321	8,353	6,387	5,698	7,951	7,591
Stations Sustainment	10,722	4,093	2,804	5,072	4,434	5,238	13,538	13,624	5,279	3,793	15,971
Distribution Sustainment	18,089	13,290	14,202	15,320	14,004	14,835	20,337	20,338	19,542	19,990	20,353
Telecommunications	1,498	1,241	1,562	1,399	1,793	4,357	1,818	2,983	6,280	5,915	3,472
CIAC	(1,349)	(493)	(1,595)	(389)	(1,501)	(1,011)	(1,276)	(1,260)	(1,293)	(1,253)	(1,354)
Subtotal, Sustainment Capital	47,228	26,808	24,050	28,978	27,115	32,216	49,467	48,838	41,817	43,404	52,547
Other Capital											
Equipment	1,744	2,132	2,536	2,636	3,099	2,638	3,407	3,338	3,274	3,681	3,388
Facilities	1,233	859	1,703	2,267	1,666	2,000	3,264	2,346	2,346	2,346	2,346
Information Systems	5,116	5,192	5,067	8,980	7,177	10,587	9,081	9,028	9,136	9,254	9,400
Subtotal, Other Capital	8,093	8,183	9,307	13,882	11,942	15,225	15,752	14,712	14,756	15,281	15,134
Major Projects											
Advanced Metering Infrastructure	13,547	23,773	3,594	613	-	-	-	-	-	-	-
Kootenay Operations Centre	800	(23)	7,166	9,550	466	-	-	-	-	-	-
UBO Old Units Refurbishment	-	-	-	8,017	8,249	7,435	5,466	356	-	-	-
Ruckles Substation Rebuild	-	-	-	3,645	2,179	-					
Corra Linn Spillway Gate Replacement	-	-	-	3,799	12,261	18,934	11,107	8,740	501	-	-
Grand Forks Terminal Transformer Addition	-	-	-	-	-	1,793	4,970	1,349	-	-	-
Kelowna Bulk Transformer Addition	-	-	-	-	-	-	5,556	7,250	6,633	-	-
Subtotal, Major Projects	14,349	23,750	10,758	25,625	23,155	28,162	27,098	17,695	7,135	-	-
Total Capital Expenditures	80,872	73,447	52,732	78,675	74,255	85,260	109,515	94,083	77,625	74,749	80,079
Term Total				445,241					436,053		

2

181.0 Reference: FEI GROWTH CAPITAL EXPENDITURES

Exhibit B-1, pp. C-58, C-61; Order G-156-19, Appendix B, p. 7

2019 Projected and Base and 2020 Forecast

On page C-58 of the Application, FEI provides the following table:

Table C3-1: FEI Growth Capital Expenditures 2014-2018 ($000s)[141]

Growth Capital	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
New Customer Mains	8,420	13,752	12,823	16,467	24,494
New Customer Services	24,675	30,064	31,246	39,149	53,993
New Customer Meters	1,583	1,960	3,430	3,927	4,397
System Improvements (DP)	2,439	5,723	2,953	3,566	4,433
CIAC	(3,757)	(2,805)	(2,505)	(2,770)	(2,529)
Total Growth (Net)	33,360	48,694	47,947	60,339	84,787
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439
Growth Unit Cost (Net)	2,456	3,003	2,778	2,897	3,779

On page 7 of the reasons for decision attached to Order G-156-19, the BCUC stated the following:

> The examination of alternative rate-setting approaches, including cost of service, is an issue which can, and is, being explored in the current proceeding. The Panel expects that parties will continue to pursue these issues in IR no. 2…All parties are welcome to pursue any information necessary to assist the Panel in making determinations regarding a potential re-basing of certain costs and an appropriate approach to rate-setting.

181.1 Please add an additional column to Table C3-1 of the Application for Projected 2019 Growth Capital. Please indicate the number of months of actual results which have been included in the Projected 2019 Growth Capital amounts.

Response:

The following table responds to BCUC IRs 2.181.1, 2.181.2 and 2.181.3. FEI has provided an amended Table C3-1 below showing:

- The categories in which the incremental Construction Price Increases and Muster Kit & Material Allocation Impacts are recorded (BCUC IR 2.181.2): To determine the inflation adjustments for 2016 through 2018, FEI used each year's annual January to December CPI and AWE indices from the approved CANSIM tables. FEI then applied the 45 percent/55 percent factors to CPI/AWE indices, respectively, to determine the actual inflation factor for each year. These actual annual inflation factors are compounded to derive the inflators used to inflate annual nominal dollars into 2019 dollars.

- Projected 2019 Growth Capital (BCUC IR 2.181.1): The Projected 2019 Growth capital amounts are based on actuals as at July 31 and all known and identified Large New Customer Mains projects in the system that are scheduled to be installed in 2019. The 2019 Growth Capital unit cost is projected to be $4,674 per GCA.
- Forecast 2020 Growth Capital (BCUC IR 2.181.3): In forecasting the 2020 Growth Capital expenditures determined under a cost of service-based-rate-setting approach, FEI used the 2019 proposed base amounts for each of the growth capital categories and assumed a 2 percent inflation in 2020 and multiplied by the Gross Customer Additions to derive the 2020 forecasted capital expenditures. Due to this, the forecast is identical to that under the proposed formulaic approach.

1

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2016 Inflation Adj Actual*	2017 Inflation Adj Actual*	2018 Inflation Adj Actual*	2016-2018 Average (A)	Construction Price Increase (B)	Muster Kit & Material alloc impact (C)	Proposed 2019 Base	2019 Projection	2020 Forecast	Ref
New Customer Mains	8,420	13,752	12,823	16,467	24,494	13,760	17,267	25,003	18,677	2,447	(625)	20,498	31,247	18,395	Col A+B+C
New Customer Services	24,675	30,064	31,246	39,149	53,993	33,527	41,052	55,116	43,232	5,663	1,267	50,162	47,556	45,015	Col A+B+C
New Customer Meters	1,583	1,960	3,430	3,927	4,397	3,680	4,118	4,489	4,095	537	-	4,632	4,215	4,157	Col A+B+C
System Improvements (DP)	2,439	5,723	2,953	3,566	4,433	3,168	3,739	4,525	3,811	499	-	4,310	2,793	3,868	Col A+B+C
CIAC	(3,757)	(2,805)	(2,505)	(2,770)	(2,529)	(2,688)	(2,904)	(2,582)	(2,725)	-	-	(2,725)	(2,742)	(2,445)	Col A+B+C
Total Growth (Net)	**33,360**	**48,694**	**47,947**	**60,339**	**84,787**	**51,447**	**63,271**	**86,551**	**67,090**	**9,146**	**642**	**76,877**	**86,664**	**68,989**	**Col A+B+C**
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439	17,261	20,825	22,439	20,175	-	-	20,175	18,540	17,750	
Growth Unit Cost (Net)	**2,456**	**3,003**	**2,778**	**2,897**	**3,779**	**2,981**	**3,038**	**3,857**	**3,325**	**-**	**-**	**3,811**	**4,674**	**3,887**	
Inflation Adjustment						107.30%	104.86%	102.08%							

2 *Equal to the Actual amounts for the year multiplied by the Inflation Adjustment for that year

3

181.2 In the same format as Table C3-1, please provide the proposed 2019 Base Growth Capital. Please specifically identify in which Growth Capital categories the proposed incremental funding amounts for Construction Price Increases and Muster Kit & Material Allocation Impacts are recorded.

Response:

Please refer to the response to BCUC IR 2.181.1.

181.3 In the same format as Table C3-1, please provide the Forecast 2020 Growth Capital expenditures under a cost of service-based rate-setting approach. Please clearly identify and explain all differences between the 2019 Base Growth Capital and the Forecast 2020 Growth Capital (excluding inflationary increases).

Response:

Please refer to the response to BCUC IR 2.181.1.

182.0 Reference: FEI GROWTH CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 40.1; Exhibit B-1, p. C-58

Contributions in Aid of Construction (CIAC)

In response to BCUC IR 40.1, FEI provided the following table:

FEI Contributions in Aid of Construction ($000s)

	2014	2015	2016	2017	2018
New Customer Mains	(688)	(584)	(653)	(656)	(576)
New Customer Services	(2,959)	(2,076)	(1,765)	(1,919)	(1,885)
Total	(3,647)	(2,660)	(2,418)	(2,575)	(2,461)

On page C-58 of the Application, FEI provides the following table:

Table C3-1: FEI Growth Capital Expenditures 2014-2018 ($000s)[141]

Growth Capital	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual
New Customer Mains	8,420	13,752	12,823	16,467	24,494
New Customer Services	24,675	30,064	31,246	39,149	53,993
New Customer Meters	1,583	1,960	3,430	3,927	4,397
System Improvements (DP)	2,439	5,723	2,953	3,566	4,433
CIAC	(3,757)	(2,805)	(2,505)	(2,770)	(2,529)
Total Growth (Net)	33,360	48,694	47,947	60,339	84,787
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439
Growth Unit Cost (Net)	2,456	3,003	2,778	2,897	3,779

182.1 Please explain what the remainder of the annual CIAC amounts are attributable to (i.e. the annual differences between the CIAC amounts in Table C3-1 of the Application and the amounts provided in the table in response to BCUC IR 40.1).

Response:

The remainder of the annual CIAC amounts are attributable to New Customer Meters. A revised table of FEI Contributions in Aid of Construction to include New Customer Meters is provided below, which also ties to the total CIAC amounts in Table C3-1 of the Application.

FEI Contributions in Aid of Construction ($000's)

	2014	2015	2016	2017	2018
New Customer Mains	(688)	(584)	(653)	(656)	(576)
New Customer Services	(2,959)	(2,076)	(1,765)	(1,919)	(1,885)
New Customer Meters	(110)	(145)	(87)	(195)	(68)
Total	(3,757)	(2,805)	(2,505)	(2,770)	(2,529)

182.2 Please explain why, despite the large increase in New Customer Mains and New Customer Services costs commencing in 2015, the annual CIAC amounts related to New Customer Mains and New Customer Services did not increase.

Response:

CIAC levels are not only dependent on the volume of growth activity, but also on the volume of system extensions that meet the Profitability Index threshold for the system extension test. This is because the system extension test is a financial evaluation applied at the time a system extension is contemplated to determine whether a main extension can proceed with or without a CIAC from the customer wishing to connect to FEI's distribution system. The test is a discounted cash flow analysis that considers both revenues and costs associated with extension of the gas service. Therefore, there are various factors such as consumptions levels (that assist in determining future revenues) and costs to extend the system which determine CIAC levels that could have impacted these years. Accordingly, the trends in New Customer Mains and New Customer Services may not directly align with CIAC.

For late 2016 onwards, changes to the system extension test have contributed to a lower CIAC.

In September 2016, the BCUC approved FEI's proposed changes to its system extension test, which included:

- updates to the Service Line Cost Allowance;
- changes to the discounted cash flow term from 20 years to 40 years;
- allowing 10 year customer addition terms where appropriate;
- changing to an overhead sliding scale;
- establishing a System Extension Fund; and
- removing the energy efficiency credits.

The changes were made in consideration of fair treatment of both new customers and existing customer groups so that new customers are not unduly burdened with attachment costs and existing customers are not exposed to undue costs from the attachment of the new customers.

The changes to the Service Line Cost Allowance, the discounted cash flow period, the customer additions term option, the overhead sliding scale, and access to System Extension Fund would likely lead to a decrease in CIAC during this period to allow new customers to gain access to natural gas service. Discontinuing the energy efficiency credit may directionally increase the likelihood and/or amount of a CIAC.

183.0 Reference: FEI GROWTH CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 41.1, 41.4, 41.5; Exhibit B-1, pp. C-56 – C-63; FEI PBR Application, pp. 227-238

FEI Customer Additions

In response to BCUC IR 41.4, FEI provided the following table:

	2018 Actual	2019 Projection
Net Customer Additions	21,087	19,174
% Change		-9%
Gross Customer Additions	22,439	18,540
% Change		-17%

In response to BCUC IR 41.4, FEI also stated the following:

> FortisBC has not produced a forecast of the number of customers and customer connections for the term of the MRPs. The Application sets out the framework and mechanism by which inflation-indexed O&M and Growth capital (for FEI only) will escalate Base O&M and Growth capital over the term of the MRPs. At each Annual Review for rates, FortisBC will forecast the average number of customers and gross customer additions (for FEI only) for the upcoming year to determine Gross O&M and Growth capital.

183.1 Please expand the table provided in response to BCUC IR 41.4 to include the forecast number of net customer additions and gross customer additions for 2020 and 2021.

Response:

While FEI has not yet prepared a forecast of 2020 and 2021 gross and net customer additions, FEI provides a high-level forecast below:

	2018 Actual	2019 Projection	2020 Forecast	2021 Forecast
Net Customer Additions	21,087	19,174	16,487	14,638
% Change		-9%	-14%	-11%
Gross Customer Additions	22,349	18,540	17,750	17,750
% Change		-17%	-4%	0%

In response to BCUC IR 41.5, FEI provided the following table:

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439	18,540
Ratio of Service Additions to Gross Customer Adds	0.82	0.76	0.71	0.76	0.74	0.76
Activities (riser or services)	11,103	12,392	12,288	15,856	16,606	14,116
Unit Costs ($ per service/riser)	2,256	2,484	2,598	2,497	3,283	3,369
Expenditures ($000s)	25,049	30,785	31,927	39,594	54,511	47,556

183.2 Please expand the table provided in response to BCUC IR 41.5 to include 2020 and 2021 amounts.

Response:

Please see an expanded version of the table provided in response to BCUC IR 1.41.5 to include 2020 and 2021 Forecasts using a number of assumptions. Since there is no $ per service/riser forecast for the proposed MRP period, for the purposes of providing an amended table in the same format for 2020 and 2021, FEI used the 2019 Base amount for New Customer Services ($2,486[46]) escalated at 2 percent per annum multiplied by the high level forecast of Gross Customer Additions to derive total expenditures related to new customer services. FEI assumed a 2017-2019 three-year average ratio of Service Line Additions to Gross Customer Additions for the 2020 and 2021 SLA/GCA ratio and multiplied that by the forecasted Gross Customer Additions to derive forecasted SLA activities.

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF	2020 YEF	2021 YEF
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439	18,540	17,750	17,750
Ratio of Service Additions to Gross Customer Ad	0.82	0.76	0.71	0.76	0.74	0.76	0.75	0.75
Activities (riser or services)	11,103	12,392	12,288	15,856	16,606	14,116	13,388	13,388
Unit Costs ($ per service/riser)	$ 2,256	$ 2,484	$ 2,598	$ 2,497	$ 3,283	$ 3,369	$ 3,362	$ 3,429
Expenditures ($000s)	25,049	30,785	31,927	39,594	54,511	47,556	45,015	45,915

[46] BCUC IR 2.181.1 2019 Base New Customer Services of $50,162 divided by 2016-2018 average GCA of 20,175.

184.0 Reference: FEI GROWTH CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 42.1

New Customer Meters

In response to BCUC IR 42.1, FEI provided the following table:

FEI New Customer Meters ($000s)

	2014	2015	2016	2017	2018
Residential and Commercial Meter sets	756	699	1,368	1,533	1,578
Large Commercial/Industrial Meter sets	827	1,261	2,062	2,394	2,819
Total New Customer Meters	1,583	1,960	3,430	3,927	4,397

184.1 Please explain the significant increase in capital expenditures for New Customer Meters from 2015 to 2016. Please provide a separate explanation for: (i) Residential and Commercial Meter sets; and (ii) Large Commercial/Industrial Meter sets.

Response:

The increase in capital expenditures for New Customer Meters from 2015 to 2016 is due to the following:

- Residential and Commercial Meter Sets – FEI experienced an increase in the number of multi-family customer attachments due to changing market trends away from single detached homes. As discussed in the response to BCUC IR 1.41.3, FEI experienced a significant increase of approximately 40 percent in multi-family attachments starting in 2016. Multi-family meter sets are more complex and higher cost to install as they include the installation of multiple meters on a manifold as compared to single-family homes. This has contributed to a significant increase in Residential and Commercial meter set costs noted above.
- Large Commercial/Industrial Meter Sets – FEI experienced a 64 percent increase from 2015 to 2016, which is 11 percent higher than the increase of 53 percent experienced from 2014 to 2015. This increase is mostly due to the addition of a few large commercial/industrial customers that required more costly multiple meter set installations.

185.0 Reference: FEI GROWTH CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 40.4, 40.5, 42.1, 47.4.1; Exhibit B-1, pp. C-56 – C-63, C-65

Distribution Pressure (DP) System Improvements

In response to BCUC IR 40.4, FEI stated the following:

> Distribution pressure (DP) System Improvements will be included in the Growth capital category for the proposed MRP term. DP System Improvements include looping of distribution gas mains to increase the capacity of the system to meet increasing customer demand. FEI has proposed this change because the primary driver for these expenditures is customer additions and the timing of the expenditures is generally within the same year that the customer additions take place. [Emphasis added]

In response to BCUC IR 40.5, FEI provided the following table showing the correlation coefficients for Growth Capital based on the actual 2014 through 2018 expenditures:

Growth Capital Correlation Coefficient	Service Line Additions	Gross Customer Additions
New Customer Mains	0.91	0.93
New Customer Services	0.93	0.95
New Customer Meters	0.88	0.94
System Improvements (DP)	0.28	0.29

185.1 When considering the low correlation coefficients between the System Improvements (DP) expenditures and both service line additions and gross customer additions, please explain why FEI considers it appropriate to move System Improvements (DP) from the Sustainment Capital category to the Growth Capital category.

Response:

As discussed in Section C3.3.1 of the Application, distribution system improvements occur when additional mains are required to be installed within the existing distribution network to increase system capacity in order to meet peak customer demand and are driven by customer additions. Distribution system improvement spending is lumpy over time and this is why the correlation with customer additions, which are added more evenly over time, is low. However, load changes resulting from customer additions are ultimately what creates the need for distribution system improvements. Therefore, it is logical to group distribution system improvements in the Growth Capital mechanism.

185.1.1 As part of the above response, please explain how FEI determined that expenditures in the System Improvements (DP) category are driven by customer additions. Please provide the analysis used to support this conclusion and detail any assumptions made.

Response:

FEI determined that expenditures in the System Improvements (DP) category are driven by customer additions since system improvements are intended specifically to manage load increases that result from these additions. System improvements occur when additional mains are required to be installed with the existing distribution network to increase system capacity in order to meet peak customer demand. The process for determining the need for System Improvements in a distribution system involves applying the peak load associated with new and future (forecasted) customer accounts in a region to a current hydraulic model of the system. The resulting "future year" models represent the projected future of the system from a flow and pressure distribution perspective. These models identify any area where the distribution system is unable to maintain minimum delivery pressure at customer locations and the year that such conditions are projected to occur. The locations in which the future load is applied to the hydraulic model is determined based on FEI's current knowledge of areas with active customer attachments, understanding of projected future development, consideration of Official Community Plans (OCPs) and other development plans within each system. The location within the distribution system of current and future load growth is an integral part of determining the location of projected low pressure areas and consequently the scope and location of any required System Improvement(s). A distribution system will generally accept more load without need for System improvements if the load is distributed evenly across the system. Account additions tend to be concentrated in areas under active development and not distributed evenly across the system. As a result, the primary driver in determining the need for System Improvements is customer additions. The proposed change to move System Improvements (DP) from Sustainment to Growth capital is based on the logic that expenditures in this category are driven by customer additions that necessitate upgrades to system capacity to maintain reliable service to existing and new customers.

185.2 Please discuss any other cost drivers FEI identified for the System Improvements (DP) expenditure category and provide the respective coefficient of correlation for each driver.

Response:

FEI did not identify any other cost drivers for distribution System Improvements.

On page C-65 of the Application, FEI provides Table C3-7 which excludes capital expenditures for Distribution System Improvements.

Table C3-7: FEI Sustainment Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Customer Measurement	31,864	30,559	31,328	31,781	32,461	32,979
Transmission System Reliability & Integrity	39,663	42,213	37,599	41,021	45,792	47,355
Distribution System Reliability	16,336	14,996	11,949	19,235	12,541	21,890
Distribution System Integrity	22,946	24,219	31,615	25,080	28,924	22,168
Sustainment CIAC	(4,013)	(3,902)	(3,902)	(3,902)	(3,902)	(3,902)
Sustainment Capital – Total	106,796	108,085	108,589	113,215	115,815	120,490

In response to BCUC IR 47.4.1, FEI provided an update to Table C3-7 to include capital expenditures for Distribution System Improvements.

	Average 2017-2019P	2020	2021	2022	2023	2024
Customer Measurement	31,864	30,559	31,328	31,781	32,461	32,979
Transmission System Reliability & Integrity	39,663	42,213	37,599	41,021	45,792	47,355
Distribution System Reliability	16,336	16,329	14,259	22,906	18,109	35,950
Distribution System Integrity	22,946	24,219	31,615	25,080	28,924	22,168
Sustainment CIAC	(4,013)	(3,902)	(3,902)	(3,902)	(3,902)	(3,902)
Sustainment Capital - Total	106,796	109,417	110,899	116,886	121,384	134,550

Based on the above tables, Distribution System Reliability expenditures excluding System Improvements (DP) are forecast to increase by $9.349 million in 2024; whereas, Distribution System Reliability expenditures including System Improvements (DP) are forecast to increase by $17.841 million in 2024.

185.3 Please explain how FEI derived the forecast for the capital expenditures required for System Improvements (DP). As part of this response, please explain the large forecast increase in 2024.

Response:

FEI actively manages its Sustainment Capital plan and derives its forecasts at the project level using its AIP tool as described in Section C.3.2 of the Application. Please also refer to the response in BCUC IR 1.47.10 that describes why the AIP optimization process results in fluctuations in portfolio expenditure levels from year to year.

As described in Section C3.3.2.1.3 of the Application, the $9.349 million increase in Distribution System Reliability (excluding System Improvements (DP)) in 2024 is mainly attributable to the following:

- **Distribution Stations Alterations Increases by $4.917 million from 2023 to 2024.** As described on page C-70 of the Application and in the response to BCUC 1.47.11.1, the increased expenditure in 2024 is caused by capital portfolio optimization to offset expenditure fluctuations in other portfolios. FEI determined that maximum value could be realized by executing 15 station alteration projects in 2024 with an average project cost of $610 thousand. A total of 85 individual projects make up the $11.940 million identified for 2024. Of these, the 15 projects identified above (totaling $9.144 million) will be in construction, while the remaining 70 projects (totaling $2.795 million) will be for prior year project closeout and design for future projects.
- **Distribution System Capacity Alterations Increases by $4.177 million from 2023 to 2024.**
  For the 2020-2024 forecast, only IP system improvements are included in this category. These projects tend to be less frequent and higher cost than the DP system improvements. As such the expenditures in this category fluctuate greatly from year to year. The elevated forecast in 2024 is mainly attributable to a single large IP system improvement (SI – 1300m x 323 IPST Riverside), on which FEI is forecast to spend $3.536 million in 2024 as shown in Table C3-12 of the Application.

The $8.492 million increase from 2023 to 2024 in the System Improvements (DP) category is a reflection of the uncertainty in the load forecast over a time horizon of 5 years. FEI updates its capacity planning models on an annual basis using the load forecast and observed system pressures. In addition to the total load increase, the exact location on the system that a customer attaches impacts FEI's ability to maintain system capacity. When modeling a 5 year forecast, FEI does not know where on the system the customers will attach. As such, FEI takes a conservative approach whereby the load is added to the end of the system where the pressures are the weakest. These assumptions are revised each year as actual customer additions are incorporated into the model to replace the forecast loads.

Once a capacity shortfall requiring a system improvement is identified within the 5 year time horizon, a project is created with a scope of work and a preliminary cost estimate. When the capacity planning models are updated each year using updated data and forecasts, the timing and scope of the projects are revised to either pull them forward if actual customer additions in the area of concern have exceeded the forecast, or delay them if actual customer additions in the area of concern have lagged the forecast. This tends to create an apparent accumulation of work in Year 5 of the forecast that will get flattened out through successive iterations that incorporate better data that cause some projects to get advanced and others to get delayed. The reliance of the System Improvements (DP) forecast on the load forecast and the actual timing and location of customer additions is the reason that FEI has moved this category of spending from the Sustainment Capital Portfolio to the Growth Capital Portfolio for the 2020-2024 MRP.

In response to BCUC IR 42.1, FEI provided the following table:

FEI DP System Improvements ($000s)

Region	2014	2015	2016	2017	2018
Lower Mainland	332	8	4	167	97
Fraser Valley	837	4,124	2,288	2,689	2,014
Interior North	210	267	300	22	0
Interior South	163	383	132	229	97
Vancouver Island	899	942	229	459	2,225
Total DP SI's	2,439	5,723	2,953	3,566	4,433

185.4 For each region in the above table, please explain the causes of the fluctuations in DP System Improvements costs in each year of the Current PBR Plan term. Please specifically identify and discuss the causes of significant increases in expenditures in certain years (e.g. 2015 expenditures in the Fraser Valley and 2018 expenditures on Vancouver Island).

Response:

The noted expenditures in the Fraser Valley and Vancouver Island can be attributed to two primary reasons:

1. The addition of large industrial customers that often apply for gas service with short notice and can drive significant system improvements to meet forecast demand.
2. The advancement of known system improvements due to higher than anticipated load growth.

Because new system improvements are being identified on a regular basis and known system improvements are being rescheduled from year to year based on updated load forecasts and hydraulic modeling, it is not possible to identify specific projects that make up the variance.

However, the primary reason that the 2018 expenditures are significantly higher on Vancouver Island compared to prior years is the installation of 5.5 km of 114 mm polyethylene DP to connect the new Deerfield Road station to the existing Campbell River DP system to supply the growing customer demand in the area. The new station and system improvements provide support to the Courtney, Campbell River and Comox distribution systems.

185.5 Please explain if FEI is expecting the trend in low (or zero) DP System Improvements costs to continue in the future in the Interior North. Please explain the basis for FEI's response, including any assumptions.

Response:

At present, FEI has not identified a large need for System Improvements in the Interior North; however, FEI is not expecting System Improvement costs to remain at zero. To maintain a healthy system, system improvements are generally scheduled to be installed in the construction season in advance of the heating season for which they are required. The Interior North, similar to other operating regions in FEI's service territory, is a collection of many independent distribution systems each having its own specific requirements for system upgrades for both timing and scale. The projects required in the region may cluster in certain years, increasing costs, while certain years may not require any significant upgrades. Such variation was also evident in the Lower Mainland region, where costs dipped in 2015-2016, which is a trend that could occur in any region. The Interior North, for example, has upcoming System Improvement expenditures in 2020 that will increase expenditure levels once again above those seen in 2017 and 2018.

186.0 Reference: FEI GROWTH CAPITAL

Exhibit B-10, BCUC IR 2.1, 2.3, 8.8, 8.10; Exhibit B-1, pp. C-60 – C-61

New Customer Services

In response to BCUC IR 8.8, FEI explained the factors contributing to the high dollar per service line addition ($/SLA) variance in 2018 of $1,388. These factors included: (i) contractor cost increases; (ii) increased internal crew charges as a result of mobilizing out of town crews to the Lower Mainland due to the "record level of gross customer and service line additions activity experienced in 2018"; (iii) management costs; and (iv) muster kit material charges.

On page C-60 of the Application, FEI states that the proposed Growth Capital base for the MRP includes the average 2016-2018 actual unit costs as a starting point with two adjustments to increase the overall unit cost Growth Capital base.

In response to BCUC IR 2.1, FEI stated: "Climate action plans, including the CleanBC Plan, the BC Energy Step code, and local government actions to strengthen their climate action initiatives, will constrain the outlook for FEI's traditional natural gas services."

In response to BCUC IR 2.3, FEI stated the following:

> Generally, the new housing construction market is expected to soften over the early period of the MRP as compared to current levels largely due to impacts of recent policy and regulation changes that affect the purchase of a home, such as tightening mortgage rules, the foreign buyer's tax, and the speculation tax…Accordingly, FEI expects that capital expenditures related to customer growth will be lower overall during the MRP term as compared to the Current PBR Plan term.

186.1 Given that the large variance in formula versus actual service line additions in 2018 is partially attributable to the record level of gross customer and service line additions activity experienced in 2018, please discuss whether it would be appropriate to normalize the actual 2018 New Customer Services amount (i.e. adjust the amount downwards) to reflect a more reasonable expectation of future activity within the MRP Growth Capital base.

Response:

FEI has normalized the impact of high levels of gross customer and service line additions in 2018 by calculating the proposed Growth Capital base using an average of the 2016-2018 actual unit costs. Additionally, FEI is proposing other appropriate adjustments that are described in the response to BCUC IR 1.41.2. As such, FEI believes that the proposed Growth

Capital base unit cost is reflective of FEI's level of capital investment required to provide service to new customers during the MRP period.

Through the Current PBR Plan term the volume variance in service line activity is attributable to the increased volume of customer attachments, the use of service line additions in the Growth capital formula, and Growth Capital activity tied to a lagging growth factor based on one half of year-over-year changes in service line additions. FEI is proposing to address these divergences in its proposed Growth Capital formula to better represent activities through the MRP by using gross customer additions, rather than service line additions, and utilizing a forward looking approach in forecasting gross customer additions that is then trued-up annually.

Further, FEI's expectations regarding customer additions activity including the slower growth in natural gas services and softening of the new housing construction market will be factored into FEI's forecast of gross customer additions as they unfold. Gross customer additions will be forecasted on an annual basis for the upcoming year to determine Growth Capital expenditures. This mechanism will allow FEI to bring forward the most current forecast information on customer growth and attachments based on the most up-to-date operating environment and housing market trends.

186.1.1 As part of the above response, please specifically address FEI's expectations regarding slower growth in traditional natural gas services and softening of the new housing construction market, and whether these expectations should result in a downwards adjustment to the Base 2019 Growth Capital.

Response:

Please refer to the response to BCUC IR 2.186.1.

In response to BCUC IR 8.10, FEI stated that contractor cost increases accounted for approximately 75 percent of the total cost variance in service line additions in 2018. One of the factors was that the "percentage of services over 15 metres in length increased indicating that the average service length installed was substantially longer than in previous years."

186.2 Please further explain the reasons why the percentage of services over 15 metres in length was significantly higher in 2018 compared to previous years.

Response:

The length of service line required to connect customers to the gas system is determined by the customer's location in relation to the main. Accordingly, the higher proportion of mains greater than 15 meters in 2018 is a result of a higher number of service lines connected to buildings that were further away from the mains than in previous years.

186.3 Please explain the likelihood that the percentage of services over 15 metres will be comparable to 2018 during the proposed MRP term. As part of this response, please compare the percentage of services over 15 metres of length experienced thus far in 2019 to the percentage in 2018.

Response:

So far, FEI has experienced fewer services over 15 meters in comparison to 2018 as shown in the table below. However, FEI is not able to determine the proportion of services over 15 meters in length in the future as it is dependent on the distance from the main that customers' buildings are located.

	Total Service Lengths				
	<15m		>15m		Total
2018	12,926	60%	8,717	40%	21,643
2019	7,859	68%	3,674	32%	11,533

2018 figures are for the full year, whereas 2019 reflects year to date figures.

186.4 Please discuss FEI's expectations regarding the amount of internal crew charges resulting from mobilizing out of town crews to the Lower Mainland during the proposed MRP term.

Response:

FEI does not have any basis on which to estimate the extent of this activity, although generally FEI can say that it will continue to mobilize out of town crews to the Lower Mainland (or elsewhere) if backlogs are created by high numbers of requested customer connections or delays in construction due to weather. FEI may also choose to redeploy crews from areas that are experiencing low volumes of work activities (primarily due to weather) to busier areas.

186.4.1 As part of this response, please provide the actual amount of internal crew charges in each of 2014 through 2018 and projected 2019.

Response:

FEI is unable to provide the actual amount of internal crew charges during the Current PBR Plan term that resulted from mobilizing out of town crews to the Lower Mainland as it does not track these types of expenditures separately. However, FEI is able to provide a high-level estimate of the incremental costs based on the actual employee expense charges for internal crews in each of 2014 through 2018 and projected 2019. FEI estimates that $112 thousand of incremental cost (Employee Exp./GCA Increase of $4.99 x 2018 GCAs of 22,439 = $112 thousand) can be attributed to the mobilization of out of town crews to the Lower Mainland in 2018.

Internal Crew – Employee Expenses

Growth Capital	2014	2015	2016	2017	2018	2019
Travel	42	67	4	22	20	45
Meals & Entertainment	24	38	44	59	75	61
Living Out Allowance	24	34	39	55	77	69
Allowance Mileage	8	4	1	1	9	8
Accomodations	0	0	72	92	179	155
Other	2	2	1	0	0	18
Total Employee Expenses (000's)	**100**	**144**	**162**	**229**	**360**	**356**
Gross Customer Additions	13,583	16,213	17,261	20,825	22,439	18,540
Employee Exp/GCA	$ 7.34	$ 8.87	$ 9.36	$ 10.98	$ 16.05	$ 19.18
		Ref				
2014-2016 Avg. EE/GCA	$ 8.52	A				
2017-2018 Avg. EE/GCA	$ 13.51	B				
Employee Exp/GCA Increase	$ 4.99	B minus A				
Adj. 2018 Increm. Cost Impact ($000's)	**$ 112**	Empl Exp/GCA incr. x 2018 GCA				

186.5 Please discuss whether FEI expects management costs to be lower in 2019 than in 2018 due to the efforts to refresh the contract for the competitive bid process being completed in 2018.

Response:

FEI does not expect management costs to be materially lower for Growth Capital in 2019 as the new contract language is subject to interpretation and clarifications. FEI continues its efforts to increase management oversight of contractor installations in order to ensure that service attachments to new customers meet contract requirements and that the capital investments necessary to add customers are prudent and reasonable.

187.0 Reference: FEI GROWTH CAPITAL

Exhibit B-10, BCUC IR 42.1.1, 42.8, 42.9, 42.10, 42.12; Exhibit B-1, pp. C-61 – C-62

Incremental Funding

In response to BCUC IR 42.1.1, FEI stated that the main factors that contributed to the Construction Price increase of approximately 13 percent were:

1. Contractor Price Increases;
2. Regional Growth Activity;
3. Field Quality Assurance;
4. Testing Installations; and
5. Muster Kit & Material Allocation Impacts.

187.1 Please clarify if FEI's statement that the Muster Kit & Material Allocation Impacts contributed to the Construction Price increase of 13 percent was in error and that only the first four items in the list in the above preamble contributed to the Construction Price increase.

Response:

Confirmed. Consistent with the discussion of Construction Price increases on pages C-61 and C-62 of the Application, only the first four items in the list in the above preamble contributed to the 13 percent ($9.146 million) Construction Price increase in 2020 as compared to the 2016-2018 average in aggregate across all of the Growth Capital activities.

In response to BCUC IR 42.1.1, FEI provided the following explanation of Muster Kit & Material Allocation Impacts:

> The total incremental impact to New Customer Services represents an increase of approximately $0.9 million and $1.3 million in 2018 and 2019, respectively. Conversely, there was a reduction in the muster kit material charge for mains muster kits based on an evaluation of actual materials used in an average mains installation. The total incremental impact to New Customer Mains is a decrease of approximately $0.6 million each year in 2018 and 2019…

…The new prices were effective March of 2018, which were prorated accordingly in calculating the cost impact for both New Customer Services and Mains.

On page C-61 of the Application, Table C3-3 shows the incremental funding for Muster Kit & Material Allocation Impacts to be $642,000.

In response to BCUC IR 42.12, FEI provided the following table:

Muster Kit Material Charges – New Customer Mains and Services ($000's)

	2014	2015	2016	2017	2018	2019
New Customer Mains	134	147	123	190	261	231
New Customer Services	1,097	1,229	1,209	1,576	3,256	3,161
Total	1,231	1,376	1,332	1,766	3,516	3,391

187.2 Please clarify if the Muster Kit Material Charges provided in response to BCUC IR 42.12 represent all of the "Muster Kit & Material Allocation Impacts" charges.

Response:

The Muster Kit Material Charges provided in the response to BCUC IR 1.42.12 included only the Muster Kit direct material charges and did not include the additional material allocation portion of the "Muster Kit & Material Allocation Impacts" charges. The Muster Kit & Material Allocation impacts referred to on pages C-61 and C-62 of the Application consist of both Muster Kit direct material charges and additional material allocation costs.

The revised table below incorporates the additional materials allocation as part of the Muster Kit & Material Allocation Impacts.

Revised Table: Muster Kit Material Charges and Material Allocation Impact – New Customer Mains and Services ($000's)

	2014	2015	2016	2017	2018	2019
New Customer Mains	468	1,035	798	954	905	562
New Customer Services	2,250	2,797	2,545	2,939	4,583	3,482
Total Muster & Material Allocation Impact	**2,718**	**3,832**	**3,343**	**3,893**	**5,488**	**4,044**

The increase from 2017 to 2018 of approximately $1.6 million is due in part to the muster kit material charge, which was implemented part way through 2018. As discussed in the Application, the adjustment to the muster kit charge was made to better reflect the actual cost of the materials used in different capital activities including Mains and Services. As muster kits are used mostly for New Services, the total muster kit and material allocation charges for New Services will increase while the allocation charges to New Mains will decrease, better reflecting the actual cost of materials used in the different capital activities. Other factors contributing to the increase of $1.6 million in 2018 include generally higher expenditures for materials and higher activities (service orders).

FortisBC notes that, in preparing the revised table above, the expected increase of approximately $1.3 million for New Customer Services due to the muster kit material change was revised to an increase of approximately $900 thousand, a reduction from the $1.3 million originally expected. Other capital activities were also identified as using muster kits (i.e., service alterations, mains alterations), resulting in a reallocation of costs from New Customer Services. Therefore, the net impact of the changes in the muster kit material charges for mains and services is approximately $300 thousand, rather than the $642 thousand as indicated on pages C-61 and C-62 of the Application. FEI proposes to update its proposed Growth capital Base unit cost for the above correction to the Muster Kit and Material Allocation Impact in its filing for 2020 permanent rates following the BCUC's Decision in this proceeding.

The 2019 numbers in the revised table represent the 2019 YEF for New Customer Mains and New Customer Services muster kit materials charges and materials allocation. The 2019 year end forecasts are based in part on 2019 July year to date expenditures and are projected to be lower than 2018 actuals, recognizing that Growth Capital activities and expenditures are cyclical and can vary from month to month.

187.2.1 As part of the above response, please explain the statement in response to BCUC IR 42.1.1 that the "total incremental impact to New Customer Mains is a decrease of approximately $0.6 million each year in 2018 and 2019" given: (i) the increased costs in 2018 and 2019 compared to 2017, as shown in the above table; and (ii) the fact that the total costs related to New Customer Mains in 2018 and 2019 are only $261,000 and $231,000, respectively.

Response:

Please refer to the response to BCUC IR 2.187.2.

187.2.2 If the Muster Kit Material Charges in the above table do not represent all of the "Muster Kit & Material Allocation Impacts" charges, please provide a revised table which includes all of the costs.

Response:

Please refer to the response to BCUC IR 2.187.2.

187.3 Please further explain the statement in response to BCUC IR 42.1.1 that Muster Kit Material Charges increased by $0.9 million and $1.3 million in 2018 and 2019, respectively, given that the Muster Kit Material Charges for New Customer Services, as shown in the above table, are projected to decrease in 2019 compared to 2018.

Response:

Please refer to the response to BCUC IR 2.187.2.

187.4 Please explain if the proposed 2019 Base Growth Capital amount for Muster Kit & Material Charges is calculated by taking the average of the actual 2016-2018 amounts provided in the above table (in response to BCUC IR 42.12), multiplying the average amount by inflation, and adding $642,000.

Response:

As explained in the response to BCUC IR 2.187.2, the table in the preamble only includes the direct material charges. The table in the response below is based on the revised table provided in response to BCUC IR 2.187.2, and includes both the direct material charges and the additional material allocation portion of the muster kit and materials allocation impacts.

The proposed 2019 Base Growth Capital amount for Muster Kit and Material Charges included in New Customer Mains and Services is based on:

- the average of 2016 to 2018 costs, inflation adjusted to 2019; plus
- the net impact of the changes in the muster kit material charges for mains and services, as discussed on page C-62 of the Application and response to BCUC IR 1.42.15 and revised in response to BCUC IR 2.187.2.

As shown in the table below, the 3-year historical expenditures for muster kit and materials allocation for New Mains and Services, inflation adjusted to 2019, is $4,424 thousand.

Muster Kit & Material Allocation ($000s)	2016 Actual	2017 Actual	2018 Actual	Average
New Customer Mains	798	954	905	
New Customer Services	2,545	2,939	4,583	
Inflation Adjustment	107.3%	104.9%	102.1%	
Inflation Adjusted Mains	856	1,000	924	
Inflation Adjusted Services	2,731	3,082	4,679	
Inflation Adusted Mains & Services	$ 3,587	$ 4,082	$ 5,602	$ 4,424

As discussed in the response to BCUC IR 2.187.2, the net impact of the changes in the muster kit material charges for mains and services is approximately $300 thousand, rather than $642 thousand as indicated on pages C-61 and C-62 of the Application. The forecast net increase of approximately $300 thousand is comprised of an increase of approximately $900 thousand for New Services offset by a decrease of approximately $600 thousand in New Mains. The reasons for this net change are described further below:

- Driving the increase for New Services is an increase in the price for the muster kit for New Services from $95 per kit to $220 per kit, which increases the cost of muster kits and materials directly charged to New Services. This is offset partially by a reduction in material costs allocated to New Services, as more material costs are directly charged to New Services under the muster kit pricing approach instead of by allocation.
- For New Mains, there was no significant change in the price of a muster kit. Instead, the estimated reduction of $600 thousand for muster kits and materials for New Mains better reflects the allocation of material charges for the various capital activities. As discussed in the response to BCUC IR 2.187.2, as muster kits are used mostly for New Services, the total muster kit and material allocation charges for New Services is expected to increase while the allocation charges to New Mains are expected to decrease, better reflecting the actual cost of materials used in the different capital activities.

The net impact of approximately net $300 thousand is added to the 3-year historical average ($4,424 thousand) calculated above to come up with the 2019 Base Growth Capital amount (New Mains and New Services) for Muster Kit and Material Charges. This approach provides a fair approximation of the expected impact of the muster kit and materials allocation change.

As noted in the response to BCUC 2.187.2, FEI proposes to update its proposed Growth capital Base unit cost for the above correction to the Muster Kit and Material Allocation Impact in its filing for 2020 permanent rates following the BCUC's Decision in this proceeding.

187.4.1 As part of the above response, please provide the 2019 Base amount related to Muster Kit & Material Charges and provide the supporting calculations.

Response:

Please refer to the response to BCUC IR 2.187.4.

187.4.2 As part of the above response, please also clearly show, with supporting calculations, how the $642,000 incremental expenditures were calculated.

Response:

Please refer to the response to BCUC IR 2.187.4.

In response to BCUC IR 42.1.1, FEI stated that two factors – Regional Growth Activity and Muster Kit & Material Allocation Impacts – have had an impact on actual Growth Capital expenditures during the 2016-2018 period.

In response to BCUC IR 42.10, FEI provided the following table:

Description	% Price Increase	Price Increase ($000s)
Contractor Price Increases	8.7%	$ 6,090
Regional Growth Activity	0.9%	$ 597
Field Qualtiy Assurance	2.2%	$ 1,515
Testing Installations	1.3%	$ 943
Total	13.1%	$ 9,146

187.5 Please provide a detailed calculation and description of how the incremental amount of $597,000 related to Regional Growth Activity was calculated.

Response:

The incremental amount of $597 thousand related to Regional Growth Activity was determined by considering cost drivers during the proposed MRP term that are expected to lead to higher costs.

The first cost driver is the impact on unit pricing of a shift from the lower priced to the higher cost contractor to perform the work due to capacity. FEI evaluates the allocation of work between the two contractors based on the unit price structure, location, risk profile, contractor capacity, quality and safety indicators and ongoing performance of the contractors. This shift is expected to lead to a cost increase of approximately $367 thousand, representing the majority of the increase expected for Regional Growth Activity. FEI acknowledges that this cost driver may have been better categorized under the Contractor Price Increases, but was grouped into this category.

The second driver, representing the remaining increase of approximately $230 thousand, is required for an expected 10 percent increase in Growth Capital for work on Vancouver Island and the Sunshine Coast areas where the costs of contractor crews are higher.

187.6 Please provide a detailed breakdown and description of the incremental costs related to Testing Installations.

Response:

For Testing Installation, FEI estimates that an increase to pressure test durations to identify material defects or installation errors before installations are placed into service will result in increased crew costs of approximately 3 percent or $943 thousand. Costs increases are related to the additional time[47] required to perform pressure testing on new service installations in alignment with CSA Z662.

[47] The duration of pressure tests for distribution pressure installations >50m is a minimum of 30 minutes and >100m is a minimum of 60 minutes.

On page C-62 of the Application, FEI states the following regarding Field Quality Assurance:

> FEI is conducting increased field audits of Growth capital construction to continue to ensure quality requirements are met and to maintain documentation and records quality. These audits serve to verify that the quality of works remains high and to identify workmanship or procedures that require correction with the goal of avoiding defects in the system that are difficult to identify at a later date.

In response to BCUC IR 42.8 FEI stated the following:

> FEI does not track completed audits by expenditure program. However, the total number of field audits completed for O&M, Growth, and Sustainment capital during the Current PBR Plan term are as follows:

2014	2015	2016	2017	2018
2,648	2,653	5,039	5,486	5,626

> FEI estimates that the number of field audits related to Growth capital is expected to increase by approximately 700 per year.

In response to BCUC IR 42.9, FEI stated the following:

> FEI cannot provide a detailed breakdown and description of the field audit costs incurred each year during the Current PBR Plan term as FEI does not track field audit costs separately within management costs. The incremental cost proposed to be added to Base Growth capital is $1.8 million for the addition of nine full time equivalents to oversee the program to continue to ensure quality requirements are met and to maintain documentation and records quality.

187.7 Please clarify FEI's statement in response to BCUC IR 42.9 that the incremental cost proposed to be added to Base Growth Capital is $1.8 million given the amount provided for Field Quality Assurance in response to BCUC IR 42.10 of $1.515 million.

<u>Response:</u>

The reference in the response to BCUC IR 1.42.9 to the $1.8 million incremental cost proposed to be added to Base Growth Capital should have been $1.5 million. Please refer to the response to BCUC IR 2.187.10 for details of the calculation.

187.8 Please separately explain in detail the field audit process for each of Growth Capital, Sustainment Capital and O&M, including what would trigger a field audit.

Response:

FEI confirms that the field audit process is identical for Growth Capital, Sustainment Capital and O&M.

FEI conducts three different types of field audits: operation field assessments, detailed work observations, and field observations. Each type is described below.

Operations Field Assessments

Operations field assessments are focused on quality assurance and are conducted by managers, operations supervisors, and construction supervisors. The assessment steps are specific to the type of on-site activities being assessed: below ground leaks, above ground gas odour, industrial meter exchange, instrument drive exchange, station heater, meter work, PE main, PE service, station chart change, gate station, steel main, steel service, and joint trenching. The assessment ensures that the correct methods are specified, understood, and complied with during the work, other utility information has been provided and assessed, that the workers have the correct competencies for the work, tools are in good working order, environmental protections are in place, and that the work is documented correctly.

Detailed Work Observations

Detailed work observations are focused on worksite safety and are conducted by managers and operations supervisors. Detailed work observations are for the assessment of internal crews and they have an extensive checklist. They include assessments of personal safety, vehicle and mobile equipment, written site safe work plan, environmental protection, ergonomics, system safety and lockout, third party facilities, and work methods and procedures.

Field Observations

Field observations are also focused on worksite safety and are conducted by construction supervisors. Field observations are for the assessment of contractor crews and they have a shorter checklist than detailed work observations. To ensure due diligence over the contractor they are used along with the operations field assessments to evaluate that all contract requirements are being met. Like the detailed work observations they include assessments of personal safety, vehicle and mobile equipment, written site safe work plan, environmental protection, ergonomics, system safety and lockout, third party facilities, and work methods and procedures.

The frequency of field audits is as follows:

- Operations Supervisors are scheduled to perform a minimum of four detailed work observations and two operation field assessments per month.
- Operations Managers are scheduled to perform two detailed work observations per month.
- Construction Supervisors are scheduled to perform a minimum of four field observations and two operation field assessments per month.

FEI's managers and supervisors travel to site to complete the observations and assessments on both employees and contractors working for FEI. Using the templates as a guide the managers will assess the ongoing field work for safety and quality compliance. The nature and progress of the work will dictate what aspect of the work is reviewed in detail. For example, the assessment may focus on complex excavation, traffic control, fusing, or welding. The results of the assessments including any corrective actions are documented in the Utility Resource Management system where they can be analyzed and communicated throughout the organization.

Usually the audits are completed by one supervisor or manager but occasionally they are completed by more than one supervisor/manager in order to ensure consistency between regions and departments.

The average time taken to complete an audit can vary significantly depending on the travel time required to and from the job site, the complexity of the activities, whether corrective actions are required and the amount of time required for documentation.

187.8.1 As part of the above response, please elaborate on the work undertaken during a field audit, the number of persons required to conduct an audit and the average time taken to complete an audit for each of Sustainment Capital, Growth Capital and O&M.

Response:

Please refer to the response to BCUC IR 2.187.8.

187.9 Please explain in detail why the number of field audits increased significantly between 2015 and 2016 and is anticipated to increase during the proposed MRP term. As part of this response, please explain in detail why it was determined that an increased number of field audits of Growth Capital are required during the proposed MRP term.

Response:

The number of documented field audits increased significantly between 2015 and 2016 as both a new retention system and the policy of completing four audits per month by supervisors and two audits per month by managers was introduced. FEI has also been experiencing a steady and significant increase in new customer additions during the Current PBR Plan period. This increase in construction activity has led to an increase in the number of field audits being conducted.

FEI does not currently plan to increase the number of field audits related to Sustainment Capital and O&M during the proposed MRP term. Additional field audits are not required for Sustainment Capital as these projects are typically larger and have historically had a high level of oversight. O&M work volume has been stable and is generally conducted by existing FEI resources, while Growth Capital has seen substantial increases in work volumes. FEI has recently focused additional resources on smaller projects and service installations in Growth Capital which, due to the nature of their short duration, are more difficult to have an on-site presence in order to provide a balanced oversight of all capital works and ensure that all contractual obligations including quality and safety are being met.

187.10 Given that FEI cannot provide a detailed breakdown of the field audit costs and the number of completed audits is not tracked by expenditure program, please explain how FEI has determined that the number of field audits for Growth Capital will increase by 700 per year. Please also explain in detail how FEI derived the incremental cost for Field Quality Assurance to be added to Base Growth Capital.

Response:

Based on the activity levels of recent years and the number of contractor crews working, FEI estimated that nine new construction supervisors would be required to achieve a level of oversight that ensures safety, quality, and value in the Growth Capital program. FEI estimated an increase of approximately 700 audits per year assuming a minimum of six audits per month are performed by the nine new construction supervisors.

Total incremental funding required for the Field Quality Assurance activities described to be added to Base Growth Capital is estimated to be approximately $1.515 million considering the number of positions (nine) and an approximate $170 thousand net incremental funding associated with each position including supporting costs (i.e. travel, vehicles, etc.).

187.11 Please provide the number of FTEs that are currently overseeing the Field Quality Assurance program and provide the total capital expenditure for the FTEs.

Response:

There are three Operations Supervisors dedicated to the Field Quality Assurance program covering both Sustainment and Growth capital. There are approximately 40 other Construction and Operations Supervisors that conduct audits (amongst other supervisory duties) as described in the response to BCUC IR 2.187.8. These audits are conducted on Sustainment and Growth capital as well as O&M activities. As stated in response to BCUC IR 1.42.9, FEI does not track field audit costs separately within management costs; therefore, FEI cannot provide the total capital expenditure on the Field Quality Assurance program for the FTEs.

187.12 Please provide the title(s), job description(s) and annual salary of the nine FTEs proposed to be hired to oversee the program.

Response:

The nine FTEs proposed to be hired to oversee the program are Construction Supervisors and their job descriptions are provided in Attachment 187.12. The position's published salary range is between $80,300 and $100,400.

187.13 Please explain if an increased number of field audits related to (i) Sustainment Capital and (ii) O&M are expected during the proposed MRP term.

Response:

Please refer to the response to BCUC IR 2.187.9.

187.13.1 If yes, please estimate the increased number of field audits and provide an estimate and description of the annual additional Sustainment Capital and/or O&M costs.

Response:

Please refer to the response to BCUC IR 2.187.9.

187.13.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.187.9.

187.14 Please further explain what activities are required as part of maintaining documentation and records quality.

Response:

The job description for the construction supervisor, provided in Attachment 187.12 to the response to BCUC IR 2.187.12, outlines the responsibilities for the position. Key responsibilities include related to maintaining documentation and record quality include:

- Supports the Project Management Office reporting requirements by providing Quality, Schedule and Cost (QSC) reports as directed by the Project Manager and others including the BCUC, weekly/monthly and/or Quarterly reports to FortisBC management, executive and Board.
- Compiles an accurate construction estimates, detailed project plans and schedules, with the assistance of FortisBC's business units and other involved stakeholders. Assists in the preparation and administration of contracts.

- Analyzes and communicates risks, establishes contingency plans for the project. Manages change control for projects. Provides tracking and reporting progress to plan to the Project Manager. Analyzes performance to plan and makes recommendations for adjustments consistent with project objectives.

188.0 Reference: SUSTAINMENT/OTHER CAPITAL

Exhibit B-10, BCUC IR 1.1, 9.1, 9.3.2; Exhibit B-1, pp. C-63 – C-64

Formula versus Forecast Approach to Regular Capital

In response to BCUC IR 9.3.2, FEI stated that it does not believe that a formula approach to Sustainment/Other Capital would provide a more reasonable approach than the current proposed forecast due to the following reasons:

- A formula approach would not provide the flexibility required to address the challenges created by the evolving operating environment in the interest of existing customers.
- Additional investment is required in physical assets and information systems to address the changing security landscape and to ensure the safe and reliable operation of an aging asset base. These expenditures are unrelated to the number of customers on the system.
- Innovation and adoption of technologies is a key aspect of transitioning to a lower carbon environment. Pursuing innovation provides an opportunity to proactively manage rate impacts while supporting GHG emissions reduction goals and helping customers.

In response to BCUC IR 1.1, FortisBC stated that it is "unable to provide a forecast of capital expenses related specifically to addressing policy impacts as many policies continue to evolve and develop. However, both FEI and FBC will forecast capital related to Investments in a Clean Growth Future…annually as part of the Annual Review of Rates."

188.1 Please explain in detail why a formula approach to Sustainment/Other capital would not "provide the flexibility required to address the challenges created by the evolving operating environment in the interest of existing customers."

<u>Response:</u>

The formulaic approach to Sustainment/Other capital from 2014 to 2019 during the Current PBR Plan term was derived from a 2013 base expenditure adjusted annually for inflation, productivity, and growth tied to the average number of customers. This type of formula approach to capital assumes a continuation of "business as usual" expenditure trends. However, FEI's experience with Sustainment and Other capital over the Current PBR Plan term suggests that its expenditures are heavily impacted by changes in its operating environment. As such, FEI has proposed a 5-year forecast approach that allows it to incorporate expenditures into the capital plan to meet the emerging challenges. This approach allows for some annual fluctuation in spending levels rather than assuming a constant spend from year to year. The ability to reforecast 2023 and 2024 capital expenditures during the 2022 Annual Review acknowledges the many uncertainties in how government policy and customer expectations will unfold over a 5-year term.

Based on FEI's experience in the Current PBR Plan term, a formula approach to Sustainment/Other capital is limited in its ability to provide the flexibility required to address the challenges created by FEI's evolving operating environment for the following reasons:

- New information cannot easily be added to a formula. The formula is based on past expenditures and, even if new expenditures could be added, it can be unclear what future scope of work is already included in the formula amounts.
- Sustainment and Other capital costs are driven by many factors other than growth or total number of customers. Asset condition and the pace of technological advancement are just two of the other driving factors for Sustainment and Other capital. Other changes in the operating environment such as evolving legislation and public policy also create the need for unforeseen expenditures which cannot be reflected in inflation and/or growth factors.
- Changing stakeholder expectations and requirements influence the way the FEI interacts with its customers and drives incremental costs in existing projects, or the need for additional projects. These changes are also not reflected in capital formulas.

While a formulaic approach to set Sustainment and Other capital spending is possible, FortisBC's proposed forecast approach provides a simple and transparent way of providing the flexibility that is required to effectively manage the challenges in FortisBC's evolving operating environment.

188.1.1 As part of the above response, please specifically identify the challenges FEI is referring to and how these challenges impact Sustainment/Other capital.

Response:

Some specific examples of the challenges in FEI's evolving operating environment, and how they affect Sustainment and Other capital are provided below.

The pillars of FortisBC's "Clean Growth Pathway to 2050" include renewable gases, energy efficiency and innovation, and transportation and reducing global GHG emissions. The indirect impacts from the introduction of renewable gases and the natural gas for transportation market are dependent on where and when RNG suppliers and NGT customers come on to the system. Lead times can range from less than a year to 2-3 years. FEI must be capable of providing responsive action in order to pursue these opportunities. Some examples of how these pillars can impact Sustainment and Other capital are as follows:

1. Renewable gases: The natural gas system has traditionally been built to transport gas from a small number of large supply points to a distributed consumer base. The introduction of smaller, non-traditional sources like RNG sometimes require the modification of neighboring stations and/or distribution systems to allow the system to move a sustained supply of RNG throughout the year.
2. Transportation: The transportation sector is a large source of GHG emissions. Converting from higher carbon fuels like diesel to CNG or LNG presents a significant opportunity for GHG reductions. The refueling facilities constructed under the NGT programs frequently drive capacity upgrades to ensure sufficient pressures to effectively operate the equipment at the location that the customer chooses to base their transportation fleet.

Other challenges that FEI is facing are technology driven. The utility industry is seeing an increasingly rapid pace of technological change. In order to keep pace with customer expectations, industry practices, and security requirements, FEI must have the flexibility to adapt to the changes in a timely fashion. For example:

1. Customer expectations are shaped by the way they interact with other service providers outside of the utility industry. This drives the need to communicate with customers through new and innovative channels while providing cost effective and innovative energy solutions aimed at helping customers meet their energy needs.
2. In response to increasing requirements for mobile computing, improved access to data, and increased activism, FortisBC needs to continue strengthening its physical and cyber security practices and systems.

FortisBC's proposed forecast approach provides a simple and transparent way of providing the flexibility that is required to effectively manage the challenges in FortisBC's evolving operating environment.

188.1.2 As part of the above response, please explain why a five-year formula would not provide as much flexibility for FEI to manage Sustainment/Other capital as would be provided under the proposed five-year forecast approach.

Response:

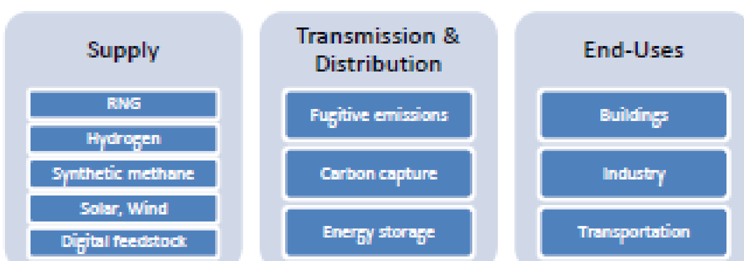
Please refer to the response to BCUC IR 2.188.1.

188.2 Please explain the relevancy of bullet point number 3 in FEI's response to BCUC IR 9.3.2 as a reason against using a formula approach to Sustainment/Other capital given that capital investments in FEI's Clean Growth Future are proposed to be treated as flow-through and therefore would be forecast annually regardless of whether a formula or forecast approach was utilized for Sustainment/Other capital.

Response:

In Figure C6-5 on page C-140 of the Application, FEI provided the following graphic that displays the utility value chain and related innovation categories that are relevant to FortisBC and proposed to be addressed under the Clean Growth Innovation Fund.

Figure C6-5: Climate Solutions Required Across the Utility Value Chain



As indicated in the preamble, investments addressing the areas listed in Figure C6-5 would be forecast annually as part of the Annual Review of Rates. However, these innovations can have indirect impacts on Sustainment and Other Capital spending:

- Renewable gases: The natural gas system has traditionally been built to transport gas from a small number of large supply points to a distributed consumer base. The introduction of smaller, non-traditional sources like RNG sometimes require the modification of neighboring stations and/or distribution systems to allow the system to move a sustained supply of RNG throughout the year.
- Transportation: The transportation sector is a large source of GHG emissions. Converting from higher carbon fuels like diesel to CNG or LNG presents a significant opportunity for GHG reductions. The refueling facilities constructed under the NGT programs frequently require capacity upgrades to ensure sufficient pressures to operate

the equipment effectively at the location that the customer chooses to base their transportation fleet.

- Operational GHG Reductions: In addition to the GHG reduction options that FEI offers to customers, FEI has the opportunity to reduce its own carbon footprint through activities such as conversion of fleet vehicles to CNG or EV, or replacing station and facilities equipment with more efficient or electric models.

These modifications to the existing gas assets that are required to support the Clean Growth Innovation fund activities are anticipated to be covered under Sustainment and Other Capital.

188.3 Please explain why additional investments for physical assets and information systems could not be addressed by providing incremental funding to a “Base 2019” Sustainment/Other capital amount, similar to the proposal to include incremental funding as part of the proposed Base 2019 O&M.

Response:

Over the initial 2 to 3 year period of the MRP term, it is possible that a formula approach to Sustainment/Other capital with additional incremental funding to a “Base 2019” could assist in addressing the challenges identified in response to BCUC IR 1.9.3.2. However, given the significant uncertainty in the environment expected over the 5 year MRP term, it is likely that some type of reforecast may be required to address changing operating conditions in the latter years of the MRP.

Given these uncertainties, a reforecast of capital spending during the 2022 Annual Review, including a review of any material changes, creates a simple and transparent regulatory process, as compared to a comprehensive review of the formula during the MRP term. If Sustainment/Other capital were subject to a formula and material changes were required during the MRP term, this could require a potentially lengthy and complex process to determine which projects or cost pressures are included in the formula and which are not, or whether any components of the formula (I, X, or G) need to be adjusted.

In response to BCUC IR 9.1, FEI stated that the correlation coefficient between the number of new attachments and actual Sustainment/Other capital Costs during the Current PBR Plan term was 0.92.

188.4 Please explain in detail the changes in circumstances that FEI believes would result in a significantly lower correlation coefficient between new attachments and actual Sustainment/Other Capital costs during the proposed MRP term.

Response:

As discussed in the response to BCUC IR 2.159.1, there are capacity-related upgrades in Sustainment Capital that are influenced by New Attachments that could explain, in part, the appearance of correlation. However, the majority of investments in Sustainment/Other Capital are required to upgrade or refurbish the existing system and are independent of New Attachments. Due to the high number of New Attachments that FEI recorded during the Current PBR Plan term, the capacity-related investments made up a higher proportion of the overall Sustainment Capital spend and may have driven some of the apparent correlation during those years. Accordingly, a decrease in the number of New Attachments could likely result in a lower correlation coefficient as investments that are independent of New Attachments would make up a higher proportion of overall expenditures.

188.5 Please calculate the annual and cumulative 2020 through 2024 Sustainment/Other Capital funding which would result from setting the "Base 2019" using each of the following two approaches: (i) the average of 2016 through 2018 actual spending (inflation adjusted); and (ii) actual 2018 spending (inflation adjusted), and then applying the same formula as is proposed for O&M to each approach. Please show all calculations.

Response:

FEI has provided the following tables as requested.

The first table includes 2016 actual through 2024 forecast Sustainment and Other Capital excluding distribution system improvements and is net of CIAC.

	2016A	2017A	2018A	2019P	2020F	2021F	2022F	2023F	2024F
Sustainment Capital	86,716	100,626	106,700	105,069	107,628	109,042	113,205	115,761	120,631
Other Capital	28,977	40,219	43,997	44,693	49,770	49,916	46,474	46,403	45,351
Total Sustainment/ Other	**115,693**	**140,845**	**150,697**	**149,762**	**157,398**	**158,958**	**159,679**	**162,164**	**165,982**

The following table provides the calculation of Sustainment and Other capital as requested with Line 25 showing the Total Sustainment / Other from the above table. FEI has made assumptions for the I-factor and the growth in Average Customers to provide this response. Actual I-factor and average customer growth will change the resulting funding of Sustainment and Other Capital under a formula approach.

Line	$000	2016A	2017A	2018A	Average (Base)	2020	2021	2022	2023	2024	Total	Reference
1	*(i) The average of 2016 through 2018 actual spending (inflation adjusted)*											
2	Sustainment Capital	86,716	100,626	106,700								
3	Other Capital	28,977	40,219	43,997								
4	Total	115,693	140,845	150,697								Line 2 + Line 3
5	Inflation Adjustment to 2019$	107.30%	104.86%	102.08%								
6	Inflation Adjusted Total	124,139	147,690	153,831	141,887							Line 4 x Line 5
7	Average number of Customers				1,024,962	1,036,640	1,047,006	1,057,476	1,068,051	1,078,732		Assumed
8	Sustainment & Other Capital per Customer Base				138							Line 7 x 1000 / Line 8
9	I-Factor					2.00%	2.00%	2.00%	2.00%	2.00%		Assumed
10	Sustainment & Other Capital per Customer				138	141	144	147	150	153		Prior Year x (1 + Line 9)
11	**Sustainment & Other Capital using O&M Formula**					**146,373**	**150,794**	**155,348**	**160,039**	**164,873**	**777,427**	Line 7 x Line 10 / Line 1000
12												
13	*(ii) Actual 2018 spending (inflation adjusted)*											
14	Sustainment Capital			106,700								
15	Other Capital			43,997								
16	Total			150,697								Line 14 + Line 15
17	Inflation Adjustment to 2019$			102.08%								
18	Inflation Adjusted Total			153,831	153,831							Line 16 x Line 17
19	Average number of Customers				1,024,962	1,036,640	1,047,006	1,057,476	1,068,051	1,078,732		Assumed
20	Sustainment & Other Capital per Customer Base				150							Line 19 x 1000 / Line 20
21	I-Factor					2.00%	2.00%	2.00%	2.00%	2.00%		Assumed
22	Sustainment & Other Capital per Customer				150	153	156	159	162	166		Prior Year x (1 + Line 21)
23	**Sustainment & Other Capital using O&M Formula**					**158,696**	**163,488**	**168,426**	**173,512**	**178,752**	**842,875**	Line 19 x Line 22 / Line 1000
24												
25	**Sustainment & Other Forecast**					**157,398**	**158,958**	**159,679**	**162,164**	**165,982**	**804,181**	

Using the 2016 to 2018 average produces capital expenditure funding through the MRP term that is below what is required, and using 2018 spending produces funding above what is required.

188.5.1 If the resulting cumulative 2020 through 2024 Sustainment/Other Capital funding under either of the two approaches is not comparable to the five-year forecast spending shown in Table C3-5 of the Application, please explain how FEI would propose to adjust the Base 2019 Sustainment/Other Capital in order to incorporate any incremental funding.

Response:

The projected level of Sustainment Capital expenditures for the proposed MRP term was developed through a robust capital planning process that included a bottom up forecast of individual asset needs that have been prioritized in an effort to increase efficiency and minimize customer rate impacts. In contrast, proposing theoretical 2019 Base adjustments under the two approaches provided by the BCUC would require FEI to consider past expenditures and make adjustments to artificially fit a formula to the forecast expenditure needs. If the BCUC were to propose a formula approach for Sustainment and Other Capital, FEI's position is that the 2020 Sustainment/Other forecast would be the most appropriate Base figure. The 2020 forecast of $157,398 thousand already incorporates the adjustments that would be required to meet the forecast expenditure needs using either of the two approaches in BCUC 2.188.5.

To achieve the required level for 2020 suggested in the question, the following table provides approximate adjustment values for some of the areas of expenditure that are likely to have incremental or reduced levels of expenditure over the proposed MRP term for the two scenarios put forth by the BCUC in IR 2.188.5.1. The rationale for the increased or reduced forecast expenditures is described below. Some of these details were also included in Section C3.3.2 of the Application in support of the forecast expenditures.

Adjustments to Base 2019 Sustainment/Other Capital	Average of 2016 through 2018 actual spending	2018 actual spending
Sustainment Capital Base	**$ 102,494**	**$ 108,919**
adjustment for Meter Materials	$ -	$ -
adjustment for Pipeline Alterations	$ -	$ 6,500
adjustment for Transmission System Telemetry Alterations	$ -	$ (2,000)
adjustment for Compressor Station Alterations	$ 1,500	$ 4,000
adjustment for Compressor Unit Overhauls	$ 1,500	$ 2,000
adjustment for LNG Plant Alterations	$ 3,500	$ 2,000
adjustment for Pipeline Inspection	$ -	$ -
adjustment for Pipeline Capacity Improvements	$ (3,500)	$ (10,000)
adjustment for Main and Service Renewals	$ 3,000	$ (2,000)
Sustainment Capital Base with Adjustments	**$ 108,494**	**$ 109,419**
Other Capital Base	**$ 39,393**	**$ 44,912**
adjustment for Tools and Equipment	$ 1,500	$ 1,500
adjustment for Fleet Services	$ -	$ (4,000)
adjustment for Cyber Security	$ 2,700	$ 2,700
adjustment for Technology Applications	$ 5,300	$ 3,000
Other Capital Base with Adjustments	**$ 48,893**	**$ 48,112**
Total Sustaiment and Other Capital	**$ 157,387**	**$ 157,531**

- **Pipeline Alterations:** 2018 was a year of relatively low expenditure in this category. Expenditures were reduced to offset the cost and resource requirements for the Whistler IP project that was taking place in the same year and to allow additional planning for future years' projects. FEI is forecasting a return to prior levels of expenditure in this category over the proposed MRP term.
- **Transmission System Telemetry Alterations:** In 2018 and 2019, FEI undertook a project to replace the Gas Control systems located in Surrey, Kelowna and Burnaby due to obsolescence. This was a large project and is not typical of expenditures in this category. FEI is forecasting reduced expenditure levels over the proposed MRP term, consistent with pre-2018 levels.
- **Compressor Station Alterations:** Expenditures in this category can fluctuate significantly depending on the size and scope of planned projects. 2017 and in particular 2018 were years of relatively low expenditure and are not representative of required levels of annual expenditure. Based on FEI's forecast of asset needs, incremental expenditures are required in this category over the proposed MRP term.
- **Compressor Unit Overhauls:** Compressor Unit overhauls are scheduled based on manufacturer recommendations and the units' operating hours. Spending in this category was very low over the Current PBR Plan period, with very few scheduled overhauls. Units 1, 2 & 3 at the V1 Compressor station are scheduled for major overhauls in the 2022-2024 period based on their current and projected operating hours. Based on FEI's forecast of asset needs, incremental expenditures are required in this category over the proposed MRP term.

- **LNG Plant Alterations:** With the addition of the Tilbury Expansion facility to the asset base, the increasing age of the Tilbury and Mt. Hayes facilities, as well as the increased usage of the LNG plants both as peak shaving resources and to provide LNG to FEI's transportation customers, additional investment in these assets is required to ensure ongoing compliance and reliability. Spending levels for LNG Plant Alterations are forecast to increase over the MRP term.
- **Pipeline Capacity Improvements:** 2018 expenditures included the Whistler IP pipeline capacity upgrade project. Based on FEI's forecast of asset needs, expenditures in this category are zero over the proposed MRP term because there are no identified pipeline capacity improvement projects during the 2020-2024 period that fall within Sustainment capital.
- **Main and Service Renewals:** This category is an ongoing program to proactively replace aging distribution mains based on their condition and rate of leaks. Each year numerous main renewals are completed across the province. Due to the short planning horizon and the availability of external contractors to execute this work, it is well suited to scale up and down from year to year to accommodate other work. The forecast expenditures in this category are, on average, higher as compared to the Current PBR Plan to ensure that the rate of main replacement is high enough to address areas where recurring leaks or mains in poor condition are identified. However, 2018 represented a year of higher expenditures in this category as projects that were delayed from earlier years of the PBR were completed.
- **Tools and Equipment:** The increased expenditure in Tools and Equipment is driven by the introduction of a five-year modified tools replacement program. Operations uses a variety of tools to operate and maintain the distribution and transmission systems. Many of the tools were designed and fabricated, or modified by the FEI machine shop and lack appropriate engineering documentation. The additional funding is to eliminate modified tools or ensure appropriate engineering documentation is available for all tools, components and sub-components that are used for pressure control or are pressure bearing.
- **Fleet Services:** Expenditures have been higher in recent years because of changes in headcount associated with new crews in the province, and because of reprioritization of vehicle purchases from earlier years of the Current PBR Plan. As such, Fleet replacement costs are lower and trending downward over 2020-2024 period compared to the Current PBR Plan term.
- **Cyber Security:** Increased sophistication in cyber threats has forced hardware and software companies to release updated code and operating systems to counteract these threats. The frequency of these updates have required the business to engage in testing, custom configuration and code updates to deploy the updates. Tools to monitor and

counteract these threats have to be evaluated and implemented to maintain an acceptable level of cyber security.

- **Business Technology Applications:** The increased expenditures forecast for 2020 to 2024 are for projects required to improve business processes and productivity, retain and attract customers, continue to meet compliance requirements, retain and attract new employees, replace outdated applications, and increase the use of data analytics.

189.0 Reference: FEI SUSTAINMENT/OTHER CAPITAL

Exhibit B-10, BCUC IR 43.2; Exhibit B-1-1, Appendix B8-1, pp. 8–9

Increased In-line Inspection Activity

On page 8 of Appendix B8-1 of the Application, FEI provides Table A:B8-1-4, which shows that increased in-line inspection activity contributed $9.785 million to the Sustainment/Other Capital cost pressures experienced during the Current PBR Plan term.

In response to BCUC IR 43.2, FEI provided a copy of its response to BCUC IR 1.9.9.2 in the FEI Annual Review for 2017 Delivery Rates proceeding which stated, in part, the following:

> …Late in 2013, FEI applied the circumferential magnetic flux leakage in-line inspection technology in a selected pipeline to evaluate the ability to detect longitudinally-oriented features. Early results obtained by this incremental technology provided material improvements to FEI's integrity management capabilities, leading to its subsequent adoption for all in-line inspected pipelines.

FEI further stated the following in response to BCUC IR 43.2:

- FEI's re-runs of geometry and standard magnetic flux leakage tools are now planned on a maximum 7-year interval. The increased frequency is consistent with industry practice and provides increased confidence in failure prevention; and
- FEI increased the number of transmission pipelines subject to in-line inspection.

FEI also stated the following in response to BCUC IR 43.2:

> Fluctuations in expenditures from one year to another during the Current PBR Plan term were primarily due to the following factors:
>
> - Delay of a planned pilot inspection with crack-detection in-line inspection technology (i.e., EMAT, or Electro-Magnetic Acoustic Transducer) on one or more pipelines in the Coastal Transmission System. The inspection was delayed due the significant complexities associated with running EMAT tools within FEI's transmission pipelines, including system modifications that must be completed in advance.
> - FEI's adoption of pipeline-specific in-line inspection frequencies ranging from five to seven years can result in some years having a higher number of inspections than others.

- Co-ordination of runs on common-diameter pipelines to reduce tool mobilization costs.

189.1 In consideration of the cost pressures experienced by FEI during the Current PBR Plan term, please explain why the adoption of circumferential magnetic flux leakage in-line inspection technology was considered necessary. As part of this response, please explain how FEI inspected the pipelines prior to 2013 and why this method was no longer considered appropriate.

Response:

FEI's approach is to adopt proven and commercialized technology within its in-line inspection program as appropriate to the specific hazards relevant to its transmission pipelines. Different types of in-line inspection tools have different capabilities to detect and size imperfections. The following table summarizes the primary capabilities for industry-adopted in-line inspection tools relevant to FEI's gas transmission pipelines:

	Geometry	Magnetic Flux Leakage (MFL)	Circumferential MFL (CMFL)	EMAT
Dents	X			
Wrinkles / Buckles	X			
Metal loss		X (circumferentially-oriented features)	X (axially-oriented features)	
Long seam weld location			X	
Girth weld location	X	X	X	X
SCC and crack-like features				X
Longitudinal seam weld flaws				X

Prior to 2013, FEI utilized magnetic flux leakage (MFL) tools for its management of external corrosion on in-line inspected pipelines. Based on FEI's initial adoption of circumferential MFL tool (CMFL) technology, it identified material benefit to its integrity management program and as such, extended the adoption of the technology across all in-line inspected pipelines. FEI's approach has been in alignment with industry practice. The improved capabilities for preventing failures of its transmission pipelines through CMFL inspections precluded FEI from deferring adoption of this continual improvement until expiration of the Current PBR Plan term.

To continue to provide safe and reliable service to customers, and irrespective of the cost pressures experienced by FEI during the Current PBR Plan term, FEI must mitigate known hazards to its transmission pipelines (such as were identified through its initial CMFL inspections) and maintain its alignment with industry practice.

189.2 FEI states that its re-runs of geometry and standard magnetic flux leakage tools are now planned on a maximum seven-year interval. Please explain at what interval FEI previously conducted its re-runs and how it determined that a maximum of seven years is appropriate.

Response:

FEI previously determined its re-inspection intervals up to a maximum 10-year frequency. In alignment with industry practice, FEI has since determined that a maximum of seven years is appropriate. This is based on the following:

1. reduced reliance on long-term corrosion growth estimates, which can fluctuate widely and be subject to considerable uncertainty, and
2. in-line inspection tool technology and analysis capabilities improve over time, and a shorter inspection interval enables FEI to leverage such improvements in a more timely manner.

On an as-required basis and based on FEI's in-line inspection analysis, re-inspections may be planned more frequently than seven years.

189.3 Please provide a list of the pipelines FEI plans to inspect during the proposed MRP term.

Response:

The following table provides FEI's currently planned in-line inspections during the proposed MRP term, excluding those in-line inspections planned as a result of the IGU and TIMC Projects. This plan is reviewed on an ongoing basis, and will be subject to change as a result of FEI's ongoing integrity analysis and other planning considerations.

Notes:

- Numbers in the cells within the columns for each of the years 2020 through 2024 indicate the number of years between re-inspections. B denotes a baseline, or first-time, inspection with a given ILI tool.
- GEO = geometry tool
- MFL = magnetic flux leakage tool
- CMFL = circumferential MFL tool
- COMBO GEO/MFL = a combination tool with the inspection capabilities of both geometry and MFL tools. FEI endeavors to leverage combination tools when the technology exists from its ILI vendor (currently only for larger diameters) as they improve efficiency during field operations by avoiding a separate tool run for each data set.
- CTS = Coastal Transmission System
- ITS = Interior Transmission System
- VI = Vancouver Island

Pipeline Outside Diameter	Pipeline Segment	Region	ILI Tool	2020	2021	2022	2023	2024
1066mm / 42"	Huntingdon-Roebuck	CTS	COMBO GEO/MFL					**7**
1066mm / 42"	Huntingdon-Roebuck	CTS	CMFL					**7**
914mm / 36"	Roebuck-Tilbury	CTS	COMBO GEO/MFL	**7**				
762mm / 30"	Huntingdon-Nichol	CTS	COMBO GEO/MFL				**7**	
762mm / 30"	Huntingdon-Nichol	CTS	CMFL				**6**	
610mm / 24"	Nichol – Fraser	CTS	COMBO GEO/MFL	**7**				
610mm / 24"	Nichol – Fraser	CTS	CMFL	**4**				
610mm / 24"	Nichol - Port Mann	CTS	COMBO GEO/MFL			**6**		
610mm / 24"	Nichol - Port Mann	CTS	CMFL			**6**		
610mm / 24"	Noons Ck - Eagle Mtn	CTS	COMBO GEO/MFL			**7**		
610mm / 24"	Noons Ck - Eagle Mtn	CTS	CMFL			**B**		
508mm / 20"	Tilbury - Fraser	CTS	COMBO GEO/MFL	**7**				
508mm / 20"	Tilbury - Fraser	CTS	CMFL		**5**			
323mm / 12"	Livingston - Coquitlam	CTS	GEO					**5**
323mm / 12"	Livingston - Coquitlam	CTS	MFL					**5**
323mm / 12"	Livingston - Coquitlam	CTS	CMFL					**5**
323mm / 12"	Tilbury – Benson	CTS	GEO	**7**				
323mm / 12"	Tilbury – Benson	CTS	MFL	**7**				
323mm / 12"	Tilbury – Benson	CTS	CMFL		**4**			

Pipeline Outside Diameter	Pipeline Segment	Region	ILI Tool	2020	2021	2022	2023	2024
323mm / 12"	Tilbury - LNG Plant	CTS	GEO	**7**				
323mm / 12"	Tilbury - LNG Plant	CTS	MFL	**7**				
323mm / 12"	Tilbury - LNG Plant	CTS	CMFL	**B**	**1**			
610mm / 24"	Southern Crossing	ITS	COMBO GEO/MFL					**7**
406mm / 16"	Oliver - Penticton	ITS	GEO			**7**		
406mm / 16"	Oliver - Penticton	ITS	MFL			**7**		
323mm / 12"	Savona – Vernon	ITS	GEO	**6**				
323mm / 12"	Savona – Vernon	ITS	MFL	**6**				
323mm / 12"	Savona – Vernon	ITS	CMFL	**5**				
323mm / 12"	Vernon-Penticton	ITS	GEO	**6**				
323mm / 12"	Vernon-Penticton	ITS	MFL	**6**				
323mm / 12"	Vernon-Penticton	ITS	CMFL	**6**				
323mm / 12"	Yahk - Trail (EKL)	ITS	GEO	**7**				
323mm / 12"	Yahk - Trail (EKL)	ITS	MFL	**6**				
323mm / 12"	Yahk - Trail (EKL)	ITS	CMFL	**4**				
273mm / 10"	Oliver Y-Penticton	ITS	GEO				**5**	
273mm / 10"	Oliver Y-Penticton	ITS	MFL				**5**	
273mm / 10"	Oliver Y-Penticton	ITS	CMFL				**5**	
273mm / 10"	Oliver Y - Grand Forks	ITS	GEO				**5**	
273mm / 10"	Oliver Y - Grand Forks	ITS	MFL				**5**	
273mm / 10"	Oliver Y - Grand Forks	ITS	CMFL				**5**	
273mm / 10"	Grand Forks-Trail	ITS	GEO				**5**	
273mm / 10"	Grand Forks-Trail	ITS	MFL				**5**	
273mm / 10"	Grand Forks-Trail	ITS	CMFL				**5**	
219mm / 8”	Trail – Castlegar	ITS	GEO		**5**			
219mm / 8”	Trail – Castlegar	ITS	MFL		**5**			
219mm / 8”	Trail – Castlegar	ITS	CMFL		**5**			
323mm / 12"	V1 Compressor-Watershed	VI	GEO			**5**		
323mm / 12"	V1 Compressor-Watershed	VI	MFL			**5**		
273mm / 10"	Watershed-Secret Cove	VI	GEO			**7**		
273mm / 10"	Watershed-Secret Cove	VI	MFL			**7**		
273mm / 10"	Texada S - Texada N	VI	GEO					**7**
273mm / 10"	Texada S - Texada N	VI	MFL					**7**
273mm / 10"	Little R - Mid Island	VI	GEO				**7**	
273mm / 10"	Little R - Mid Island	VI	MFL				**7**	
273mm / 10"	Mid Island - Victoria	VI	GEO				**7**	
273mm / 10"	Mid Island - Victoria	VI	MFL				**7**	
219mm / 8”	Campbell River Lateral	VI	GEO			**7**		

Pipeline Outside Diameter	Pipeline Segment	Region	ILI Tool	2020	2021	2022	2023	2024
219mm / 8”	Campbell River Lateral	VI	MFL			**7**		
168mm / 6"	Pt Alberni Lateral	VI	GEO					**7**
168mm / 6"	Pt Alberni Lateral	VI	MFL					**7**
168mm / 6"	Harmac Lateral	VI	GEO					**7**
168mm / 6"	Harmac Lateral	VI	MFL					**7**
168mm / 6"	Crofton Lateral	VI	GEO					**7**
168mm / 6"	Crofton Lateral	VI	MFL					**7**
273mm / 10"	Mt. Hayes Lateral	VI	GEO				**6**	
273mm / 10"	Mt. Hayes Lateral	VI	MFL				**6**	

190.0 Reference: FEI SUSTAINMENT/OTHER CAPITAL

Exhibit B-1-1, Appendix B8-1, p. 8; FEI Annual Review for 2017 Delivery Rates proceeding, Exhibit B-3, BCUC IR 9.5

Installation of Bypass (Jomar) Valves

On page 8 of Appendix B8-1 of the Application, FEI provides Table A:B8-1-4, which shows that the installation of bypass (Jomar) valves contributed $11.510 million to the Sustainment/Other Capital cost pressures experienced during the Current PBR Plan term.

In response to BCUC IR 9.5 in the FEI Annual Review for 2017 Delivery Rates proceeding, FEI stated the following:

> The capital costs for the Jomar valves are required to reduce the future O&M cost of the meter exchange program and to improve the customer experience associated with meter exchange service. As discussed in response to CEC IR 1.5.3, savings from the installation of Jomar valves are anticipated in association with any visits subsequent to the Jomar valve installation that require turning off gas at the meter set.

190.1 In consideration of the cost pressures experienced by FEI during the Current PBR Plan term, please explain in detail why the Jomar valve installation project was considered necessary and could not have been deferred to future years.

Response:

The installation of bypass valves on customer meters has numerous benefits including:

- Increased customer satisfaction by eliminating the inconvenience and disruption associated with having to schedule meter exchange appointments and requiring the customer to be present during a meter exchange (to allow appliance re-lights);
- Decreased future contact centre costs by removing the requirement to schedule meter exchange appointments; and
- Increased operational efficiencies by reducing the time to complete individual meter exchanges, as well as allowing meter exchange activities to be geographically clustered (reducing the associated time and travel).

It is not possible to achieve these benefits in any substantial way until the deployment of bypass valves is significantly complete. On this basis, FEI determined it was the best long-term decision to begin installation of bypass valves so that the benefits could begin to be realized in the future.

190.1.1 Please confirm, or explain otherwise, whether the Installation of Bypass (Jomar) Valves project is complete. If not, please provide the anticipated completion date and the remaining capital expenditures required for the project.

Response:

The Installation of Bypass (Jomar) Valves project is not complete. At current deployment rates, FEI expects that the project will be substantially complete in approximately 20 years, dependent on the meter exchange volumes in each year. Currently, FEI is retrofitting approximately 45,000 meters per year with bypass valves, at an approximate cost of $2 million dollars per year.

FEI is also considering completing the bypass valve installations in conjunction with the meter replacements that would be required in a future Advanced Metering Infrastructure (AMI) project. In that scenario, further information regarding the schedule and costs would be contained in the project's CPCN application.

190.2 Please provide a detailed description of the type and amount of savings anticipated during the proposed MRP term from the installation of the Jomar valves and whether these savings were taken into account when developing the 2019 Base O&M.

Response:

During the proposed MRP term from 2020 to 2024, FEI does not anticipate any significant O&M savings from the installation of Jomar valves.

The installation of Jomar valves began on a trial basis in 2015 with activities ramping up starting in 2017. As a result, savings related to not having to turn off the meter set during the meter exchange process are not expected to be realized until 2026, approximately 9 years after the first installation of Jomar valves. This is explained further below.

The accuracy of the meters that FortisBC uses for its residential customers needs to be validated within 10 years of installation in order to ensure accuracy and to be certified by

Measurement Canada. FEI achieves this by exchanging a sample of each group of meters in year 9. If the samples pass, the remaining meters in the group are certified for either another 2, 4, 6 or 8 years, and the process is repeated. If the sample fails, the remainder of the group needs to be exchanged with a new certified meter in the following calendar year. This is when replacement of a customer's meter would take less time and cost less with a Jomar valve installed.

As a result of this period of time between installation and the realization of meter exchange benefits, no O&M savings related to the Jomar valves are expected during the MRP term, and no savings were embedded in the development of the 2019 Base O&M.

190.2.1 If the savings were taken into account, please explain how and in what O&M area(s) the savings are expected.

Response:

Please refer to the response to BCUC IR 2.190.2.

190.2.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.190.2.

191.0 Reference: FEI SUSTAINMENT/OTHER CAPITAL

Exhibit B-10, BCUC IR 45.1, 46.2, 46.3, 47.4.1, Attachment 46.2; Exhibit B-1, p. C-64

Project Planning

In response to BCUC IR 45.1, FEI stated the following:

> Prior to each year of the Current PBR Plan term, FEI's planning process consisted of a review of known work, assemblage of necessary work into projects, development of project scopes, preparation of schedules and then prioritizing the projects based on risk and ability to execute the projects in consideration of available resources. The inventory of asset needs was constantly updated with new requests, projects or updated project information…
>
> Once approved, the capital plan is managed through monthly, or more frequent, forecasting of all projects and programs to provide the expected timing and amount of planned expenditures in comparison to the approved capital budget. By totalling all of the project and program forecasts, FEI is able to forecast expected capital expenditures of projects during the current year as well as for following years.
>
> As stated on page 10 of Appendix B8-1 of the Application, the management of the capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints.

191.1 Please discuss FEI's strategic decision-making plan for Sustainment and Other Capital work, including the persons responsible for decision-making for the allocation of capital and resources and how FEI applies checks and balances to the plan to ensure work and projects are delivered.

<u>Response:</u>

For reference, FortisBC included a discussion of how FEI prioritizes projects and programs using the AIP tool in Section C3.2 of the Application and a discussion of how it manages project development and execution in the response to BCUC IR 1.46.5.

The strategic decision-making process for Sustainment and Other Capital is a collaborative process between Asset Management, Project Management, and other internal project stakeholders who are consulted throughout the project lifecycle as described in BCUC IR 1.46.5. These groups collaboratively provide input into the capital plan. The final decision to proceed with the plan as proposed rests with FEI's Executive and Board of Directors. The steps related to capital planning include:

- Identification of Needs (3+ years prior to execution): Asset needs and/or business needs can be identified by anyone in the company as a project stakeholder. The projects are documented and managed through the next stages of development by centralized Asset Management groups based on the asset type.
- Analyze Need and Develop Solution (2-3 years prior to execution): Alternatives are developed and analyzed. Project stakeholders and engineering/technical resources are consulted to develop alternatives. Each alternative receives a preliminary cost estimate and quantified value using the AIP value framework to represent the benefit or risk reduction expected by executing the alternative. A preferred alternative is selected based on the cost and value.
- Prioritize (1-2 years prior to execution): Projects are evaluated through the AIP value framework to create a multi-year plan that achieves the greatest overall portfolio value based on high level resource and budget constraints. The outcome is a five-year forecast.
- Refinement (1 year prior to execution): The next one to two years of the capital plan is reviewed with execution resources such as Project Management and Operations or other FortisBC stakeholders. Further refinement of the plan is carried out to account for regional resource constraints and/or improved coordination of work. The next years' plan is finalized and signed off by Asset Management, Project Management, Engineering, Operations and/or other internal stakeholders as appropriate.
- Approval (1 year prior to execution): Capital plans and proposed budgets are submitted for executive approval.
- Execution and plan management (during execution): The capital plan is managed through monthly, or more frequent, forecasting of all projects and programs to provide the expected timing and amount of planned expenditures in comparison to the approved capital budget. By totalling all of the project and program forecasts, FEI is able to forecast expected capital expenditures of projects during the current year as well as for following years.

As stated on page 10 of Appendix B8-1 of the Application, the management of the capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints.

On page C-64 of the Application, FEI provides Table C3-6 which summarizes the actual/projected Sustainment Capital expenditures for 2014 to 2019, including System Improvements (DP). Based on Table C3-6, the average annual Sustainment Capital spending was $97,881,000.

In response to BCUC IR 47.4.1, FEI provided a table which summarized the forecast Sustainment Capital expenditures for 2020 to 2024, including System Improvements (DP). Based on this table, the forecast average annual Sustainment Capital spending is $118,627,000.

In response to BCUC IR 46.3, FEI provided a breakdown of all the projects or programs in the Sustainment or Other Capital categories with a capital cost of $2 million or greater that FEI had planned to deliver in the Current PBR Plan term.

In response to BCUC IR 46.2, FEI provided Attachment 46.2, which summarizes the projects with an estimated cost over $2 million in the Sustainment Capital category that FEI plans to deliver over the proposed MRP term:

1. 5 Year Turnaround at Tilbury LNG Expansion ($2,485,000)
2. 240 St. & 102 Ave. Station, Maple Ridge – Insufficient Capacity ($2,500,000)
3. Grand Forks to Trail 273 Pipeline Alteration ($3,589,000)
4. Huntingdon to Nichol In Line Inspection ($2,760,000)
5. NW Kamloops Secondary Supply – Install Loop from Westsyde to Rayleigh ($3,900,000)
6. Penticton Second Supply ($2,100,000)
7. SI – 1300m x 323 IPST Riverside, Abbotsford ($3,587,000)
8. SI – 1850m x 168 IPST McLeod, Chilliwack ($2,404,000)
9. Tilbury LNG Air Cooler Upgrade ($3,184,000)
10. V1 Compressor Unit 1, 2 & 3 Engine Overhaul and Emissions Reduction to 15 PPM ($7,889,000)

191.2 Please consolidate the information provided in Attachment 46.2 and the table provided in response to BCUC IR 46.3 to summarize the projects FEI intends to deliver during the proposed MRP term.

Response:

For clarity, BCUC IR 1.46.2 asked:

> For the Proposed MRP term, please provide, as a new Appendix, a one-page summary for each project or program with a capital cost of over $2 million...

In the response to BCUC IR 1.46.2, FEI provided the requested information for all projects over $2 million that it is currently aware of that it intends to deliver during the proposed MRP term. Therefore, no further consolidation of the table in BCUC IR 1.46.3 is required. FEI confirms that the projects planned, but not delivered, under the Current PBR Plan term are either already included in the response to BCUC IR 1.46.2, included as a potential Major Project, or are no longer contemplated for execution during the MRP term.

For reference, FEI has reproduced the table listing all projects over $2 million that FEI is currently aware of that it intends to deliver during the proposed MRP term below.

Project Name	Construction Start Year	In-Service Year	Expected Capital Cost ($000)
5 Year Turnaround at Tilbury LNG Expansion	2023	2023	2,485
240 St. & 102 Ave. Station, Maple Ridge – Insufficient Capacity	2021	2021	2,500
Grand Forks to Trail 273 Pipeline Alteration	2020	2020	3,589
Huntingdon to Nichol In Line Inspection	2023	2023	2,760
NW Kamloops Secondary Supply – Install Loop from Westsyde to Rayleigh	2023	2023	3,900
Penticton Second Supply	2020	2020	2,100
SI – 1300m x 323 IPST Riverside, Abbotsford	2024	2024	3,587
SI – 1850m x 168 IPST McLeod, Chilliwack	2022	2022	2,404
Tilbury LNG Air Cooler Upgrade	2023	2023	3,184
V1 Compressor Unit 1, 2 & 3 Engine Overhaul and Emissions Reduction to 15 PPM	2022-2024	2022-2024	7,889

191.3 Please confirm, or explain otherwise, that based on the table provided in response to BCUC IR 46.3, nine out of the twelve projects were not completed during the Current PBR Plan term.

Response:

Confirmed. However, the list of projects provided in the response to BCUC IR 1.46.3 represents only a small portion of the projects undertaken during the Current PBR Plan term and in no way represents a "majority" of planned projects. The projects contained in the list that were not completed during the Current PBR Plan term had a total forecast capital cost of $24 million whereas the total Sustainment Capital expenditure during the Current PBR Plan term will be approximately $608.5 million. Thus, the projects identified in the list as not being completed during the Current PBR Plan term will represent approximately 4 percent of the total Sustainment Capital expenditure over the Current PBR term.

Some of the reasons that the projects identified were not completed during the Current PBR Plan term were provided in the responses to BCUC IRs 1.46.3 and 1.46.4.1.

With regard to the Pattullo Bridge Crossing Replacement, FEI's schedule is subject to the schedule established by Translink and the Ministry of Transportation & Infrastructure for negotiations and investigation of solutions to replace the existing pipeline crossing. The project has become much more complicated than originally perceived and requires further development.

With regard to the other projects, the primary reasons for not completing them during the Current PBR Plan term are related to obtaining permissions to proceed as well as prioritization of capital expenditures as new issues are identified, evaluated, and mitigated. Many of these projects require discussions with landowners and permissions from municipal or provincial government agencies, which can take significant time.

The management of capital expenditures is an ongoing process often requiring reconsideration of priorities, necessitating alterations to the schedule of projects. This is explained in Appendix B8-1 of the Application which also provides a discussion of Annual Sustainment/Other Capital variances over the Current PBR Plan term. Note that the cumulative variances identified in Table A:B8-1-4 far exceed the forecast capital cost of the projects that were not completed during the Current PBR Plan term.

191.3.1 Please explain why the majority of the planned projects did not proceed during the Current PBR Plan term. As part of this response, please provide a high-level overview of the capital projects that were incurred for Sustainment Capital during the Current PBR Plan term. Please also identify the key areas of expenditure and any unplanned projects or expenditure categories that resulted in the increase in costs.

Response:

Please refer to the response to BCUC IR 2.191.3.

191.4 In consideration of the increased forecast Sustainment Capital spending during the proposed MRP term, the increased number of planned projects, and the planned versus actual Sustainment Capital project results during the Current PBR Plan term, please explain why FEI considers the projected level of Sustainment Capital expenditures for the proposed MRP term to be appropriate.

Response:

The projected level of Sustainment Capital expenditures for the proposed MRP term was developed through a robust capital planning process that includes a bottom up forecast of individual asset needs that have been prioritized in an effort to increase efficiency and minimize customer rate impacts. In the Application, FEI used the average 2017-2019P Sustainment Capital expenditures as a basis for comparison because it believes that the expenditure levels from 2017 to 2019 are most representative of the expenditure levels required to maintain the safety and reliability of the gas system. When compared to the expenditures in those years, the Sustainment Capital expenditures for the proposed MRP term represent increases less than annual inflation.

As described on page 8 of Appendix B8-1 in the Application, between 2014 and 2016 FEI attempted to manage its sustainment/other capital spending levels close to or within the formula allowed amounts. This resulted in re-prioritization of work, but this approach was found to be unsustainable over the full term of the Current PBR Plan. Between 2017 and 2019, FEI exceeded[48] the allowed sustainment/other formula amount, including the deadband, to complete unanticipated urgent work, as detailed in Table A:B8-1-4 of the Application, and to catch up on an accumulation of work that had been reprioritized from previous years of the Current PBR Plan. In spite of the increased expenditures in the latter part of the Current PBR Plan there remain some outstanding projects that were intended to be completed over the 2014-2019 term, as noted in the preamble and in the responses to BCUC IRs 2.191.3 and 2.191.3.1.

The question refers to an increased number of projects in the forecast for the proposed MRP term. FEI is uncertain what the question is referencing. Nevertheless, the number of past projects or planned future projects is not an indication of the appropriateness of the forecast of

[48] For 2019, FEI projects that it will exceed the deadband

capital expenditures. The forecast reflects FEI's evolving operating environment and the challenges and opportunities that impact Sustainment Capital expenditures, for example:

- The addition of non-traditional sources and new end uses of gas leads to new sustainment capital projects and system modifications.
- The increased need for engagement with stakeholders and Indigenous communities lengthens project timelines and increases costs.
- The increased need for investment in aging infrastructure requires programs like main renewals and in line inspections to expand to keep pace with changes in observed asset condition.

The forecast that FEI has provided of Sustainment Capital expenditures for the proposed MRP term is forward looking and based on identified asset needs over the MRP term. FEI evaluates its capital plans on an ongoing basis in order to meet forecast load and to ensure the safety, reliability and integrity of the gas system. Due to the evolving operating environment and other uncertainties inherent in a five-year forecast, FEI intends to review the capital forecasts for 2023 and 2024 in the Annual Review for 2023 Rates.

192.0 Reference: FEI SUSTAINMENT CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 47.1

Asset Age

In response to BCUC IR 47.1, FEI provided updated figures showing the current asset conditions compared to the conditions at the time of the FEI PBR Application. Based on these figures, approximately 36 percent of distribution mains are now older than 40 years compared to approximately 27 percent at the time of the FEI PBR Application, and approximately 50 percent and 55 percent of TP and IP Pipelines, respectively, are older than 40 years compared to 34 percent and 38 percent, respectively, at the time of the FEI PBR Application.

192.1 Please explain the cause(s) of the trend in increased asset ages.

Response:

The construction of the gas system over time has had periods of high activity and periods of low activity. The graph provided in the response to BCUC IR 1.47.1 groups the asset ages into 10-year age groupings. The trend in increased asset ages is caused by a population of pipe moving from one age grouping to another. At the time of the FEI PBR Application, any pipe installed prior to 1973 would have fallen into the 40+ Years category. Now, any pipe installed prior to 1979 falls into the 40+ Years category. The increase is attributable to any pipe installed between 1973 and 1979, minus any pre-1979 installed pipe that has been replaced over the intervening time.

192.2 Please explain in detail the near-term and long-term implications of the increased proportion of transmission and distribution assets having ages greater than 40 years.

Response:

In the near-term, there are no immediate implications to the safe and effective operation of the gas system as a result of having a greater proportion of pipelines greater than 40 years in age. If properly installed and maintained, a pipeline can safely remain in service for well over 40 years. For example, FEI has an ongoing distribution main replacement program to remove gas mains from service that have a history of leaks or poor condition. Further, FEI manages its transmission lines through inline inspections and proactive repair of anomalies.

In the long-term, if FEI were to start seeing an overall decline in pipe condition as evidenced by leak statistics or other condition monitoring activities, it may identify the need for additional work such as accelerated replacement programs and/or incremental inspections and repairs.

192.3 Please discuss FEI's expectations regarding the change in the distribution of asset ages at the conclusion of the proposed MRP term and explain the basis for these expectations.

Response:

At the conclusion of the MRP term, all pipe with an installation year pre-1984 will fall into the 40+ year age grouping. At that time FEI expects that the percentage of pipe in the 40+ year category will increase relative to current levels. The early 1980s represented a time of significant growth in the FEI system as many customers were transitioning from oil to natural gas for home heating. Currently, there are over 2,100 km of distribution mains and 108 km of intermediate pressure (IP) and transmission pressure (TP) pipelines that were installed over the course of 1979 to 1983. This represents 9 percent of the distribution main population and 3.6 percent of the TP and IP pipeline length on FEI's system.

It should be noted that the age of a pipeline is not necessarily representative of the condition of that pipeline. As stated in the response to BCUC IR 2.192.2, FEI has replacement, inspection, and repair programs in place to manage and, where possible, extend the life of pipeline assets. Different materials, coatings and construction practices in use at the time of installation also impact the expected life of a pipeline. Although the early 1980s represented a time of significant growth, it also represents the introduction of polyethylene distribution mains and services. With no threat of corrosion, polyethylene pipe is expected to have a longer life expectancy than steel pipe under typical operating conditions.

193.0 Reference: FEI SUSTAINMENT CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 47.5; Exhibit B-1, p. C-69

FEI Sustainment Capital Expenditures

In response to BCUC IR 47.5, FEI provided the following breakdown of Customer Measurement expenditures:

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Customer Measurement						
Meter Materials	12,952	16,691	18,914	21,824	23,104	19,799
Residential Meter Alteration & Exchange	8,101	7,203	8,032	7,479	7,422	6,939
Small Commercial / Industrial Meter Alteration & Exchange	1,531	1,744	913	700	1,255	935
Large Commercial / Industrial Meter Alteration & Exchange	1,791	2,879	2,280	1,482	1,490	3,164
Total Customer Measurement	24,375	28,516	30,140	31,485	33,271	30,837

193.1 Please explain why the 2019 projected "Large Commercial / Industrial Meter Alteration & Exchange" expenditures are expected to be significantly higher than the past the two years.

Response:

The meter sets that serve commercial and industrial customers can range from a simple meter and regulator configuration to a TP/DP station that serves a single large customer. These large customer stations are functionally no different than a station that serves a community, except that there is only one customer. Like FEI's other regulator stations, these customer stations require periodic upgrades and rebuilds to address asset condition, equipment obsolescence, or to meet changing customer demand needs.

In 2019, FEI is building a new station at the Fording River site near Sparwood to serve a load increase requested by the customer. The new station will replace the existing customer station that is not capable of meeting the new load requirements. The forecast cost of this project is $2.069 million in 2019.

In response to BCUC IR 47.5, FEI provided the following breakdown of Distribution System Reliability expenditures:

	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Distribution System Reliability						
Distribution Stations Alterations (Applicant 60, 58, 66)	7,522	7,709	8,472	11,979	7,748	9,441
Distribution System Telemetry Alterations (Applicant 59 and	890	751	491	796	1,852	742
Distribution System Capacity Alterations (Applicant 63)	3,812	5,894	3,784	5,112	6,385	2,150
Distribution Stations NEW (Applicant 77)	323	924	911	329	1,011	698
Revelstoke Propane Plant Alterations (Applicant 62)	140	11	1	16	690	38
Distribution Sectioning Valves (Applicant 65)	88	53	394	0	-	20
Distribution System Reliability - Total	12,775	15,342	14,052	18,232	17,686	13,088

193.2 Please explain why the "Distribution Stations Alterations" expenditures were significantly higher in 2017.

Response:

As explained in the response to BCUC IR 1.47.10, FEI manages and optimizes its Sustainment Capital portfolios as a whole; therefore, spending can fluctuate within lower level portfolios from year to year.

In 2017, there were 165 projects underway in the Distribution Stations Alterations portfolio. Of those, 67 projects were in construction during 2017, 53 were constructed in previous years and completing the closeout process in 2017, and 45 were in the design phase in 2017 for execution in later years. The average spend per project in 2017 was $76 thousand. By contrast, the average spend per project in 2016 and 2018 was $47 thousand and $60 thousand respectively.

193.3 Please explain why the "Distribution System Telemetry Alterations" expenditures were significantly higher in 2018.

Response:

As explained in the response to BCUC IR 1.47.10, FEI manages and optimizes its Sustainment Capital portfolios as a whole; therefore, spending can fluctuate within lower level portfolios from year to year.

The majority of projects in this portfolio are small in scope and are completed within one to two years. In 2018 there were 53 projects underway in the Distribution System Telemetry Alterations portfolio with an average cost of $32,723. In contrast, the average cost of projects in this portfolio in 2017 and 2019 were $14,374 and $10,752, respectively. The relatively higher average project cost in 2018 was a result of a larger number of projects with larger scope being completed in 2018. There were six projects over $100,000 completed in 2018, compared to just three in 2017 and two in 2019.

193.4 Please explain why the "Revelstoke Propane Plant Alterations" expenditures were significantly higher in 2018.

Response:

The Revelstoke Propane Plant Alterations Portfolio consists only of work done at the Revelstoke Propane plant. To make efficient use of resources, FEI assembles and plans multiple work activities at a single site to be done together. When viewed at the level of detail for a single site, this creates annual fluctuations in expenditures. The higher expenditures in 2018 are attributable to the following:

- Replacement of one of the vaporizers ($461 thousand)
- Upgrade of the controls on the other vaporizer ($105 thousand)
- Regulator replacement ($14 thousand)
- Generator upgrade ($32 thousand)
- Rail spur upgrade ($78 thousand)

On page C-69 of the Application, FEI provides the following table:

Table C3-11: FEI Distribution System Reliability Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020 YEF	2021 YEF	2022 YEF	2023 YEF	2024 YEF
Distribution Stations Alterations	9,723	9,673	9,524	14,131	7,023	11,940
Distribution System Telemetry Alterations	1,130	1,356	1,207	1,486	2,779	2,173
Distribution System Capacity Alterations	4,549	489	64	2,412	1,331	5,508
Distribution Stations NEW	679	2,787	766	846	955	1,619
Revelstoke Propane Plant Alterations	248	162	312	274	311	650
Distribution Sectioning Valves	7	72	529	75	87	141
Total Distribution System Reliability	16,336	14,539	12,403	19,223	12,486	22,032

193.5 Please explain the cause(s) of the forecast increased expenditures for Distribution System Telemetry Alterations during the proposed MRP term compared to the Current PBR Plan term (with the exception of 2018).

Response:

The main areas of expenditure in the Distribution System Telemetry Alterations portfolio are:

1. Remote Terminal Unit (RTU) Replacements due to obsolescence
2. Upgrades of existing telemetry installations
3. Installation of new telemetry

Over the Current PBR Plan term, RTU replacements accounted for 56 percent of expenditures, upgrades of existing telemetry installations accounted for 19 percent of expenditures, and installation of new telemetry accounted for 26 percent of expenditures.

FEI is forecasting a similar level of expenditure over the MRP term to replace obsolete telemetry equipment and upgrade existing installations. The equipment required to collect and transmit data from remote stations and measurement points throughout the gas system is technology based. Similar to other computing and communication based technologies, the equipment is experiencing an accelerated rate of obsolescence as new technologies are introduced and old equipment ceases to be supported by manufacturers and communications providers. FEI frequently receives very little notice before support for a piece of equipment is discontinued. Failure to upgrade the equipment could mean that station operating data can no longer be transmitted from site for remote monitoring.

FEI is forecasting additional expenditures of approximately $2.5 million over the MRP term to install additional telemetry where none exists today. New telemetry installations and additional measurement points are increasingly being requested by operations personnel to enable early warning of system-upset conditions and to allow more efficient and informed deployment of resources. The ability to remotely collect system data allows operations personnel to more effectively assess the cause and severity of a system-upset condition, thereby informing a decision of which resource(s) to send or possibly avoiding an after-hours call out altogether.

194.0 Reference: OTHER CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 48.1, 59.1; Exhibit B-1, pp. C-73, C-74, C-102

FEI Fleet Services and FBC Fleet Vehicles

On page C-73 of the Application, FEI provides the following table:

Table C3-18: FEI Equipment Capital Expenditures 2020-2024 ($000's)

Equipment	Average 2017-2019P	2020	2021	2022	2023	2024
Tools and Equipment	2,565	4,450	3,300	3,300	3,300	3,300
Fleet Services	8,737	8,160	7,710	6,800	6,710	6,720
Measurement Services	412	503	505	505	507	507
Radio Communications	1,874	1,580	1,450	1,350	1,250	1,250
Supply Chain	332	413	413	333	333	333
Total Equipment Capital	13,919	15,106	13,378	12,288	12,100	12,110

In response to BCUC IR 48.1, FEI provided the following table:

FEI Equipment Capital Expenditures 2014-

Equipment	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 YEF
Tools and Equipment	1,923	1,778	1,837	1,703	2,242	3,750
Fleet Services	3,043	3,363	3,927	8,103	11,507	6,600
Measurement Services	756	722	525	519	213	503
Radio Communications	2,521	1,456	1,418	1,983	1,750	1,890
Supply Chain	-	-	-	304	278	413
Total Equipment Capital	8,242	7,319	7,706	12,611	15,990	13,156

On page C-74 of the Application, FEI states the following regarding Fleet Services:

> Expenditures have been higher in recent years because of changes in headcount associated with new crews in the province, and because of reprioritization of vehicle purchases from earlier years of the Current PBR Plan…As such, Fleet replacement costs are lower and trending downward over 2020-2024 period compared to the 2017-2019 average expenditure.

On page C-102 of the Application, FBC states the following regarding Fleet Vehicles: "This category includes the replacement and/or acquisition of heavy fleet vehicles, light duty vehicles, passenger vehicles, service vehicles, speciality vehicles, specialty equipment and off road vehicles necessary to meet the operational requirements of FBC."

In response to BCUC IR 59.1, FBC provided the following tables:

Table 1: FBC Vehicles, Tools and Equipment Capital Expenditures, 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Vehicles	1,311	1,736	2,040	2,098	2,570	2,100
Tools and Equipment	432	396	497	537	529	538
Total	1,744	2,132	2,536	2,636	3,099	2,638

Table 2: FBC Vehicles, Tools and Equipment Capital Expenditures, 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Vehicles	$ 2,256	$ 2,700	$ 2,770	$ 2,695	$ 3,090	$ 2,785
Tools and Equipment	535	707	568	579	591	603
Total	$ 2,791	$ 3,407	$ 3,338	$ 3,274	$ 3,681	$ 3,388

In response to BCUC IR 59.1, FBC stated the following regarding Fleet Vehicles:

> The main factor contributing to the increases in costs for Fleet Vehicles has been the change in the US$/CDN$ exchange rate starting in 2015. The specialized assets utilized by FBC are almost exclusively built and manufactured in the United States and Fleet Vehicles expenditures in the proposed MRP reflect a further increase in price due to the change in the US$/CDN$ exchange rate.

194.1 Please compare and contrast FEI and FBC's Fleet Services/Vehicles expenditures, including the types of vehicles purchased, where the vehicles are purchased (Canada, US, other) and the cost drivers.

Response:

Gas and Electric utilities require specialized vehicles and equipment that are built for the specific utility application and vary significantly between the two utilities. This is due to FEI's infrastructure being primarily underground and FBC's infrastructure being primarily above ground. For example, FEI utilizes backhoes for excavation to reach below ground infrastructure, and FBC utilizes bucket trucks to reach above ground power lines. The type of vehicles purchased are shown in the table below, with vehicles types that are common to both gas and electric utilities shown in **bold**.

Type of Fleet Asset	Types of Units Included in Asset Category
Service and Light Duty Vehicles	**Pickup Trucks**, Welding Trucks, Customer Service Tech Vans, **Passenger Vehicles**, **Service Body Trucks**
Medium and Heavy Duty Vehicles	Gas Crew Construction Trucks, Pipeline Trucks, **Crane Trucks, Flat Deck and Delivery Trucks, Dump Trucks**, Bucket Trucks, Digger Derricks, Rubber Trucks
Equipment and Trailers	**Trailers**, Backhoes, Mini-Excavators**, Forklifts, Off Road Vehicles**

The main cost drivers that have impacted the cost of these vehicles recently are as follows:

1. US/CDN $ Exchange - Although all Fleet Assets (vehicles and equipment) are acquired in Canada in Canadian funds, many of the vendors that are utilized for vehicles, equipment and utility specific applications manufacture and produce the units in the US and export to their Canadian subsidiary or Canadian distributors. Over the PBR term, the strength of the Canadian dollar has significantly weakened, translating to higher vehicle and equipment prices.
2. Fuel Economy and Emissions Requirements – Vehicle and Equipment manufacturers must adhere to national standards, this requirement to produce more efficient and cleaner engines will continue to increase vehicle and equipment prices
3. Zero Emission Vehicles (ZEV) – Zero Emission Vehicles primarily Battery Electric Vehicles or Hydrogen Fuel Cell vehicles have higher capital costs than traditional internal combustion engine vehicles.
4. Safety Technology and Safety Standards – FEI and FBC are deploying new safety technologies that have become available recently to help prevent and reduce vehicle incidents, such as backup cameras, reverse sensing and lane departure warnings. Canada Motor Vehicle Safety Standards (CMVSS) are continuously evolving to improve transportation safety.
5. Field Employee Headcounts – for FEI the expenditures have been higher in recent years because of the increases in headcount associated with new construction crews and other field employees.

194.2 For each of FEI and FBC, please provide a table showing the following for each year of the Current PBR Plan term and for each year of the proposed MRP term:

- The number of vehicles purchased by type of vehicle; and
- The average cost per type of vehicle in US$ and in CDN$.

Response:

Many factors are taken into consideration when an actual vehicle replacement decision is made and each replacement decision is evaluated on a unit-by-unit basis. As such, the mix and types of vehicles replaced will vary greatly from year to year.

For this response, FEI and FBC have categorized all fleet assets into the three different types of vehicles and equipment discussed in response to BCUC IR 2.194.1. All vehicles and equipment are acquired in Canadian funds so there are no US$ amounts shown below.

Table 1: FBC Current PBR Plan Term, # of Vehicles by Type and Average Cost in CDN$

Type of Fleet Asset	2014 # Of Units	2014 Average Cost	2015 # Of Units	2015 Average Cost	2016 # Of Units	2016 Average Cost	2017 # Of Units	2017 Average Cost	2018 # Of Units	2018 Average Cost	2019 # Of Units	2019 Average Cost
Service and Light Duty Vehicles	15	43,991	1	29,685	5	82,539	6	73,306	23	40,552	22	48,163
Medium/Heavy Duty Vehicles	3	91,699	6	283,573	9	182,353	6	270,794	5	279,826	3	315,706
Equipment	4	93,545	-		-		2	16,931	7	34,012	2	53,000

Table 2: FBC Proposed MRP term, # of Vehicles by Type and Average Cost in CDN$.

Type of Fleet Asset	2020 # Of Units	2020 Average Cost	2021 # Of Units	2021 Average Cost	2022 # Of Units	2022 Average Cost	2023 # Of Units	2023 Average Cost	2024 # Of Units	2024 Average Cost
Service and Light Duty Vehicles	29	68,621	14	58,929	15	79,667	13	64,615	13	53,077
Medium/Heavy Duty Vehicles	2	315,000	6	324,167	4	375,000	5	450,000	5	419,000
Equipment	2	40,000	-		-		-		-	

Table 3: FEI Current PBR Plan Term, # of Vehicles by Type and Average Cost in CDN$

Type of Fleet Asset	2014 # Of Units	2014 Average Cost	2015 # Of Units	2015 Average Cost	2016 # Of Units	2016 Average Cost	2017 # Of Units	2017 Average Cost	2018 # Of Units	2018 Average Cost	2019 # Of Units	2019 Average Cost
Service and Light Duty Vehicles	24	$ 44,959	36	$ 40,389	41	$ 60,676	51	$ 57,160	67	$ 56,863	58	$ 64,868
Medium/Heavy Duty Vehicles	6	$164,331	11	$ 135,757	9	$ 117,021	13	$ 141,167	31	$ 183,567	13	$ 144,231
Equipment	19	$ 49,168	16	$ 25,966	11	$ 35,072	26	$ 62,262	16	$ 124,152	16	$ 59,876

Table 4: FEI Proposed MRP term, # of Vehicles by Type and Average Cost in CDN$.

Type of Fleet Asset	2020 # Of Units	2020 Average Cost	2021 # Of Units	2021 Average Cost	2022 # Of Units	2022 Average Cost	2023 # Of Units	2023 Average Cost	2024 # Of Units	2024 Average Cost
Service and Light Duty Vehicles	38	60,658	28	62,214	43	60,642	42	68,750	43	65,898
Medium/Heavy Duty Vehicles	18	219,722	17	233,694	14	254,021	10	245,300	8	247,800
Equipment	11	172,727	16	124,800	4	161,650	28	48,911	34	56,000

194.3 With regard to FEI, please explain why it is not expected that Fleet Services expenditures will return to levels experienced during 2015 and 2016.

Response:

Fleet Services expenditures are not expected to return to 2015 and 2016 levels for FEI, as vehicle purchases were reprioritized during the earlier years of the Current PBR Plan (2015 and 2016 spending was below normal levels). In addition, over the upcoming MRP term, there is a significant number of larger units in the plan (Gas Construction Crew Trucks and Backhoes) that require replacement due to the age of the assets, safety and reliability issues.

195.0 Reference: FEI MAJOR CAPITAL PROJECTS
Exhibit B-10, BCUC IR 49.5
Rate Impacts

In response to BCUC IR 49.5, FEI provided the actual/projected capital spending on Major Projects during the Current PBR Plan term, which totaled $1.090 billion over six years.

In response to BCUC IR 49.5, FEI also provided the forecast capital spending on Major Projects during the proposed MRP term, which totals $1.548 billion (though a number of projects are listed as “under development”). The forecast spending is an increase of 42 percent over the Current PBR Plan term.

195.1 Please explain, and quantify where possible, the potential rate impacts to FEI customers during the proposed MRP term of the forecast capital spending on Major Projects. Please provide potential rate impacts based on hypothetical low, medium and high load growth scenarios.

Response:

While FEI provides the information requested below, consistent with past revenue requirements applications, FEI does not seek recovery of the costs of CPCN projects that have not been approved by the BCUC in its rate setting applications under an MRP. FEI will be filing a CPCN application for each of its Major Projects, at which time the BCUC will be able to review each project and determine whether it is in the public interest based on its own merits. FEI will seek approval to recover the costs of Major Projects in rates only after the BCUC has granted the CPCN and the project is forecast to be in service in the test period.

In the response to BCUC IR 1.49.5, FEI provided a summary of the Major Projects that FEI is anticipating executing during the proposed MRP term. The Major Projects listed here and in the Application are at varying stages of development and forecast costs such that they are preliminary estimates only and they are likely to change. When FEI proceeds with a CPCN application for any of the listed projects, it will include scope definition and cost estimates consistent with the CPCN guidelines.

The table below is a reproduction of Table 2 from the response to BCUC IR 1.49.5.

Major Projects ($000)	2020	2021	2022	2023	2024
Eagle Mountain - Woodfibre Gas Pipeline Project				347,731	
Tilbury 1B Expansion	36,667	64,563	1,003	1,062	1,124
Tilbury LNG Plant	109	17,382			
CPCN LMSU	27,500				
Inland Gas Upgrade	62,217	99,311	93,483	67,377	31,164
Transmission Integrity Management Capability		25,736	155,933	154,810	155,094
Okanagan Capacity Upgrade	4,384	41,909	107,173	7,778	
Pattullo Bridge Gas Line Replacement	8,200	18,600			
Southern Crossing Class Location Upgrades	200	1,500	16,000	200	
Sun Peaks Conversion		Under Development			
Sunshine Coast Capacity Upgrades		Under Development			
Advanced Metering Infrastructure		Under Development			
Total	139,277	269,000	373,593	578,958	187,382

Using the table above, FEI has provided estimated rate impacts of each project below. FEI has added these total rate impacts to the lower bound (low), reference case (medium) and upper bound (high) cases from FEI's 2017 Long Term Gas Resource Plan in the last table below.

The rate impacts provided are estimated residential bill impacts. The tariff (RS50) relevant to the Eagle Mountain – Woodfibre Gas Pipeline Project is designed to recover from the RS50 customer the cost of service on the pipeline and return a benefit to all other customers; therefore, the rate impact is a reduction in rates.

Major Projects	2020	2021	2022	2023	2024
Eagle Mountain - Woodfibre Gas Pipeline Project	0.0%	0.0%	0.0%	-1.0%	0.0%
Tilbury 1B Expansion	0.0%	0.0%	1.2%	0.2%	0.0%
Tilbury LNG Plant	0.0%	0.0%	0.2%	0.0%	0.0%
CPCN LMSU	2.3%	3.2%	0.0%	0.0%	-0.1%
Inland Gas Upgrade	0.1%	0.7%	1.2%	1.3%	0.7%
Transmission Integrity Management Capability	0.0%	0.0%	0.3%	1.9%	1.8%
Okanagan Capacity Upgrade	0.0%	0.0%	0.0%	1.9%	0.0%
Pattullo Bridge Gas Line Replacement	0.0%	0.0%	0.3%	0.0%	0.0%
Southern Crossing Class Location Upgrades	0.0%	0.0%	0.0%	0.0%	0.2%
Total	2.3%	3.9%	3.1%	4.4%	2.6%

Long Term Resource Plan	2020	2021	2022	2023	2024
Lower Demand Bound	2.9%	2.9%	5.0%	5.4%	4.8%
Reference Case (Medium Demand)	1.4%	1.7%	2.9%	3.9%	1.4%
Upper Demand Bound	0.9%	1.4%	2.3%	2.5%	-0.2%

Long Term Resource Plan + Major Projects	2020	2021	2022	2023	2024
Lower Demand Bound	5.2%	6.8%	8.2%	9.8%	7.5%
Reference Case (Medium Demand)	3.8%	5.7%	6.1%	8.3%	4.0%
Upper Demand Bound	3.3%	5.3%	5.4%	6.9%	2.4%

196.0 Reference: FBC CAPITAL EXPENDITURES

Exhibit B-1-3, p. C-81

Project Planning

On page C-81 of the Application Errata dated June 21, 2019, FBC provides Table C3-20 which summarizes the actual/projected Regular Capital expenditures during the Current PBR Plan term. Based on this table, the average annual Regular Capital spending was $63.127 million.

Table C3-21 on page C-81 summarizes the Regular Capital expenditures forecast for the proposed MRP term. Based on this table, the forecast average annual Regular Capital spending is $88.401 million.

196.1 Please provide a detailed comparison of the anticipated workload to deliver the capital expenditures planned during the proposed MRP term with the workload that was required to deliver the capital expenditures during the Current PBR Plan term.

Response:

FBC normally executes its capital programs using a combination of internal and external resources. To deliver the capital plan during the proposed MRP term, FBC will require additional employees both internally and externally. Currently, an analysis of the current and future anticipated workload by department and discipline is underway. This analysis will support FBC's execution of the plan during the MRP term.

There are a number of larger projects in the MRP term, which are similar to previous years, in which FBC was able to respond to high workload demand though contracting strategies for engineering and construction resources. This was demonstrated, for example, in years 2000 to 2010 and in 2013 (FBC's capital expenditures profile from 2007 to 2018, for example, is shown in the response to ICG IR 2.16.1) where such increases occurred and large programs and projects were successfully executed through effective resource planning. Based on current market conditions, FBC is confident in the availability of qualified external resources to supplement its internal workforce to meet the increase in construction activities over the term of the MRP.

196.2 Please explain in detail how FBC plans to deliver the increased workload anticipated for the proposed MRP term.

Response:

Please refer to the response to BCUC IR 2.196.1.

196.2.1 As part of the above response, please explain if FBC anticipates an increase in the number of FTEs and/or an increase in the number of contractors during the proposed MRP term and, if so, please provide estimates of the increased FTEs and/or contractors.

Response:

Please refer to the response to BCUC IR 2.196.1.

196.3 Please discuss the impacts to ratepayers, if any, if FBC is unable to deliver all of its planned capital expenditures during the proposed MRP term.

Response:

The impacts to ratepayers from under (or over) spending on capital during the proposed MRP term arise from variances in financing and depreciation experienced versus the amounts included in rates. The risks discussed in FortisBC's response to BCUC IR 1.48.5 in regard to FEI's Sustainment and Other capital expenditures are also applicable to FBC's planned capital expenditures. For reference, the response to BCUC IR 1.48.5 is repeated below.

> 48.5 Please discuss any risks to FEI and ratepayers of establishing capital expenditures for Sustainment and Other Capital based on a five-year forecast.
>
> As explained in Section C3.3.2 of the Application, FEI intends to review its Sustainment and Other capital forecast for 2023 and 2024 in its Annual Review for 2023 delivery rates. The review will allow FEI to account for any material changes to the 2023 and 2024 forecasts that may occur over the 2020 through 2022 period and ask for approval of any material changes. Consequently, the risk of a five-year forecast should be viewed as similar to the risk from a cost of service application that typically includes a two-year capital forecast.

Under a cost of service regime, the earnings difference from capital variances flow to the shareholder. However, as described in the workshop held May 1, 2019 and in materials provided as Exhibit B-2, variances in Sustainment and Other capital forecasts will cause changes in achieved earnings and be shared symmetrically with customers on a 50/50 basis, which reduces the risk to ratepayers and to the Company of any variances.

Please also refer to the response to BCUC IR 2.196.1 which explains FBC's planning for the execution of its planned capital expenditures.

196.4 In consideration of the forecast 40 percent increase in Regular Capital spending during the proposed MRP term, please explain why FBC considers the projected level of Regular Capital expenditures for the proposed MRP term to be reasonable.

Response:

The projected level of Regular Capital spending for the proposed MRP term was developed through a robust capital planning process that includes a bottom-up forecast of individual asset needs which have been prioritized in an effort to increase efficiency and minimize customer rate impacts.

As described on page 2 of Appendix B8-3 in the Application, in 2014 to 2016 FBC attempted to manage its capital spending levels close to or within the formula allowed amounts. This resulted in re-prioritization of work and was found to be unsustainable over the full term of the Current PBR Plan. Between 2017 and 2019, FBC exceeded the formula allowed amount, including the deadband, to complete unanticipated work, as detailed in Table A:B8-3-1 of the Application, and to catch up on an accumulation of work that had been reprioritized from previous years of the Current PBR Plan. In spite of the recent spending increases, further increases to expenditure levels are required in the MRP term, as noted in the preamble and in the responses to BCUC IR 1.54.2, 1.54.3, 1.56.2 and 1.59.2 and in the responses to BCUC IR 2.201.2, 2.201.3 and 2.201.4.

The forecast reflects FBC's evolving operating environment and the challenges and opportunities that impact Regular Capital expenditures, for example:

1. The increased spending levels required in the PCB Environmental Compliance Project.
2. The introduction of the Porcelain Cutouts Replacement Program.

3. The continued need for investment in aging infrastructure requires programs like station transformer replacement and substation upgrades to expand to keep pace with changes in observed asset condition.

The forecast that FBC has provided of Regular Capital expenditures for the proposed MRP term is forward looking and based on specific identified asset needs over the MRP term. FBC evaluates its capital plans on an ongoing basis in order to meet forecast load and to ensure the safety, reliability and integrity of the electric system. Due to the evolving operating environment and other uncertainties inherent in a five-year forecast, FBC intend to review the capital forecasts for 2023 and 2024 in its Annual Review for 2023 rates.

197.0 Reference: FBC GROWTH CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 51.3, 51.4, 52.1, 53.1, 53.2; Exhibit B-1, p. C-82; FBC PBR Application, Exhibit B-1, p. 208

FBC Transmission Growth Capital

On page C-82 of the Application, FBC provides the following table:

Table C3-23: FBC Transmission Growth Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	$ 278	$ 4,633	$ -	$ -	$ -	$ -
Summerland Transformer Replacement	n/a	539	2,063	-	-	-
Beaver Park Substation Upgrade	n/a	-	-	2,740	5,195	-
DG Bell 2nd Transformer Addition	n/a	-	-	-	-	1,086
Other Transmission Growth	1,295	-	-	-	-	-
Total	$ 1,572	$ 5,172	$ 2,063	$ 2,740	$ 5,195	$ 1,086

197.1 Please provide a similar table to Table C3-23 to show a breakdown of the annual actual/projected Transmission Growth Capital expenditures for years' 2014 through 2019.

Response:

The requested information, in $ thousands, is provided in the table below.

	2014	2015	2016	2017	2018	2019P
Huth 2nd Transformer Addition	$ 267	$ 2,389	$ -	$ -	$ -	$ -
42 Line Meshed Operation	154	-	-	-	-	-
Voltage Support in South Okanagan	616	726	-	-	-	-
Spall Breaker House Reconfiguration	162	1,108	-	-	-	-
RG Anderson Modifications	-	-	62	2,939	945	-
Sexsmith 2nd Transformer Addition	-	-	-	-	-	833
Inventory Adjustment	(821)	-	-	-	-	-
Total Transmission Growth	$ 377	$ 4,224	$ 62	$ 2,939	$ 945	$ 833

In response to BCUC IR 52.1, FBC provided the following table:

Table 1: FBC Growth Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Transmission Growth	$ 377	$ 4,224	$ 62	$ 2,939	$ 945	$ 833
Distribution Growth	3,027	1,105	500	1,795	1,153	747
New Connects	15,416	15,938	14,895	17,599	21,906	15,939
Total	$ 18,821	$ 21,267	$ 15,456	$ 22,333	$ 24,003	$ 17,519

In response to BCUC IR 53.2, FBC provided the following table showing Transmission Growth projects over $1 million:

Project Name	Ellison to Sexsmith Transmission Tie		Huth 2nd Distribution Transformer Addition		RGA Carmi Voltage Conversion Construction		Sexsmith 2nd tranformer Addition	
Year	Forecast (in million)	Actual Capital Cost (in million)	Forecast (in million)	Actual Capital Cost (in million)	Forecast (in million)	Actual Capital Cost (in million)	Forecast (in million)	Actual Capital Cost (in million)
2014	2.628	2.461	0.372	0.267				
2015			2.449	2.407				
2016					0.049	0.062		
2017					4.368	2.939		
2018					0.000	0.945		
2019							0.807	0.038
2020							4.633	

197.2 Please explain the following discrepancies between BCUC IR 52.1 and BCUC IR 53.2:

- The actual Transmission Growth Capital in 2014 in BCUC IR 52.1 is only $0.377 million; however, the response to BCUC IR 53.2 shows an actual capital cost for the Ellison to Sexsmith Transmission Tie project and the Huth 2nd Distribution Transformer Addition project of $2.461 million and $0.267 million, respectively, in 2014.
- The actual Transmission Growth Capital in 2015 in BCUC IR 52.1 is $4.224 million; however, the response to BCUC IR 53.2 shows an actual capital cost for the Huth 2nd Distribution Transformer Addition project of $2.407 million in 2015.
- The projected Transmission Growth Capital in 2019 in BCUC IR 52.1 is $0.833 million; however, the response to BCUC IR 53.2 shows a projected capital cost for the Sexmith 2nd Transformer Addition project of $0.038 million in 2019.

Response:

The table filed in response to BCUC IR 1.53.2 is in error. A corrected table is provided below and is being filed in an Errata filed concurrently with these IR responses.

Project Name	Huth 2nd Distribution Transformer Addition		Voltage Support in South Okanagan		Spall Breaker House Reconfiguration		RGA Carmi Voltage Conversion		Sexsmith 2nd Transformer Addition	
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Projected
Year	($ millions)									
2014	$ 0.372	$ 0.267	$ 0.572	$ 0.616	$ 1.307	$ 0.162	-	-	-	-
2015	2.449	2.389	0.731	0.726	-	1.108	-	-	-	-
2016	-	-	-	-	-	-	0.049	0.062	-	-
2017	-	-	-	-	-	-	4.368	2.939	-	-
2018	-	-	-	-	-	-	-	0.945	-	-
2019	-	-	-	-	-	-	-	-	0.833	0.833
2020	-	-	-	-	-	-	-	-	4.607	4.607

Please refer to the table in response to BCUC IR 2.197.1 which reconciles the response to BCUC IR 1.52.1 with the revised table above.

In response to BCUC IR 51.3, FBC provided the following table showing the Regular Capital projects that were completed during the Current PBR Plan term:

	Forecast ($ millions)	Actual ($ millions)	Anticipated Start/ In-Service Dates	Actual In-Service Date	Explanation of Variances
Ellison to Sexsmith Transmission Tie	$ 7.083	$ 5.083	2011/2013	Dec 2014	Scope of project reduced because of planned highway expansion.
PCB Environmental Compliance	26.200	22.938	2011/2014	Nov. 2014	Reduced scope and contingency drawdown.
Spall Breaker House Reconfiguration	1.443	1.270	2014/2015	Dec. 2015	Construction costs lower than anticipated
RGA/Carmi Voltage Conversion	4.417	3.946	2016/2018	2018	Cost fully recovered through CIAC
Huth 2nd Distribution Transformer	2.821	2.390	2014/2015	2015	Construction costs lower than anticipated

197.3 Please explain the discrepancies in actual capital expenditures shown in the responses to BCUC IR 53.2 and 51.3 for the Ellison to Sexsmith Transmission Tie and Huth 2nd Distribution Transformer Addition projects.

Response:

Please refer to the responses to BCUC IRs 2.197.1 and 2.197.2 regarding the reconciliation of BCUC IRs 1.51.3 and 1.53.2.

In response to BCUC IR 51.4, FBC provided the planned Growth Capital projects that were not executed in the Current PBR Plan term, including the following:

- Glenmore Low Voltage Bus Capacity Upgrade;
- Summerland Substation Transformer;
- Grand Forks Terminal Feeder Addition;
- DG Bell 4 Feeder Addition; and
- Okanagan Long Term Solution.

On page 208 of the FBC PBR Application, FBC provided a list of the following planned Transmission and Stations Growth Capital projects during the Current PBR Plan term:

- 42 Line Meshed Operation;
- Voltage Support in South Okanagan;
- Huth 8kV Capacity Upgrade;
- Glenmore LV Bus Capacity Upgrade;
- Reconductor 52 & 53 Lines;
- Summerland Transformer Replacement
- Spall Breaker House Reconfiguration; and
- Saucier Protection and Metering Upgrade.

197.4 Please clarify which of the projects listed on page 208 of the FBC PBR Application are included in either the table showing the completed projects during the Current PBR Plan term (i.e. BCUC IR 51.3) or the table showing the planned but not completed projects during the Current PBR Plan term (i.e. BCUC IR 51.4).

Response:

The following table shows the status of the projects listed on page 208 of the FBC 2014 PBR Application.

Project	Status
42 Line Meshed Operation	Completed in 2014 at a cost of $0.154 million – not included in BCUC IR 1.51.3 (capital cost less than $2 million)
Voltage Support in South Okanagan	Completed in 2015 at a cost of $1.342 million – not included in BCUC IR 1.51.3 (capital cost less than $2 million)

Project	Status
Huth 8V Capacity Upgrade (referred to as Huth 2nd Distribution Transformer in response to BCUC IR 1.51.3)	Completed in 2015 at a cost of $2.656 million – included in BCUC IR 1.51.3
Glenmore LV Bus Capacity Upgrade	Not Completed – not included in BCUC IR 1.51.4 (capital cost less than $2 million). Redistribution of load supplied from this substation allowed the $0.2 million project to be deferred beyond 2024.
Reconductor 52 & 53 Lines	Not completed – see below. Project deferred beyond 2024 due to lower than anticipated load growth.
Summerland Transformer Replacement	Not Completed – not included in BCUC IR 1.51.4 (capital cost less than $2 million). Project deferred due to lower than anticipated load growth. Expected to be completed during the MRP term, pending District of Summerland decision on voltage conversion.
Spall Breaker House Reconfiguration	Completed in 2015 at a cost of $1.270 million – included in BCUC IR 1.51.3
Saucier Protection and Metering Upgrade	Completed in 2015 at a cost of $0.599 million – not included in BCUC IR 1.51.3 (capital cost less than $2 million)

The Reconductor 52 & 53 Lines project was inadvertently omitted in the response to BCUC IR 1.51.4. This project is forecast to be required in service outside of the MRP term based on the load forecast. The information requested in BCUC IR 1.51.4 is provided below.

Name-Description	Reason for Delay	Estimated Cost ($millions)	Classification	Year Originally Planned	Current status
Reconductor 52 & 53 Lines This project involves reconductoring the existing 52 Line and 53 Line between the Huth substation and the R.G. Anderson Terminal station with conductors having a higher ampacity rating. This is required to ensure adequate transmission capacity is available to maintain an N-1 level of reliability for approximately 50,000 customers between Summerland and Oliver.	Lower load growth than previously forecast in Penticton area	$8.0	Class 5	2018	Deferred beyond 2024

197.5 If any of the projects listed on page 208 of the FBC PBR Application are not included in either the table provided in response to BCUC IR 51.3 or the table provided in response to BCUC IR 51.4, please explain why not and please provide an update on the project(s).

Response:

Please refer to the response to BCUC IR 2.197.4.

197.5.1 If the project(s) have been completed, please provide the total costs incurred and date of completion.

Response:

Please refer to the response to BCUC IR 2.197.4.

197.5.2 If the project(s) have not been completed, please explain if the project(s) are planned to be undertaken during the proposed MRP term. If yes, please explain when. If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.197.4.

On page C-82 of the Application, FBC states: “Regular Transmission Growth capital consists of discrete projects as dictated by transmission system capacity requirements based on forecast load, for adequate supply during periods of peak demand and adverse weather conditions.”

197.6 Please discuss, with reference to the Transmission Growth Capital expenditures during the Current PBR Plan term, FBC's ability and historical experience forecasting the timing of Transmission Growth Capital projects.

Response:

Five out of eight of the Transmission and Stations Growth Capital projects that were listed on page 208 of FBC's PBR application were completed as planned during the PBR term.

The Reconductor 52 & 53 Lines and Summerland Transformer Replacement projects were able to be deferred based on lower load growth than previously forecast at the time of the PBR Application. At the moment, Summerland Transformer Replacement is on hold pending a decision regarding voltage conversion by the District of Summerland.

The Glenmore LV Bus Capacity Upgrade project is a relatively small capital expenditure (approximately $0.2 million) that was able to be deferred beyond 2024 by redistributing the load supplied from this substation.

It is not always possible to forecast localized load growth with accuracy over a five-year period, since even a single new customer, if of sufficient size, can drive a need to advance or delay a project. FBC will respond to differences in growth experienced by adjusting the timing of projects within its capital plan. In order to address changing circumstances, FortisBC intends to file an update in 2022, if warranted, to its capital forecast for the final two years of the MRP term.

197.7 Please explain in detail for each of the following planned projects the likelihood that each project will be required (and will therefore be completed) within the timeframe forecast in the Application:

(i) Sexsmith Second Transformer Addition;

(ii) Summerland Transformer Replacement; and

(iii) Beaver Park Substation Upgrade.

Response:

Sexsmith Second Transformer Addition:

Peak load on the existing Sexsmith T1 transformer is forecast to exceed its nameplate rating in 2020. This project is currently in execution and must be completed within the timeframe forecast in the Application in order to maintain the current levels of reliability and meet planning criteria.

Summerland Transformer Replacement:

Peak load at this wholesale delivery point to the District of Summerland is forecast to exceed 95 percent of the contract demand limit in 2021. FBC's wholesale supply contracts provide that measures must be taken to increase supply capability to bring future demand to or below 95 percent of the demand limit.

If significant new load that is currently forecast to be added to the District of Summerland system does not materialize, it is possible that this project could be deferred. Based on development information communicated by the District of Summerland, it is believed unlikely that significant deferral will be possible. The timing of this project is dependent on the District of Summerland's pending decision on voltage conversion of its distribution utility.

Beaver Park Substation Upgrade:

This project proposes to increase capacity and rebuild the Beaver Park (BEP) station on the existing station footprint. The project is necessary to meet load growth and to continue to reliably supply electricity to the area. It will also address aging infrastructure and condition of equipment issues.

BEP T1 is forecast to exceed the nameplate rating in Winter 2021. To meet planning criteria, this project should be completed within the timeframe forecast in the Application.

In response to BCUC IR 53.1, FBC stated the following regarding the Summerland Transformer Replacement Project:

> The estimate for this project is currently at the Class 5 level of scope definition and scope definition is ongoing. A detailed cost breakdown is not available at this time. No further description beyond what was included in the Application is available at this time.

197.8 Please explain whether the cost to deliver the Summerland Transformer Replacement project has increased as a result of being deferred from the Current PBR Plan to the proposed MRP and if so, why.

Response:

FBC is not aware of any factors other than inflation affecting the project cost due to deferral. The scope described in the 2014 PBR Application was more extensive, as it included a breaker replacement that has since been completed under a stations sustainment program in 2018 and an assumption that a station would need to be expanded. The cost in the MRP Application is based on a recent evaluation indicating that a simple transformer replacement should be possible without station expansion. However, the project scope is incomplete as FBC is awaiting the District of Summerland's decision on the distribution voltage.

197.9 Please explain why FBC is unable to provide further information on the Summerland Transformer Replacement Project considering construction is planned to begin in 2020.

Response:

Scope definition is presently on hold pending direction from the District of Summerland related to its future voltage conversion plans. FBC will proceed with project scope and design once the customer's voltage requirements are known and the customer is ready to proceed.

198.0 Reference: FBC GROWTH CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 52.1; Exhibit B-5, BCOAPO IR 63.1; Exhibit B-1, p. C-83

FBC Distribution Growth Capital

On page C-83 of the Application, FBC provides the following table:

Table C3-24: FBC Distribution Growth Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Small Growth Projects	$ 419	$ 1,040	$ 1,070	$ 1,102	$ 1,122	$ 1,137
Unplanned Growth Projects	813	707	805	704	777	784
DG Bell Feeder 4 Addition	n/a	1,970	-	-	-	-
Total	$ 1,232	$ 3,716	$ 1,876	$ 1,807	$ 1,899	$ 1,921

In response to BCUC IR 52.1, FBC provided the following table:

Table 1: FBC Growth Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Transmission Growth	$ 377	$ 4,224	$ 62	$ 2,939	$ 945	$ 833
Distribution Growth	3,027	1,105	500	1,795	1,153	747
New Connects	15,416	15,938	14,895	17,599	21,906	15,939
Total	$ 18,821	$ 21,267	$ 15,456	$ 22,333	$ 24,003	$ 17,519

In response to BCOAPO IR 63.1, FBC provided the following table:

	2013	2014	2015	2016	2017	2018	2019P
Small Growth Projects	$ 375	$ 1,356	$ 467	$ 29	$ 672	$ 452	$ 132
Unplanned Growth Projects	418	953	608	471	1,123	701	615

198.1 Please expand the table provided in response to BCOAPO IR 63.1 to provide a breakdown of all of the annual actual/projected Distribution Growth Capital expenditures for years' 2014 through 2019.

<u>Response:</u>

The breakdown of the capital expenditures between 2014 to 2019P is provided below.

Table 1: Small Growth Projects, 2014 – 2019P

2014		
Small Growth Projects		($000s)
Bountiful Phase Addition	$	259
HOL5-BLK2 Feeder Upgrade		191
OOT1 Regulator Move		176
SEX3 Feeder Tie		182
Eng GLE6 Reconductor Dist Small Growth		18
Mat GLE6 Reconductor Dist Small Growth		41
Constr GLE6 Reconductor Dist Small Growt		211
Eng PRI4 Regulators Dist Small Growth		1
Mat PRI4 Regulators Dist Small Growth		127
Constr PRI4 Regulators Dist Small Growth		61
Common Costs and Direct Overheads		92
Total, Small Growth Projects	$	1,357

2015		
Small Growth Projects		($000s)
ELL3 Quail Ridge Capacity Up(15)	$	267
HOL5-BLK2 Feeder Upgrade(14)		8
HOL5-BLK2		120
Misc		9
Common Costs and Direct Overheads		64
Total, Small Growth Projects	$	467

2016		
Small Growth Projects		($000s)
ELL3 Quail Ridge Capacity Up(15)	$	27
Common Costs and Direct Overheads		3
Total, Small Growth Projects	$	29

2017		
Small Growth Projects		($000s)
GLE5 Capacity Up SmGr(17)	$	279
VAL Feeder Redesign SmGr(17)		189
DGB1 Capacity Up SmGr(17)		138
Common Costs and Direct Overheads		67
Total, Small Growth Projects	$	672

2018		
Small Growth Projects		($000s)
WEB1 49L Underbuild SmGr(18)	$	286
KER1 6th Ave SmGr(18)		110
Common Costs and Direct Overheads		56
Total, Small Growth Projects	$	452

2019P		
Small Growth Projects		($000s)
KER1 6th Ave(18)	$	(3)
DUC1 74N4578 RegulatorRpl		114
Common Costs and Direct Overheads		21
Total, Small Growth Projects	$	132

Table 2: Unplanned Growth Projects, 2014 – 2019P

2014	
Unplanned Growth Projects	($000s)
Lakeshore Rd Overloaded Tx	$ 7
1949 Ethel System Upgrades	4
DGB4 Egress Cables	102
Acland Rd Loop	71
Jasmine Rd Upgrades	8
390 Royal Upgrade	7
1167 Henderson Dr	7
1523 Mission Ridge Voltage Problems	30
McDonalds Rd Up	1
3945 E Kelowna Rd	3
Santa Rosa Recloser 2549836	4
Midgely Mtn Recloser	5
Laburnum Drive Upgrade	10
Sectionalizing Switch Addition	32
Creston Back Lane	2
Granite Mtn Voltage Conversion	205
Plant Tie Volt Conv Ph2	10
EP Farms 2555580	0
Voltage Upgrades	1
Vanwijk - 321 Bear Rd Nelway - 2548576	7
60C21 Switch Upgrade	11
Coffee Ck Regulators	47
Upgrade Trans Bank 965 Hwy 33 W 2544802	15
Upgrade GLE3 O/H Conductor 2545435	111
Upgrade 91N310 Reclosers in Pri	46
Complete Loop Feed along Acland Rd – C36	42
Gem Lake Regulator	3
Hwy 33 Crossing Conduit Install on Rutla	38
SDP-DG2810 MDY & GRN Recloser Automation	(2)
Feeder Balancing/Labelling	22
Extend primary at Hawkins Rd	(1)
SDP-DG2810 Voltage Improvement 2550029	0
PLA2 Switch Addition	15
PBR C/OPlant Tie Line Voltage Conversion	9
Lab Dis Plant Tie Line Voltage Conversion Ph2	(0)
Common Costs and Direct Overheads	81
Total, Unplanned Growth Projects	$ 953

2015	
Unplanned Growth Projects	($000s)
1949 Ethel System Upgrades(14)	$ 1
390 Royal Upgrade(14)	9
Mountain Ave Switcher(14)	30
1167 Henderson Dr(14)	7
McDonalds Rd Up(14)	22
3945 E Kelowna Rd(14)	1
947 Bernard Up(15)	7
2470 Pandosy Ave (15)	3
Highway 97 Upgrades(15)	45
Perth Rd (15)	6
Autumn Rd Upgrade(15)	2
KSA2 Single Phase (15)	6
79JB174 Cable Upgrade	9
EV Station	51
Meter Location Upgrades (15)	15
Dry Valley Rd Upgrade (15)	1
Hall Rd Upgrade (15)	1
74th Ave Osoyoos (15)	2
Kelowna Reclosers (15)	30
1467 Sutherland (15)	5
Gibson Rd Switch (15)	8
Laburnum Dr Up UnplGr(14)	17
Sectionalizing Switch Addition(14)	10
Granite Mtn Voltage Conversion(14)	12
60C21 Swtch Up UnGw(14)	0
Plant Tie Volt Conv Ph2(14) (Non PBR)	29
Coffee Ck Regulators(14)	49
Slocan Ridge Recloser Add (15)	8
4thSt Rossland SwtchAdd (15)	14
Upper Levels Rd OI 2558503 (15)	16
Sheep Creek Recloser (15)	10
Thompson Mtn Recloser(15)	12
Pilot Point Recloser(15)	16
FBC 38 Ave Erickson (15)	7
West Trail Overload (15)	3
Upper Gibson Rd Up (15)	20
Passmore Lower Rd UnGw(15)	4
57N235 Creston (15)	5
Lab Dis Plant Tie Line Voltage Conversion Ph2	20
Common Costs and Direct Overheads	94
Total, Unplanned Growth Projects	$ 608

2016	
Unplanned Growth Projects	($000s)
1949 Ethel System Upgrades(14)	$ 2
382 Ave Reconductor(15)	7
Sundial Rd Reconductor(15)	45
79JB174 Cable Upgrade	8
EV Charging	50
Meter Location Upgrades (15)	5
Dry Valley Rd Upgrade (15)	7
Hall Rd Upgrade (15)	30
1467 Sutherland (15)	0
72N887 Copper UnGw(16)	25
545 Ziprick(16)	10
Bowes St Upgrade UnGw(16)	0
Recreation Ave Upgrade	63
GLE1 Fuses UnGw(16)	6
Thompson Mtn Recloser(15)	1
Pilot Point Recloser(15)	1
Upper Gibson Rd Up (15)	57
57N235 Creston (15)	0
1414 Green Rd Fruitvale (16)	3
Warfield Voltage Complaint (16)	2
Creston 20th and Birch (16)	22
1078 Columbia Rd Castlegar (16)	1
Warfield Fusing (16)	3
GF Beach Rd (16)	28
Trail Riverside Ave (16)	22
CAS Xmer Up (16)	6
Fruitvale Kootenay Ave Triplex (16)	2
Buma’s Farm Cu SmPl(16)	1
Common Costs and Direct Overheads	65
Total, Unplanned Growth Projects	$ 471

2017	
Unplanned Growth Projects	($000s)
Sundial Rd Reconductor(15)	$ 73
Service Upgrades(16)	0
Apex Regulators(17)	18
Recreation Ave Tie(17)	85
Fitzgerald Rd(17)	43
Chute Lake Rd(17)	6
John Hindle Conduit	51
Feeder Protection (17)	146
74SA064 Upgrades (17)	14
OKM Feeder Conduit Install (17)	43
Beaverdell Reg (17)	21
Tronson Dr (17)	81
Creston 20th and Birch (16)	21
Warfield Fusing (16)	5
GF Beach Rd (16)	2
Trail Riverside Ave (16)	111
Service Upgrades (16)	0
Fruitvale Kootenay Ave Triplex (16)	5
GF Marchal & Siminoff Railway (16)	29
GFT Esouloff Rd (16)	33
Buma's Farm Cu (16)	8
Nelway Fuse Coordination(17)	0
60CUT10RplSolidBlades w/ AirBrkSw (17)	19
Air Brk Sw between FRU&Montrose(17)	18
2202 Mackay Rd AAL(17)	20
Boswell Upgrade Secondary AAL(17)	2
#6 cu Reservoir Rd GFT(17)	1
50N875 Gravel Pit(17)	69
Creston Live Front Xmer (17)	27
Café Michaels (17)	9
Glade Unbalance (17)	11
CRE 56N83 Cu Rpl (17)	7
SAL Green Xmer (17)	4
PLA2 Fuse Coordination (17)	2
Cascade Cove (17)	6
Common Costs and Direct Overheads	134
Total, Unplanned Growth Projects	$ 1,123

2018	
Unplanned Growth Projects	($000s)
Dry Valley Rd Upgrade (15)	$ 11
Fitzgerald Rd(17)	34
Chute Lake Rd(17)	6
John Hindle Conduit	16
Feeder Protection (17)	36
74SA064 Upgrades (17)	0
OKM Feeder Conduit Install (17)	42
Beaverdell Reg (17)	10
Tronson Dr (17)	(8)
Willow Street (18)	26
ShepherdRdExt (18)	13
GF Beach Rd (16)	20
Buma's Farm Cu (16)	25
Nelway Fuse Coordination(17)	1
View Rd CU Removal AAL(17)	15
Boswell Upgrade Secondary AAL(17)	25
50N875 Gravel Pit(17)	1
Creston Live Front Xmer (17)	64
CRE 56N83 Cu Rpl (17)	11
PLA2 Fuse Coordination (17)	6
Cascade Cove (17)	(0)
7th St Salmo (17)	0
Sanca AAL (17)	5
Whimster Rd (18)	8
651 Ponderosa Dr (18)	13
Cutout Rpl UnGW(18)	190
2650 AlmondGardensRd (18)	4
Common Costs and Direct Overheads	126
Total, Unplanned Growth Projects	$ 701

2019P	
Unplanned Growth Projects	($000s)
Shores Switcher (18)	$ 62
COK Aiport Beacons (15)	24
Fitzgerald Rd(17)	0
Willow Street (18)	(0)
OKM3 Collett Rd Fusing Up (19)	10
AWA2 OkanaganMtn 1Ph Recloser (19)	20
WEB2 N'Kwala Mtn 1Ph Recloser (19)	20
KET1 ChristianValley 1PhRecloser (19)	20
PIN2 Kobau Mtn 1Ph Recloser (19)	20
BLK3 FuseUp(19)	0
SPL McMillanRd Voltage (19)	15
SPL SpillerRd Voltage (19)	30
GF Beach Rd (16)	1
PLA2 Fuse Coordination (17)	3
7th St Salmo (17)	(0)
Sanca AAL (17)	55
Whimster Rd (18)	5
Cutout Rpl (18)	(0)
COT1 Whitewater3phRecloser (19)	50
CSC1 RedMt3phRecloser (19)	62
CSC1 MannRdProtCoord (19)	10
CSC1 RedMtFCIs (19)	25
GLM2 BellaBrosAutoSupply (19)	23
Broadwater Rd (19)	21
CRE2 - 4730CanyonListerRd UnGw(19)	7
Total Project NC Reserve	40
Common Costs and Direct Overheads	90
Total, Unplanned Growth Projects	$ 615

198.2 Please explain why the Actual 2016 and Projected 2019 Distribution Growth Capital expenditures were/are significantly lower than in the other years of the Current PBR Plan term.

Response:

The volume of expenditures on Small Growth projects varies from year to year depending on the timing and location of load growth with FBC's distribution system. FBC's Growth Capital plan includes projects classified as mandatory, essential, and flexible, in order to levelize and manage workload to the extent possible. In 2016, as FBC attempted to maintain spending within its formula capital envelope, fewer lower-priority projects were completed. In 2019, expenditures were lower as requirements for additional capacity and voltage regulation were lower than in other years during the PBR term.

198.3 Please provide a breakdown and description of the $1,123,000 Unplanned Growth Projects expenditures incurred in 2017.

Response:

Please refer to the response BCUC IR 2.198.1.

On page C-83 of the Application, FBC states the following regarding Distribution Growth Capital:

> These projects include service upgrades, voltage regulation, ties to accommodate load splitting, single to three phase upgrades and conductor upgrades that are necessary due to load growth. The Small Growth Projects program consists of planned projects less than $0.5 million in size.

In response to BCOAPO IR 63.1, FBC stated the following regarding its planned spending on "Small Growth Projects": "Forecast expenditures for the 2020 to 2024 period are due to significant load growth in recent years and upgrades that are required to ensure continuing acceptable standards of service."

198.4 Please explain what projects, programs or work is contained in "Small Growth Projects." As part of this response, please explain if this work is Mandatory, Essential, or Flexible, according to FBC's Capital Priority Classification.[49]

Response:

Small Growth Projects consist of planned projects less than $0.5 million in size, and include service upgrades, voltage regulation, ties to accommodate load splitting, single to three phase upgrades and conductor upgrades that are necessary due to load growth.

Small Growth Projects are composed of 25 percent mandatory work, 50 percent essential work, and 25 percent flexible work. The percentage breakdown is based on Asset Management judgment with input from Operations, Engineering, and other stakeholders.

198.5 Please explain the impacts, if any, of maintaining the spending on "Small Growth Projects" at the 2017-2019P Average during the proposed MRP term.

Response:

The 2017-2019P Average would be insufficient to ensure that acceptable standards of service are maintained for FBC customers, based on a number of service requests recently received. If the 2017-19P Average were maintained, other necessary projects would need to be deferred in favour of new growth projects, which could negatively impact service to FBC customers.

[49] Exhibit B-1-1, Figure A:B8-3-1, p. 8.

199.0 Reference: FBC SUSTAINMENT CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 54.1, 54.2; Exhibit B-1, pp. C-85, C-87 – C-88

FBC Generation Sustainment Capital

On page C-85 of the Application, FBC provides the following table:

Table C3-27: FBC Hydraulic Dam Structures Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	$ 462	$ 685	$ 821	$ 979	$ 1,128	$ 1,019
LBO Spillway Gates Refurbishment	92	1,467	1,396	-	-	-
Other Gates Upgrades	283	481	100	414	241	545
Dam Safety Instrumentation	428	715	765	-	-	806
Guarding of Rotating Parts	6	194	324	458	295	287
Other Hydraulic Dam Structures Projects	58	588	320	355	291	73
Total	$ 1,329	$ 4,130	$ 3,726	$ 2,206	$ 1,955	$ 2,730

In response to BCUC IR 54.1, FBC provided the following table:

Table 2: FBC Hydraulic Dam Structures Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Concrete Structures Rehabilitation	$ 705	$ 425	$ 293	$ 505	$ 493	$ 389
LBO Spillway Gates Refurbishment	-	100	-	117	1	159
Other Gates Upgrades	-	131	28	233	608	-
Dam Safety Instrumentation	-	-	-	253	588	445
Guarding of Rotating Parts	-	-	-	-	-	17
Other Hydraulic Dam Structures Projects	-	25	27	-	-	182
Total	$ 705	$ 681	$ 348	$ 1,108	$ 1,689	$ 1,190

In response to BCUC IR 54.2, FBC stated the following regarding the Lower Bonnington Dam (LBO) Spillway Gates Refurbishment project:

> This project involves the refurbishment of the two spillway gates installed at LBO to rectify age-related condition issues, meet current regulations, and minimize the risks to public and employee safety. The Current PBR Plan did not include a similar project.

199.1 Please provide a description of the capital expenditures incurred for the "LBO Spillway Gates Refurbishment" project in 2015, 2017 and 2019, as shown in Table 2 in response to BCUC IR 54.1. As part of this response, please clarify if the expenditures are related to the project described in response to BCUC IR 54.2.

Response:

Components of the LBO spillway gates are the subject of capital expenditures in both the Current PBR Plan and the proposed MRP, as explained below.

The LBO Spillway Gates Refurbishment project described in the response to BCUC IR 1.54.2 involves the refurbishment of the two spillway gates (one planned for 2021 and one for 2025) installed at LBO to rectify age-related condition issues, meet current regulations, and minimize the risks to public and employee safety.

During the Current PBR Plan term, capital expenditures related to the LBO spillway gates in 2015 and 2017 were for upgrades of the electrical system of the hoists that operate the gates. These expenditures are not related to the project planned for the MRP term as described in FBC's response to BCUC IR 1.54.2.

The capital expenditures for the LBO Spillway Gates Refurbishment project in 2019 involve two separate items:

- The replacement of the access ladders to the hoists that operate the LBO spillway gates, which are not related to the project described in FBC response to BCUC IR 1.54.2; and
- Engineering costs related to the design of the stop logs required for the upgrade of the first spillway gate in the MRP term, which are related to the project described in FBC response to BCUC IR 1.54.2. The stop logs will be purchased in 2020.

In response to BCUC IR 54.2, FBC described the "Other Gates Upgrade Project" and stated that the "Current PBR Plan did not include a similar project."

199.2 Please provide a description of the capital expenditures incurred for the "Other Gates Upgrades" project in 2015 through 2018, as shown in Table 2 in response to BCUC IR 54.1. As part of this response, please clarify if the expenditures are related to the "Other Gates Upgrades" planned to be undertaken during the proposed MRP term.

Response:

All of the expenditures are related to work on the intake, spill gates and head gates at FBC's plants. The components addressed vary from year to year. The capital expenditures incurred during the Current PBR Plan term included:

1. In 2015, to reinforce the head gates at SLC and at LBO to address structural concerns raised by an Engineering assessment.
2. In 2016, to reinforce the head gates at UBO to address structural concerns raised by an Engineering assessment.

3. In 2017, a condition assessment of all intake, spill and head gates at all dams and the upgrade of the Unit 5 UBO head gate hoist. These condition assessments resulted in the SLC tailrace gates and embedded parts upgrade planned for 2022 and the COR tailrace gates upgrade planned for 2024 listed below.
4. In 2018, a condition assessment of the gate superstructures at all dams including an assessment of superstructure access ladders for compliance with OHS requirements, completion of the Unit 5 UBO head gate hoist upgrade and replacement of LBO tailrace gates. These condition assessments resulted in the ladders replacement projects at SLC, UBO and COR listed below.

The expenditures planned to be undertaken during the proposed MRP term are related to the following:

- UBO Unit 6 head gate hoist upgrade (2020)
- SLC headgates hoist access ladders replacement (2021)
- SLC tailrace gates and embedded parts upgrade (2022)
- UBO headgate and spillway gates hoist access ladders replacement (2023)
- COR headgate gates hoist access ladders replacement and COR tailrace gates upgrade (2024).

In response to BCUC IR 54.2, FBC stated the following regarding the Dam Safety Instrumentation project: “The project started under the Current PBR Plan in 2018 with the first plant, Lower Bonnington, to be completed in 2019. The spending under the Current PBR Plan was $0.32 million.”

199.3 Please clarify the timing of the commencement of the Dam Safety Instrumentation Project and the spending under the Current PBR Plan given the expenditures provided in response to BCUC IR 54.1 (Table 2) related to Dam Safety Instrumentation.

Response:

FBC notes that the response to BCUC IR 1.54.2 should read “…The spending under the Current PBR Plan was $1.285 million.”

The capital expenditures incurred in 2017 under the Dam Safety Instrumentation project were related to preliminary design and cost estimates undertaken for all FBC plants in order to allow FBC to plan its Dam Safety Instrumentation program and determine the costs for this program under the proposed MRP. The engineering, procuring of materials, and construction for the Lower Bonnington Dam Safety Instrumentation project started in 2018 and will be completed in 2019.

199.4 Please explain what projects, programs, or work is contained in "Other Hydraulic Dam Structures Projects." As part of this response, please explain if this work is Mandatory, Essential, or Flexible, according to FBC's Capital Priority Classification.[50]

Response:

The detail of the forecast expenditures on the Other Hydraulic Dam Structures Projects is set out in the table below.

Other Hydraulic Dam Structures Projects ($000s)

	2020	2021	2022	2023	2024
Superstructures Upgrades	$ 41	$ 29	$ 29	-	-
Dam Stability Anchors	128	58	58	58	-
Forebay Well Upgrades	233	233	233	233	-
LBO Superstructure Anchor Bolts	174	-	-	-	-
UBO Old Side Gantry	-	-	-	-	-
SLC Gantry Limits	-	-	23	-	-
UBO Oil Skimmer	-	-	12	-	-
COR Spillway	-	-	-	-	73
Water Level Instrumentation	12	-	-	-	-
TOTAL	$ 588	$ 320	$ 355	$ 291	$ 73

A description of the projects is provided below:

[50] Exhibit B-1-1, Figure A:B8-3-1, p. 8.

- The Superstructure Upgrades project includes the rehabilitation of plant superstructure in order to maintain its service life. FBC undertook superstructure condition assessments for all its plants in 2018. The assessments have identified the need for rehabilitation work to ensure their long-term viability. This project is mandatory due to the requirements of the BC Dam Safety Regulation.
- The Dam Stability Anchors project includes the replacement and rehabilitation of the corrosion protection system for the dam stability anchors installed at FBC's plants. As a result of dam stability studies undertaken in 1991, a total of 255 dam stability anchors were installed at LBO, UBO and COR dams between 1991 and 1993. The dam stability anchors are post-tensioned rock anchors made up of steel anchor cables drilled through the dam foundation and bonded into the bedrock below the dam with grout. In 2019, FBC plans to undertake an assessment of all anchor bolts and the remediation of the corrosion protection system of selected anchors at UBO and COR. This project is mandatory due to the requirements of the BC Dam Safety Regulation.
- The Forebay Well Upgrades project includes the replacement or upgrade of the forebay valves installed on the generator cooling systems of FBC's generator equipment. The generator cooling systems at FBC's plants contain piping and valves that are original, with a service life between 78 and 111 years. The water used for the generator cooling system was originally supplied from the forebay through a valve. The cooling system is also fitted with water strainers, which must be cleaned regularly when in use. The piping and valves are in a deteriorated condition and must be rehabilitated or replaced in order to make sure that they will not fail and result in failure of the generator cooling system. In 2019 FBC plans to complete preliminary design and cost estimates for the upgrade at SLC. This project is essential as it is required to replace degraded assets which are necessary in the production of energy.
- The LBO Superstructure Anchor Bolts project includes the replacement of the LBO superstructure anchor bolts which are in danger of failing. In 2019 FBC plans to undertake a preliminary design and a cost estimate for the replacement of the anchor bolts. This project is mandatory due to the requirements of the BC Dam Safety Regulation.
- The UBO Old Side Gantry project will address overloading of the existing superstructure when the hoist operates the stop logs in 2019. This project is mandatory due to the requirements of the BC Dam Safety Regulation.
- The Corra Linn Spillway project includes an assessment planned for 2024 of the COR overflow spillway which is original and has not been refurbished since construction. The scope of the condition assessment will be to assess the integrity of the structures, their suitability for continued operations and perform a Class 5 cost estimate for recommended refurbishment works. It is expected that this assessment will result in a project with expenditures over $20 million and will be addressed as a separate

application to the BCUC in the 2025-2030 time frame. This project is mandatory due to the requirements of the BC Dam Safety Regulation.

- Three small projects to rehabilitate the water level instrumentation (planned for 2020), the gantry limits at SLC and an oil skimmer and UBO which are planned for 2022. These projects are flexible.

199.5 Please provide a detailed description of the "Other Hydraulic Dam Structures Projects" projected for 2019 and of the projects planned for each year of the proposed MRP term.

Response:

Please refer to the response to BCUC IR 2.199.4.

199.6 Please explain the basis for FBC's forecast for "Other Hydraulic Dam Structures Projects" during the proposed MRP term, including why the forecasts (with the exception of 2024) are significantly higher than the actual expenditures during the Current PBR Plan term.

Response:

The forecasts for "Other Hydraulic Dam Structures Projects" during the proposed MRP term are significantly higher than the actual expenditures during the Current PBR Plan term due four new projects. These four projects are required to address deterioration of dam infrastructure. The forecast costs of these projects are as follows:

1. Superstructure Upgrades project. The forecast cost for this project is $0.99 million for the period 2020-2022.
2. LBO Superstructure Anchor Bolts project. The forecast cost for this project is $0.174 million in 2020.
3. Dam Stability Anchors project. The forecast cost for this project is $0.302 million for the period 2020-2023.
4. Forebay Well Upgrades project. The forecast cost for this project is $0.930 million for the period 2020-2023.

Refer to the response to BCUC IR 2.199.4 for further description of the above projects.

On page C-87 of the Application, FBC provides the following table:

Table C3-28: FBC Generating Equipment Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
UBO Unit 6 Turbine Runner Replacement	$ -	$ -	$ 35	$ 582	$ 2,035	$ -
Generator Excitation and Control Systems	-	-	67	556	556	-
Generator Thrust Bearing Cooling System	100	247	271	295	198	198
Other Generating Equipment Projects	517	811	834	716	488	669
Total	$ 616	$ 1,058	$ 1,207	$ 2,148	$ 3,277	$ 866

In response to BCUC IR 54.1, FBC provided the following table:

Table 3: FBC Generating Equipment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
UBO Unit 6 Turbine Runner Replacement	$ -	$ -	$ -	$ -	$ -	$ -
Generator Excitation and Control Systems	-	-	-	-	-	-
Generator Thrust Bearing Cooling System	-	-	-	1	103	299
Other Generating Equipment Projects	2,091	134	90	308	274	864
Total	$ 2,091	$ 134	$ 90	$ 309	$ 377	$ 1,163

199.7 Please provide a detailed description of the "Other Generating Equipment Projects" capital expenditures incurred in 2014 and projected to be incurred in 2019.

Response:

FBC's expenditures incurred in 2014 under the "Other Generating Equipment Projects" are related to repairs undertaken at UBO following a failure of Unit 3 in 2013 where several key components of the unit were damaged. The repairs to Unit 3, which were completed in 2014, included the refurbishment of the turbine runner, bearings, governor components and rebuilding concrete foundations.

FBC's expenditures projected for 2019 under the "Other Generating Equipment Projects" are summarized in the following table:

Other Generating Equipment Projects ($000s)

Description	2019
Generator protection systems	150
Replacement of failed generator cable tray supports	190
Installation of duplex filters	20

Description	2019
Upgrade of plant Human Machine Interface	27
Procurement of critical spares	60
Provision for unforeseen emergency replacement	174
Wicket gate guarding	168
Corra Linn potential transformer replacement	64
TOTAL	**864**

199.8 Please provide a detailed description of the planned annual capital expenditures for "Other Generating Equipment Projects" during the proposed MRP term.

Response:

FBC's planned annual capital expenditures under the "Other Generating Equipment Projects" during the MRP term are:

- The Generator Protection Systems project which includes the upgrade or replacement of the generator overspeed protection and generator vibration monitoring. Some of these devices are original to the plants and are experiencing failures.
- The Generator Condensation Mitigation project which includes the installation of condensation mitigation equipment on FBC's units' generator equipment. FBC generators use an open-ventilated, air-cooled design that exposes the windings to moisture ingress that can cause insulation failure. A failure of the generator's insulation most likely will require a rewind of the generator.
- The Governor Oil Filtration Improvement Project which includes the addition of a filtration system to the governor hydraulic oil system to mitigate miss operation of the governor's hydraulic control valves.
- The Upgrade of Plant Human Machine Interface (HMI) project which includes the replacement of the existing HMI which is obsolete and is no longer supported by the manufacturer.
- The Critical Spares project which includes the procurement of critical spare parts.
- Emergency Replacement project which includes unforeseen replacements of failed equipment.

The forecast costs of the above Other Generating Equipment projects are set out in the table below.

Other Generating Equipment Projects ($000s)

	2020	2021	2022	2023	2024
Generator Protection Systems	76	130	93	93	93
Generator Condensation Mitigation	105	116	116	116	116
Governor Oil Filtration Improvement	178	227	227	-	227
Upgrade of plant HMI	47	70	47	47	
Critical spares	233	116	58	58	58
Emergency replacement	174	174	174	174	174
TOTAL	**811**	**834**	**716**	**488**	**669**

199.8.1 As part of the above response, please explain why the forecast expenditures during the proposed MRP term are higher than the average actual/projected expenditures during the Current PBR Plan term.

Response:

FBC's forecast expenditures for Generating Equipment Capital during the MRP term are higher than the average actual/projected expenditures during the Current PBR Plan term due mainly to the difference in scope, the timing and the duration of the projects identified during the MRP term.

While the majority of projects included in the Current PBR Plan term spanned one to three years, the projects included in the MRP term span four to five years. Examples of these longer-duration projects include:

- Generator Protection Systems project commenced in 2017 and will continue throughout the MRP.
- Upgrade of plant HMI project will start in 2019 and will continue throughout the MRP.
- Generator Condensation Mitigation project will start in 2020 and will continue throughout the MRP.
- The Governor Oil Filtration Improvement Project will start in 2020 and will continue throughout the MRP.

- The Critical Spares project commenced in 2018 and will continue throughout the MRP term.
- Emergency Replacement project commenced in 2017 and will continue throughout the MRP term.

On page C-88 of the Application, FBC provides the following table:

Table C3-29: FBC Generation Auxiliary Equipment Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Dewatering and Drainage Systems	$ 60	$ 116	$ 349	$ 349	$ 349	$ 349
Station Service Upgrade	64	333	495	286	286	300
Other Auxiliary Equipment Projects	753	506	189	175	175	175
Total	$ 876	$ 955	$ 1,033	$ 809	$ 809	$ 823

In response to BCUC IR 54.1, FBC provided the following table:

Table 4: FBC Generation Auxiliary Equipment Capital Expenditures Forecast 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Dewatering and Drainage Systems	$ -	$ 56	$ 215	$ 52	$ 72	$ 55
Station Service Upgrade	4	-	-	8	61	122
Other Auxiliary Equipment Projects	2,167	517	924	937	741	581
Total	$ 2,171	$ 573	$ 1,139	$ 997	$ 875	$ 758

On page C-88 of the Application, FBC states that the Dewatering and Drainage Systems Rehabilitation Project is a continuation of the program started in 2011.

In response to BCUC IR 54.2, FBC stated the following regarding the Dewatering and Drainage Systems Rehabilitation Project: “Under the Current PBR Plan FBC incurred expenditures of approximately $0.5 million.”

199.9 Please explain the cause(s) of the forecast increase in expenditures for the Dewatering and Drainage Systems Rehabilitation Project commencing in 2021 compared to forecast 2020.

Response:

FBC’s 2020 expenditures for the Dewatering and Drainage Systems Rehabilitation Project reflect costs to complete the upfront engineering for the project. Execution of the project will commence in 2021 at an estimated cost of $0.349 million per year to rehabilitate the dewatering and drainage system for one Unit.

199.10 Please provide a detailed description of the expenditures incurred during the Current PBR Plan term related to the Dewatering and Drainage Systems Rehabilitation Project. In particular, please explain the cause(s) of the large amount of capital expenditures incurred in 2016.

Response:

FBC's expenditures related to the Dewatering and Drainage Systems Rehabilitation Project during the Current PBR Plan term are related to the following elements:

- 2015: valve upgrades for the dewatering system of U1 and U2 at UBO.
- 2016: valve replacements, modifications to the valve stem and also piping repairs for the dewatering system of U1 and U2 at COR.
- 2017: refurbishing one valve at SLC.
- 2018/2019: condition assessment, option analysis, preliminary design and cost estimates for the replacement/upgrade of the dewatering system at SLC in order to start the project in 2020.

The larger amount of capital expenditures incurred in 2016 is due to the higher scope of work in that year.

199.11 Please compare and contrast the projects undertaken in the "Other Auxiliary Equipment" category between the Current PBR Plan term and the proposed MRP term. As part of this response, please explain the expected decrease in spending in this category commencing in 2021.

Response:

The projects that FBC completed in the "Other Auxiliary Equipment" during the Current PBR Plan term included the following:

- Upgrade of fire panels which included the replacement and the upgrade of the fire panels to bring them into compliance with the ULC requirements.
- Replacement of UBO U3 Generator Step-Up Transformer, which included the replacement of a transformer that failed in 2016;

- Phone system upgrades, which included the installation of cellular phone boosters in the power houses;
- UBO Air System Upgrade project, which included the addition of an air compressor and air dryer, replacement of aged piping and valves;
- Battery bank upgrades, which included replacement of battery banks and installation of acid spill management equipment;
- UBO Station Service Circuit Breaker Decommissioning project, which included the removal of a redundant circuit breaker and modifications to the electrical system; and
- Fire safety upgrades which included the installation of fire rated doors, and the upgrade of fire egress and fire stopping.

Three projects are proposed for the MRP term as identified below:

- The Surveillance and Security project includes the upgrade of the current security system of security systems at FBC generation plants. The capital expenditures for this project are $0.872 million for the period 2020-2024. A similar project in the Current PBR Plan period is planned in 2019 at a cost of $0.030 million.
- The Sump Pump Upgrade project includes the addition of protection systems to the sump pumps. The capital expenditures for this project over the proposed MRP term are $0.014 million in 2021. A similar project in the Current PBR Plan period was started in 2015 and completed in 2017 for a total of $0.110 million.
- The DC Crane Control Upgrades project includes the replacement of the DC drives and PLC on the COR powerhouse crane. The capital expenditures for this project under the proposed MRP term are $0.331 million in 2020. A similar project in the Current PBR Plan term was started in 2016 and will continue in 2019 for a total of $1.113 million.

FBC’s expected decrease in spending in this category commencing in 2021 is related to the completion of the DC Crane Control Upgrades project at COR in 2020 for $0.331 million.

On page C-88 of the Application, FBC provides the following table:

Table C3-30: FBC Generation Buildings and Structures Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
COR Annex Building Replacement	$ 76	$ -	$ -	$ -	$ 198	$ 1,606
Floor Covers Replacement	223	349	116	116	349	116
Roof Replacement	-	62	291	233	233	233
Other Buildings and Structures Projects	354	143	393	797	187	140
Total	$ 653	$ 554	$ 800	$ 1,146	$ 966	$ 2,095

In response to BCUC IR 54.1, FBC provided the following table:

Table 5: FBC Generation Buildings and Structures Capital Expenditures Forecast 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
COR Annex Building Replacement	$ -	$ 111	$ 24	$ 176	$ 52	$ -
Floor Covers Replacement	-	-	-	25	468	177
Roof Replacement	-	-	-	-	-	-
Other Buildings and Structures Projects	760	763	504	695	177	189
Total	$ 760	$ 874	$ 528	$ 897	$ 697	$ 366

In response to BCUC IR 54.2, FBC described the Corra Linn Annex Building Replacement Project and stated that the Current PBR Plan did not include a similar project.

199.12 In consideration of FBC's statement in response to BCUC IR 54.2 regarding the Corra Linn Annex Building Replacement Project, please explain the expenditures incurred in years' 2015 through 2018 under the heading "COR Annex Building Replacement," as provided in Table 5 in response to BCUC IR 54.1.

Response:

FBC's 2015 and 2016 expenditures under the heading COR Annex Building Replacement in Table 5 in response to BCUC IR 1.54.1 related to assessment of the structural issues of the building and installing temporary support beams. The expenditures incurred in years 2017 and 2018 are related to a geotechnical assessment to determine the cause for the settling of the building foundation, an option analysis and development of a repair plan.

In response to BCUC IR 54.2, FBC described the "Floor Covers Replacement" Project and stated the following:

> In 2013 FBC received a WorkSafe BC order to address the floor covers situation at one of its third party plants. FBC has complied with the order and in 2017 FBC

replaced the floor covers installed on the tailrace deck at South Slocan. The Current PBR Plan did not include a similar project. The estimated cost of this project is approximately $1.0 million over the period 2020-2024.

199.13 Please clarify if the actual/projected capital expenditures incurred in 2018 and 2019 related to the Floor Covers Replacement project are related to the 2017 South Slocan floor covers installation described in response to BCUC IR 54.2.

Response:

FBC incorrectly stated that the floor covers at SLC have been replaced in 2017. The project to replace the floor covers installed in the tailrace at SLC started in 2017 and was completed in 2018. The 2019 projected costs are for the replacement of floor covers installed at the LBO tailrace.

199.13.1 If yes, please explain why the costs for this project spanned three years.

Response:

Please refer to the response to BCUC IR 2.199.13.

199.13.2 If no, please clarify FBC's statement that the Current PBR Plan did not include a similar project to the Floor Covers Replacement project planned for the proposed MRP term.

Response:

FBC`s statement referred to the capital expenditures described in FBC's 2014 PBR Application, which did not include a similar project. As explained in the response to BCUC IR 1.54.2, the need for this project was driven by a WorkSafeBC Order to address the floor covers at one of its third party plants in 2013. Subsequently FBC submitted a compliance plan to WorkSafeBC, which includes the following steps:

1. a review of the design and load rating of all the covers;
2. a plan to mark the load rating of each cover;

3. all mobile equipment with a weight of over 5000kg to have the GVW marked on its exterior; and
4. a communication plan to its workers to not place any loads on covers.

Between 2014 and 2016 FBC performed an engineered load capacity assessment for floor covers at all of the plants. The capacity of the floor covers has been identified by color coding of the floor covers. The majority of the existing floor covers have been determined to be suitable for foot traffic only and have been painted red with warning signs placed on the floor covers. The conclusion of the load capacity assessment was that the majority of the floor covers' capacity is inadequate for the locations they are installed when compared to present day regulations (such as Canadian Highway Bridge Design Code CSA-S6-14 for covers over large openings or ASME standard A112.6.3 for smaller covers) and FBC operating procedures.

200.0 Reference: FBC SUSTAINMENT CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 55.1; Exhibit B-5, BCOAPO IR 70.3.2; Exhibit B-1, pp. C-89 – C-90

FBC Transmission Sustainment Capital

On page C-89 of the Application, FBC provides the following table:

Table C3-32: FBC Transmission Line Rehabilitation Capital Expenditures Forecast 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
30 Line Rehabilitation	$ 500	$ 1,100	$ -	$ -	$ -	$ -
Other Transmission Line Rehabilitation	2,686	4,913	4,332	3,354	5,819	5,290
Total	$ 3,186	$ 6,013	$ 4,332	$ 3,354	$ 5,819	$ 5,290

On page C-90 of the Application, FBC states the following regarding the "30 Line Rehabilitation between the South Slocan and Coffee Creek Substations" project:

> This project includes expenditures for structural stabilization of the transmission line, based on the 2018 condition assessment. This includes stubbing poles and replacing poles and cross-arms. The total cost of this project is $2.6 million, with a forecast of $1.5 million in 2019 and $1.1 million in 2020, and an estimated in service date of 2020.

In response to BCOAPO IR 70.3.2, FBC stated the following:

> Transmission Line Rehabilitation costs are forecast by region, based on the number of poles in the prior year's condition assessment program and the inflation-adjusted historical unit cost of rehabilitation. As the number of structures to be rehabilitated cannot be known in advance, the unit costs are determined on the basis of poles assessed, which assumes a constant proportion of poles for rehabilitation to poles assessed. In the 2020-2024 term, additional funds have been included to replace insulators.
>
> The 83 percent represents the increase between 2020 and the average (2017-2019) for the Other Transmission Lines Rehabilitation. In 2020, the increase relates to the higher number of poles in the transmission lines that are going to be rehabilitated and the replacement of the insulators.

200.1 Please explain the condition assessment results that are driving the investment in the "30 Line Rehabilitation between the South Slocan and Coffee Creek Substation" project.

Response:

A list of the issues found on 30L as determined from the 2018 condition assessment inspections and follow-up reviews is as follows:

1. General repairs that include missing/deteriorated guy guards, missing structure tag numbers, cotter pins backing out or missing, fatigued vibration dampers, replacement of rotten cross-bracing, loose hardware, framing issues, conductor damage, etc.;
2. Defective porcelain bell insulators are present on some transmission structures and need to be replaced;
3. Older vintage poles showing significant signs of shell rot, internal rot, and rotten pole tops;
4. Structures requiring replacement due to: pole internal rot, poles/cross-bracing deteriorated, framing/design issues, significant pole top rot, and overall poor condition;
5. Clearance violations that require structure replacements with taller poles or new mid-span structures;
6. Poles requiring steel stub, or the steel banding deteriorating and to be replaced with wider straps; and
7. Marker balls damaged and in need of replacement.

200.2 Please explain whether condition assessments found any other transmission line sections in similar states of disrepair elsewhere in the FBC system.

Response:

Condition assessments are performed on an eight-year cycle. FBC assesses the condition of a particular transmission line and determines at that time if it is in need of repair. There are also aging infrastructure issues for older vintage transmission lines in the FBC system, which will need to be addressed and are identified through the condition assessments. In most cases transmission lines are maintained through the repair and replacement of individual poles or clusters of poles and infrequently through rehabilitation or rebuilding of larger sections of lines, such as the 30 Line Rehabilitation project.

FBC's 9L and 10L 63 kV transmission lines are also aged and deteriorated. FBC will be removing approximately 45 kilometers and repurposing to distribution 22 kilometers of these lines between the Christina Lake substation and the Cascade substation near Rossland as part of the Grand Forks Terminal Station Reliability project approved by Order C-2-19.

Approximately 80 structures between Christina Lake substation and Grand Forks terminal station will also be rehabilitated during the MRP term.

There are no other transmission lines requiring similar levels of rehabilitation at this time.

200.3 Please explain how decisions are made to prioritize rehabilitation of transmission lines based on condition assessment.

Response:

A number of transmission lines are condition assessed each year. The determination of which transmission lines should be prioritized for rehabilitation is based on voltage level (i.e., 230 kV lines completed first), system reliability, criticality of the line, and operational importance to the system.

Once a particular transmission line is selected for rehabilitation, the work is prioritized based on the necessity of the rehabilitations. When a transmission line is assessed, the rehabilitation work is categorized as urgent, priority or recommended. Urgent work should be addressed within six months since the deficiencies pose imminent dangers. Priority work is to be completed within the next year as part of the rehabilitation package. Recommended work is completed in a planned schedule over the next few years.

201.0 Reference: FBC SUSTAINMENT CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 56.1, 56.2; Exhibit B-1, pp. C-91 – C92

FBC Stations Sustainment Capital

FBC provides the following table on page C-92 of the Application:

Table C3-35: FBC Station (T&D) Transformer Replacement Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
AS Mawdsley Transformer Replacemer	n/a	$ -	$ -	$ -	$ -	$ 3,802
Trout Creek Transformer Replacement	n/a	2,263	-	-	-	-
Kaleden Transformer Replacement	n/a	-	-	-	-	2,716
Total	n/a	$ 2,263	$ -	$ -	$ -	$ 6,518

201.1 Please explain why the forecast cost for the “AS Mawdsley Transformer Replacement” is higher than any of the other planned transformer replacements during the proposed MRP term.

<u>Response:</u>

The factors causing a higher cost for the AS Mawdsley Transformer Replacement project include an upgrade of the transformer to a unit with a larger capacity (120 MVA) and diverter style tap-changers, requiring the foundation pad and bus connections to be reconstructed to accommodate the larger transformer. The AS Mawdsley transformers are also operated at a higher voltage level (161/63kV) as compared to the other two stations (20MVA units operated at 63/13kV and 63/8.6kV).

On page C-91 of the Application, FBC provides the following table:

Table C3-34: FBC Stations Sustainment Capital Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Station Urgent Repairs	$ 634	$ 574	$ 594	$ 687	$ 614	$ 655
Station Assessment/Minor Planned	1,209	1,317	1,354	1,394	1,419	1,438
Transformer Replacements	420	2,263	-	-	-	6,518
Salmo Station Upgrade	n/a	3,718	7,154	-	-	-
Fruitvale Station Upgrade	n/a	-	-	-	-	3,802
Station Equipment	2,652	5,667	4,522	3,198	1,760	3,559
Total	$ 4,915	$ 13,538	$ 13,624	$ 5,279	$ 3,793	$ 15,971

In response to BCUC IR 56.1, FBC provided the following table:

Table 1: FBC Stations Sustainment Capital Expenditures 2014-2019P ($000s)

	2014	2015	2016	2017	2018	2019P
Station Urgent Repairs	$ 676	$ 894	$ 553	$ 436	$ 897	$ 568
Station Assessment/Minor Planned	1,166	1,158	1,352	1,262	1,079	1,286
Transformer Replacements	-	-	-	1,261	-	-
Salmo Station Upgrade	-	-	-	-	-	-
Fruitvale Station Upgrade	-	-	-	-	-	-
Station Equipment	8,880	2,041	899	2,114	2,457	3,384
Total	$ 10,722	$ 4,093	$ 2,804	$ 5,072	$ 4,434	$ 5,238

In response to BCUC IR 56.2, FBC provided the following information regarding the planned station sustainment capital during the Current PBR Plan term:

> In the Current PBR Plan term, FBC executed, in addition to its ongoing Sustainment Capital programs, the following Station Sustainment Capital projects described in Section 5.4.3 of the FBC 2014-2018 PBR Application:
>
> - Environmental Compliance (PCB Mitigation) for stations;
> - Osoyoos 63 kV Breaker Addition; and
> - DG Bell 138 kV Breaker (CB13) and Voltage Transformer Addition.
>
> Of the above projects, the Environmental Compliance and Osoyoos 63 kV Breaker Addition projects were completed. FBC will execute the DG Bell 138 kV Breaker (CB13) and Voltage Transformer Addition project during the MRP term.

201.2 Please explain the drivers behind FBC's planned increase in the number of: (i) larger transformer replacements; and (ii) station upgrades during the proposed MRP term compared to the Current PBR Plan term (i.e. three transformer replacements and two station upgrades compared to the three projects listed in response to BCUC IR 56.2).

Response:

The drivers behind the increases are discussed below.

1. As noted in the Application, Station Transformer Replacements are triggered by "…condition assessment which includes asset health, reliability, age, risk of failure, loading, outdated load tap changers and the impact to the FBC system. Specific planned expenditures for each transformer replacement are identified after completion of the condition assessment in the previous year." The historical rate of transformer replacement was not a consideration in determining the number of replacements required in the MRP term. Asset condition is the driver for the three proposed replacements.
2. Similarly, station upgrades in the MRP term are driven by asset condition as described in the Application. The historical rate of station upgrades was not a consideration when

identifying these two station upgrade projects. These two projects also allow for the decommissioning of Ymir and Hearns stations as described in the Application.

201.3 In consideration of the fact that only two of the three identified Station Sustainment Capital projects were completed during the Current PBR Plan term, please explain in detail the likelihood that FBC will be able to complete all of the planned Station Sustainment Capital projects during the proposed MRP term.

Response:

FBC is confident that that all of the planned Station Sustainment Capital projects can be completed during the proposed MRP term. It is important to note that it was not a lack of labour resources or technical constraints that resulted in the DG Bell 138 kV Breaker and Voltage Transformer Addition project being moved from the Current PBR Plan term to the proposed MRP term. The decision to defer was made in response to ongoing capital pressure.

201.4 Please explain, with specific reference to the planned projects provided in Table C3-34 of the Application, if the need for any of these projects arose during the Current PBR Plan term (i.e. subsequent to the FBC PBR Decision being issued) but the project(s) was deferred by FBC due to capital formula spending pressures.

Response:

The need for two of the projects listed in Table C3-34 of the Application arose during the Current PBR Plan term. These projects are the Salmo Station Upgrade and Fruitvale Station Upgrade. Based on asset condition data, the timing of these projects in the proposed MRP term is appropriate. As such, these projects were not deferred by FBC due to capital formula spending pressures.

The Station Urgent Repairs, Station Assessment/Minor Planned, Transformer Replacements and Station Equipment items listed in Table C3-34 are ongoing programs that were identified prior to the Current PBR Plan term and were not deferred by FBC due to capital formula spending pressures. However, some projects categorized as flexible within the Station Assessment/Minor Planned program have been deferred into 2020-2024.

202.0 Reference: FBC SUSTAINMENT CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 57.13; Exhibit B-1, pp. C-95 – C-98; FBC PBR Application proceeding, Exhibit B-1, p. 202

FBC Distribution Sustainment Capital

On page C-97 of the Application, FBC states the following regarding the "Environmental Compliance – Distribution Equipment (PCB)" project:

> The federal PCB Regulations (SOR/2008-273) came into force on September 5, 2008. As per the PCB Regulations, the release of one gram of PCBs into the environment is prohibited. This prohibition applies to all PCBs, without exception and at all times, including during the conduct of activities permitted by the PCB Regulations. Although pole mounted transformers have an in-service exemption until 2025, the one-gram release prohibition still applies.
>
> FBC has approximately 38,600 pieces of oil-filled distribution-class field equipment including transformers (pole and padmount), reclosers, capacitors banks, metering units and regulators. Currently, the PCB level for the majority of the equipment has been confirmed through testing or nameplate information. The proposed expenditures for this project are for the remediation plan which begins in 2019.

202.1 Please confirm, or explain otherwise, that all 38,600 pieces of oil-filled distribution-class field equipment will be remediated of PCBs through this remediation plan.

Response:

FBC confirms that all 38,600 pieces of oil-filled distribution-class field equipment will be remediated of PCBs through the remediation plan. Pursuant to the regulation, equipment with a PCB contamination of 50 ppm or more will be replaced.

202.2 Please provide the date when this remediation plan will be completed.

Response:

The remediation plan will be completed by the end of 2025, at which time FBC will have met the requirements of the regulations regarding the use of PCBs as set by Environment Canada.

202.3 Please explain whether FBC has any other PCB-containing equipment classes that will require remediation that will have not yet been remediated at the end of the remediation plan described in the above preamble.

Response:

Please refer to the response to BCUC IR 2.202.2.

On page 202 of the FBC PBR Application, FBC described Small Planned Capital expenditures as follows:

> The planned expenditures for this project are based on a three-year rolling average of historical expenditures, adjusted for inflation. The three-year rolling average method is used to derive this budget as FBC is unable to predict the variables in the future that would affect this budget. Using historical spending patterns to predict the basis of future years budgets is the most reasonable approach from FBC's perspective.

202.4 Please explain if FBC has utilized the same approach to forecast Distribution Small Planned Capital expenditures for the proposed MRP term (i.e. a three-year rolling average adjusted for inflation).

Response:

Yes, FBC used a three-year rolling average method, adjusted for inflation and other known requirements to derive the proposed Small Planned Capital budget for the MRP term.

The table below provides the calculated values for the Distribution Small Planned Capital. Forecast expenditures in nominal dollars are calculated as a rolling three-year average, with 2020 based on the average of the last three complete years (2016 – 2018) and future nominal forecasts on the next three-year period throughout the MRP term. FBC used a general inflation rate of 2 percent for escalation. Because cost of removals were included in capital expenditures during the Current PBR Plan, an adjustment has been made to remove costs of removal from the 2020 – 2024 estimates in order to align the definition of capital expenditures as presented in the capital plan.

Year	2016	2017	2018	2019P	2020	2021	2022	2023	2024
Inflation	0.924	0.942	0.961	0.980	1.000	1.020	1.040	1.061	1.082
Actual/Projected Gross Expenditures ($nominal)	0.722	0.872	0.825	0.916					
Actual/Forecast Expenditures ($2020)	0.782	0.925	0.858	0.934	0.855	0.906	0.883	0.898	0.881
Forecast Expenditures ($nominal)					0.855	0.924	0.918	0.953	0.954
Porcelain Cut-Out Replacement					0.280	0.280	0.280	0.280	0.431
Direct Overhead					0.074	0.087	0.106	0.107	0.112
Cost of Removal					(0.175)	(0.186)	(0.094)	(0.095)	(0.000)
Table C3-37 of the MRP Application					1.034	1.105	1.210	1.245	1.497

FBC notes that the Porcelain Cut-Out Replacement program is shown as a separate line in Table C3-37 and therefore, there is a duplication of the amounts that were included in Table C3-37 between that line and the Distribution Small Planned Capital line. The Distribution Small Planned Capital line includes $0.280 million of expenditures to replace the highest-risk porcelain cutouts in each year from 2020 to 2023 and $0.431 million of expenditures in 2024, as shown in the table above.

Upon approval of FBC's forecast capital for inclusion in rates over MRP term, FBC will update its Small Planned Capital program forecast to remove the duplication of costs noted above when seeking 2020 permanent rates. If the forecast capital for the separate Porcelain Cut-out Replacement project is not approved for inclusion in rates, it will be necessary to continue with the replacement of the highest risk cut-outs under the Small Planned Capital program, as they pose a severe safety risk to FBC's employees and/or contractors when conducting line work.

202.4.1 If yes, please provide the supporting calculations and compare the calculated results to the expenditures provided in Table C3-37 on page C-95 of the Application.

Response:

Please refer to the response to BCUC IR 2.202.4.

202.4.2 If no, please explain why not and please provide the annual forecast expenditure amounts for the proposed MRP term using the above-described approach.

Response:

Please refer to the response to BCUC IR 2.202.4.

Table C3-37 on page C-95 of the Application provides FBC's annual forecast expenditures for Porcelain Cutouts Replacement.

202.5 Please provide a more detailed breakdown and description of the annual forecast expenditures for the Porcelain Cutouts Replacement project, including the basis upon which FBC derived its forecast for expenditures.

Response:

As described in the Application, the annual forecast expenditures shown in Table C3-37 are based on the replacement of approximately 2,000 porcelain cutouts per year. An all-in replacement cost of approximately $1,600 per cutout replacement was based on historical actuals for limited cutout replacements performed in recent years.

A breakdown of the forecast cost for the first year of the program is provided below as an example:

	($ millions)
Labour	$ 0.950
Material	1.150
Project Management, GIS Updates, Contingency	0.900
Direct Overheads	0.233
Total	$ 3.233

On page C-98 of the Application, FBC states the following regarding Meter Exchanges expenditures:

> The AMI project was complete in 2016; therefore, FBC has not had to exchange any meters for compliance purposes during the 2014 – 2019 period. Instead, FBC has only had expenditures for meters and ancillary equipment to cover meter damage, and meter failures. Beginning in 2020 FBC will begin the compliance sampling program again.

In its response to BCUC IR 57.13, FBC stated the following:

> Measurement Canada regulations require that FBC begin sampling any type of meter, including AMI meters, prior to their seal expiry to ensure ongoing accuracy. The need to resume the meter exchange program has been expected and the costs were included in the project financial analysis in the CPCN application.

202.6 Please describe the sampling program required by Measurement Canada, including intervals of sampling, number of meters required to be sampled, process, and costs.

Response:

Measurement Canada S-S-06 - Sampling Plans for the Inspection of Isolated Lots of Meters in Service is the legal specification for Compliance Sampling meters in Canada. This specification establishes the requirements that are applicable to sampling of electricity or gas meters, where a meter owner has chosen to utilize sampling inspection for the purposes of extending the reverification period of an in-service lot of meters.

Costs for sample activities have been budgeted at $72 thousand per year. Please refer to the response to BCUC IR 2.202.7 for a breakdown of other related costs.

The table below details the number of meters to be removed per year, and the number of meters represented by the sample tests.

Year	Number of sample Meters (N min)	Sample size
2020	400	Test year for sample program
2021	400	31,000
2022	400	36,000
2023	400	36,000
2024	400	36,000

202.7 For each year of the proposed MRP term, please provide a breakdown of the Meter Exchanges costs into the following categories (please ensure that the total annual amount agrees with Table C3-37 of the Application):

- Meter damage-related costs;

- Meter failure-related costs;
- Compliance sampling-related costs; and
- Other (if applicable).

Response:

FBC does not currently have a system that can discern between meter damage and meter failure related costs. The table below shows forecast costs (in $ thousands) for 2020 to 2024, including a line showing the compliance sample costs.

	2020	2021	2022	2023	2024
Meter Damage and Meter Failure related costs	$ 30	$ 30	$ 30	$ 30	$ 30
Compliance Costs	72	75	85	85	86
Customer driven exchanges: relocated services, or load changes	25	25	25	25	25
Total	$ 127	$ 130	$ 140	$ 140	$ 141

203.0 Reference: FBC SUSTAINMENT CAPITAL EXPENDITURES

Exhibit B-10, BCUC IR 58.1; Exhibit B-1, pp. C-99 – C-101; FBC PBR Application proceeding, Exhibit B-1, pp. 205–206

FBC Telecommunications Sustainment Capital

On page 205 of the FBC PBR Application, FBC stated the following regarding System Smart Device Upgrades:

> FBC still has a number of electromechanical and electronic relays that do not meet current monitoring and protection standards. Replacement of these relays is a priority and will facilitate Operations, Engineering and Planning efficiencies and enhance system reliability by providing co-ordination of protective devices, accurate information and real time telemetry on system status, faults and other problems and decreasing the need for complex protection schemes.

On page C-99 of the Application, FBC provides the following table:

Table C3-38: FBC Telecommunications Expenditures 2020-2024 ($000s)

	Average 2017-2019P	2020	2021	2022	2023	2024
Communications Upgrades	$ 247	$ 367	$ 379	$ 390	$ 397	$ 402
Station Smart Device Upgrades	428	323	380	329	328	326
SCADA Systems Sustainment	570	937	945	1,685	970	1,451
Systems Upgrades and Replacements	1,086	-	1,086	3,677	4,016	1,086
Other Telecommunications	186	190	194	200	204	206
Total	$ 2,516	$ 1,818	$ 2,983	$ 6,280	$ 5,915	$ 3,472

203.1 In consideration of FBC's statements in the FBC PBR Application that the System Smart Device Upgrades were a priority, please explain why FBC did not complete these upgrades during the Current PBR Plan term.

Response:

FBC did undertake the Smart Device Upgrades during the Current PBR Plan term as an ongoing program with a fixed budget each year; the program continues through the MRP term. This program is in place to address aging and failing station protection, control and metering equipment. Deficiencies identified by Operations and Engineering are prioritized and added to this program for resolution as the budget allows.

203.2 Please explain if FBC expects the System Smart Device Upgrades project to continue beyond the end of the proposed MRP term.

Response:

FBC confirms that the Smart Device Upgrades project will continue beyond the end of the proposed MRP term because it is an ongoing program.

In response to BCUC IR 58.1, FBC stated: "The 2019 Telecommunications expenditures include the acquisition of existing fibre optic cable on FBC's transmission lines."

FBC states on page C-100 of the Application with reference to "Systems Upgrades and Replacements" that "included in this category is the 2019 acquisition of fibre optic cable on FBC's transmission lines between Vernon and Penticton and some fibre spans near Christina Lake and Castlegar."

203.3 Please provide the total projected 2019 expenditures related to the acquisition of fibre optic cable.

Response:

The 2019 projected expenditure for this project is $2.815 million.

On pages C-100 and C-101 of the Application, FBC describes three projects which it states are in excess of $1 million included in the forecast capital expenditures for Systems Upgrades and Replacements during the proposed MRP term.

203.4 Please provide a more detailed breakdown of the annual Systems Upgrades and Replacements expenditures forecast for the proposed MRP term. Please specifically identify the costs related to the three projects above $1 million as part of the breakdown.

Response:

The table below details the forecast expenditures (in $ thousands) for the Telecommunications System Upgrades and Replacement expenditures. As shown in the table below, the three projects over $1 million are the only projects in this category.

	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	$ -	$ -	$ 937	$ 953	$ -
SCADA System Replacement	-	1,086	2,192	2,188	1,086
VHF Radio System Replacement	-	-	548	875	-
Total, Systems Upgrades and Replacements	$ -	$1,086	$3,677	$4,016	$1,086

On page 206 of the FBC PBR Application, FBC described the Backbone Transport Technology Migration project and stated: "This project will replace FBC's existing SONET network with a new high speed data network supporting all present and anticipated future applications needed to provide safe and reliable service."

On pages C-100 and C-101 of the Application, FBC describes the Backbone Transport Technology Migration project and states: "This project will replace FBC's existing SONET network with a new high-speed data network supporting all present and anticipated future applications needed to provide safe and reliable service."

203.5 Please clarify if the project described in the current Application is the same project that was described in the FBC PBR Application.

Response:

The project described in the current Application is the same project that was described in the FBC PBR Application.

203.5.1 If the projects are the same, please explain why the project was not completed as planned during the Current PBR Plan term.

Response:

The project was not completed during the Current PBR Plan term since FBC was able to get a commitment from the vendor of the legacy SONET equipment to continue supporting the product for several more years. This allowed FBC to defer the expenditures associated with the replacement of the equipment. With this option available, the decision was made to defer the Backbone Transport Technology Migration to allow higher priority or more time sensitive projects to move forward.

203.5.2 If the projects are the same, please explain whether the cost to deliver the project has increased as a result of being deferred from the Current PBR Plan to the proposed MRP and if so, why.

Response:

Except for the impact of inflation, the cost to deliver the Backbone Transport Technology Migration has not increased as a result of being deferred from the Current PBR Plan. However, as indicated in the response to BCUC IR 2.203.6, some additional expenditures were required to ensure short and medium term substation communications needs were met during the deferral timeline.

Significant technological risk is being mitigated through the deferral of this project as there are several different technological options available to migrate the legacy system to. Many utilities are in the midst of this migration now and the deferral will allow FBC to take advantage of their learnings as well as benefit from evaluating mature solutions. Accordingly, FBC expects the savings from the deferral of this project to offset any additional expenditures required.

203.6 Please explain if any expenditures related to the Backbone Transport Technology project were incurred during the Current PBR Plan term and if so, please provide the amounts and the year(s) that the expenditures were incurred.

Response:

To provide for the immediate and medium term data needs and to facilitate the deferral of the replacement of the legacy system, the current system was supplemented in 2018 at a cost of $0.370 million.

F. ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

204.0 Reference: OTHER REVENUE

Exhibit B-10, BCUC IR 6.3.1, 63.5

Forecast versus Actual Results

In response to BCUC IR 63.5, FortisBC provided the following tables showing the cumulative forecast versus actual variances for Other Revenue for FEI and FBC during the Current PBR Plan term:

FEI	2017 Forecast	2017 Actual	2017 Variance	2018 Forecast	2018 Actual	2018 Variance	Total Variance
Other Revenue							
Late Payment Charge	(2,180)	(2,750)	(570)	(2,688)	(2,583)	105	(1,233)
Connection Charge	(3,118)	(3,139)	(21)	(3,148)	(2,875)	273	55
NSF Returned Cheque Charge	(76)	(91)	(15)	(80)	(80)	-	51
Other Recoveries	(243)	(229)	14	(288)	(269)	19	(42)
NGT Tanker Rental Revenue	(448)	(307)	141	(583)	(544)	39	119
NGT Overhead and Marketing Recovery	(332)	(346)	(14)	(320)	(325)	(5)	(132)
Depreciation on all Plant but Tilbury Expansion	168,190	166,339	(1,851)	177,092	175,686	(1,406)	(5,349)
Interest Expense	122,183	122,947	764	134,461	135,880	1,419	503
Income Taxes	35,651	40,654	5,003	50,137	56,649	6,512	22,014
Total	**319,627**	**323,078**	**3,451**	**354,583**	**361,539**	**6,956**	**15,986**

FBC	2017 Forecast	2017 Actual	2017 Variance	2018 Forecast	2018 Actual	2018 Variance	Total Variance
Other Revenue							
Apparatus and Facilities Rental	(4,576)	(4,808)	(232)	(4,736)	(5,808)	(1,072)	(2,479)
Contract Revenue	(1,865)	(1,915)	(50)	(1,769)	(1,939)	(170)	(1,328)
Transmission Revenue	(1,179)	(1,190)	(11)	(1,170)	(1,111)	59	135
Interest Income	(24)	(43)	(19)	(16)	(29)	(13)	(114)
Connection Charges	(270)	(606)	(336)	(368)	(589)	(221)	(1,465)
Other Recoveries	(142)	(1,162)	(1,020)	(356)	(663)	(307)	(729)
Depreciation	56,046	55,980	(66)	58,408	58,802	394	3,272
Interest Expense	40,191	38,127	(2,064)	40,059	40,069	10	(5,647)
Income Taxes	10,849	12,201	1,352	9,633	12,545	2,912	4,067
Total	**99,030**	**96,584**	**(2,446)**	**99,685**	**101,277**	**1,592**	**(4,288)**

In response to BCUC IR 63.1, FortisBC stated that the criteria used to determine which variances would: (i) flow through in future revenue requirements, (ii) be subject to earnings or sharing, or (iii) be subject to other treatment were based on the following:

- Whether the treatment aligned with the proposed earnings sharing mechanism;
- Consideration of which costs are controllable; and
- Whether the costs drive incremental revenues or are more generally supportive of Clean Growth initiatives.

204.1 With regard to FEI's (i) Late Payment Charge, (ii) Connection Charge, (iii) NSF Returned Cheque Charge and (iv) Other Recoveries, please explain how each of these items relates to each of the three criteria described in the above preamble.

Response:

FortisBC did not intend that all three criteria listed in the response to BCUC IR 1.63.1 would apply to each revenue requirement line item where a change was being proposed. The three criteria were the general criteria that were considered, and which one was relevant would depend on the line item.

FortisBC was conveying that:

- For certain capital related variances, it was due to "alignment with the proposed earnings sharing mechanism";
- For certain other revenue and expense line items, it was due to the fact that FortisBC has a degree of control and that incenting performance in that area may be able to achieve further savings for customers; and
- For certain other revenue and expense line items, it was due to the incremental revenues they are associated with or that they support Clean Growth Initiatives which are flow-through.

Specifically, FEI sets out below its rationale for the three line items requested in this IR;

- Late Payment Charges and NSF Returned Cheques – change in treatment is due to FEI being able to influence the level of these revenues. FEI works with customers to provide opportunities and solutions that support continuation of services and payment arrangements which affects the amount of late payment charges and returned cheque fees recovered.
- Connection Fees – change in treatment is due to FEI being able to influence the level of these revenues. FEI plays a role in customer growth through engagement initiatives and through working with customers, developers, larger customers, and new industries.
- Other Recoveries – change in treatment is due to FEI being able to influence the level of these revenues. FEI identifies opportunities to recover costs for non-recurring services. Further, consistent with supporting Clean Growth Initiatives, revenues related to activities such as NGT and Renewable Gas continue to be flowed through.

204.1.1 As part of the above response, please specifically address how each of the above items is "controllable,"

Response:

Please refer to the response to BCUC IR 2.204.1.

204.2 Please explain the cause(s) of the large variances in forecast versus actual Late Payment Charges for FEI in 2014 and 2017.

Response:

Late Payment Charges are forecast using the average of the most recent three-year actual results, expressed as a ratio of overall total revenues in a year. Thus, forecast late payment charges will reflect recent experience rates multiplied by weather normalized revenue projections for the year. This compares to actual late payment charges that will reflect actual revenue, consumption and general economic conditions and, to the extent that these factors are different from recent experience, they will contribute to variances between forecast and actual late payment charges.

While larger variances occurred in 2014 and 2017, much smaller variances were seen in 2015 and 2018, a $3 thousand and $105 thousand variance, respectively.

FEI notes that in both 2014 and 2017 larger balances of bad debt expense relative to other years (2015, 2016 and 2018) were also experienced. This may indicate that the cause of the larger variance between forecast and actual late payment charges in 2014 and 2017 may have been impacted by larger changes in the economy or consumption relative to the three most recent preceding years.

204.3 With regard to FBC's (i) Apparatus and Facilities Rental Revenue, (ii) Contract Revenue, (iii) Connection Charges and (iv) Other Recoveries, please explain how each of these items relates to each of the three criteria described in the above preamble.

Response:

Please refer to the response to BCUC IR 2.204.1 which discusses in general terms the applicability of the three criteria to revenue requirements line items.

FBC sets out below its rationale for the four line items requested in this IR:

1. Apparatus and Facilities Rental Revenue – change in treatment is due to FBC being able to influence the level of these revenues. Rental rates are set by contract with third

parties and the management of attachments is partly controllable by FBC, which affects the amount of revenue.

2. Contract Revenue – change in treatment is due to FBC being able to influence the level of these revenues. Fee structures are set by contract with third parties; the volume of work performed and management of resources are partly controllable by FBC, which affects the amount of revenue.
3. Connection Fees – change in treatment is due to FBC being able to influence the level of these revenues. FBC plays a role in customer growth through engagement initiatives and through working with customers, developers, larger customers, and new industries.
4. Other Recoveries – change in treatment is due to FBC being able to influence the level of these revenues. FBC identifies opportunities to recover costs for non-recurring services. Further, consistent with supporting Clean Growth Initiatives, revenues related to activities such as Electric Vehicle Charging Stations will be flowed through.

204.3.1 As part of the above response, please specifically address how each of the above items is "controllable."

Response:

Please refer to the response to BCUC IR 2.204.3.

204.4 Please explain the cause(s) of the following large variances in forecast versus actual Other Revenues for FBC:

- Apparatus and Facilities Rental Revenues in 2014 and 2018;
- Contract Revenue in 2014;
- Connection Charges in 2014 (i.e. why were no Connection Charges forecast in 2014); and
- Other Recoveries in 2017.

Response:

Apparatus and Facilities Rental Revenues were higher than forecast by $0.664 million in 2014 and were higher than forecast by $1.072 million in 2018.

- In 2014, as explained in Section 5.2 of FBC Annual Review for 2015 Rates application, the actual revenues were higher than forecast primarily due to a reconciliation of billings for unreported contacts as determined during an audit of pole contacts that was completed during 2014. This updated billing amount was not known when the forecast was set for 2014 revenue requirements.
- In 2018, the increase related to higher than forecast unit rental rates that are determined each year, as well as additional billings for unreported contacts as determined during an audit of pole contacts that was completed near the end of 2018. These increases to billed amounts during 2018 were not known when the forecast was set for 2018 revenue requirements.

Contract Revenue in 2014 was higher than forecast by $0.691 million due to an increased scope of work performed at both the Waneta and Brilliant plants, which related primarily to capital work on refurbishment and upgrades of spillgates at both plants. Annual budgets and work scope for Waneta and Brilliant are determined through a planning committee comprised of the owners of the plant and FBC, and the increase from forecast was due to timing of when budgets were approved compared to when the forecast was set for 2014 revenue requirements.

Connection Charges in 2014 were forecast as part of Other Recoveries in the above table, as explained in Section C3.4 of FBC's 2014-2018 Multi-Year PBR Plan application. The table provided in the response to BCUC IR 1.63.5 that shows Connection Charges being higher than forecast by $0.619 million also shows a lower than forecast variance for Other Recoveries of $0.537 million because of how Connection Charges were grouped in forecast versus actual. Netting these two variances together provides a net variance of $0.082 million.

Other Recoveries in 2017 were higher than forecast by $1.020 million due to management fees earned in 2017 and 2018 from construction work for a third party. As explained in Section 5.6 of FBC's Annual Review for 2018 Rates application, this work related to the upgrading of a substation owned by a city in FBC's service territory, performed under a one-time contract. The income from the work wasn't forecast at the time of setting 2017 revenue requirements as the contract wasn't yet executed. The work resulted in approximately $1.1 million in management fees from the one-time contract, with approximately 80 percent earned in 2017 and the remaining 20 percent earned in 2018.

205.0 Reference: FLOW-THROUGH EXPENSES

Exhibit B-1, pp. C-112–C-113

Renewable Natural Gas (RNG)

On pages C-112 and C-113 of the Application, FEI describes the RNG program costs as follows under the Current PBR Plan:

> These costs are ultimately transferred to the BVA [Biomethane Variance Account] for recovery from biomethane customers through the BERC [Biomethane Energy Recovery Charge] rate, with any unrecovered balances transferred to the BVA Rider deferral account and recovered from non-bypass rate payers through the BVA rider…
>
> …FEI recommends that the BVA transfer mechanism should continue.

205.1 Please provide the following actual/projected amounts for each year of the Current PBR Plan term:

- Operating costs to support the RNG program;
- Capital costs to support the RNG program;
- Total amount of costs recovered from biomethane customers through the BERC rate; and
- Unrecovered balance transferred to the BVA Rider deferral account and recovered from non-bypass ratepayers.

Response:

The following table includes the operating costs, annual capital expenditures, total BERC recoveries and BVA balance transfers. The data is sourced from previously submitted reports to the BCUC including the Annual Reviews for the Current PBR Plan period. Years 2014 through 2018 are Actual and 2019 is a Projection.

$000s						
Item	2014	2015	2016	2017	2018	2019P
Operating Cost to Support RNG Program[51]	761	185	696	771	1,314	1,100
Capital Expenditures to Support the RNG Program[52]	3,656	1,350	1,346	965	45	12,861
BERC Recoveries[53]	1,645	2,167	2,147	2,451	2,771	4,683
BVA Balance Transfers[54]	-	-	2,203	1,867	2,702	2,228

51 Category titled Direct Biomethane Admin in the Confidential Portion of the BVA Status Report, 2019 Projected

52 From Annual Review for 2019 Delivery Rates Application (2014 – 2017 amounts from page 79, Table 10-2, Line 25 and 2019 amount from page 58, Table 7-4, Lines 2 + 3), 2018 amount from FEI BCUC Annual Report.

53 2014 – 2018 amounts from BVA Status Report and 2019 amount from FEI Q4 2018 Gas cost Report

54 2016 – 2018 amounts from BVA Status Report and 2019 amount from FEI Q4 2018 Gas Cost Report

206.0 Reference: RATE PLAN PROJECTIONS

Exhibit B-1, pp. C-173–C-174; Exhibit B-1-3, Errata dated June 21, 2019

2020 Rate Changes

On pages C-173 and C-174 of the Application, FortisBC provides the indicative 2020 rate changes for FEI and FBC, respectively. For FEI, the indicative 2020 rate change is 5.3 percent and for FBC, the indicative 2020 rate change is 4.0 percent.

On page C-172 of the Application, FortisBC states the following:

> These projected rate impacts for 2020 should be considered indicative only and will be updated in FortisBC's future requests for interim rates to be filed later in 2019. The Companies may also propose the utilization of part or all of their respective revenue surplus deferral accounts, which is not included in these indicative rates, to mitigate the rate increases.

206.1 Please explain if the indicative rate increases provided on pages C-173 and C-174 of the Application have changed since the filing of the Application.

Response:

No, the indicative rate increases provided in the Application have not changed. FBC stated in its response to BCMEU IR 1.17.1 that the rate projections would be updated in the Companies' requests for interim rates, which will be filed in October 2019. FortisBC demonstrates in its response to BCUC IR 2.206.1.1 that the errata filed in this Application do not have a measurable impact on the indicative rate increases.

206.1.1 If yes, please provide a revised Table C9-1 and C9-2 as an Application erratum. As part of this erratum, please include the results of any applicable revisions filed in the Errata dated June 21, 2019.

Response:

The Errata dated June 21, 2019 did not have any measurable impact on the indicative rate increases. Revised Tables C9-1 and C9-2, updated for the June 21, 2019 Errata, showing 2020 indicative rate changes for FEI and FBC are provided below. In addition to the adjustments for the Errata, the tables also include a correction for a misclassification of costs in the original tables affecting the Net O&M and Other line items but which do not impact the total rate change.

FEI's revenue deficiency decreases by $0.471 million as a result of:

- the recalculation of Base O&M as set out in the revised Table C9-1 on page C-19 (a decrease of $0.537 million); and
- the change in Cash Working Capital Requirements as set out in the revised Schedule II-1 to Appendix D3-1 (a decrease of $0.66 million).

The indicative 2020 delivery rate change remains the same at 5.3 percent.

Revised Table C9-1: FEI Indicative 2020 Delivery Rate Change

Particulars	Revenue Requirement $ millions
PBR/MRP Plans	
Resetting Rate Base	2.0
Resetting Base O&M	(0.7)
Subtotal	1.3
Studies	
Depreciation Study	3.5
Shared Services Study	(0.3)
Corporate Services Study	0.3
Cash Working Capital - Lead-Lag Study	(0.1)
Subtotal	3.4
Projected Revenue Requirements	
Customer Growth and Volume - Margin	3.4
LMIPSU - Coquitlam and Burnaby portions	32.2
Rate Base Growth	7.2
Net O&M	4.2
Deferral Accounts	(0.6)
Other	(8.3)
Subtotal	38.2
Total	42.8
Margin @ Existing Rates	810.4
Approximate Delivery Rate Change	5.3%

A revised Table C9-2, updated for the June 21, 2019 Errata, which shows the 2020 indicative rate change for FBC is provided below.

FBC's revenue deficiency decreases by $0.016 million as a result of:

- the recalculation of Base O&M as set out in the revised Table C2-14 on page C-44 of the Errata dated June 21, 2019.

The indicative 2020 rate change remains the same at 4.0 percent.

Revised Table C9-2: FBC Indicative 2020 Rate Change

Particulars	Revenue Requirement $ millions
PBR/MRP Plans	
Resetting Rate Base	0.6
Resetting Base O&M	0.9
Subtotal	1.5
Studies	
Depreciation Study	2.2
Shared Services Study	0.3
Corporate Services Study	(0.3)
Cash Working Capital - Lead-Lag Study	0.1
Subtotal	2.3
Projected Revenue Requirements	
Net Margin (Revenue less Power Supply)	1.9
Corra Linn Spillway Gates/UBO Refurbishment	1.6
Rate Base Growth	3.4
Net O&M	0.4
Deferral Accounts	4.1
Other	(3.3)
Subtotal	11.0
Total	14.9
Margin @ Existing Rates	373.3
Approximate Rate Change	4.0%

FortisBC has also included the revised Tables C9-1 and C9-2 in an Errata filed concurrently with these IR responses.

206.1.2 If no, please revise Tables C9-1 and C9-2 to the Application to reflect the results of any applicable revisions filed in the Errata dated June 21, 2019.

Response:

Please refer to the response to BCUC IR 2.161.1.

G. FORTISBC CLEAN GROWTH INNOVATION FUND

207.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 2.2, 2.4, 26.10, 70.6, 71.5.1, 77.5, 77.6, 81.1, 81.2; Exhibit B-6, BC Sustainable Energy Association and Sierra Club BC (BCSEA) IR 21.5; Exhibit B-5, BCOAPO IR 85.2; Exhibit B-1, pp. C-142–C-143;

Exhibit B-1-1, Appendix C6-1, C6-4

Benefits of the Innovation Fund[55]

In response to BCOAPO IR 85.2, FortisBC stated the following:

> The goals of the Clean Growth Innovation Fund are described on page C-128: "… to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe and reliable solutions for our customers." These goals directly benefit FortisBC customers and British Columbians in general. The goals do not directly benefit the utility shareholder.
>
> It is in the best interest of customers, the Utilities and society for the Utilities to pursue projects which address strategic and emerging issues, serve customer needs, and maintain the long-term health of the Utilities. In this regard, FortisBC believes its interests are aligned with its customers.
>
> For these reasons, FortisBC believes it is appropriate for the costs to be paid by ratepayers. [Emphasis Added]

On page C-142 of the Application, FortisBC states the following:

> The purpose of the Fund is to ensure there are opportunities for FortisBC to participate and thrive in an evolving climate policy context by continuing to utilize its natural gas and electric delivery systems. [Emphasis Added]

In addition, on page C-143 of the Application, FortisBC notes that the Concentric report (Appendix C6-1 to the Application) states that innovative technology programs "de-risk investments" for both customers and shareholders.

207.1 Please explain why "maintaining the long-term health" and ensuring there are opportunities for FortisBC to "thrive in an evolving climate policy context" do not represent direct benefits to the utility shareholder.

---

[55] The proposed Clean Growth Innovation Fund is also referred to as the Innovation Fund and the Fund in this document.

Response:

FortisBC's response to BCOAPO IR 1.85.2 explained that customers, who consume the Companies' energy products and services on a daily basis, receive the direct benefits of innovation. Shareholders benefit indirectly and over the long term as the Utilities remain in existence and continue to thrive, allowing shareholders the opportunity to earn a fair return on their investment. In this respect, like all other utility investments, the shareholder must provide the requisite equity investment for any utility asset, including those resulting from innovation.

207.1.1 To the extent that innovation activities do benefit shareholders, please discuss how shareholders will contribute to innovation during the proposed MRP term (i.e. financial or other contribution).

Response:

Please refer to the response to BCUC IR 2.207.1.

In response to BCUC IR 70.6, FortisBC stated: "Customers, and British Columbians in general, should benefit quickly from commercial innovations such as increased use of natural gas for transportation and electric fleet vehicles."

207.2 Given that successful commercial innovations are expected to lead to new streams of revenue and net income, please explain what the potential benefits to shareholders would be from commercial innovation. If there are no benefits, please explain why not.

Response:

As discussed in the response to BCUC IR 2.207.1, successful commercial innovations that directly benefit customers and British Columbians in general also indirectly benefit shareholders over the long-term. More specifically, successful commercial innovations can lead to new growth opportunities for which the utility provides the requisite capital, and in return, earns a return on its investment.

In response to BCUC IR 2.4, FortisBC stated the following:

> Yes, if left unmitigated, the evolving operating environment and the impacts of the CleanBC Plan have the potential to create an increased risk of stranded assets over the long term by constraining FEI's ability to attach, retain, and deliver energy to its customers… While policy developments continue to evolve and unfold. FortisBC's alternatives for mitigating the increased risk of stranded assets include:
>
> - Developing pathways to pay for the early retirement of assets, and/or
> - Developing alternative energy products and services that leverage existing assets while also reducing emissions…
>
> FEI's response has appropriately focussed on developing alternative energy products and services that leverage its existing assets including reducing their lifecycle carbon intensity. This strategy is reflected in FortisBC's MRPs…

207.3 Given the two alternatives for mitigating the increased risk of stranded assets identified in response to BCUC IR 2.4, please provide the pros and cons of each alternative from the perspective of ratepayers and from the perspective of the utility, and explain why FEI's chosen response was to "develop alternative energy products and services that leverage existing assets" (i.e. option #2).

Response:

FEI confirmed in its response to BCUC IR 1.2.4 that, if unmitigated, the operating environment and the impacts of the CleanBC Plan have the potential to create an increased risk of stranded assets over the long-term by constraining FEI's ability to attach, retain and deliver energy to its customers. FEI has chosen to mitigate this risk and does not believe that developing pathways for the early retirement of its assets is reasonable or warranted at this time for reasons such as the following:

1. There is no tangible or foreseeable change supporting the development of early retirement pathways at this time;
2. Stringent policy scenarios are most likely to create excess capacity as opposed to stranded assets;
3. FortisBC's assets are critical to achieving GHG emission targets;
4. There is considerable uncertainty regarding how the transition to a low carbon economy will unfold; and

5. Preparing for the retirement of assets conflicts with the development of alternative energy products and services.

FEI expands on these reasons in further detail below.

There is no tangible or foreseeable change supporting the development of early retirement pathways at this time

FEI currently serves over 1 million natural gas customers in the province through nearly 49,000 kilometers of pipelines.[56] Moreover, FEI has experienced strong growth in the past few years, adding more than 22,500 natural gas customers[57] in 2018, and increased throughput, delivering nearly 230 PJs of energy in 2018[58]. This shows that the demand for natural gas and use of FEI's assets continues.

Over the longer term, FEI's 2017 Long Term Gas Resource Plan examined a range of demand scenarios, but concluded through the reference case scenario that demand is expected to grow over the foreseeable 20-year time horizon.[59]

Nonetheless, the prospect of early asset retirement was considered in FEI's depreciation study. In the study, Concentric confirms that there is insufficient evidence to support the development of early retirement pathways at this time:

> However, at this time the future impacts of the CleanBC plan have not been sufficiently studied, nor have specific programs been developed in enough detail or had sufficient time to provide indications of changes in the utilization of assets.[60]

FEI expects that future depreciations studies, which are performed on 3 to 5 year intervals, will continue to examine this issue. FEI believes that any change to depreciation practices needs to be supported by a tangible and foreseeable change in the expected use of assets. Such a case does not exist at this time and a change to depreciation rates now would amount to an unwarranted increase in customer rates, and lead to the customers of tomorrow not paying their fair share of the cost of assets that will be used and useful in the future.

---

56 Exhibit B-1-1. Appendix A2-1.
57 As measured by gross customer additions.
58 Exhibit B-1. Section B-1, Page B-12.
59 FortisBC Energy Inc. 2017 Long Term Gas Resource Plan Application. Section 3. Figure 3-6. Page 68.
60 Exhibit B-1-1. Appendix D-2, Section 3.4, Page 3-15.

Stringent policy scenarios are most likely to create excess capacity as opposed to stranded assets

The policy environment will continue to evolve into the future and FEI believes that, even under stringent policy scenarios, FEI is more likely to experience excess capacity as opposed to stranded assets.

For example, the City of Vancouver's Big Move #4 (zero emission space and water heating) mandating a transition to zero emission heating and hot water, as proposed, would be triggered by the end of the useful life of existing customer equipment after 2025. Upon replacement, the City's mandate requires the installation of zero emission heating and hot water equipment, which will take 25 to 30 years to implement. Considering FEI's zero carbon offerings (i.e. renewable gases) and other gas end-uses that are left unrestricted by this policy, including significant industrial load that relies on gas, the gas energy delivery system in the City will continue to be used and useful into the foreseeable future. In other words, the useful life of the energy delivery assets is unchanged.

Moreover, any defections from the gas system are expected to be sporadic and dispersed, both geographically and over time. This pattern necessitates the continued use of the gas system, albeit at lower demand levels, which can create excess capacity, but does not strand assets. The excess capacity provides an opportunity for FEI to leverage the gas delivery system and provide increasing amounts of zero emission energy to customers in the future, which is aligned with FEI's chosen path.

FortisBC's assets are critical to achieving emissions targets

As noted in the response to BCUC IR 1.2.4 and in FortisBC's Clean Growth Pathway document, FortisBC believes its assets will play a critical role in helping British Columbia transition to a low-carbon, renewable energy future. In its Clean Growth Pathway document, FortisBC states:

> FortisBC believes that gas - as an energy carrier - will continue to be a critical component of a decarbonized energy system in British Columbia. Gas infrastructure in the province is a multi-billion dollar asset that provides reliable, safe, affordable and high-quality energy services to British Columbians. This infrastructure is designed to serve difficult-to-decarbonize end-uses such as building and industrial heating and heavy-duty freight. Additionally, BC's gas infrastructure is equipped to handle decarbonization pathways that use drop-in fuels such as RNG and hydrogen, along with other key mitigation options like carbon capture and storage. The provincial government and stakeholders like FortisBC need to work to define the key role of the gas system to achieve our GHG reduction objectives and develop policies and other support mechanisms to leverage this system in a low-carbon transition.[61]

[61] Exhibit B-1-1. Appendix A5, Clean Growth Pathway to 2050. Page 5.

In its response to BCUC IR 1.2.4, FortisBC also noted that the CleanBC Plan relies on renewable gas delivered through FEI's natural gas system to achieve 75 percent of the total GHG reductions from buildings by 2030.[62] This clearly signals that the provincial government shares FortisBC's view of the importance of the gas delivery system in BC and the role it plays in reducing provincial emissions. To that end, FortisBC's contributions to emissions reductions are spread across all sectors including buildings, transportation and industry.

Accordingly, FortisBC believes that developing early retirement pathways for its assets would not only depart from its commitment to support emissions reductions in BC, but would be misaligned with provincial policy objectives. Further, FortisBC believes its success in pursuing alternative energy products and services that leverage its existing assets while also lowering emissions demonstrates that its pathway is realistic and achievable.

There is considerable uncertainty regarding how the transition to a low carbon environment will unfold

In its response to BCUC IR 1.2.4, FortisBC highlighted many of the inherent challenges and uncertainties with respect to how the transition to a low-carbon environment will unfold. Some of the challenges and uncertainties that were highlighted include:

- The need for the gas and electric energy delivery systems to work in tandem to provide reliable, low-cost energy, to complement one another, and to provide redundancy;
- The challenges associated with the electrification of end-uses including the requirement to double current electrical infrastructure to replace heating loads alone; and
- The challenges with difficult-to-decarbonize energy end-uses such as building and industrial heating and heavy duty freight.

These and other challenges signal that any transition will occur over a long period of time. The pace of change will be impacted by technology, policy decisions, as well as economic realities. As such, it is premature to begin retiring assets, particularly due to the key role that the gas delivery system is expected to play in the future.

Preparing for the retirement of assets conflicts with the development of alternative energy products and services

Pursuing the early retirement of assets is ideologically opposed to the development of alternative products and services using those assets. The early retirement of assets signals a decision limiting the future of the gas delivery system in BC, which would be unwarranted at this time and may never occur. As a public utility, FEI has an obligation under the Utilities Commission Act to provide safe, efficient, just and reasonable service to the public and may not discontinue serve service without permission of the Commission. As discussed above,

[62] Exhibit B-1. Application. Section B1.2.2.2. Page B-5.

restrictive policies are more likely to create excess capacity rather than stranded assets, which means that FEI will need to continue to provide service to customers and to invest in the growth and sustainment of the gas system until there is a clear and foreseeable reason to alter course. FEI cannot prepare for the early retirement of an asset, which is expected to remain used and useful well into the future. Moreover, preparing for the retirement of assets would only serve to increase costs for customers while also decreasing the competitiveness of the gas energy delivery system. Therefore, developing pathways for the early retirement of assets is premature and unwarranted. FortisBC's pathway to pursue the development of alternative energy products and services that leverage its existing assets, while also reducing emissions, is the reasonable and appropriate pathway at this time.

Pros and Cons of Each Approach

FortisBC provides the pros and cons of each approach for the utility and for ratepayers in the table below:

<u>Approach 1 – Developing pathways to pay for the early retirement of assets</u>

Pros

- Accelerates the recovery of capital in rates to reduce the potential for future stranded investments in the future.

Cons

- There is no tangible or foreseeable change supporting the development of early retirement pathways at this time;
- Stringent policy scenarios are most likely to create excess capacity as opposed to stranded assets leaving the useful life of the assets unaffected;
- Misaligned with government emissions policies and the important role of the gas system in achieving GHG emission targets;
- Increases customer rates and decreases the competitiveness of the gas delivery system for a scenario that is premature and may never occur;
- Provides an incorrect signal to the public, employees and capital markets, of a future where the gas delivery system will be underutilized, which is premature and may never occur.

<u>Approach 2 – Developing alternative energy products and services that leverage existing assets while also reducing emissions</u>

Pros

- Recognizes the critical role and contribution of the gas system to GHG emissions targets and as an integrated energy deliver system which can provide reliable, low-cost energy and redundancy.
- Leverages the investment of FortisBC's ratepayers in a multi-billion dollar gas delivery system to deliver low emission fuels broadly and to specifically target hard to decarbonize groups such as building and industrial heating and heavy-duty freight.
- Provides a means to utilize any excess capacity created through stringent policy scenarios for the delivery of new products and services.
- Recognizes and leverages FortisBC's successful history of developing alternative energy products and services.
- Avoids unnecessary increases in customer rates while also mitigating future rate increases as new products and services are introduced which drive incremental demand.
- Avoids signaling a future of the gas delivery system to the public and employees when considerable uncertainty exists with respect to how and at what pace the transition to a low-carbon environment will occur.

Cons

- None.

Summary

For the reasons mentioned above, the early retirement of assets would be premature and unwarranted, and FortisBC is pursuing the development of alternative energy products and services that leverage its existing assets while also reducing emissions.

207.3.1 As part of the above response, please also explain why the alternative "to develop pathways to pay for the early retirement of assets" (i.e. option #1) was not chosen.

Response:

Please refer to the response to BCUC IR 2.207.3.

In response to BCUC IR 2.2, FortisBC stated the following:

> It is difficult to ascertain the impact on FBC from the various Climate actions plan, including the CleanBC Plan, the BC Energy Step code, and local government actions to strengthen their climate action initiatives. As these policies continue to solidify into legislative mandates, FBC anticipates there will be reductions in demand as policies that improve energy efficiency, such as the BC Energy Step code, are adopted, while there will be opportunities for increased demand with electrification of space and water heating in buildings and the increased adoption of electric vehicles (EVs).

In response to BCUC IR 71.5.1, FortisBC stated that "FBC, as an electrical utility, has no role in the existing partnerships" with the other Natural Gas Innovation Fund (NGIF) member utilities and that the "NGIF was not, and is not, intended to address electricity innovation."

207.4 Please explain and discuss whether FBC has any partnerships with other electrical utilities or other organizations for the purposes of addressing electricity innovation.

Response:

Fortis Inc. has established an "innovation network" comprised of representatives from all Fortis regulated companies that meets to exchange and discuss innovative ideas. Although gas-related innovation is relevant to some regulated Fortis companies, all of the companies have electric operations. As such, the majority of the discussion at the first meeting related to electricity innovation and that trend is likely to continue.

In addition, FortisBC has established relationships with other organizations and utilities where electricity-related innovations are discussed. These include the Canadian Electricity Association, the Clean Energy Research Centre at the University of British Columbia, the Alliance for Transportation Electrification, the Cleantech Cluster Initiative Advisory Group and the Vancouver Economic Commission Tech Deployment Network. FBC is also working with BC Hydro on a number of electricity-related innovations, including electric vehicle charging, demand-side management technologies, smart home technologies and smart grid technologies.

207.5 Please confirm, or explain otherwise, that FBC has not/will not make any investments in electricity innovation during the Current PBR Plan term.

Response:

FBC does not expect to invest in any pre-commercial innovation activities during the PBR term. However, FBC has invested in commercial products that could be considered innovative, such as the Outage Management System, during the PBR term.

207.5.1 If not confirmed, please provide the nature and amount of FBC's investments in electricity innovation during the Current PBR Plan term by year. Please also explain where the spending was recorded (e.g. formula O&M).

Response:

Please refer to the response to BCUC IR 2.207.5.

207.6 Please explain in detail, in consideration of the challenges and opportunities described in the Application and in responses to IRs, and in consideration of the planned activities proposed to be undertaken through the Innovation Fund, the necessity for FBC to receive approval for the proposed Innovation Fund.

Response:

The activities proposed to be undertaken through the Innovation Fund related to FBC are required primarily to support increased reliance on the electricity infrastructure.

The increased reliance is driven by an expansion in the use of electricity. In some cases, this expansion is driven by new end-uses such as transportation. In other cases, growth is driven by a push for increased electrification of end-uses such as space heating.

Increasing the complexity of serving this anticipated increase in demand is a growing desire by customers to install distributed generation sources. Significant penetration of these small, green generation sources, which have less predictable output than conventional generation technologies, require additional storage and control for them to be optimally integrated with the electric grid.

The FBC innovation activities detailed in the Application are primarily related to transportation electrification, which FBC has identified as the most immediate need, both in terms of provincial priority and medium-term system impact.

In addition to transportation electrification, FBC has the opportunity to further support renewable electricity generation and improve electric system reliability through new, innovative storage capabilities. For example, the Blending Hydrogen initiative described in Section 1.1 of Appendix C6-4 has the potential to benefit the electric system by creating a long-term storage mechanism for excess electricity from renewables.

Battery storage technologies are expected to continue to improve from a cost and efficacy perspective over the MRP term, so FBC will consider implementing battery storage pilot projects, possibly in conjunction with renewable energy generation, in parts of the service territory with lower-than-average reliability.

207.6.1 Please specifically address the benefits and the risks to ratepayers of FBC receiving approval to collect annual funding for the Innovation Fund versus the benefits and risks to ratepayers of FBC not receiving approval.

Response:

The biggest risk of not approving the Innovation Fund for FBC is a less effective response to the increased reliance on the electricity infrastructure described in the response to BCUC IR 2.207.6.

The benefits and risks for FBC associated with the Innovation Fund will depend on the specific initiative being funded. For example, funding related to high-speed charging technologies for medium and heavy-duty vehicles, if successful, would increase the demand for electricity. All else equal, higher electricity sales will benefit electricity customers by lowering rates while also reducing emissions for the benefit of all British Columbians.

Similarly, innovation funding directed toward improved electricity storage technologies, if successful, could benefit customers by making renewable sources of electricity more cost-effective to integrate and by making the grid more resilient to outages and power quality fluctuations. Without this kind of investment, FBC may have to restrict the use of distributed generation or risk a less reliable electricity grid.

As with all innovation funding, there are inherent risks. Not all innovation projects will successfully lead to commercial innovations that will benefit customers. However, FortisBC believes that the evidence cited in the Application, along with the proposed governance structure, provides FBC customers with reasonable assurance that benefits will outweigh risks.

207.7 When considering the innovation initiatives planned for FBC during the proposed MRP term, please estimate the proportion of these initiatives which would be considered "commercial" and the proportion which would be considered "pre-commercial." Please explain the basis for these estimates.

Response:

FBC has not determined all of the innovation initiatives that it will participate in, although activities related to EV Charging are a priority. Appendix C6-4 Section 1.7 - 1.10 indicates that FBC intends to pursue innovation activities related to electric vehicle charging at TRL 4-6. FortisBC considers pre-commercial activities to be generally well-funded in the electric vehicle industry and consequently FBC will expand the funding focus to include late-stage TRL 9 and commercial demonstration and pilot projects related to electric vehicle charging. FortisBC expects that approximately half of the funding for these activities will be related to commercial demonstration and pilot projects while the remainder will fund pre-commercial innovation, including those activities identified in Section 1.8-1.10 of Appendix C6-4 (pages 6 to 7).

In response to BCSEA IR 21.5, FortisBC stated that "a denial of the Innovation Fund would be a failure to address the essential need to invest to accelerate innovation and adoption of new technologies to meet policy objectives."

In response to BCUC IR 26.10, FortisBC stated: "If the proposed Clean Growth Innovation Fund is not approved, FortisBC plans to continue funding the NGIF at current levels under the index-based O&M mechanism."

207.8 Please explain why FortisBC's plan to continue funding the NGIF at current levels alone is not sufficient to address "the need to invest to accelerate innovation and adoption of new technologies." Why does FortisBC consider additional funds to be necessary?

Response:

The Natural Gas Innovation Fund invests in innovative solutions for current and emerging opportunities in Canada's natural gas industry. It functions as a collaborative organization allowing the member utilities to leverage each other's available funding to drive innovation on projects where we share a common purpose.

While an effective fund, the NGIF does not support commercial (market ready) innovation activities, nor electric innovation activities, both of which are important activities that will be supported by the Clean Growth Innovation Fund. Additionally, FEI may also wish to pursue innovation opportunities specific to the context of British Columbia, which are not of interest, or of lesser interest, to the other members of the NGIF. A current example is the creation of RNG from woody biomass. In such contexts, is will be important to have a channel to provide innovation funding outside of the NGIF.

Finally, NGIF funding is limited on a per project basis to a maximum of 50 percent of a project's cost. FortisBC may wish to pursue an opportunity more vigorously than the current NGIF rules would allow and thus, an alternative channel to the NGIF would be necessary to help protect the long-term interests of FEI's customers.

207.9 Given the need identified by FortisBC to address "the evolving operating environment and the impacts of the CleanBC plan", please explain why FEI's chosen response to this need (i.e. option #2 identified in response to BCUC IR 2.4) would not be pursued regardless of whether the BCUC approved the Innovation Fund.

Response:

FortisBC has a long track record of pursuing innovation to meet the needs of its customers and will continue this into the future even if the Clean Growth Innovation Fund is not approved. However, a denial of the Clean Growth Innovation Fund would inhibit its ability to accelerate the adoption of new clean technologies, to meet the expectation to reduce emissions and support the transition to a lower carbon economy, and to maximize the use of its energy delivery systems for the benefit of its customers.

Please also refer to the response to BCUC IR 2.207.3.

207.9.1 In the event that the Innovation Fund is not approved, please discuss whether FEI would consider the option of "developing pathways to pay for the early retirement of assets", as described in response to BCUC IR 2.4. If yes, please explain when such a proposal would be considered (e.g. in the timeframe proposed by the MRP). If no, please explain why not and discuss what the risks are of not implementing either one of the alternatives for mitigating the increased risk of stranded assets over the term of the proposed MRP.

Response:

Please refer to the response to BCUC IR 2.207.3.

In response to BCUC IR 81.1, FortisBC stated that it provided a number of examples of customer benefits that were achieved from innovation funds in other jurisdictions in Section C6.3 and Appendix C6 of the Application. FortisBC stated that it believes the proposed Innovation Fund will result in the same type of benefits cited. Specifically:

> FortisBC intends to positively impact safety and reliability by pursuing initiatives that will:
>
> - Improve and reduce the cost of pipeline inspections;
> - Address gas supply disruptions using demand response measures in addition to supply side measures; and
> - Improve electric system reliability using storage and distribution generation technologies

207.10 Please explain why FortisBC would not be able to pursue the specific initiatives that would positively impact safety and reliability, as identified above, if the Innovation Fund is not approved. As part of this response, please clarify which projects in Appendix C6-4 to the Application are intended to impact safety and reliability.

Response:

FortisBC did not indicate it would not be able to pursue initiatives that positively impact safety and reliability of the gas and electric systems. Rather, FortisBC noted that the denial of the Clean Growth Innovation Fund will mean the opportunity to accelerate these initiatives may be lost, as funding may not be readily available for innovation in these areas. With or without the Innovation Fund, if important projects that would improve safety and reliability emerged over the MRP term, FBC could consider funding such projects through existing funding, or by application for additional funding.

Appendix C6-4 of the Application provides a list of the Fund's main innovation activities, but it is not meant to be an exhaustive list of all innovation opportunities. Innovative programs such as those cited in the preamble to the question would be eligible for Clean Growth Innovation Fund funding if they met the Selection Criteria outlined in the response to BCUC IR 2.218.3.

> In response to BCUC IR 81.2, FortisBC stated: "Not every innovative initiative will result in immediate benefits to customers. For those that do, FortisBC expects to report on these benefits at the Annual Reviews."

207.11 Please explain the basis for FortisBC's expectation that the customer benefits that were achieved from innovation funds in other jurisdictions will be achieved by the proposed Innovation Fund. As part of this response, please clarify which projects in Appendix C6-4 are intended to achieve the same benefits (and which projects relate to which benefits).

Response:

The basis of FortisBC's assertion that the Innovation Fund will achieve benefits similar to those experienced by ratepayer-funded innovation funds in other jurisdictions is not based on the similarity of projects, but on the similarity of the funding and governance models and the need for innovation.

For example, the governance model for the proposed Innovation Fund, as described in BCUC IR 2.218.3, aligns with the approach taken by other successful funds, including innovation funds administered by Ofgem and Gas Research Institute (GRI). FortisBC is recommending elements such as an open call for proposals, evaluation of proposals based on an open set of criteria, an External Advisory Council to provide feedback on proposals, and an ongoing evaluation framework and regular reporting on project developments through an annual report. These elements align with the approach used by Ofgem, but also account for the more centralized nature of FortisBC's energy infrastructure as compared to the UK.

Because of similarities in the way they are governed and funded, and because of similarities in the objective criteria, FortisBC believes it will achieve benefits similar to those generated by the program administered by Ofgem.

In addition to the governance process, the need for continued innovation from FortisBC, along with the intended benefits, is clearly highlighted in the CleanBC Plan as discussed on page C-132 of the Application:

> The need for innovation is highlighted by CleanBC's 15 percent renewable gas target which is forecast to achieve 75 percent (1.5 Mt) of the total emission reductions sought in the buildings sector. This target makes FortisBC's renewable gas supply and the associated generation and delivery infrastructure central components of the provincial strategy to reduce GHG emissions.
>
> Achieving this target by 2030 will be a significant challenge for the Province, FortisBC and industry, requiring collaboration to develop the necessary policy

framework, technology strategy, R&D and corresponding investment in innovation. At recent average throughput in FortisBC's gas system, 15 percent renewable gas would require approximately 30 petajoules (PJ) of renewable supply. Although FortisBC's RNG program is world leading in many respects, current renewable supply in FortisBC's system is currently 0.3 PJ, necessitating a 100-times scaling of renewable gas supply in the next 11 years.

The potential for benefits from innovation in this province are great and we expect the Innovation Fund will help realize these benefits, as similar programs have met the needs for innovation in other jurisdictions.

207.12 Please explain what methodologies are used by the Gas Research Institute and Low Carbon Network Fund to evaluate and quantify benefits.

Response:

Low Carbon Network (LCN) Fund:

Ofgem looked to evaluate the benefits of the Low Carbon Network (LCN) Fund in a variety of ways. They submitted an open letter following the implementation of the LCN Fund for the general public to review the benefits and submit comments.[63] They also commissioned an independent evaluation of the LCN Fund by third party consultants, Poyry and Ricardo Energy.

Poyry and Ricardo Energy used a qualitative and a quantitative assessment to evaluate benefits. The qualitative evaluation looked at whether there had been any cultural change by the Distribution Network Operators (DNOs) to become more innovative, whether projects were suitable for and being integrated into the business for deployment, and what third-party/stakeholder engagement had been undertaken by the DNOs. The qualitative evaluation was done by sending out questionnaires to a broad range of stakeholders about their experience of the LCN Fund projects.[64] In the quantitative evaluation, the consultants utilized a questionnaire sent to all DNOs. From the responses they received from the DNOs, they were able to analyze operating costs, project funding, and current and future financial and CO_2

63 https://www.ofgem.gov.uk/sites/default/files/docs/151217_-_two_year_review_open_letter_au.pdf.
64 https://www.ofgem.gov.uk/system/files/docs/2016/12/innovation_review_consultation_final.pdf.

emissions benefits from the funded projects to calculate benefits of DNO projects funded by the LCN Fund[65].

Gas Research Institute

Since 2004, RD&D has been taken over by the Gas Technology Institute as the taxation that funded the Gas Research Institute was phased out[66]. While it was in commission, there were five principal tests for the adequacy of the RD&D program that were established by the Federal Energy Regulatory Commission. In order to meet them to obtain the funding from the customer surcharge, the GRI took a series of steps. The step used to analyze and evaluate benefits from R&D funding was the development and use of the Project Appraisal Methodology which provided a benefit/cost analysis of all applied RD&D projects to assess consumer benefits and RD&D multi-year costs. They used criteria such as consumer (dollar) savings, energy saved, environmental benefits, consumer options enhanced and O&M savings to industry.[67]

207.13 Please explain what method(s) FortisBC will use to evaluate and quantify benefits. Please also explain how the evaluation method(s) FortisBC anticipates using compares to the methods used in other jurisdictions.

Response:

FortisBC intends to use the following Selection Criteria as the primary objective determinants of benefits to customers and British Columbians:

- Estimated CO_2e reduction in British Columbia;
- Estimated non-CO_2e emission reduction (NOx, SOx) in British Columbia; and
- Estimation of energy cost reductions for customers.

These Selection Criteria will be used to both select innovative projects and measure their potential and actual success. FortisBC will incorporate similar methods developed in other jurisdictions to quantify benefits of innovation spending.

65 https://www.ofgem.gov.uk/system/files/docs/2016/11/evaluation_of_the_lcnf_0.pdf.

66 https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas utility/190311-fei-fbc-2020-2024-mrp-application-no-appendices-ff.pdf?sfvrsn=1e31bee4_2.

67 https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/190311-fei-fbc-2020-2024-mrp-application-appendices-ff.pdf?sfvrsn=c494572a_2.

In response to BCUC IR 77.5 and 77.6, FortisBC provided the following comparison between the Innovation Fund and the New York State Millennium Fund:

Benefits	FortisBC Innovation Fund	Millennium Fund
Provides low-risk experimentation	In a highly risk averse industry, the Innovation Fund provides a means for the objective evaluation of innovative solutions for affordability while containing the risk to ratepayers.	Costs spread out over investor-owned utility distribution customers and investors allows for low-risk experimentation. Investors and consumers will also share the benefits if companies deliver outputs for less money.

207.14 Please explain how the Innovation Fund provides "a means for the objective evaluation of innovative solutions for affordability while containing the risk to ratepayers."

Response:

The evaluation process used to assess innovation projects will be objective and thorough, relying on expertise from FortisBC along with an external advisory council. Regulatory oversight will be provided through FortisBC's reporting to the BCUC at each Annual Review. The proposed evaluation criteria and reporting metrics for the Innovation Fund are discussed in the response to BCUC IR 2.218.3. These processes, along with the fixed contribution by ratepayers, will aid in managing risk.

207.15 Please describe the features of the New York State Millennium Fund such that "Investors and consumers will also share the benefits if companies deliver outputs for less money."

Response:

The statement was not referring to any specific features of the fund.

Both the proposed Innovation Fund and the Millennium Fund support low-risk experimentation. To the extent that the low-risk experimentation results in lower costs for a given utility output, both the utility, the innovation provider and its customers will benefit.

An example of such an innovation in the context of British Columbia would be a company that develops, with the assistance of grants from the Innovation Fund, a lower-cost process for producing renewable natural gas. FortisBC customers benefit from lower costs, the company providing the product makes a profit and both the utility and customers benefit from long-term viability of the natural gas distribution system.

207.16 Please explain why the above-noted benefit is not a benefit of FortisBC's proposed Innovation Fund. Please specifically explain what aspect(s) of the design of the proposed Innovation Fund prevents FortisBC from stating that "investors and consumers will share the benefits if companies deliver outputs for less money."

Response:

FortisBC confirms that investors and consumers will share the benefits if FortisBC delivers outputs for less money. Please also refer to the response to BCUC IR 2.207.15.

208.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 26.6, 26.8, 71.2

Natural Gas Innovation Fund (NGIF)

In response to BCUC IR 26.6, FortisBC stated the following:

> NGIF's members pay an annual administrative fee to be part of the fund which is based upon their size. Members also contribute funds to specific projects where they elect to be a participant…

> Through an NGIF structured process, applicants' funding requests are reviewed and successful applicants are determined based upon utility needs and the ability to fund the opportunity. Each individual utility then chooses whether to fund an applicant and the funding costs are split amongst the participating utilities…

In response to BCUC IR 26.8, FortisBC stated: "The $0.400 million includes grant funding to participants in the NGIF for the successful completion of project milestones, as well as contributions towards the regular operating expenditures of the NGIF."

FortisBC further stated in response to BCUC IR 26.8 that the NGIF and the participating utilities agree on how much each participating utility will fund and the "NGIF requests these amounts from the utilities and then disburses the funding to the proponent based upon an agreed upon schedule and milestone framework."

208.1 Please provide a detailed breakdown of FEI's $0.400 million contribution to the NGIF in 2018 to separately show the: (i) annual administrative fee; (ii) contribution towards the NGIF's regular operating expenditures (if separate from the administrative fee); and (iii) funds contributed to specific projects (please include each of FEI's contributions to specific projects as a separate line item).

<u>Response:</u>

The breakdown of NGIF invoices to FEI for 2018 are as follows (please refer to BCUC IR 2.208.1.2 for project descriptions):

Item	$ Amount
Administration fees:**	$ 197,494.00
Project Contributions	
Project 1	$ 20,000.00
Project 2	$ 15,100.00
Project 3	$ 58,313.00
Project 4	$ 60,334.00
Project 5	$ 48,750.00
Project 6	$ 42,234.00
Project 7	$ 15,110.00
Project 8	$ 53,927.00
Project 9	$ 39,872.44
Project 10	$ 12,066.83
Project 11	$ 15,905.38
Project 12	$ 11,674.75
Less Credits	
2017 Project Carry Forward	$ (150,000.00)
Project Cancellation Carry Forward	$ (30,000.00)
TOTAL	$ 410,781.40

**Note that this fee is not differentiated from the NGIF's regular operating expenses.

Notes Re: Credit:

1. 2017 Project Carry Forward - Funding provided for projects in 2017 that were delayed and moved to 2018. Monies carried forward and applied in 2018.
2. Project Cancellation Carry Forward - Amount paid by FEI for a 2016 project which was subsequently canceled by the proponent and NGIF. Monies carried forward and credited in 2018.

208.1.1 With regard to the annual administrative fee, please explain how this amount was calculated (i.e. please provide the total administrative fee paid by all members to the NGIF and FEI's relative size to the other participants in the NGIF). Please also explain in detail the types of activities/costs the fee is contributing to.

Response:

The total annual administrative fee for a given calendar year is determined by the NGIF prior to the beginning of the year. The administrative fee, which is required for the operation of the fund, is then reviewed and approved by the member organizations. For 2018, the total administrative fee payable by the NGIF gas utility members was $889,718.

Each member pays its portion of the total annual administration fee in proportion to its size as a utility. For 2018, the total administrative fee paid by FortisBC represented approximately 22 percent of the total shown above.

The administration fee covers the costs incurred by the NGIF in the course of pursuing its activities. The fund currently has 7 full-time staff, as well as some part time staff. Their scope of work includes:

- oversight and execution of all aspects of the setup and issuance of funding calls;
- receiving applications and performing an initial review;
- work with project proponents to correct any proposals based on feedback from the members;
- organize meeting for the innovation and investment committees;
- organize and attend site visits at project proponent's facilities;
- administer the funding agreements and funding disbursements;
- track proponent progress toward milestones;
- work with proponents on remediation plans should they fail to progress;
- develop and maintain results tracking;
- publicize the results of NGIF activities; and
- manage trusted partnerships with Federal and Provincial funding agencies.

This list is not exhaustive, but intended to be illustrative of the tasks undertaken by the NGIF staff.

208.1.2 With regard to the contributions to specific projects, for each specific project identified, please provide:

- A brief description of the project (e.g. the proponent, project objective(s), expected level of contribution towards CleanBC targets, if any, etc.);
- The total funding cost split amongst the participating utilities;
- FEI's portion of the total funding cost and how that amount was determined; and
- A breakdown of both the total funding cost and FEI's portion of the total funding cost between the project milestones which were met in 2018 (and the funds disbursed) and future milestones, including the expected schedule for disbursement.

<u>Response:</u>

The requested details are provided in the table below. FEI notes that the NGIF is currently working to quantify emissions reductions for each project, but that information is not yet available.

	Description	Contribution to CleanBC Targets	Total FEI Funding Commitment	Total NGIF Funding Commitment	2018 FEI Expenditure	2018 Milestones Completed	Next Expected Milestone
Project 1	Residential heating and power	None	$ 40,000.00	$ 165,000.00	$ 20,000.00	Milestone 1	Project Completed
Project 2	Cooling technology for industrial applications	None	$ 43,142.00	$ 200,000.00	$ 15,100.00	None	Milestone 2 - Completed Q3 2019
Project 3	Renewable natural gas technology from carbon feedstock	Reduce atmospheric GHG emissions by direct removal of carbon dioxide from the air	$ 116,627.00	$ 250,000.00	$ 58,313.00	None	Project Canceled
Project 4	CNG Storage technology for transportation	Reduce vehicle GHG emissions by addressing a barrier to the adoption of CNG in the light duty truck market	$ 120,668.00	$ 500,000.00	$ 60,334.00	None	Milestone 1 - Q4 2019
Project 5	Residential heating and power	None	$ 93,750.00	$ 375,000.00	$ 48,750.00	None	Milestone 1 - Q4 2019
Project 6	Renewable natural gas technology from landfill gas	Enhance availability of GHG neutral RNG	$ 84,468.00	$ 265,532.18	$ 42,234.00	None	Milestone 1 - Q1 2020
Project 7	Net zero commercial building	Demonstrate the viability of natural gas as an energy source for buildings in a low emissions future	$ 30,220.00	$ 95,000.00	$ 15,110.00	None	Milestone 1 - Completed Q2 2019 Milestone 2 - Q1 2020
Project 8	Residential heating and power	None	$ 107,853.98	$ 500,000.00	$ 53,927.00	None	Milestone 1 - Q3 2020
Project 9	Renewable natural gas technology from industrial waste feedstock	Enhance availability of GHG neutral RNG	$ 80,993.00	$ 335,600.00	$ 39,872.44	None	Mielstone 1 - Q4 2019
Project 10	Green Hydrogen from natural gas	Enhance availability of clean burning Hydrogen. Carbon from the feedstock to be captured and used for other purposes	$ 24,134.00	$ 100,000.00	$ 12,066.83	None	Milestone 1 - Q2 2020
Project 11	Renewable natural gas technology from CO2	Enhance availability of GHG neutral RNG	$ 47,716.00	$ 150,000.00	$ 15,905.38	None	Milestone 1 - Q2 2020
Project 12	Renewable natural gas technology from biomass	Enhance availability of GHG neutral RNG	$ 61,675.00	$ 890,089.00	$ 11,674.75	None	Milestone 4 - Completed Q3 2019 Milestone 5 - Q4 2019

Notes:

1. The Total NGIF Funding Commitment for each project is determined by the Investment Committee at its discretion. The funding commitments from each interested utility are apportioned by the NGIF Funding Commitment in the same manner as each individual utility's annual NGIF administration fee. In the case where not all the member utilities support a particular project, the funding proportions are adjusted in relation to the utilities that will provide support.
2. Milestone disbursements are made by FortisBC to the NGIF in advance of the proponents achieving their next expected milestone. NGIF holds these funds, and disburses them to the project proponents upon completion of the milestones as reviewed and approved by the NGIF members. In the case of projects that are canceled prior to a disbursement being made to the proponent, any funding advanced to the NGIF is typically used as a credit against future invoices. This is the case for Project 3, for example.
3. FortisBC does not maintain records showing the funding amounts required by each respective utility for every particular project.

In response to BCUC IR 71.2, FEI stated that it is a founding member of the NGIF and that it has a governance role as a member of the Investment Committee and it is a member of the Evaluation Committee.

FEI further stated in response to BCUC IR 71.2 that it "only funds projects that have passed the Investment Committee stage and which FEI has an interest in funding."

208.2 Please explain if FEI incurred any costs in 2018 for its participation as a member of the NGIF Investment Committee and Evaluation Committee and if so, the amount of those costs.

Response:

FEI understands this question to be asking about costs incurred that do not represent grant funding provided to innovation project proponents. In this sense, FEI incurred two types of costs for its participation as a member of the NGIF Investment Committee and Evaluation Committee. These are:

1. The NGIF Administration fee: This fee must be paid in order to participate in the noted committees. Please refer to the response to BCUC IR 2.208.1.
2. Additional non-labour costs: FEI incurred the cost of a trip to Toronto to meet with the round 3 funding call project proponents, and another trip to Toronto for an Investment Committee meeting. This additional cost was approximately $4 thousand.

208.2.1 If FEI did incur costs for its participation in the above-mentioned committees, please explain whether the cost of FEI's participation was included in or excluded from FEI's $0.400 million contribution to the NGIF in 2018. If the cost was excluded, please explain where these costs were recorded.

Response:

The $0.400 million represents the cost incurred by FEI per the invoices FEI received from the Canadian Gas Association. This includes the payment of the annual administration fee, which entitles FEI to participate in the above-mentioned committee.

The additional non-labour costs noted in the response to BCUC IR 2.208.2 are not included in the $0.400 million. Rather, these costs have been recorded under O&M Account 310-12 Energy Solutions, and 310-11 Energy Solutions & Ext Relations – Supervisor as part of formula O&M.

208.3 Please estimate the cost (labour and non-labour), if any, related to FEI's participation in the governance of the NGIF and as a member of the Investment and Evaluation Committees during the proposed MRP term.

Response:

The total labour and non-labour costs related to FEI's participation in the governance of the NGIF Investment and Evaluation Committees will vary annually depending on the number of funding calls completed, the number of project proposals received per funding call and the number of projects selected for funding support. As described in the response to BCUC IR 2.208.2, non-labour costs were approximately $4 thousand in 2018, while any time spent on the NGIF (labour costs) is spread out amongst a number of existing employees and has not been separately tracked, but is not significant.

208.3.1 If costs are expected to be incurred for these activities, please explain whether such costs would be incremental to FEI's annual NGIF contribution and whether they would result in increased O&M requirements.

Response:

FEI understands this question to be asking about the labour and non-labour costs associated with involvement with NGIF governance and Evaluation and Investment Committees.

The labour and non-labour cost of these activities have been included in formula O&M during the Current PBR Plan term and are in addition to the $0.400 million annual NGIF expense. FEI has not requested incremental O&M funding for these costs as they will be captured as part of the administrative costs for the Clean Growth Innovation Fund during the MRP term, if approved.

208.4 Please explain how FEI would determine its level of contribution to the NGIF each year and what the minimum and maximum contributions would likely be (under both a scenario where the Innovation Fund is approved and a scenario where it is not approved).

Response:

Participation in the NGIF will require payment of the annual administration fee. The amount of the annual administration fee will depend on the total administrative costs and the number of members contributing to the NGIF.

If the Innovation Fund is approved, support for individual projects within the NGIF will be determined by the governance process detailed in the response to BCUC IR 2.218.3. The amount of annual project funding provided to NGIF projects could therefore range in theory from $0 up to $4.5 million although FEI has no plans to allocate all of its funding to the NGIF.

In the event the Innovation Fund is not approved, NGIF projects will be evaluated in a similar manner, but the total funding available will be constrained. During the Current PBR Plan period, FEI contributed approximately $0.2 million annually in grant funding toward NGIF projects (excluding the annual administration fee) and would not expect that amount to change by more than +/- 50 percent.

209.0 Reference: INNOVATION FUND

Exhibit B-10, BCUC IR 72.2, 72.3, 72.4

CleanBC Industry Fund

FortisBC provided the following information on the CleanBC Industry Fund (CBCIF) in response to BCUC IR 72.2:

> The CBCIF is a component of the CleanBC Program for Industry. Industrial facilities emitting over 10,000 tonnes of CO2e are automatically included in the program. These facilities are eligible for the Industrial Incentive Program which rebates carbon tax payments above $30 per tonne to individual facilities provided they achieve a carbon intensity performance benchmark…
>
> …The CBCIF is a funding pool open to all participants in the CleanBC Program for Industry…The fund is focused on projects that achieve real GHG reductions and is not currently open for applications for demonstration or innovation projects.

209.1 Please clarify if the Industrial Incentive Program, which is described as rebating carbon tax payments, and the funding for projects provided by the CBCIF, are independent of each other (i.e. are participants in the CleanBC Program such as FortisBC potentially eligible for one but not the other?)

Response:

The Climate Action Secretariat has confirmed that FortisBC would not be eligible for the Industrial Incentive Program, but would be eligible to participate in the CBCIF.

In response to BCUC IR 72.4, FortisBC provided its feedback that was submitted to the provincial Climate Action Secretariat regarding the CleanBC Program for Industry.

209.2 Please indicate if FortisBC has received a response to its feedback from the Climate Action Secretariat and if so, please provide the response and the implications of the response to FEI (and to FBC if applicable).

Response:

Please refer to the response to BCUC IR 2.209.1.

209.3 Does FortisBC anticipate that it will be eligible to receive rebates through the Industrial Incentive Program? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 2.209.1. FortisBC does not anticipate that it will receive rebates for the carbon tax paid on fuel consumed for the operations of its natural gas distribution system as part of the CleanBC Industrial Incentive.

209.3.1 If FortisBC is not eligible at this time based on the current design of the Industrial Incentive Program, what specific changes would both FortisBC and the program itself be required to make in order for FortisBC to be eligible? Please discuss.

Response:

Please refer to the response to BCUC IR 2.209.1. FortisBC will not be eligible for the carbon tax incentive, but it will be eligible to apply to the CleanBC Industry Fund for projects that reduce FortisBC's corporate GHG emissions.

In response to BCUC IR 72.3, FortisBC stated the following:

> The proposed Clean Growth Innovation Fund has a separate and distinct focus from the CleanBC Industry Fund (CBCIF)…the CBCIF is focused on funding immediate GHG reductions from projects using existing technologies across all industries…the CBCIF and the [Clean Growth Innovation] Fund do not overlap and FortisBC is interested in using both funds to advance GHG reductions in its system while moderating costs to ratepayers.

209.4 If FortisBC is approved to establish the Innovation Fund, is there a risk that it will not have the resources to focus on the development of projects for both the CBCIF (and therefore miss out on funding opportunities through the CBCIF) and the Innovation Fund? Please discuss.

Response:

FortisBC is committed to ensuring adequate resources are available to effectively manage activities that reduce emissions and increase cost-effectiveness. This is one of the primary purposes of the governance structure described in the response to BCUC IR 2.218.3. Activities associated with the Innovation Fund will not substitute or displace other activities focused on reducing corporate GHG emissions or participating in other public sector initiatives such as the CBCIF.

209.5 Please explain how the goals and planned projects related to the proposed Innovation Fund are (i) complementary to and (ii) not complementary to the Province's CleanBC Plan.

Response:

The goals and planned projects related to the proposed Innovation Fund are complementary to CleanBC. In Section C6.2.2 of the Application, FortisBC outlined how all levels of government identify innovation as critical to achieve their 2030 GHG reduction goals. Similarly, FortisBC's Innovation Fund is designed to promote innovation that will result in GHG reductions.

The Innovation Fund and the CBCIF, which is an outcome of CleanBC, are aligned in their goals. The early phases of the CBCIF will focus on commercially ready projects that can reduce GHG emissions whereas the Innovation Fund will focus on bringing technologies closer to commercial readiness. With this complementary sequencing, the Innovation Fund potentially opens up more project investment opportunities in the CBCIF with successful technology research, pilots and demonstrations.

FortisBC is not aware of any instances where the goals and planned projects related to the proposed Innovation Fund are not complementary.

210.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 73.14.1; Exhibit B-1, p. C-139

Province-wide Funding Approach

In response to BCUC IR 73.14.1, FortisBC stated the following:

> Both the Provincial and Federal governments have had funding mechanisms that can be leveraged, but they are typically seeking partnership opportunities in order to spread their funding as far as possible…The Clean Growth Innovation Fund will allow FortisBC to more effectively access these kinds of partnerships and ensure that funding was directed for those areas that most benefit our customers.

On page C-139 of the Application, FortisBC states: “A guiding principle of the proposed Clean Growth Innovation Fund is to leverage partnerships with other organizations including government grants, utilities, associations and innovative technology firms to provide greater access to capital, expertise and opportunities available.”

210.1 Please explain how the Innovation Fund will allow FortisBC “to more effectively access” Provincial and Federal government innovation funding mechanisms. In what way(s) does FortisBC expect to improve its access and compared to what alternative(s)?

<u>Response:</u>

The Innovation Fund and the associated governance structure will increase the focus on innovative activities and opportunities. This will increase employee interactions with government agencies, utilities, academic institutions, and other organizations that are familiar with innovation funding sources, including provincial and federal innovation funding mechanisms. This is expected to improve knowledge of, and access to, funding mechanisms as compared to the status quo.

The increased funding will also allow FortisBC to participate in other innovation programs that require multiple funding sources and would expand the pool of funding focused on solutions for FortisBC’s ratepayers.

210.2 Please explain what criteria FortisBC uses to evaluate which innovation activities benefit, or most benefit, its customers. What are considered to be the customer benefits worth pursuing?

Response:

The criteria for selecting innovative activities are set out below.

Clean Growth Innovation Fund - Selection Criteria:

1. Amount of co-funding secured (from applicant and third parties)
2. Estimated CO_2e reduction in British Columbia
3. Estimated non-CO_2e emission reduction (NOx, SOx) in British Columbia
4. Estimation of energy cost reductions for customers
5. Relevant experience of the applicant project team

Items 2 and 3 will be based on the technical potential identified by the applicant along with BC market potential estimations from the applicant and FortisBC staff.

Item 4 will be based on retail cost and energy use reduction estimates from the applicant combined with BC market potential estimations from the applicant and FortisBC staff.

Items 5 will be calculated based on subjective scoring of the applicant's submissions, presentations and resumes provided.

Please refer to the response to BCUC IR 2.218.3 for further detail on how these criteria fit in the context of the overall governance structure.

210.3 Please discuss how a province-wide approach changes the potential for FortisBC to (i) leverage partnerships, and (ii) gain greater access to capital, expertise, and opportunities available, compared to the proposed Innovation Fund.

Response:

FortisBC assumes that "province-wide approach" refers to a potential funding mechanism described in the response to BCUC IR 1.73.14 as an approach, which "… could involve an innovation fund and funding mechanism that includes BC Hydro and/or other BC utilities."

Without more information about the mandate, funding mechanism, project selection criteria and governance process, it is not possible to comment on how the approach changes the potential to allow FortisBC to leverage partnerships and gain greater access to capital. However, the proposed Innovation Fund is designed to leverage partnerships and gain greater access to capital, expertise and opportunities for the benefit of FortisBC's customers in alignment with provincial government clean energy objectives as that is its explicit mandate.

211.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 73.9.1, 73.9.2; Exhibit B-1, pp. C-142–C-143; FEI 2019-2022 DSM Expenditures Plan Application proceeding, Exhibit B-1, p. 26

DSM Innovative Technologies Program (DSM Funding)

On pages C-142 and C-143 of the Application, FortisBC provides the guiding principles underpinning the design and operation of the Innovation Fund.

On page 26 of the FEI 2019-2022 DSM Expenditures Plan Application (FEI DSM Application), FEI listed the DSM guiding principles.

In response to BCUC IR 73.9.1, FortisBC stated the following:

> FortisBC has a successful and well-established Innovative Technologies program within its demand side management portfolio. The Clean Growth Innovation Fund builds on that success by utilizing similar management methodologies and by adding funding to existing initiatives where there may be benefits that meet the criteria for both funds.

In response to BCUC IR 73.9.2, FortisBC also stated that "the Innovation Fund will be used to support innovative initiates that would be ineligible, or only partly eligible, for DSM funding."

211.1 Please explain who developed the DSM guiding principles.

<u>Response:</u>

In FEI's original 2008 Energy Efficiency and Conservation (EEC) Application, it presented the principles it had developed to guide DSM activities for the gas utility. Many of them were based on a report prepared for the Canadian Gas Association in 2005 by IndEco Consulting in association with B. Vernon and Associates. Further input was provided in conjunction with the DSM Stakeholder group, comprised of government, industry, trades, manufacturers, non-governmental organizations, advocacy groups, other utilities and customers. The current version of the DSM Guiding principles, which contain some adjustments from the original application in order to ensure consistency across both the gas and electric utility DSM programs, were reviewed in 2018 by the BCUC and Interveners as part of the 2019-2022 DSM Expenditures Application (page 26 of the application).

211.2 Please compare and contrast each of the DSM guiding principles with the guiding principles identified for the Innovation Fund.

Response:

The DSM guiding principles apply to the entire C&EM portfolio and are not specific to the Innovative Technologies portfolio. As such, the DSM guiding principles are intended to govern how energy efficiency programs are operated, not how innovative technologies are selected and managed. Regardless, one similarity between the guiding principles for the Innovation Fund on page C-142 of the Application compared to the Conservation and Energy Management (C&EM) DSM guiding principles on page 26 of the 2019-2022 DSM Expenditures Application is to seek collaboration and partnerships with other parties such as governments, other utilities and relevant stakeholders.

However, the guiding principles generally differ since they result from differing goals, legal frameworks and regulatory requirements. In particular, DSM cost-effectiveness tests would be difficult to apply since the future costs and benefits of commercial products that may result from innovation activities at some point in the future would be difficult to assess either on a measure or a portfolio level. Instead Innovation Fund projects will rely on the metrics as described in the response to BCUC IR 2.218.3.

211.2.1 As part of the above response, for each of the DSM guiding principles which are inconsistent or not contemplated as part of the Innovation Fund guiding principles, please explain why it would not be appropriate to incorporate the principle as part of the Innovation Fund guiding principles.

Response:

Please refer to the response to BCUC IR 2.211.2.

211.3 To the extent that one project may be eligible for both DSM Innovative Technologies and the Innovation Fund program funding, please explain how the costs of the innovative initiatives will be split amongst the two funds.

Response:

A project may be eligible for both DSM Innovation Technologies funding and the Innovation Fund only if there are aspects of the project that meet requirements related to both. If that is the case, the cost split will be on a proportional basis. An example of this is the Carbon Capture Project where GHG emission reductions are attributed to both DSM and Non-DSM activities. The DSM activities are attributed energy savings of both recovering heat from the flue gas and the exothermic reaction caused from the carbon sequestration process and using that heat to preheat water for the domestic hot water system. The Non-DSM activities are attributed to the carbon sequestration process that involves the interaction of the CO_2 in the flue gas with sodium hydroxide (NaOH) to produce sodium bicarbonate ($NaHCO_3$). As such, the costs were broken out based on activities specifically linked to those DSM and non-DSM activities. The expenditures and costs associated with the energy efficiency improvements were covered through FEI's DSM budget while the expenditures and costs associated with evaluating the carbon sequestration activities were covered from O&M.

211.4 Please clarify whether initiatives which are only "partly eligible" for DSM funding receive DSM funding.

Response:

Yes, initiatives which are partly eligible for DSM funding can receive DSM funding. In a case where an initiative is not completely an energy efficiency project, such as the Carbon Capture project, partial funding can be provided through DSM funding. Please also refer to the response to BCUC IR 2.211.3.

211.4.1 If yes, please explain how the amount of the DSM portion of the funding is determined.

Response:

Please refer to the response to BCUC IR 2.211.3.

211.4.2 If no, please confirm, or explain otherwise, that the costs of the initiatives which are only "partly eligible" for DSM funding are included within formula-driven O&M.

Response:

Please refer to the response to BCUC IR 2.211.4.

212.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 26.9, 72.2, 73.9; Exhibit B-1, pp. C-137–C-139

Innovation Funding Gaps

Figure C6-4 on page C-139 of the Application illustrates the innovation gaps to be addressed by the Innovation Fund.

212.1 For clarity, please confirm whether the categorization of "the innovation gaps" in Figure C6-4 refers to gaps in <u>innovative technologies that FortisBC has access to</u> or general innovative technology gaps (i.e. in the BC or Canadian marketplace).

<u>Response:</u>

The innovation gaps referenced represent areas of opportunity for improvements in products or services through innovation and where there are funding gaps in the marketplace. The Clean Growth Innovation Fund will help address these gaps by providing funding to existing initiatives. In some cases, where the market is not responding, FortisBC will consider issuing a Call for Proposal to help better identify the gaps in the marketplace.

212.1.1 If the innovative technologies gaps are FortisBC's, please discuss the incentives for partnership that partner organizations[68] may have.

<u>Response:</u>

Please refer to the response to BCUC IR 2.212.1. Because the innovation gaps also represent gaps in the marketplace, there are good opportunities for partnerships with other organizations, which is an opportunity FortisBC intends to act on. Organizations will be incented to partner with FortisBC to access funding, expertise, customers and testing facilities, accelerating their development cycles and mitigating risk.

In response to various BCUC IRs (e.g. BCUC IR 26.9, 72.2, 73.9), FortisBC provided information describing the differences and similarities in the purpose/objective and scope

[68] In these IRs, "partner organizations" mean other utilities institutions, business, industry associations, provincial government, federal government and other non-government organizations which are third-parties to FortisBC.

of the proposed Innovation Fund compared to: (i) other FortisBC program funds that have a component of funding innovation (e.g. DSM Innovative Technologies); and (ii) innovation funds provided by third-party organizations.

212.2 In order to show the innovation funding gaps that will be specifically addressed by the Innovation Fund, please provide a matrix table detailing the differences and similarities in funding eligibility between the proposed Innovation Fund and the following: (i) other program funds with an innovation funding component; and (ii) innovation funds provided by third-party organizations. Please provide a separate table for FEI and for FBC.

Response:

The following matrix table identifies the differences and similarities in funding eligibility criteria across different innovation funding areas categorized by whether it is required, not required, permitted or not permitted. Permitted means that it is not a requirement, but if it is an outcome then it is allowed. Please note that there is no differentiation between the funds across FEI and FBC.

Funding Eligibility	DSM Innovation Technologies "DSM"	Natural Gas Innovation Fund "NGIF"	Clean Growth Innovation Fund "Innovation Fund"	CleanBC Industry Fund "CBCIF"	OFGEM - Low Carbon Networks Fund "LCN FUND"
To conserve energy or promote energy efficiency	Required	Permitted	Not required	Not required	Not required
To reduce the energy demand a public utility must serve	Required	Permitted	Not required	Not required	Not required
To shift the use of energy to periods of lower demand	Required	Permitted	Not required	Not required	Not required
Fuel switching	Not permitted	Permitted	Permitted	Permitted	Permitted
Not commonly used in British Columbia	Required	Permitted	Required	Not required	Not required
Load Growth	Not permitted	Permitted	Permitted	Not required	Permitted
DSM Portfolio Cost Effectiveness	Required	Not required	Not required	Not required	Not required
Reduces Emissions	Not required	Permitted	Required *	Required	Required
Reduces Cost of Energy	Not required ^	Permitted	Required *	Permitted	Permitted
Commercial Technologies	Permitted	Not permitted	Permitted	Required	Permitted
Pre-commercial Technologies	Permitted	Required	Permitted	Not permitted	Permitted
Electric Technologies	Permitted	Not permitted	Permitted	Permitted	Permitted
Natural Gas Technologies	Permitted	Required	Permitted	Permitted	Permitted
Investments in other Innovation Funds	Not permitted	Not permitted	Permitted	Permitted	Permitted

* At least one of these is required.
^ Certain cost-effectiveness tests are required

213.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 79.4, 79.5, 79.7; Financial Accounting Standards Board Accounting Standards Codification Topic 730 – Research and Development

Financial Accounting Treatment

Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic (ASC) 730 – Research and Development – establishes standards of financial accounting and reporting for research and development costs. As noted in ASC 730-10-05-1, the guidance in ASC 730 specifies:

(a) Those activities that shall be identified as research and development for financial accounting and reporting purposes

(b) The elements of costs that shall be identified with research and development activities

(c) The accounting for research and development costs; and; and

(d) The financial statement disclosures related to research and development costs.

ASC 730-10-05-2 to 3 state:

> At the time most research and development costs are incurred, the future benefits are at best uncertain. In other words, there is no indication that an economic resource has been created… Research and development costs therefore fail to satisfy the suggested measurability test for accounting recognition as an asset. Also, there is often a high degree of uncertainty about whether research and development expenditures will provide any future benefits… The general lack of discernible future benefits at the time the costs are incurred indicates that the immediate recognition principle of expense recognition should apply.” [Emphasis Added]

Finally, ASC 730-10-55-1 and 2 provides examples of activities typically included and excluded in research and development, respectively.

In responses to BCUC IR 79.4 and 79.7, under the topic heading “Use of Funding,” FortisBC stated in the “FortisBC Innovation Funds and Rate Rider” column:

> … the funding is not meant for capital expenditures on currently commercially viable projects that would otherwise require separate BCUC approval. If, through research and development activities administrated under the Innovation Fund, precommercial technologies become technically and commercial viable as well as acceptable to FortisBC’s customers and stakeholders in terms of cost effectiveness, safety, and reliability, FortisBC will seek approval for future

expenditures for implementation, if necessary and subject to regulatory requirements at that time.

In response to BCUC IR 79.5, FortisBC also stated: "The results of the Innovation Fund may ultimately give rise to future capital investments, but the capital costs of such a project would be collected from customers once an asset is in service…"

213.1 Please confirm, or explain otherwise, that the "Use of Funding" for the proposed Innovation Fund is consistent with the standards of financial accounting and reporting for research and development costs established by ASC 730.

Response:

FortisBC's proposed "Use of Funding" to establish the Innovation Fund over the MRP term has been determined in the context of a rate-regulated entity and therefore will differ from how research and development costs would be recognized as a period expense under ASC 730 for non-regulated entities. FortisBC has proposed to fund the Clean Growth Innovation Fund through a flat-fee, basic charge rider each month, resulting in these funds set aside as a liability reserve and drawn down as qualifying innovation activities are incurred over the term of the MRP. However, the nature of the innovation activity costs incurred against the Innovation Fund are consistent with ASC 730 in that they would otherwise qualify as period expenses, similar to research and development costs.

While FortisBC's proposed funding mechanism for the Innovation Fund is not described under ASC 730, it is permissible under US GAAP ASC 980 rate-regulated operations and has consistency with other funding arrangements under the BCUC Uniform System of Accounts (USofA) prescribed for both gas and electric utilities.

To the extent that any qualifying innovation activity costs incurred meet the measurability test for accounting recognition as an asset, FortisBC will seek separate approval for capital expenditures. To clarify, costs that qualify as an asset would not be consistent with ASC 730 and therefore, will not be funded by the Innovation Fund.

213.1.1 If confirmed, for additional clarity, please confirm, or explain otherwise, the following: (i) that the innovation activities described in Appendix C6-4 of the Application meet the definition of research and development activities (as defined by ASC 730) and thus, should be expensed as costs are incurred; and (ii) to the extent that further research and development on any project meets the measurability test for accounting recognition as an asset, FortisBC will seek separate approval for capital expenditures (i.e. these costs will not be funded by the Innovation Fund).

Response:

Please refer to the response to BCUC IR 2.213.1.

214.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 70.2, 70.4, 70.5, 71.1.1, 75.5, 79.1, 79.4, 79.7, 80.1, 80.1.1, 82.8; Exhibit B-1, p. C-145

Design of the Innovation Fund Deferral Account and Rate Rider

In response to BCUC IR 70.2, FortisBC confirmed that the total amount of funding collected from customers over the term of the proposed MRPs will be impacted by FEI and FBC's actual number of customers.

In response to BCUC IR 70.5, FortisBC confirmed that its commitment "is not to spend more than the aggregate amount collected over the term of the MRPs."

214.1 Given that funds will be collected from customers at the same time as the innovation costs are incurred, please explain, from a practical standpoint, how FortisBC will not spend more than the aggregate amount collected over the term of the proposed MRPs.

Response:

The average forecast error for the number of customers over the last six years has been less than 1 percent, for both FEI and FBC. With variances[69] this small, the funds to be collected are reasonably certain. The cost of the programs will be controlled by FortisBC, and, as grant funding commitments are made in advance, FortisBC will be able to cease or slow funding to new projects as it approaches the allowed funding envelope. FortisBC will report to the BCUC each year in the Annual Review process showing how it is managing the fund within the amounts to be collected.

214.1.1 In the event that more innovation costs are incurred than the funding collected from customers (e.g. due to a lower number of actual customers compared to forecast), please explain how (and by whom) FortisBC proposes to collect the funding shortfall.

Response:

Please refer to the response to BCUC IR 2.214.1. FortisBC believes the funds collected will be reasonably certain and FortisBC will manage expenditures on programs within the funding

69 Customer count variances are lower than usage variances, particularly for FEI whose load is affected by temperature.

envelopes. Should expenditures on innovation programs exceed funds collected over the term of the MRP due to an under-collection of funding from customers below the cumulative amount, FortisBC will apply to the BCUC for disposition of the deferral balance. As described in the response to BCUC IR 2.214.1, grant funding commitments are known in advance, allowing FortisBC to cease funding new projects as it reaches the cumulative funding envelope. Accordingly, FortisBC does not expect that it will spend more than the cumulative funding envelope.

FortisBC stated the following in response to BCUC IR 70.4:

> Even though, for FortisBC, the proposed rate rider will not appear separately on each customer's bill (it will be bundled together with the basic charge), the proposed approach allows FortisBC to charge each customer the same amount, whereas if it was embedded in the revenue requirement customers would be charged differently based on their volume.

In response to BCUC IR 75.5, FortisBC stated that one of the "pros" of this method (that is, Method 1: "Add a rate rider for the Innovation Fund to the fixed basic charges to accumulate funds") is "Greater transparency of costs and recoveries." In addition, FortisBC stated that this method is "similar to how other FortisBC approved rate riders are included on a customer's bill."

214.2 Please explain how bundling a rate rider with a basic charge would contribute to "greater transparency of costs and recoveries."

Response:

As rate riders are shown separately within the tariff, a rate rider makes it clear to the BCUC, interveners, and customers that read the tariff exactly how much each customer is contributing, even if the rate rider is not shown separately on a customer's bill. With a deferral account and amortization, it is not clear how much each customer is contributing.

214.3 Please explain why, for FEI, the proposed Innovation Fund rate rider is not proposed to be shown separately on customers' bills, similar to other FEI rate riders.

Response:

FEI believes that the approach of embedding the rate rider within delivery and/or commodity rates allows for a greater ease of understanding of rates overall, reducing the potential for confusion that can result from individual items being displayed. This is consistent with FEI's existing rate riders which are also not shown as separate line items on the bill. Rather, they are embedded within the related rate (i.e., Commodity, Storage and Transport, Delivery). Thus, embedding the Innovation Fund rate rider within the basic charge is consistent with the treatment for all other rate riders (which are currently all volumetric) in place at this time. Finally, embedding the rate rider within existing rates for billing purposes avoids additional time and costs, although minimal[70], associated with the design and testing of the bill.

Although a rate rider is not identified separately on a customer's bill, the detail for any rate rider, as will be the case with the proposed Innovation Fund rate rider, can be found within each Rate Schedule tariff and is accessible to all customers. Thus, overall this approach provides for clear and transparent communication while maintaining the cost allocation benefits of a separate line item without added costs.

Please also refer to the response to BCUC IR 2.214.5.

214.3.1 Does FEI have the capabilities to show the Innovation Fund rate rider as a separate line item from the basic charge on customer bills? Please explain.

Response:

FEI confirms it has the capability to show the Innovation Fund rate rider as a separate line item from the basic charge on customer bills.

214.3.2 To the extent that the one of the reasons for not showing the Innovation Fund rate rider separately from the Basic Charge on customers' bills is due to system limitations, please provide the project timeline and costs

70 Approximately $25 thousand each for FEI and FBC, and an additional two weeks for configuration and testing for FEI, and 4 weeks for FBC.

to build the appropriate functionality in the billing system to overcome the limitations.

Response:

Please refer to the response to BCUC IR 2.214.3.1.

214.4 Please explain if FBC has the capabilities within its current system to utilize rate riders (either volumetric or fixed). If yes, does FBC have the capability to show the rate rider as a separate line item on customer bills?

Response:

The system is capable of embedding rate riders within existing charges as well as displaying rate riders as a separate line item on customer bills; however, to this point in time FBC has not needed to configure the system to do so.

Configuration and testing to support embedding rate riders within the basic charge requires lead time of approximately two to three weeks and is expected to cost approximately $15 thousand. Configuration and testing to create a separate line item on the bill for rate riders would require approximately one month of lead time and is expected to cost approximately $25 thousand.

214.4.1 If FBC does not currently have the capability to utilize rate riders at all, please explain how it intends to add this functionality to its billing system and if there are any costs associated with adding this functionality.

Response:

Please refer to the response to BCUC IR 2.214.4.

214.4.2 If FBC currently has the capability to utilize rate riders but does not have the capability to separately show the Innovation Fund Rate Rider from the Basic Charge on a customer bill, please provide the project timeline and costs to build the appropriate functionality in the billing system to overcome the limitations.

Response:

Please refer to the response to BCUC IR 2.214.4.

214.5 Please discuss the pros and cons for each of FEI and FBC of displaying the Innovation Fund rate rider as a separate line item on customers' bills.

Response:

The pros and cons for both FEI and FBC customers are the same with respect to displaying the Innovation Fund rate rider as a separate line item. Thus, a single discussion is provided below which outlines the pros and cons associated with this approach (Option A); however, for comparison purposes, additional discussion has been provided outlining the pros and cons associated with embedding the rate rider within Basic[71] Charge rates (Option B).

Option A: Innovation Fund Rate Rider as Separate Line Item on Bill

Creating a separate line item on the bill for the Innovation Fund Rate Rider singles out and highlights the cost of this fund relative to other line items on the bill, making it clearly identifiable. The challenge with this approach is that it is a departure from existing rate rider treatment and as such, having an additional line item on the bill may create unnecessary confusion as well as call into question the importance of other rate riders relative to the Innovation Fund Rate Rider. Further, although expected to be minimal, there would be additional time and costs associated with this approach. Finally, recent customer research conducted as part of the bill redesign initiative indicates that customers prefer simplicity and focus on higher level information such as amount owing, consumption information and payment due dates. That is, more detailed rate information on a bill does not mean that it is more understandable or meaningful from a customer perspective.

Option B: Innovation Fund Rate Rider Embedded within Basic Charge Rates

Embedding the Innovation Fund Rate Rider within the basic charge is consistent with the existing treatment of rate riders on the bill. Although it is not as clearly definable as a separate line item on the bill, the details of the rider will be clearly identifiable in each Rate Schedule and

[71] FBC uses the term 'Customer' charge.

bill messages or other forms of communication may be used to call further attention to the rider if considered necessary. Thus, overall this approach provides for clear and transparent communication while maintaining the cost allocation benefits of a separate line item. In comparison to Option A, it may also reduce the unnecessary confusion of having multiple line items on the bill. In addition, because this is consistent with existing rate rider treatment on the bill for FEI, incremental costs are not associated with this approach; however, minor additional time and costs would be required for FBC.[72]

In response to BCUC IR 71.1.1, FortisBC stated: "in [the] absence of approval of the Clean Growth Innovation Fund, FEI is likely to limit its contribution to a maximum of $0.400 million, funded annually through its Base O&M."

On page C-145 of the Application, FortisBC states: "the Companies propose to use a basic charge rate rider in lieu of a volumetric rate rider so that all customers fund Innovation equally."

214.6 Please explain why FortisBC proposes that innovation expenditures should be funded equally by each customer if the Innovation Fund is approved, but volumetrically (for FEI) if the Innovation Fund is <u>not</u> approved. Why are the two proposals for collecting innovation costs from customers not the same?

<u>Response:</u>

When FEI commenced funding innovation through the NGIF, the amounts FEI pledged were lower than the current level of funding. At that time, the relatively low amount of funding and administrative efficiency of including these funds in O&M were considered, and FEI determined that embedding them in delivery rates (through O&M) was a reasonable choice. FortisBC is now bringing forward an entirely new program and, on that basis, has considered the most appropriate method of recovering the costs. FortisBC considers that the basic charge rate rider approach is now the best approach. Please refer to the responses to BCUC IRs 1.79.1, 1.79.2, and 1.79.3 for the reasons why FortisBC has proposed to collect the Innovation Fund equally from all customers.

[72] As compared to Option A for FBC, approximately 1-2 weeks less time and approximately $10 thousand less will be required under Option B. Option A cost and timing is provided in the response to BCUC IR 2.214.3.

In responses to BCUC IR 79.4 and 79.7, FortisBC stated it "believes it is fair that all customers fund innovation activities equally since all customer types, not just higher volume users, will experience the benefits."

214.7 Please clarify whether FortisBC considers it to be "unfair" for innovation activities to be funded volumetrically, or simply that it is "more fair" if customers were to fund innovation activities equally. Please provide the rationale for FortisBC's position.

Response:

FortisBC does not consider it "unfair" if innovation activities are funded volumetrically. Rather, FortisBC believes it is "more fair" if innovation activities are funded by customers equally through a fixed per-customer rate rider. The rationale for FortisBC's includes the following:

- The costs required for proposed Innovation Fund activities identified in Appendix C6-4 of the Application are largely fixed and do not vary by volume.
- The reduction of GHG emissions resulting from the successful research and development activities will benefit all customer types (and all British Columbians), not just higher volume customers.

FortisBC acknowledges that, in addition to the reduction of GHG emissions, some activities might lead to other benefits such as reduced costs through new energy efficiency technologies that may only be applicable to certain types of customers. However, FortisBC currently is not able to predict which activities might ultimately succeed and which types of customers, if not all, might benefit.

FortisBC does not consider it "unfair" if innovation activities are funded volumetrically since, in some cases, high volume customers might experience greater benefits in terms of reduced utility bills through the advancement of technology. However, due to the uncertainty of which activities might prove successful, FortisBC believes it is "more fair" to recover innovation activities equally from all customers over the proposed MRP term.

214.8 In the event that the Innovation Fund is approved, but as a volumetric rate rider, what is the expected range and distribution of impacts on customers' bills (e.g. what would the highest volume customer pay versus the lowest volume customer, and how are customer volumes distributed)?

Response:

Table 1 below shows the Innovation Fund Rate Rider for FEI and FBC as a volumetric rate rider.

Table 1: Calculation of Volumetric Rate Rider[73]

	FEI	FBC
Anticipated Funding Level	$ 4.9 million	$ 0.5 million
Forecast of 2020 Volume (FEI is non-bypass)	200,330 TJ	3,330 GWh
Volumetric Rate Rider	***$ 0.024/GJ***	***$ 0.150/MWh***

Based on the calculation of the volumetric rate rider calculated above, the range of annual bill impacts related to the Innovation Fund rate riders is as shown in Table 2 below, with the highest volume customers paying $58,540 for FEI and $50,611 for FBC under the volumetric approach. This compares to the basic/customer charge approach, which results in a maximum annual cost of $4.80 per customer for FEI or $18.00 for FBC[74]. As expected, residential customers will experience the lowest impact from a volumetric rate rider, while high volume customers such as industrial (FEI) and wholesale (FBC) will experience the highest impact.

Table 2: Annual Bill Impacts to Lowest and Highest Volume Customers[75]

	FEI	FBC
Lowest Volume (Residential, Commercial)	0 TJ	0 GWh
Total Annual Rate Rider		
Volumetrically	$ -	$ -
Fixed	$ 4.80	$ 3.60
Highest Volume (FEI: RS22; FBC: Wholesale)	2,393 TJ	337 GWh
Total Annual Rate Rider		
Volumetrically	$ 58,540	$ 50,611
Fixed	$ 4.80	$ 18.00

Tables 3 and Table 4 below show the distribution of impacts on customers' bills for FEI and FBC, respectively, based on the average use per customer in each rate class[76].

[73] Using a preliminary 2020 volume forecast
[74] $0.40 x 12 = $4.80 for FEI; $0.30 x 5 x 12 = $18.00 for FBC as the largest customer is a wholesale customer with 5 service points.
[75] Using 2018 volumes
[76] Ibid

Table 3: FEI Distribution of Annual Bill Impacts Using Volumetric Approach

FEI (Non-bypass)	Avg. Annual Use per Customer (GJ)	Avg. Annual Rate Rider per Customer (Volumetric)
Residential		
RS 1 Residential	83	$ 2
Commercial		
RS 2 Small Commercial	323	$ 8
RS 3 Large Commercial	3,463	$ 85
RS 23 Transportation	5,261	$ 129
Industrial		
RS 4 Seasonal	9,000	$ 220
RS 5 General Firm Service	12,548	$ 307
RS 6 Vehicle Service	3,625	$ 89
RS 7 Interruptible Service	75,250	$ 1,841
RS 22 Large Volume Transportation	788,175	$ 19,279
RS 25 Transportation	26,033	$ 637
RS 27 Transportation	62,305	$ 1,524

Table 4: FBC Distribution of Annual Bill Impacts Using Volumetric Approach

FBC	Avg. Annual Use per Customer (MWh)	Avg. Annual Rate Rider per Customer (Volumetric)
Residential	11	$ 2
Commercial	59	$ 9
Wholesale	95,333	$ 14,311
Industrial	7,333	$ 1,101
Irrigation	38	$ 6

In FortisBC's opinion, a fixed rate rider per customer/basic charge for the innovation fund represents a small impact to all customers regardless of their volumes and rate class (maximum of $4.80 annually for FEI and ranges from $3.60 to $18.00 annually for FBC). However, under a volumetric rate rider, some industrial and wholesale customers with relatively high volume will experience a much higher impact annually ($19,279 for the average use per customer or $58,540 for the highest volume customer for FEI; $14,311 for the average use per customer or $50,611 for the highest volume customer for FBC).

214.9 Please provide other examples for each of FEI and FBC where a per-customer rate rider has been approved instead of some form of volumetric recovery (e.g. volumetric rate rider, O&M, amortization expense). Please explain in detail the types of costs that were recovered and the rationale for the per-customer recovery approach.

Response:

For FEI, the two most recent examples of per-customer rate riders (fixed monthly or daily applied to Basic Charge) were the Deferred Non-Core Margin Increase rate rider from 1996 to 1998 approved with BCUC Order G-98-96 and the Amortization of Income Tax Refund rate rider in 2001 approved with BCUC Order G-124-00. FortisBC notes that both of these rate riders include a per-customer fixed component and a volumetric component. Given the magnitude of the Innovation Fund rate rider and the complexities involved, FortisBC does not see a benefit to a split between a fixed and volumetric component in this case.

The details of each rate rider are included below:

- ***Deferred Non-Core Margin Increase rate rider (1996 to 1998)*** – This rate rider was established and approved with BCUC Order G-98-96 as part of the 1996 Rate Design Application by BC Gas, the predecessor of FEI. The purpose of the rate rider was to defer 50 percent of the 1996 non-core margin increase (Rate Schedules (RS) 7, 8, 22, 22A, 22B, 25, and 27 at that time) and recover the deferral over the following two years (1997 and 1998). The deferral of non-core margin increase and the establishment of the deferral account were originally approved under BCUC Order G-99-95 as part of the Alternative Dispute Resolution (ADR) process in 1995 filed for the 1996, 1997, and 1998 Revenue Requirement Application by BC Gas. In its decision, the BCUC directed BC Gas to determine the disposition of the deferred amount in the 1996 Rate Design Application. The rate rider, developed as part of the two settlement packages from the 1996 Rate Design Application, included both a per-customer fixed component and a volumetric component to recover the deferred non-core margin increase proportionally from the basic and volumetric charge for each of the non-core rate classes.
- ***Amortization of Income Tax Refund (2001)*** – This rate rider was approved by BCUC Order G-124-00 to refund the remaining credit balance of the income tax refund, totaling to $13.2 million in 2001, over a one-year period to all customers. For RS 1 (Residential) and RS 2 (Small Commercial) customers only, this rate rider included both fixed and volumetric components. For all other rate schedules, the rate rider was volumetric only. The fixed component of the rate rider for RS 1 and RS 2 was designed to keep their basic charges constant from 2000 to 2001. This is because RS 1 and RS 2 have some zero and low volume customers, and if the rate rider was volumetric only, these customers would not have received any share of the income tax refund through their rates at that time.

For FBC, there has not been a per-customer rate rider except in the case of a bypass rate, which is calculated as a fixed monthly charge based on the estimated cost of a bypass for the specific bypass customer and part of a Bypass Rate Agreement between FBC and the bypass customer.

214.10 Please clarify based on FortisBC's statements in response to BCUC IR 79.4 and 79.7 (as provided in the above preamble) if, expanding on this rationale, it is reasonable to conclude that FortisBC's costs which are recovered volumetrically are recovered in this manner because higher volume users are benefiting the most from the expenditures.

<u>Response:</u>

It is not reasonable to conclude that FortisBC's costs which are recovered volumetrically are recovered in this manner because higher volume users are benefiting the most from the expenditures. Both FEI's and FBC's costs (i.e., revenue requirements) are recovered through a combination of fixed daily/monthly charges, demand charges and volumetric charges.

The rates for FEI and FBC, like most utilities, are fundamentally designed based on cost causation for each rate class, yet are also a balance between competing rate design principles. In terms of variable costs, a high volume customer will generally cause higher costs than a low volume customer and, therefore, will tend to pay more of the revenue requirement than low volume customers. However, higher volume customers are also affected by rate design principles that send price signals that encourage participation in energy efficiency activities as discussed in recent Rate Design Applications for both FEI (2016) and FBC (2017).

Furthermore, the fixed charges (daily or monthly) in most rate classes for both FEI and FBC are only recovering a portion of the fixed per-customer costs of each rate class while the volumetric charges recover the remaining portion of the fixed per-customer costs.

Finally, a large proportion of FortisBC's costs are recovered from higher volume customers not only because of cost causation but also because of rate design principles that influence the balance of fixed and volumetric charges as well as government policy seeking to encourage energy conservation.

214.11 Please confirm, or explain otherwise, that similar to other load-attracting investments, if the investments through the Innovation Fund result in new customers being added to the system or the retention of existing customers, the positive impact will be experienced volumetrically as opposed to equally for each customer.

Response:

Under current rate and rate design frameworks, FEI customers will experience the positive impact of additional throughput from new customer additions and the retention of existing customers volumetrically[77]; however, FBC customers will experience these positive impacts through both the fixed customer charge and volumetric charges[78].

In response to BCUC IR 82.8, FortisBC stated the following:

> FortisBC would be unable to proceed with the innovation activities in the identified investment areas due to a lack of funding within the index-based O&M proposed. [Emphasis Added]

In response to BCUC IR 79.1, FortisBC stated the following:

> FEI and FBC would not characterize the Clean Growth Innovation Fund request as a pre-collection in advance of costs being incurred, but rather as a mechanism designed to more closely match the collection of funds against the costs as they are incurred… FortisBC's proposed approach is essentially the same as the normal process to forecast and recover of [sic] the Utilities' revenue requirement. [Emphasis Added]

214.12 In the event that the proposed Innovation Fund was not approved, but some form of innovation funding is deemed reasonable during the proposed MRP term, please discuss in detail the pros and cons of the following three approaches (please exclude a discussion of the pros/cons of the volumetric versus per-customer approach):

- Approach 1 – Innovation expenditures are forecast by FortisBC annually through the Annual Review process, with actual expenditures subject to flow-through treatment (similar to FortisBC's proposed treatment for Investments in a Clean Growth Future).

[77] FEI's general rate changes flow through volumetric charges only
[78] FBC's general rate changes flow through both the customer and volumetric charges

- Approach 2 – Innovation expenditures are forecast by FortisBC annually through the Annual Review process but variances between forecast and actual expenditures would be subject to the ESM.
- Approach 3 – The Base 2019 O&M is adjusted to include incremental funding for innovation expenditures. Please discuss an appropriate incremental funding amount for FEI and FBC under this approach and the rationale for the proposed amounts.

Response:

In responding to this question, FortisBC has assumed that the process for Approaches 1 and 2 would be the same as its Investments in Clean Growth Future. For instance, at each Annual Review FortisBC would provide an explanation of variances between the previous forecast and actual expenditures as well as anticipated expenditures in the upcoming year. In other words, FortisBC would not be seeking approval on a project-by-project basis, as discussed in the response to BCUC IR 2.214.13.

The pros and cons of the three approaches provided in the preamble are set out in the table below.

Pro's (✔) and Con's (✖)	Approach # 1	Approach # 2	Approach # 3
Consistent treatment with other large, variable O&M expenditures	✔		
Increased regulatory efficiency - expenditure level added to base funding as part of index-based O&M			✔
Variances between forecasted and actual expenditures are trued-up and returned to or recovered from customers in the following year	✔		
New deferral account not necessary although it may be desired for more transparency (could use existing flow-through deferral account for Approach # 1)	✔	✔	✔
Method to recover the innovation funding amount from customers based on volumetric through delivery charge	✖	✖	✖
Results in less stable fundign for programs. Among other things, this means that FortisBC could not make funding commitments beyond the current year which would limit the number of projects that could receive grants.	✖	✖	
Inconsistent treatment - results in sharing of variances from a forecast (as opposed to formula)		✖	
Subjecting variances to the ESM provides an incentive for FortisBC to reduce spending on innovation, when FortisBC should have an incentive to fund innovation.		✖	✖

In reference to the request to discuss an appropriate incremental funding amount for FEI and FBC under Approach 3, the amounts are difficult to determine because they pre-suppose the O&M inflation factors for 2020 through 2024. For example, if the inflation factor was expected to be 2 percent for 2020 through 2024, the appropriate Base 2019 O&M amounts would be $4.616 million and $0.471 million for FEI and FBC, respectively. When inflated by 2 percent each year, that amount would produce the following amounts for each of the five MRP years:

Year	FEI	FBC
2019 Base	$4.616 million	$0.471 million
2020	$4.708 million	$0.480 million
2021	$4.802 million	$0.490 million
2022	$4.899 million	$0.500 million
2023	$4.997 million	$0.510 million
2024	$5.096 million	$0.520 million
Total	$24.502 million	$2.500 million

Average	$4.900 million	$0.500 million

In response to BCUC IR 80.1, FortisBC stated the following:

> FortisBC believes it is important to establish clear criteria for each initiative funded by the Clean Growth Innovation Fund. However, measuring the completion of initiatives by performance targets or key success indicators may be difficult… lagging criteria could not be established on a broad basis in advance.

In response to BCUC IR 80.1.1, FortisBC stated the following:

> Please refer to BCUC IR 1.80.1. Ratepayers will be able to evaluate success by looking at the leading indicators in terms of completing projects on time, on budget and within scope, and additionally, at the lagging indicators specific to individual innovation projects that have been completed and by the specific benefits that are expected to be achieved from each.

214.13 Given that lagging indicators specific to individual innovation projects cannot be established on a broad basis in advance, please explain why FortisBC does not propose to seek approval for innovation expenditures in the Annual Reviews on an individual project-by-project basis after the lagging indicators specific to individual projects are determined.

Response:

FortisBC has not proposed seeking approval of innovation expenditures in Annual Reviews as it believes its proposed approach will result in greater benefits to customers as it gives flexibility for FortisBC to grant funding proposals in a timely manner while allowing sufficient oversight through the governance and reporting processes. Under the proposed approach, FortisBC has the flexibility to grant funding in response to proposals throughout the year and on the timelines that may be required by applicants. This should result in FortisBC being able to grant funding in a way that maximizes opportunities as they arise for the benefit of customers.

If individual innovation projects were approved during the Annual Review process, funding decisions would occur only once per year and there would be no opportunity to increase funding for a specific initiative or to add an initiative during the year. Since some approved innovation initiatives may be dropped during the year, and the need for increased funding and new funding opportunities could arise mid-year, the once-a-year approval process is likely to result in underspending and missed opportunities.

Furthermore, if individual innovation projects were approved during the Annual Review process, FortisBC may not be able to process applications quickly enough to meet the needs of applicants. FEI's experience with the NGIF is that funding is generally required in much less than a year from an applicant's initial request, often due to government co-funding requirements related to budget cycles.

These timing requirements are incompatible with a project-by-project approval process at the annual review, which would add up to a year of lag time (depending on when an innovation proposal is received). Before the proposals could be included in the Annual Review, they would need to go through the process for selection and approval described in the response to BCUC IR 2.218.3. This process itself is expected to take three to six months to complete. FortisBC would then need to prepare the information on the proposal for inclusion in its Annual Review materials. Based on the Annual Reviews over the Current PBR Plan, there is then usually approximately four months between the filing of the Annual Review materials and a decision from the BCUC. The end result is that proposals for funding would need to be received around the beginning of each year for a final funding decision by the beginning of the following year.

Since FortisBC intends to pursue innovative projects that already have established co-funding, which is often time dependent, the additional time required to pre-approve innovation proposals in the Annual Review will limit the number of initiatives that can be considered.

214.13.1 Would FortisBC be amenable to this alternative approach? Please explain why or why not and discuss the pros and cons of this approach.

Response:

FortisBC is not amenable to this alternate approach for the reasons described in the response to BCUC IR 2.214.13.

215.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 77.3, 77.5, 77.6; Exhibit B-5, BCOAPO IR 85.3; Ofgem "Regulating energy networks for the future: RPI-X@20 Emerging Thinking – A specific innovation stimulus" supporting paper (Supporting Paper), pp. 5, 12[79]

Access to the Innovation Fund

In response to BCUC IR 77.3, 77.5 and 77.6, under the item "Competitiveness of the Funding Award Process" for the Innovation Fund, FortisBC stated the following:

> FortisBC's fund would be initially allocated to the FortisBC companies, with the potential to award funding to, or partner with, private sector organizations, the public sector or research institutions moving forward. Dependent on the quality and number of partner organizations for potential projects, FortisBC would encourage a competitive funding award process and collaborative third-party engagement.

In response to BCOAPO IR 85.3, FortisBC stated the following:

> FortisBC expects to provide grant funding to assist in accelerating the commercialization of clean innovations. It does not intend to take an equity position in any related companies or own any intellectual property developed in the partnerships. [Emphasis Added]

215.1 Please explain how (i.e. what criteria) FortisBC will use to decide whether to award funding to, or partner with, other organizations.

Response:

For clarity, the statement "*FortisBC's fund would be initially allocated to the FortisBC companies, with the potential to award funding to, or partner with, private sector organizations, the public sector or research institutions moving forward*" was meant to convey that, unlike the funds in the comparison which are administered by third parties who determine how funds are allocated, the Clean Growth Innovation Fund is allocated to (and collected by) FortisBC to determine which projects, either internal or external, are to be funded.

FortisBC intends to evaluate potential projects according to the selection criteria discussed in detail in response to BCUC IR 2.218.3. FortisBC intends to leverage co-funding opportunities in all cases.

---

[79] Retrieved from: https://www.ofgem.gov.uk/ofgem-publications/51952/et-innovationpdf.

215.2 Please explain why FortisBC's fund should be initially allocated only to the FortisBC companies.

Response:

Please refer to the response to BCUC IR 2.215.1.

In response to BCUC IR 77.3, FortisBC stated the following:

> The disaggregated nature of the UK's natural gas market has allowed many large-scale utility distribution companies the chance to operate within a competitive environment. Therefore, programs, such as Innovation Funds, require a centralized administrative process through a single governing body, such as the utility regulator.

On page 5 of the Ofgem Supporting Paper, Ofgem stated the following:

> Awarding funding via a competitive process allows equal access for all parties. The process would need to have strong independent governance to ensure fair assessment of proposed projects.

On page 12 of the Ofgem Supporting Paper, Ofgem stated the following:

> We think that <u>a competitive process</u> offers real benefits by allowing proposed projects to be assessed independently against a set of established public criteria. It would ensure <u>that projects with the best potential to deliver benefits</u> for consumers and support the transition to a sustainable energy sector <u>would be selected to receive funding</u>. Under the competitive process, <u>parties submitting bids would also be incentivised to consider potential efficiencies in their proposals</u> to achieve advantages over other bidders. [Emphasis Added]

215.3 Please explain whether FortisBC considers the natural gas and electricity innovation markets in BC to be disaggregated given that the innovation is being undertaken by private sector organizations, the public sector, research institutions, academia and by FortisBC.

Response:

The response to BCUC IR 1.77.3 was not referring to the disaggregated nature of the innovation market in the UK but rather the nature of the natural gas distribution market. The UK's natural gas market is disaggregated because of the many large-scale utility distribution companies (14+) that operate across the UK.[80] It is because of the number of distribution companies that innovation programs in the UK require a centralized administrative process through a single governing body.

FortisBC does not consider the innovation market to be 'disaggregated' in BC. Innovation in the electricity and natural gas space requires the collaboration of utilities, public and private sector organizations, research institutions and academia where interests align. FortisBC intends to use the Clean Growth Innovation Fund to encourage and fund collaboration that meets the goals outlined in the Application. This will minimize 'disaggregation'.

215.3.1 If yes, please discuss whether "a centralized administrative process through a single governing body" would be beneficial in BC.

Response:

Please refer to the response to BCUC IR 2.215.3 where FortisBC discusses why it does not consider the innovation market in BC to be disaggregated. Further, FortisBC does not believe that a centralized administrative process through a single British Columbia governing body is necessary or offers advantages over its approach to act as the centralized body that will guide innovation activities focused on FortisBC's infrastructure and ratepayers.

215.4 Please discuss the advantages and disadvantages of awarding funding via a competitive process for all grant funding (i.e. the Ofgem approach) as compared to FortisBC's proposal to initially allocate funds to the FortisBC companies and then provide a competitive funding award process only if it awards funding to, or partners with, another organization.

80 https://www.ofgem.gov.uk/electricity/distribution-networks/gb-electricity-distribution-network.

Response:

FortisBC agrees with the statement by Ofgem as it relates to the benefit of competition. The governance process described in the response to BCUC IR 2.218.3 is a competitive process in that it is:

1. open to a wide variety of entities;
2. has clear selection criteria; and
3. has limited funding.

A competitive process offers many benefits for proposed projects. The resources from the Innovation Fund will be for FortisBC to distribute, on a competitive basis, to third party organizations. FortisBC expects that the majority of the funding will be going to projects with other partners and that the number of projects and demand for innovation funds will exceed the size of the proposed Innovation Fund.

On page 5 of the Ofgem Supporting Paper, Ofgem also stated: "Providing partial funding ensures that parties progressing innovation bear some risks of the project reflecting the opportunities available for them to achieve benefits."

215.5 Please discuss the extent to which FortisBC agrees or disagrees with the above-noted statement on page 5 of the Ofgem Supporting Paper.

Response:

FortisBC agrees with the statement provided by Ofgem. FortisBC does not intend to provide full funding to partner organizations for any innovative initiative. Grants from the Innovation Fund would leverage funding from the awarded organizations and/or other third parties.

215.6 In the event that funding is awarded to partner organizations, please discuss whether FortisBC intends to provide full or partial funding to the parties. If the decision is project-dependent, please provide the criteria which FortisBC will use to evaluate whether full or partial funding should be awarded.

Response:

FortisBC does not intend to provide full funding to partner organizations for any innovative initiative.

As described in the response to BCUC IR 2.218.3, the process to select projects for funding will depend on a set of criteria that weighs the amount of co-funding, to the GHG and pollutant reduction potential, the cost-reduction potential and the expertise and experience of the project team. A project deemed to have very high GHG and cost reduction potential could be funded with less co-funding. FortisBC believes that this is a benefit of the proposed Innovation Fund in that it allows for flexibility to choose projects that have may have lower risks and/or higher long-term impacts.

216.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 82.1, 82.2

Government Grants

In response to BCUC IR 82.1, FortisBC stated that it is not possible to state in advance the type or amount of government grants that may be available for the innovative activities that will be pursued because funding programs change rapidly.

FortisBC also stated in response to BCUC IR 82.1: "In addition to the above, funding from provinces outside of BC may be available depending where research, development and demonstration activities take place."

216.1 Please explain how, and whose responsibility it is, to monitor and keep FortisBC informed of the type, amount and criteria for government funding programs (including funding from provinces outside of BC) that are available, including when these funding programs may expire and the application deadlines.

Response:

Monitoring funding opportunities at FortisBC is a responsibility shared across multiple business units and FortisBC has designated the Director of Business Innovation as responsible to collect, coordinate and communicate information about different opportunities across units as they arise.

216.1.1 Please discuss what oversight will be in place to ensure that the funds collected from the Innovation Fund are spent in a way that leverages to the greatest extent possible the availability of the funding programs.

Response:

As described in the response to BCUC IR 2.218.3, the process to select projects for funding will depend on a set of criteria that weighs the amount of co-funding. FortisBC intends to seek co-funding in all cases, whether from government grants or other sources. The Innovation Fund will open new opportunities to leverage external funding programs for innovation. The proposed Innovation Fund will allow FortisBC to participate in other innovation programs that require multiple funding sources and would expand the pool of funding focused on solutions for FortisBC's ratepayers.

In response to BCUC IR 82.2, FortisBC stated the following:

> The estimated financing required for Innovation Activities, net of grants, in each investment area is provided in the response to BCUC IR 1.70.1. FortisBC has not estimated the amount of government grants expected in each area and therefore does not know the total planned funding amount for each investment area since this will depend on the amount of grants received. <u>If grant funding is greater, then the total investment will be increased</u>. [Emphasis Added]

216.2 Given the above statement, would FortisBC agree that the estimated investment in each investment area provided in response to BCUC IR 70.1 represents FortisBC's minimum expected investment for 2020? Please explain why or why not.

<u>Response:</u>

The amounts shown in the response to BCUC IR 1.70.1 represent the amount of FortisBC investment expected from the Innovation Fund. FortisBC intends to seek co-funding in all cases, whether from government grants or other sources, so the total investment in each area from all sources will be greater than FortisBC's investment.

217.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 75.1, 75.2, 75.3, 75.4.1

Stakeholder Engagement

In response to BCUC IR 75.1, FortisBC stated that discussions with stakeholders regarding the proposed Innovation Fund were included as part of the overall consultation process regarding the Application. FortisBC stated that the stakeholders involved were the interveners who regularly participate in the Current PBR Plans' annual review processes: BCOAPO, BCSEA, ICG, BCMEU, CEC and MoveUp. In addition, FortisBC stated that it met with representatives from the Ministry of Energy, Mine and Petroleum Resources and the BC Business Council.

217.1 Please explain why FortisBC considers it sufficient to have limited its Innovation Fund consultation to interveners who regularly participate in the Current PBR Plans' annual reviews, the Government, and the BC Business Council. As part of this response, please discuss whether there are other stakeholder groups which FortisBC could have consulted with but did not (e.g. residential customers) and, if so, why these groups were not consulted.

<u>Response:</u>

FortisBC's consultation efforts were conducted not only to obtain feedback on the Innovation Fund, but to cover a number of topics focused on the Companies' Application and its next rate-setting proposal. The topics discussed included:

- Highlights of the Current PBR Plans
- Next Generation PBR Application
- Key Themes
    - Engagement
    - Investment
    - Innovation
- PBR Questions and Discussion
- Benchmarking Study Update

As a result, FortisBC selected stakeholders that regularly participated in the Current PBR Plans' annual review processes, who have an interest in and are able to provide feedback on the different topics, in addition to the Innovation Fund.

Regarding efforts to consult specifically with residential customer groups, FEI notes that the BCOAPO provides representation for low-income residential customers' interests. FortisBC also met with the BCUC Staff to solicit their feedback on the different topics.

Please refer to the response to BCUC IR 2.155.1 for highlights of the discussion with the Ministry of Energy, Mines and Petroleum Resources and the BC Business Council.

217.2 Please clarify whether FortisBC specifically discussed the proposed quantum of the Innovation Fund rate riders and the proposed collection method, for each of FEI and FBC, with the Ministry of Energy, Mine and Petroleum Resources or the BC Business Council.

Response:

Stakeholder discussions, including MEMPR and the BC Business Council, varied depending on their interests. For example, as referenced in BCUC IR 2.155.1, conversations with MEMPR focused on how the Companies' application would support the policy objectives of CleanBC. The Companies discussed the total funding envelope at a high level, but there was no discussion of the quantum of the ensuing rate rider. In the view of FortisBC, the interest of the MEMPR and the BC Business Council were more in the purpose and objectives of the Fund as opposed to the specifics of the rate rider and collection method.

FortisBC considered the feedback it received about the alignment between its interests and those of stakeholders into its Application, including the proposed Innovation Fund.

217.2.1 If yes, please discuss any feedback received and how it impacted the proposed Innovation Fund.

Response:

Please refer to the response to BCUC IR 2.217.2.

217.2.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.217.2.

In response to BCUC IR 75.2, FortisBC provided a copy of three slides which were used during its October 2018 Update on FortisBC Next Generation Rate Making Approach consultation sessions that relate to innovation funding. FortisBC noted that questions and comments from stakeholders on these slides included the following:

- Is the innovation initiatives mostly O&M expenditures?
- How have you been engaging with customers to determine their interest in the R&D initiatives?
- Is the proposed R&D funding going to be in addition to the GGRR funding? Will you be using a rate rider to fund the R&D activities?

217.3 Please provide FortisBC's responses during the consultation sessions to the above-noted questions, as well as details of any further discussion or feedback that were considered by FortisBC following those responses and how the feedback was/was not incorporated into the Innovation Fund proposal.

Response:

FortisBC provides the following responses to the noted questions raised by stakeholders during the October consultation sessions. As FortisBC was still developing its Innovation Fund proposal, the responses were to be considered preliminary and indicative in nature.

Is the innovation initiatives mostly O&M expenditures?

Answer – Yes, O&M, maybe treated as deferral expenditures, with the focus on recovering what is spent.

How have you been engaging with customers to determine their interest in the R&D initiatives?

Answer - We will be engaging customers as part of the research required.

Is the proposed R&D funding going to be in addition to the GGRR funding? Will you be using a rate rider to fund the R&D activities?

Answer – The proposed R&D funding is in addition to the GGRR funding. At this time, we are still evaluating the different ways to fund the R&D activities.

Additional stakeholder feedback was obtained regarding the quantum of funding for the Innovation Fund as part of the preparation for the December 2018 Workshop on the Review of Multi-Year Year Rate Plans and Cost of Service Regulation (Section B2 of Application, page B-60). In preparation for the workshop, stakeholders were asked a number of questions including the following question on how much customers would be willing to pay to support Innovation Technologies. The responses received to the question are also provided below.

December 2018 – Review of Multi-Year Year Rate Plans and Cost of Service Regulation Workshop

Q5. Advancing the development of Innovative Technologies for the benefit of customers and to support government policy will be a key theme of FortisBC's next ratemaking application. FortisBC intends to apply for funding to support research and development and pilot programs. Please choose one of the following options indicating how much you think customers are willing to pay to support Innovation Technologies.

Total: 3 participants

		Total
	Total	3
1	Up to $5 per customer per year	1
		33%
2	Between $5 and $10 per customer per year	1
		33%
3	Greater than $10 per customer per year	1
		33%

Proprietary and Confidential 10

The stakeholder feedback received was considered and has helped to informed the development of FortisBC's Innovation Fund proposal outlined in the Application.

217.4 Please clarify if the above-noted slides included the proposed methodology and quantum of the proposed Innovation Fund, including the rate-riders. If no, please explain why not.

Response:

At the time of the consultation sessions in October 2018, FortisBC had not finalized its proposal on the quantum of the proposed Innovation Fund, including the rate-rider. The focus of the discussion with stakeholders was on the need for innovation funding, innovation funding principles and the different types of initiatives that would be funded.

In response to BCUC 75.3, FortisBC stated the following:

- FortisBC Attitudes Survey show that customers are willing to pay for "innovation" if there is an environmental benefit. Environmental innovation is a key design feature of the Innovation Fund.

217.5 Please provide further details regarding the FortisBC Attitudes Survey, including but not limited to the following information regarding the sampling model:

- The scope and purpose of the survey;
- How and when the survey was conducted, and by whom;
- The intended targeted audience of the survey;
- The type(s) of actual survey respondents; and
- The survey response-rate.

Response:

FortisBC mistakenly referred to the slide in the response to BCUC IR 1.75.3 as the "FortisBC Attitudes Survey". The slide provided in that response was from the Canadian Electric Association's (CEA), "National Electricity Customer Satisfaction Report" from December 2018.

The CEA commissioned the Innovative Research Group to conduct the research for the National Electricity Customer Satisfaction Report. The survey sought to understand public attitudes towards the electricity companies that serve them.

The key topics included:

- Overall satisfaction
- Performance attributes
- Customer experience
- Net Promoter Score

Other topics included:

- Key satisfaction metrics for transmitters
- The price of electricity
- Interest in conservation programs
- New technology
- Environmental controls (i.e., underlying exogenous factors that may impact perceptions of electricity companies)

The survey was an online survey conducted by Innovative Research Group. Data collection occurred between October 4th and October 29th, 2018, among 7,192 Canadian adults (18 years or older).

The survey sample was weighted by age, gender, and region using 2016 Statistics Canada Census data to reflect the actual demographic composition of the Canadian adult population. Upon CEA member request, additional oversamples were included in several distribution service territories or provinces to provide greater confidence in the data at a sub-regional level of analysis. In the final data, the oversampled regions were weighted down to a representative national sample size of n=1,600.[81] Tracking results are drawn from previous CEA National Surveys from 2013 to 2017.

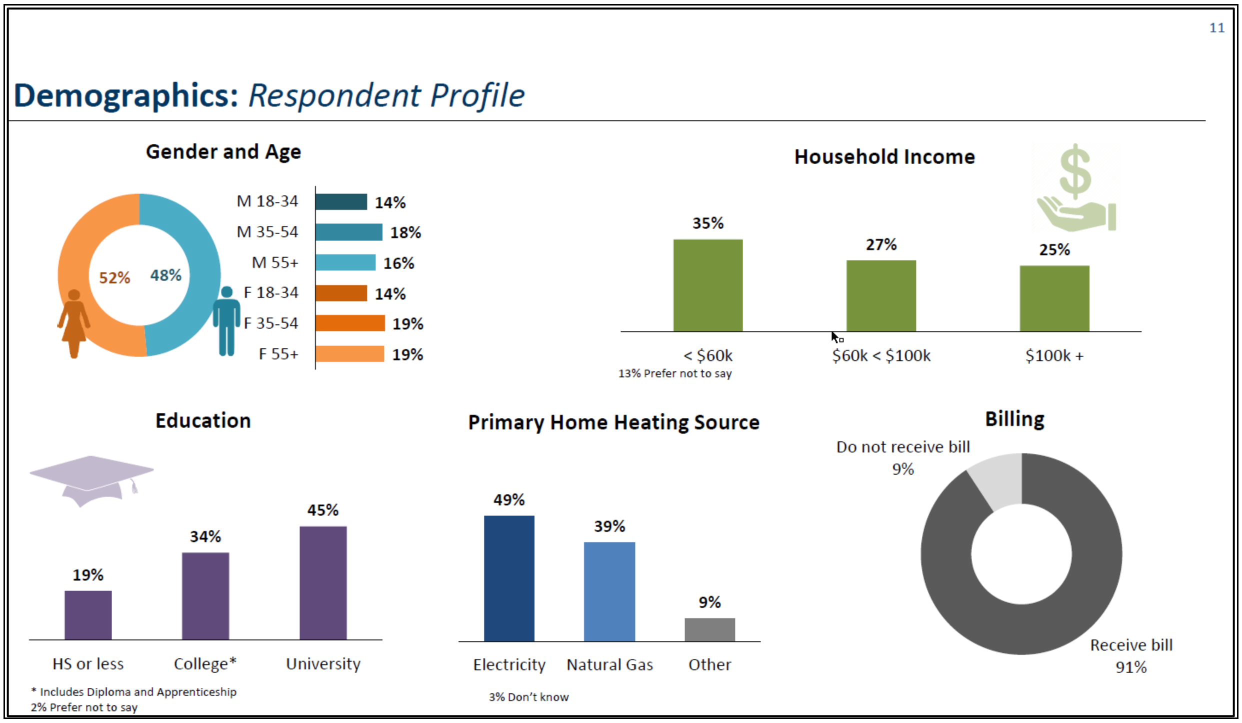
Survey respondents were recruited from a wide variety of sources to reflect the age, gender, and regional characteristics of the country as a whole. Because this is an online survey and not a random probability sample, the results cannot be generalized across all Canadians, so Innovative Research Group did not apply a margin of error or identify the overall response rate.

Innovative Research Group provided each survey respondent with a unique URL (hyperlink) to the online survey via an email invitation. This step ensured that only invited respondents were able to complete the survey. Unique URLs were disabled upon survey completion to ensure that invited participants could only respond once.

[81] In BC, there were 465 responses. Once weighted, the BC n=214 and the National n=1,600.

Figure 1 below shows the profile of the responders to the survey.

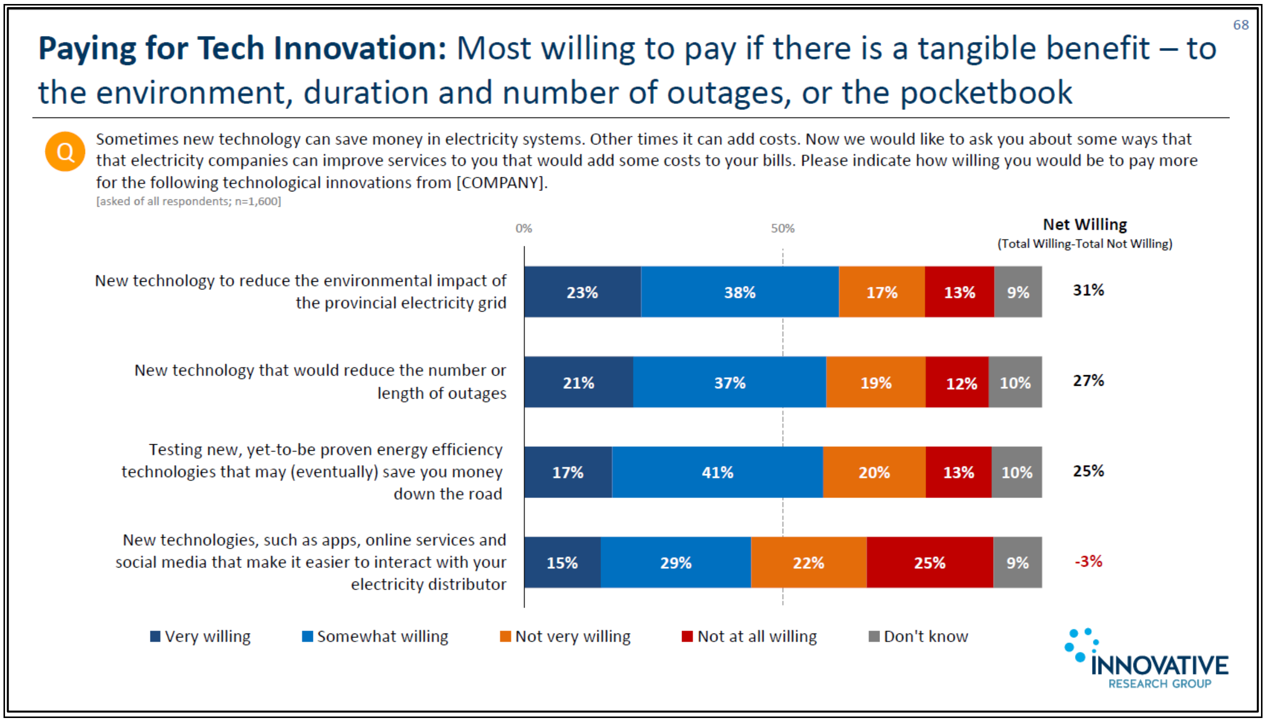
Figure 1: Respondent Profile



The scope and purpose of the survey was not explicitly intended to collect information regarding customers' views on the impact of the CleanBC Plan on FortisBC. However, in lieu of specific research, FortisBC believes that the results should serve as a proxy by which to gauge general consumer support for investments like the FortisBC Innovation Fund.

As shown above, the survey included a healthy sample size, weighting was appropriate, and it asked respondents a variety of helpful questions about their overall willingness to pay more for technological, energy-related innovations. While additional research may shed further light on consumer perceptions, the survey results as presented in the response to BCUC IR 1.75.3, and reproduced below, are informative.

Figure 2: Diagram from BCUC IR 1.75.3 duplicated here for reference



217.5.1 To the extent that the scope and purpose of the FortisBC Attitudes Survey was not intended to collect information regarding customers' views on the impact of the CleanBC Plan on FortisBC, please explain why the results of the FortisBC Attitudes Survey serve a role in informing customers' support for the proposed Innovation Fund.

Response:

Please refer to response to BCUC IR 2.217.5.

217.6 Given that the questions posed in the FortisBC Attitudes Survey related to electricity companies and electricity innovation, please discuss (with examples) how the results of the survey have impacted or influenced the main innovation activities/projects that FBC intends to pursue with the Innovation Fund.

Response:

As noted in the response to BCUC IR 2.217.5, the "FortisBC Attitudes Survey" referred to the National Electricity Customer Satisfaction Report commissioned by the Canadian Electric Association (CEA) in December 2018 and produced by Innovative Research Group.

While the survey focused on electrical utilities, almost 40 percent of the study's respondents use natural gas as their primary heating fuel. For these consumers, natural gas plays an essential role in their existing household energy requirements. Therefore, the information collected likely approximates the beliefs and attitudes of both FortisBC natural gas and electricity customers.

Neither the Innovative Research Group results discussed above, nor the Corporate Reputation study results referenced in the response to BCUC IR 1.75.3, shaped specific FEI or FBC innovation activities. However, the research findings align with and support the FortisBC view that consumers want cleaner energy options and that they are willing to contribute to such initiatives. Environmental innovation (through emissions reduction) is a key design feature of the Innovation Fund.

217.6.1 Given the above-mentioned focus on electricity, how/why are these results influential with regard to FEI's activities? Please explain.

Response:

Please refer to the response to BCUC IR 2.217.6.

In response to BCUC IR 75.3, FortisBC also stated the following:

- FortisBC 2018 Corporate Reputation Presentation showing that "innovation" and Environment" are important to FortisBC customers. Environmental innovation is a key design feature of the Innovation Fund.

217.7 Please provide details regarding the information shown in the FortisBC 2018 Corporate Reputation Presentation slide, including but not limited to:

- Where FortisBC collected the data;
- How the data was collected;
- When the data was collected; and

- How the data was analyzed such that:
  - FEI concluded: "Among gas customers, environment more strongly influences reputation and has above average performance"; and
  - FBC concluded: "Innovation more strongly influences reputation among electric customers but is underperforming. Among electric customers, performance is lowest on affordable services; potentially underpinning the importance of new energy solutions."

Response:

The 2018 FortisBC Corporate Reputation Study ran from August 30, through September 10, 2018, using an online, general population panel. Participants came from across all FortisBC service regions, with quotas established for the four service areas based on population, age, and gender. The final, weighted response rates were as follows:

Table 1: Original survey quotas proportionate to age and gender in each service area

	Lower Mainland			Vancouver Island			Interior and North (except SST)			Shared Service Territory (SST)		
	18-34	35-54	55+	18-34	35-54	55+	18-34	35-54	55+	18-34	35-54	55+
Male	67	92	97	33	46	49	33	46	49	22	30	32
Female	67	93	98	34	47	49	34	47	49	22	31	33

Overall, 62 percent of all responses were from the Lower Mainland, 17 percent from the Interior, 12 percent from Vancouver Island, and 9 percent from the Shared Service Territory (i.e., where FortisBC delivers both natural gas and electricity).

Once data collection was complete, the data was cleaned to ensure quality data responses by removing respondents who: 1. completed the survey too quickly to give quality responses; 2. flat-lined (i.e., respondent provided the same score across attribute ratings); or responded that they were "not at all familiar" with FortisBC. After cleaning the data set, there were 1,118 BC residents 18 years of age or older who were familiar with or had heard the name FortisBC participating in the survey.

Calculation of the FortisBC Reputation Index includes contributions from four attribute measures to establish an overall assessment of FortisBC's reputation health. Attributes include:

- FBC is a company I trust
- FBC is a company I have a good feeling about
- FBC is a company I respect

- FBC has a good overall reputation

Illumina Research Partners, which surveyed on behalf of FortisBC, used driver analysis to understand the relationship between the FortisBC Reputation Index and respondents' perceptions on 39 other attributes. Driver analysis quantifies the importance of a series of predictor variables in predicting an outcome variable. In the case of the FortisBC Reputation Index Study, the higher the correlations (r-squared) between the Reputation Index and specific attributes, the stronger their impact on influencing FortisBC's corporate reputation. The driver analysis led Illumina to identify the influence customer perceptions about environmental practices and ability to innovate have on FortisBC's corporate reputation.

Despite the large overall sample, the subset of FBC electric customers (n=48) is small. Therefore, caution is advisable in interpreting the advance analytics results drawn from electricity-only customers.

Results of the driver analysis indicate that in comparison to FortisBC electricity-only customers:

- FortisBC gas-only customers have a stronger perception of FortisBC's reputation (Reputation Index of 67 vs. 59 for electricity customers).
- Attributes related to the environment more strongly influence gas customers' perceptions of FortisBC's reputation (based on the driver analysis). Likewise, gas-only customers rate FortisBC stronger on environment attributes compared to electricity customers, including the following:
    - Operates in an environmentally responsible manner
    - Follows through on commitments
    - Is responsive to environmental and community concerns
    - Is environmentally responsible

In comparison to FortisBC gas-only customers:

- FortisBC electricity-only customers have overall lower perceptions of FortisBC.
- Attributes related to innovation and good value for money have more influence on customers' overall perceptions of FortisBC's reputation (based on driver analysis). However, electricity customers rate FortisBC's performance lower on these aspects, including:
    - Is an innovative company
    - Delivers new energy solutions
    - Offers innovative energy products and services

- Offers services that are good value for money

217.8 Please provide examples explaining how environmental innovation is a key design feature of the Innovation Fund.

Response:

Environmental innovation relates to finding ways that FortisBC can reduce its own impact on the environment and the ways it can help its customers to reduce their impact on the environment. In this regard, the Clean Growth Innovation Fund's objective is to accelerate the pace of clean energy innovation and address the expectation to reduce emissions and support the transition to a lower carbon economy. Further, all of the Main Innovation Activities detailed in Appendix C6-4 help achieve those goals.

217.9 Please discuss (with examples) how FortisBC's findings with respect to its corporate reputation have impacted or influenced the main innovation activities/projects that FEI and FBC intend to pursue with the Innovation Fund.

Response:

Please refer to the response to BCUC IR 2.217.6.

In response to BCUC 75.4.1, FortisBC stated that it expects "limited negative reaction" to the proposed rate riders.

217.10 Please provide detailed reasons why FortisBC expects "limited negative reaction" to the proposed Innovation Fund rate riders.

Response:

FortisBC expects limited negative reaction given its analysis of the results of the 2018 CEA National Electricity Customer Satisfaction Report and the Corporate Reputation Survey which concludes that customers want cleaner energy and are willing to contribute to such initiatives (please refer to the responses to BCUC IRs 2.217.5 and 2.217.6). Further, should customers inquire about the increase to their bills, FortisBC would address customer concerns according to our typical practice, which is to provide our Customer Service Representatives with information on how they can respond to customer concerns of this nature.

217.10.1 In the event of strong negative reaction to the proposed rate riders, what action(s) will FortisBC take, if any?

Response:

Depending on the nature of any "strong negative reaction" from customers, FortisBC may take one of more of the following actions:

- Answer questions directly with each customer in the communication channel of their preference;
- Produce and provide directly to customers a Frequently Asked Questions document that addresses common customer concerns;
- Include the Frequently Asked Questions document on the FortisBC website; and
- Hold "town hall meetings" with concerned groups of customers, either in person or by phone.

218.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 73.14.2, 78.1, 78.2, 78.4.1, 82.6, 82.7.1; Exhibit B-1,

pp. C-144–C-145

Governance Structure

In response to BCUC IR 73.14.2, FortisBC stated the following:

> The disadvantage of a third-party innovation fund administrator, such as the NGIF, is that they may have an evaluation mechanism that results in different investment decisions than the members might make on their own. Conversely, the benefit of a third-party administrator like NGIF that accepts funding from multiple investors, is that FortisBC investments can be leveraged for innovations that have a common benefit to a number of investors. Accordingly, FortisBC believes that its proposed approach, which has the ability to include third-party administrators and direct partnerships with third-party innovation proponents, is the most flexibility and practical.

218.1 Please further explain the extent to which FortisBC's proposed approach includes "the ability to include third-party administrators." Is FortisBC referring to the funding it provides to the NGIF or is the ability to include third-party administrators related to something else? Please explain.

Response:

In its response to BCUC IR 1.73.14.2, FortisBC is referring to the ability to include third-party administrators like the NGIF. FortisBC is not aware at this time of a similar third-party fund in which FortisBC could invest.

A third-party administered fund in which FortisBC would invest would need to have 1) goals that generally align with the Innovation Fund Selection Criteria 2) a robust governance structure, and 3) the ability for FortisBC to select the specific projects in which it invests. The NGIF has all three of these characteristics.

218.2 Please explain in detail why FortisBC considers its proposed approach to be "flexible" and "practical" (i.e. what criteria or definition was used to establish whether the proposed Innovation Fund is "flexible" or "practical"?)

Response:

The Innovation Fund governance design is "flexible and practical" because it allows FortisBC to provide funding to a variety of types of organizations at a range of TRL levels throughout the year as needed. This flexibility is balanced by the constraints of the governance structure and Selection Criteria, as well as the reporting to the BCUC which provides oversight over the program.

On pages C-144–C-145 of the Application, FortisBC states that an Innovation Working Group and Executive Steering Committee will be established to provide oversight of the Innovation Fund. Additionally, FortisBC proposes to establish an External Advisory Council to provide insight and feedback on the Companies' innovation initiatives.

FortisBC also states that the Innovation Working Group will be responsible for the Identification, Evaluation and Selection, and Execution stages of projects; and the Executive Steering Committee will provide the strategic direction for the Innovation Fund.

In response to BCUC IR 78.2, under the heading "Stage 2 – Project Selection," FortisBC stated the following:

> On a regular basis, [Innovation] Working Group meetings will be held to review new innovation projects… New innovation projects will not generally be reviewed individually, but as a group in a sub-portfolio. The same sub-portfolio will be reviewed with the External Advisory Council prior to a final investment decision being made as to which (if any) projects within the sub-portfolio will be approved for funding. Between two and four sub-portfolios are envisioned in any particular calendar year.

218.3 Please provide the following information on the decision-making structure of the proposed Innovation Working Group and the Executive Steering Committee:

- How investment decisions will be made and by whom;
- How potential sub-portfolios or groups of projects will be prioritized; and
- The process that would be undertaken to assess and resolve issues of competing interests and objectives. Please also discuss the types of competing interests and objectives which might be encountered.

Response:

FortisBC provides the following supplemental information to its response to BCUC IR 1.78.2 to address the above question in the context of the overall governance structure of the Clean Growth Innovation Fund. Additional information addressed and supplemented below includes project selection criteria and the addition of the stage-gate process that projects will follow.

Clean Growth Innovation Fund - Selection Criteria

FortisBC will use the following five Selection Criteria when selecting innovation proposals for funding from the Clean Growth Innovation Fund:

1. Amount of co-funding secured (from applicant and third parties)
2. Estimated CO_2e reduction in British Columbia
3. Estimated non-CO_2e emission reduction (NOx, SOx) in British Columbia
4. Estimation of energy cost reductions for customers
5. Relevant experience of the applicant project team

Items 2 and 3 will be based on the technical potential identified by the applicant along with BC market potential estimations from the applicant and FortisBC staff.

Item 4 will be based on retail cost and energy use reduction estimates from the applicant combined BC market potential estimations from the applicant and FortisBC staff.

Items 5 will be calculated based on subjective scoring of the applicant's submissions, presentations and resumes provided.

Stage Gate Process

Innovation proposals that FortisBC grants funding will follow a three-stage process, as outlined below.

<u>Stage 1 – Project Identification</u>

FortisBC will become aware of potential funding opportunities in several ways, including:

- Proactively, through a Call for Proposal; or
- Reactively, by becoming aware of potentially relevant innovation projects during the regular course of business:
    - Meetings with other Fortis utilities
    - External Advisory Council meetings

- Industry events
- Meetings with industry associations, technology vendors, academic institutions
- Discussions with other utilities.

Stage 2 – Project Selection

Working Group meetings will be held on a regular basis to review new innovation projects to be included in the overall Innovation Fund portfolio. New innovation projects will not generally be reviewed individually, but as a group in a sub-portfolio. The same sub-portfolio will be reviewed with the External Advisory Council prior to a final investment decision being made as to which (if any) projects within the sub-portfolio will be approved for funding. Between two and four sub-portfolios are envisioned in any particular calendar year.

Each project within a sub-portfolio will be selected through the following stage gate process:

1. **Proposal Outline.**
   The Proposal Outline is a written submission that provides a high-level description of the proposal, the requested funding and the expected benefits (emissions reduction and/or cost reduction).

2. **Grant Proposal.**
   If, based on the Proposal Outline, the applicant proposal is considered by the Innovation Working Group likely to provide customer benefits as defined by the Selection Criteria (see above), then the applicant will be approved to submit a Grant Proposal.

   The Grant Proposal must include:

   a. a detailed written proposal that includes the emission reduction, cost reduction and BC market potential estimates necessary to calculate estimates for the Selection Criteria;
   b. specific project milestones and funding requirements at each milestone event; and
   c. a provision for an on-site meeting to meet the management team and discuss the Grant Proposal.

   After the on-site meeting, it is likely that the Grant Proposal will be revised based on feedback provided by the Working Group.

   Once any revisions of the Grant Proposal are completed by the Applicant, the Working Group will prepare funding recommendations for all of the applicant projects within the sub-portfolio.

If there are more projects that merit funding than allowed by the annual budget, the funding recommendations provided by the Working Group will take into account funding priorities established by the Executive Steering Committee. This may mean that certain projects that may otherwise meet the Selection Criteria are recommended for no funding or for lower funding than requested by the applicant.

The Working Group will also explicitly consider whether there are any undesirable funding duplications or desirable co-funding opportunities with external organizations or with the DSM Innovative Technologies Fund, and adjust their recommendations accordingly.

3. **Consultation**

After the Working Group has completed the funding recommendations for a sub-portfolio based on the Grant Proposals, a meeting with the External Advisory Council will be held to discuss the recommendations and to gather feedback.

The Working Group may amend their funding recommendations based on feedback from the External Advisory Council. The External Advisory Council feedback will form part of the information package for each project presented to the Executive Steering Committee.

4. **Approval**

The Working Group will present the final funding recommendations to the Executive Steering Team for approval.

The Executive Steering Committee may take the recommendations of the Working Group without change or they may modify their approval in their sole discretion.

Individual project budgets, pre-funding conditions, timelines and fund release milestones for approved innovation projects will be finalized after Approval for Execution.

<u>Stage 3 – Execution</u>

The Working Group will meet on a regular basis to review the progress and approve fund releases for all approved and active Innovation Fund projects.

Fund releases will be based on project proponents meeting:

- Pre-funding conditions
- Milestone events

In addition, the Working Group can:

- Approve new milestones and related funding amounts
- Cancel funding for projects
- Close completed projects

Clean Growth Innovation Fund – Annual Review Reporting

FortisBC proposes to report at the Annual Review for each project in the Execution Phase on the following elements.

- Project description and key innovation(s)
- Main innovation activity category (as described in Appendix C6-4)
- Funding portfolio in which the project was approved
- Co-funding obtained and expected
- Estimated benefits
- Quality, Schedule and Cost progress toward pre-funding conditions, milestones and completion

In some cases, details regarding key innovation(s) may be limited at the Annual Review presentation due to confidentiality concerns.

218.4 Please clarify how often the Innovation Working Group intends to meet for the purposes of reviewing new projects. Given that "between two and four sub-portfolios are envisioned in any particular calendar year," does that mean that the Innovation Working Group will meet two to four times per year? For clarity, will the number of meetings be dependent on the number of new innovation projects available for review?

Response:

The Working Group is expected to meet monthly to discuss the progress of innovation projects that are underway and to review any new applications, if any.

218.5 Please explain why FortisBC expects that new innovation projects will "not generally be reviewed individually." What are the pros and cons of reviewing new innovation projects as a group in a sub-portfolio as compared to individually?

Response:

Reviewing projects individually rather than as part of a sub-portfolio can provide a more timely response to the applicant. In some cases, where a project is of high value and the funding need is urgent, this may be the right approach. However, this is expected to be a rare occurrence as it is generally preferable to review projects as part of a sub-portfolio since this allows the governance process to consider the priority and funding requirements of individual innovation projects versus others in the sub-portfolio. This helps optimize funding across the total portfolio.

218.6 Please explain how new innovation projects will be grouped into sub-portfolios (i.e. what criteria) and the number of individual innovation projects that are expected to be included in one sub-portfolio.

Response:

Innovation project applications will generally be grouped into sub-portfolios according to the date in which the Working Group and External Advisory Council review of each Grant Proposal is complete.

In some cases, where a particular innovation area is deemed to require more focus by the Executive Steering Team (based in part on feedback from the Working Group and Executive Advisory Council), FortisBC may issue a request for proposals that meet more specific criteria. In this case, the sub-portfolio would be grouped by those criteria.

218.7 For clarity, please confirm, or explain otherwise, that investment decisions will be made based on individual innovation projects and not the approval/rejection of an entire sub-portfolio.

Response:

Confirmed.

In response to BCUC IR 78.2, under the heading "Stage 3 – Project Management," FortisBC stated: "On a regular basis, the [Innovation] Working Group will meet to review the progress and approve fund releases for all approved and active Innovation Fund projects."

218.8 Please confirm, or explain otherwise, that the term "Project Management" (used in response to BCUC IR 78.2) refers to the same stage of project oversight as the term "Execution" (used on page C-144 of the Application).

Response:

Confirmed.

218.9 Please clarify how often the Innovation Working Group intends to meet for the purposes of reviewing progress and approving fund releases.

Response:

Please refer to the response to BCUC IR 2.218.4.

In response to BCUC IR 78.2 and 82.7.1, FortisBC confirmed that "Project selection and fund disbursements" and "Project halting and financing reallocations" will be done by the Innovation Working Group "in compliance with the strategic direction established by the Executive Steering Committee and will consider the feedback provided by the External Advisory Council."

218.10 Please clarify how often the Executive Steering Committee intends to meet, and how/how often the "strategic direction" of the committee will be documented or updated and communicated to the Innovation Working Group.

Response:

The Executive Steering Committee is expected to meet to review the funding recommendations for each sub-portfolio, which is expected to be two to four times per year. In addition, the

Executive Steering Committee will meet at least once per year to establish the strategic direction for the Innovation Fund.

218.11 Please explain how the Innovation Working Group will "consider the feedback" provided by the External Advisory Council (i.e. what is the nature of the feedback which will be sought from the External Advisory Council, and how, if at all, must that feedback be incorporated into the Innovation Working Group's decisions?)

Response:

Please refer to the response to BCUC IR 2.218.3.

In response to BCUC IR 78.1, FortisBC confirmed that the Innovation Working Group and the Executive Steering Committee will be comprised solely of FortisBC employees.

218.12 Please explain why FortisBC considers that FEI and FBC employees should comprise the entirety of the Innovation Working Group and Executive Steering Committee.

Response:

FortisBC considers that FEI and FBC employees should comprise the Innovation Working Group and Executive Steering committee for a number of reasons, including:

- FortisBC has responsibility for operating the utilities. FortisBC does not believe this obligation can or should be transferred to an external party;
- FortisBC's employees have the expertise required to evaluate innovation proposals that best meet the Selection Criteria of the Clean Growth Innovation Fund within the context of the environment in which FortisBC operates; and
- The governance process for the Clean Growth Innovation Fund already includes an avenue for gathering meaningful external input through the External Advisory Committee as described in the response to BCUC IR 2.218.3.

218.12.1 Does FortisBC consider it necessary or appropriate for either one or both of the two governance bodies to also include representation from external stakeholders (e.g. government, regulators, academia, customers, and/or industry groups)? Please explain why or why not.

Response:

FortisBC considers it appropriate to include representation from external stakeholders, such as those cited in the question, on the External Advisory Council. As described in the response to BCUC IR 2.218.3, the feedback from the External Advisory Council will be considered by both the Innovation Working Group and the Executive Steering Committee. Please refer to the response to BCUC IR 2.218.12.1.

In response to BCUC IR 78.4.1, FortisBC stated that it intends to canvas intervener groups for representation in the External Advisory Council and that "FortisBC would like to have representation from academia and industry groups. A specific process for contacting and selecting representatives will be established pending approval of the Innovation Fund."

218.13 Please discuss the number and type of represented groups which FortisBC would like to have as part of the External Advisory Council and the "minimum" level of acceptable representation.

Response:

The minimum level of representation for the External Advisory Council would comprise one representative with "clean technology" experience from:

- Academia;
- Government;
- FortisBC regulatory process interveners;
- Commission staff; and
- Industry.

More representatives from each group, and potentially representatives from different groups, would be considered depending on relevant experience. However, FortisBC would prefer to keep the External Advisory Council membership to ten representatives or fewer.

218.14 Please discuss the level of interest expressed so far by potential groups to be part of the External Advisory Council.

Response:

FortisBC has not yet canvassed groups and has not formally been approached by groups regarding membership on the advisory council. FortisBC will canvass different groups for External Advisory Council membership following the approval of the Innovation Fund.

218.15 Please explain how often FortisBC intends to meet with the External Advisory Council (i.e. the number of meetings annually and the expected annual time commitment, including meetings and preparation time for meetings).

Response:

The External Advisory Council will need to meet prior to every sub-portfolio funding presentation to the Executive Steering Committee. This is expected to occur two to four times annually. It is expected that members will review the Grant Proposal documents and the draft recommendation of the Working Group prior to the meeting, which might take as much as a day depending on the number of proposals under consideration.

The meetings themselves are expected to be a half-day. Therefore, a maximum annual commitment of six working days for External Advisory Council members is expected.

Please also refer to the response to BCUC IR 2.218.3.

In response to BCUC IR 78.3, FortisBC stated the following:

> FortisBC expects to incur minimal incremental expenses to operate the governance bodies. When also considering costs for the External Advisory Council, annual amounts for meetings and related travel and support costs are expected to total less than $100 thousand (1.8 percent of total expenditures)

across both FEI and FBC funds. These costs are included in the total funding and recovered by the proposed rate rider.

218.16 Please provide a breakdown of the annual cost of Innovation Fund governance by governance body (i.e. Innovation Working Group, Executive Steering Committee, External Advisory Council) and by type of cost (e.g. travel, support, meetings).

Response:

FortisBC expects the labour costs related to governance to be charged to O&M (in the case of the Innovation Working Group and Executive Steering Committee) and to be absorbed by the organizations participating on the External Advisory Council.

The non-labour amounts for each governance body are shown in the following table:

Governing Body	Non-labour costs
Innovation Working Group	$55,000
Executive Steering Committee	$5,000
External Advisory Council	$40,000

These non-labour costs for the governance bodies will be charged to the Innovation Fund and are expected to be limited to travel expenses necessary for site visits and meetings.

218.16.1 Please clarify if there are any governance costs which are not included in the above breakdown which will be charged to O&M. If yes, please provide the amount and why this treatment is appropriate.

Response:

Internal labour costs related to governance of Clean Growth Innovation Fund will be charged to O&M. These costs are for existing staff and are not incremental to the O&M requirement, which is why they are not charged to the Clean Growth Innovation Fund.

218.17 Given that the Innovation Working Group and Executive Steering Committee will be comprised of staff from both FEI and FBC, please discuss how governance costs will be allocated between FEI and FBC and explain the potential impact (e.g. short-term, long-term) of participation in the staff's existing areas of responsibility (e.g. what work and departments are most likely to be impacted and why?)

Response:

Governance costs will be allocated between FBC and FEI on the basis of fund distributions to successful innovation project applicants during the year.

The department that will be most involved is Business Innovation, which will oversee and coordinate the activities of the three governing bodies as well as prepare reports. Other departments that are involved should see minimal impact from an overall workload perspective although there will be times when the work requires focus.

Although there is an overall increase in workload, FortisBC expects that employees will find the work engaging and rewarding and will be able to manage existing responsibilities effectively. Meeting this type of challenge is in line with FortisBC's commitment to find efficiencies to enable it to do more with its existing resources.

In response to BCUC IR 73.10, FortisBC stated the following:

> To capture efficiencies in managing both funds, FortisBC has established the governance committee structure shown in Figure C6-8 of the Application, which includes both the Clean Growth Innovation Fund and the DSM innovative technologies funding.

218.18 Please provide the current annual cost of governance for the DSM Innovative Technologies Fund.

Response:

FortisBC assumes that the IR reference to the DSM Innovative Technologies Fund is the same as approved funding through the Conservation and Energy Management (C&EM) portfolio for the Innovative Technologies Program Area as per BCUC Order G-10-19 (page 5 of the Decision).

The 2018 non-labour costs incurred to support the Innovative Technologies Program Area in 2018 was approximately $87 thousand, which includes membership fees and travel expenses related to technology selection. It is important to note that the costs associated with governance activities for the DSM Innovative Technologies Program Area is unrelated and not comparable to that of the Clean Growth Innovation Fund. The Clean Growth Innovation Fund will be managed as a separate activity and maintain different governance structures than that of the DSM Innovative Technology Program Area as further detailed in the response to BCUC IR 2.218.3. The involvement of the DSM Innovative Technologies stakeholder in the Innovation Working Group as referenced in Figure C6-8 of the Application is to act as an advisor in the determination of whether the technology meets the DSM funding requirements and should be considered or partially considered for DSM funds.

218.18.1 Please confirm, or explain otherwise, that the “less than $100 thousand” cost of Innovation Fund governance provided in response to BCUC IR 78.3 is incremental to the cost of governance for the DSM Innovative Technologies Fund.

Response:

Confirmed.

218.19 Please explain how the total costs of governance will be allocated between the proposed Innovation Fund and the DSM Innovative Technologies fund.

Response:

There will be no allocation required between the proposed Innovation Fund and the DSM Innovative Technologies Program Area as they are managed separately and have differing goals and regulatory requirements. Please refer to response to BCUC IR 2.218.18 for more details.

In response to BCUC IR 82.6, FortisBC stated: “By establishing a central governing committee for expenditures and ensuring that the governing committee is as aware as possible of the research being conducted in each investment area, FortisBC intends to optimize the use of the Innovation Fund."

218.20 Please confirm, or explain otherwise, that the "central governing committee" referenced in the preamble above refers to the governance structure described in Section C6.5 of the Application and shown in Figure C6-8.

Response:

Confirmed.

218.20.1 If not confirmed, please explain what the composition and role of the "central governing committee" is and how it will interact with the governance bodies established for the Innovation Fund.

Response:

Please refer to the response to BCUC IR 2.218.20.

218.21 Please elaborate on the referenced statement above, explaining how the central governing committee will enable FortisBC to be "made as aware as possible" of the research being conducted in each investment area.

Response:

As confirmed in the response to BCUC IR 2.218.20, the reference to a central governance committee in response to BCUC IR 1.82.6 is a reference to the governance structure of the Innovation Fund shown on Figure C6-8 of the Application.

The Innovation Working Group and Executive Steering Committee will have broad knowledge of each investment area for three reasons:

1. The governing bodies will be aware of innovative projects funded by both the Clean Growth Innovation Fund and the DSM Innovative Technologies Fund as well as the innovative activities of the Renewable Natural Gas and Natural Gas for Transportation teams;

2. Employees from different departments will be part of the governing bodies, broadening the range of knowledge and experience; and

3. The governing bodies will receive feedback from the External Advisory Council, further increasing the breadth of information received.

219.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 77.5; Exhibit B-1-1, Appendix C6-1, p. 16

Governance Structure - Comparison with New York State's Millennium Fund

On page 16 of Appendix C6-1, Concentric states the New York Public Service Commission (NYPSC) approved a surcharge intended to fund medium-to-long term R&D by New York's investor-owned natural gas local distribution companies through the Millennium Fund.

In response to BCUC IR 77.5, FortisBC stated the following:

> [An] important difference between New York and BC relates to the role and function of New York State Energy Research and Development Authority (NYSERDA). NYSERDA is a public benefit corporation with the mission to advance innovative energy solutions in ways that improve New York State's economy and environment… Since 1996, NYSERDA's budget is funded by ratepayers through the System Benefit charge (SBC) program. The SBC is collected by investor-owned utilities from gas and electric customers in the State, and funds the majority of NYSERDA's programs. In contrast, such an organization does not exist in BC…

219.1 Please describe the role of each of the NYPSC and the NYSERDA in the governance of the Millennium Fund.

<u>Response:</u>

NYSERDA has no role relating to governance or decision-making with respect to Millennium Fund projects[82]. NYSERDA is an entity that is primarily funded by State ratepayers through the Systems Benefits Charge (SBC) on participating utility bills. These funds are then allocated to the Clean Energy Fund and the Renewable Portfolio Standard for Energy Efficiency programs, research and development initiatives, and other clean energy activities.[83] These funds are distributed into programs[84] that can help consumers and businesses lower their home/business energy bills, reduce their environmental impact, and/or support clean energy and transportation in New York State.

The NYPSC originally approved the incorporation of a Millennium Fund in 1999 to replace the federal surcharge used to support broad-based gas related R&D conducted by the Gas

---

82 Confirmed by NYSERDA through telephone consultation, August 22, 2019.
83 https://www.nyserda.ny.gov/About/Funding.
84 https://www.nyserda.ny.gov/All-Programs.

Research Institute.[85] The Millennium Fund is controlled by energy utilities based in New York.[86] The fund is spent on eligible projects via research providers (such as NYSEARCH - a natural gas research and development group[87]) at the utilities' discretion. In order to qualify for the Millennium Fund, a project must be medium to long term in nature (i.e., projects that are at least twenty-four months or more from becoming a commercially deployable project) and 80 percent of Millennium Funds must be spent on co-funded projects[88].

Utilities propose projects and assess them to see if they meet the qualifications for the Millennium Fund stated above. These projects are then implemented and administered by the utilities who contract research providers (like NYSEARCH) to conduct the research[89]. The NYPSC, similarly to the BCUC, has the ability to inquire into projects and ask questions about how funds are being allocated and what share of the funds come from internal programs, NYSERDA, and the Millennium fund.

219.2 Please explain the method for awarding and administering funds from the Millennium Fund and the role of each of the NYPSC and the NYSERDA in the decision-making process.

Response:

Please refer to the response to BCUC IR 2.219.1.

In response to BCUC IR 77.5, FortisBC stated the following:

> …<u>the administration and management of the Millennium Fund is left largely under the jurisdiction of New York's investor-owned utilities</u> to provide them with the flexibility required to incorporate R&D projects into their unique business circumstances. In comparison, <u>FortisBC's Innovation Fund would be administered by the FortisBC Companies'</u> for innovation projects at all stages of

---

85 Please refer to Attachment 219.1 for a copy of the NYPSC Order Establishing Rates and Terms of Two-Year Rate Plan in Cases 04-G-1047 and 04-G-0837.

86 Please refer to Attachment 219.1 for a copy of NYPSC Exhibit SSP-10, Shared Services – R&D.

87 https://www.nysearch.org/about.php.

88 Attachment 219.1.

89 Please refer to Attachment 219.1 for a copy of NYPSC Cases 16-G-0058 and 16-G-0059, Exhibits dated May 2016.

the value chain to maximize the utilization of its natural gas assets in an evolving climate policy context. [Emphasis Added]

219.3 Please elaborate on the comparison of the role of the utilities in the administration of innovation funds between the Millennium Fund and the Innovation Fund. How are the utilities' roles different?

Response:

The Utilities' role in regard to the collection and governance of the Innovation Fund is similar.

Like the Millennium Fund, the Clean Growth Innovation Fund will be funded by a surcharge on ratepayers' utility bills. The role of the utilities regarding governance and reporting in New York is less clear. Based on the information publicly available, FortisBC believes the NYPSC has the discretion to inquire about the amount spent on a project from NYSERDA funding, Millennium funding and any internal funding on a case-by-case basis. The Utilities' role in New York is, if required by the NYPSC, to report funding to the NYPSC as requested.

FortisBC is proposing to report to the BCUC in a more formal way via the Annual Review process as detailed in response to BCUC IR 2.218.3. The reporting on the Clean Growth Innovation Fund will include information for each project in its Execution Phase, including information on project activities, funding levels, estimated benefits and project timelines.

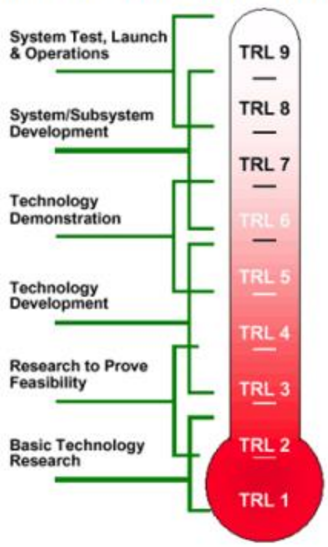
220.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1, p. C-141

Technology Readiness Levels (TRLs)

On page C-141 of the Application, FortisBC provides the following figure showing the broadly-accepted technology readiness levels (TRL) for pre-commercial and commercial innovation activities, which range from TRL 1 through TRL 9:

Figure C6-6: Levels of Technology Readiness Activities[177]



In footnote 177 on page C-141, FortisBC provides a link to the National Aeronautics Space Administration (NASA) which states that the TRL system was adopted by the NASA space program for project tracking and management.

220.1 Please provide a description of each TRL as understood by, and applicable to, FortisBC.

Response:

At this time, FortisBC uses the Innovation Canada definitions of TRL levels (https://www.ic.gc.ca/eic/site/080.nsf/eng/00002.html). FortisBC has reproduced the descriptions below:

Level 1: Basic principles of concept are observed and reported

- Scientific research begins to be translated into applied research and development. Activities might include paper studies of a technology's basic properties.

Level 2: Technology concept and/or application formulated

- Invention begins. Once basic principles are observed, practical applications can be invented. Activities are limited to analytic studies.

Level 3: Analytical and experimental critical function and/or proof of concept

- Active research and development is initiated. This includes analytical studies and/or laboratory studies. Activities might include components that are not yet integrated or representative.

Level 4: Component and/or validation in a laboratory environment

- Basic technological components are integrated to establish that they will work together. Activities include integration of "ad hoc" hardware in the laboratory.

Level 5: Component and/or validation in a simulated environment

- The basic technological components are integrated for testing in a simulated environment. Activities include laboratory integration of components.

Level 6: System/subsystem model or prototype demonstration in a simulated environment

- A model or prototype that represents a near desired configuration. Activities include testing in a simulated operational environment or laboratory.

Level 7: Prototype ready for demonstration in an appropriate operational environment

- Prototype at planned operational level and is ready for demonstration in an operational environment. Activities include prototype field testing.

Level 8: Actual technology completed and qualified through tests and demonstrations

- Technology has been proven to work in its final form and under expected conditions. Activities include developmental testing and evaluation of whether it will meet operational requirements.

Level 9: Actual technology proven through successful deployment in an operational setting

- Actual application of the technology in its final form and under real-life conditions, such as those encountered in operational tests and evaluations. Activities include using the innovation under operational conditions.

220.2 Please explain how FortisBC assigns TRLs to innovation activities (e.g. steps undertaken, review process, etc.)

Response:

FortisBC expects that the determination of the TRL level will not be problematic for the Innovation Working Group who will establish a preliminary assessment upon receiving the Proposal Outline in Stage 2 of the governance process described in the response to BCUC IR 2.218.3. The final TRL assignment will be made when the Grant Proposal is reviewed and the technology readiness level of the proposal is compared to the TRL level descriptions provided in the response to BCUC IR 2.220.1.

220.3 Please explain how the TRL levels correspond to the designation of innovation activities as pre-commercial versus commercially ready innovation.

Response:

FortisBC confirms that TRL Levels 1 through 9 are all considered pre-commercial.

221.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-4, p. 1

Main Innovation Activities – Blending Hydrogen

On page 1 of Appendix C6-4 (Main Innovation Activities), FEI states that it plans to: (i) investigate the feasibility of blending hydrogen into its natural gas delivery system; and (ii) investigate the potential to deliver renewably sourced hydrogen and methanized hydrogen.

221.1 Please provide an estimate of the number of projects FEI intends to initiate related to each of the two investigative activities noted in the preamble above (including pilot projects). For each identified project, please provide the project description/objectives, expected project start/end dates, and the TRL.

Response:

The preamble refers to projects to be undertaken under the Clean Growth Innovation Fund. FEI is currently in the preliminary stages of evaluating the feasibility of blending hydrogen into its natural gas delivery system.

Please refer to the response to BCUC IR 2.221.3 for the potential projects related to hydrogen production and blending that FEI is considering. No other specific projects have been identified at this time; however, some of the objectives that FEI is likely to pursue are:

- Technical due diligence to validate the impacts of hydrogen injection on the gas transmission and distribution systems, including:
  - Material properties
  - Gas metering
  - Injection and control
  - Gas turbine performance.
- Customer end use studies to validate the ability of end users to accept hydrogen blended natural gas:
  - Impacts to residential appliances
  - Impacts to industrial machinery and equipment
  - Impacts to pressure vessels and other materials
  - Ability to separate and remove hydrogen from natural gas.
- Evaluation of supply availability:
  - Assessment of technologies to produce hydrogen

    - Comparison of cost and environmental impact.
- Project opportunity studies:
    - Evaluation of specific projects to determine the technical feasibility and the implementation plan. These projects could be initiated by FEI or by third parties.

In addition to the significant challenges of technical feasibility, there remains considerable uncertainty regarding the policy framework that the provincial and federal governments will pursue, as well as the technical regulatory approvals that will be required. FEI is actively engaging with other utilities, educational institutions and other organizations regarding the hydrogen initiative to look for opportunities to share knowledge and to collaborate on both the investigative activities and the hydrogen blending projects.

221.1.1 Please explain whether FEI plans to undertake these projects on its own or in collaboration with partner organizations.[90] If FEI plans to collaborate with partner organizations, please specify the organization for each project and FEI's role in the project.

Response:

Please refer to the responses to BCUC IRs 2.221.1 and 2.221.3.

FortisBC further states the following in Appendix C6-4:

> FEI intends to initiate two hydrogen injection pilot projects in 2019. Should the technologies that allow hydrogen to be blended into the conventional natural gas distribution system prove to be technically and commercially viable (including safety and operational considerations) and acceptable to customers and stakeholders, FEI proposes that it would then come forward with an application for funding to support a more extensive deployment of hydrogen production and integration technologies. [Emphasis Added]

[90] In these IRs, "partner organizations" means other utilities, academic institutions, businesses, industry associations, provincial government, federal government and other non-government organizations which are third-parties to FortisBC.

221.2 In the event that either one of the two hydro injection pilot projects proves to be technically and commercially viable and acceptable to customers and stakeholders, please clarify whether FEI intends to seek additional funding for the Innovation Fund or separate capital funding to proceed with the project(s).

Response:

FEI confirms that it would seek separate capital funding if it decided to proceed with a commercially viable hydrogen injection project as capital investments are outside the scope of the Clean Growth Innovation Fund. Depending on the project, funding could be approved as regular capital through FEI's Investments in a Clean Growth Future, or through a separate application.

On page 1 of Appendix C6-4, FortisBC also states that FEI and FBC will assess "other related opportunities" including power-to-gas technologies that bridge the traditional electrical power grid and natural gas delivery system.

221.3 Other than the "power-to-gas technologies" project, please provide the number of "other related opportunities" that FEI and FBC plan to undertake, including the project descriptions/objectives, and the TRL of each project.

Response:

FortisBC, through the NGIF, is considering funding two different projects that could lead to the commercial production of renewable hydrogen. One is at TRL 9 and uses methane stream reforming to create hydrogen from RNG. The other is at TRL 4 and uses an innovative proton exchange membrane catalyst to create hydrogen from electrolysis. In addition, the University of British Columbia is considering creating a hydrogen injection pilot on campus in which FortisBC would consider participating.

221.4 Please explain whether the project to assess "power-to-gas technologies" will be funded by the Innovation Fund for FEI or FBC or both, and please provide the TRL of the project. If it will be funded by both FEI and FBC, please explain how the funding costs will be split between FEI and FBC's Innovation Funds.

Response:

For clarity, the above preamble refers to other power-to-gas technologies that FEI and FBC are assessing. Such opportunities could include hydrogen as a storage medium for the electric system. FBC has not considered investing in the opportunities identified in the response to BCUC IR 2.221.3 at this time, but if a potential benefit to FBC were identified, innovation expenses would be shared in an equitable manner according to the potential benefit flowing to FEI and FBC respectively.

221.5 Please explain whether FEI or FBC plan to undertake each of the above projects on its own or in collaboration with partner organizations. If FortisBC plans to collaborate with partner organizations, please specify the organization for each project and FortisBC's role in the project.

Response:

FEI and FBC are likely to undertake power-to-gas innovation projects in partnership with external organizations. Please refer to the response to BCUC IR 2.221.3 for potential partnerships.

222.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 74.2, 74.3; Exhibit B-1-1, Appendix C6-4, pp. 1 – 2

Main Innovation Activities – Renewable Natural Gas

On pages 1–2 of Appendix C6-4 (Main Innovation Activities), FEI states that it plans to undertake a project to produce RNG using wood waste as feedstock and provides a brief description of the project.

In response to BCUC 74.2, FortisBC stated the following:

> Policy and legislation support is needed from the Province to advance the commercial production of hydrogen. FortisBC understands the Province is currently developing a BC Hydrogen Roadmap, which will form the basis for such policy and legislative changes.

222.1 Please discuss when FortisBC anticipates the BC Government will release the BC Hydrogen Roadmap and enact the associated policy and legislative changes.

Response:

FortisBC attended a workshop on July 3, 2019 hosted by the BC Bioenergy Network regarding the findings of the hydrogen report completed by Zen and the Art of Clean Energy Solutions (Zen) on behalf of the BC Government. The report completed by Zen is complete. In conversations with the BC Government since the workshop, the plan to release the report is still being developed. The Companies' understanding is the BC Government is determining whether the Zen report will form the foundation of the BC Hydrogen Roadmap or if it will be the Roadmap itself.

Hydrogen is one potential source of renewable gas. FortisBC, along with BCUC staff, attended a workshop hosted by the BC Government on June 10, 2019 aimed at kicking off consultation related to the Province's 15 percent renewable gas target outlined in CleanBC. During this meeting, the BC Government indicated it intended to create a renewable gas standard applicable to companies like FortisBC and Pacific Northern Gas. In contrast to the current Greenhouse Gas Reduction Regulation which sets allowable, discretionary limits for RNG, a renewable gas standard would require FortisBC to meet yet to be determined renewable criteria over a given time period.

FortisBC's understanding is that this consultation process will be the forum in which any potential legislative changes will be pursued. No additional details on process, including policy and legislative changes, have been provided by the BC Government since the June 10th meeting.

The BC Government has clearly indicated it is prioritizing RNG as shown by the fact that in CleanBC, 75 percent of the 2030 GHG reductions in the building sector are forecast to come from RNG, an amount far greater than reductions expected from electrification. Furthermore, as mentioned above, the BC Government has told FortisBC and the BCUC it intends to develop legislation requiring renewable content. Given these factors and as confirmed in BCUC IRs 1.2.4 and 2.207.3, it is imperative that FortisBC accelerate the adoption of RNG through innovative projects enabled by the Clean Growth Innovation Fund.

Given this context and the fact the province has signaled its intent to require FortisBC by legislation to meet a renewable criteria, FortisBC believes that it would be imprudent to stop any work on innovation related to renewable gases until all the policy work is put in place. Further, FortisBC knows from its experience with implementing other innovative programs, such as natural gas for transportation and the first stage of renewable natural gas, that innovation informs the policy process.

222.2 Please discuss whether FortisBC is aware if the BC Government will issue policy and legislative changes with regard to RNG and, if so, please indicate the expected timing.

Response:

Please refer to the response to BCUC IR 2.222.1.

222.2.1 Please discuss whether it would it be more appropriate for FEI to delay all innovation projects related to RNG until after such policy and legislative changes are in place. If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.222.1.

222.3 Please explain the impact that the BC Hydrogen Roadmap is expected to have on FEI's research regarding using wood-waste as feedstock for RNG, if any.

Response:

Although FortisBC does not anticipate any impact from the BC Hydrogen Roadmap on wood-waste RNG production research, the content has not been published by the BC Government, as discussed in the response to BCUC IR 2.222.1.

However, the report completed by Zen and the Art of Clean Energy Solutions referenced in the response to BCUC 2.221.1 refers to biomass gasification as a potential hydrogen feedstock. Assuming the BC Hydrogen Roadmap also references biomass gasification, the Companies foresee using these findings to inform its research requirements.

Biomass feedstock, such as wood-waste, has many potential competing uses including for the production of renewable gases such as RNG, syngas and hydrogen as well as other liquid and solid fuels. FortisBC is continuing to monitor developments in this area.

In response to BCUC IR 74.3, FortisBC stated:

> The wood-waste process is currently under development and not commercially available, although it has the potential to increase RNG generation in BC to about 90 PJ annually." However, despite the ongoing research and development of wood-waste technology, FEI stated that it believes "it will need to source RNG from outside of the province to achieve the 15 percent renewable gas policy goal by 2030.

222.4 Please clarify and explain the extent to which FEI intends to leverage/build-on existing research in wood-waste technology and/or undertake entirely new research in this technology. To the extent that FEI intends to collaborate on or fund third-party research, please explain what FEI's role will be in these circumstances and the extent of its potential funding contributions.

Response:

FEI's intends to leverage existing research in this area and seek partnerships to move technologies forward. Appendix C6-4 references some of the research activity already underway that may be leveraged. FortisBC would seek to collaborate with those and other parties to move research forward. Accordingly, FEI's funding contribution would fund a portion of total research dollars. FEI's role in the collaboration would include establishing the commercial value and terms of the end product, measuring energy and gas quality, carbon accounting and policy work all related to FEI's interest in acquiring the RNG on behalf of its customers.

A related example is work that FEI has very recently initiated in collaboration with the BC Pulp and Paper Bio-Products Alliance, the Ministries of Energy, Mines and Petroleum Resources, Forest Lands and Natural Resource Operations, Environment and Climate Change, the BC BioEnergy Network and FP Innovations. The group has co-funded a technology scan looking at two opportunities. The first is technologies that could convert wood waste into syngas (a renewable gas) to partially or wholly displace natural gas in pulp mill lime kilns. The second opportunity would be to convert that syngas into methane gas for injection into the FEI system. FEI is funding approximately 30 percent of the study's costs. All of the parties that are involved in the collaboration have their own reasons for participating. The BC Government, for example, is interested in both the opportunity to develop value added industries for woody biomass that currently goes to waste and they are seeking ways to reduce British Columbia's greenhouse gas emissions as part of CleanBC. The pulp and paper industry is interested in reducing its waste streams which represent potential costs and FEI is interested in new sources of renewable gasses.

Should the study show there is a business case for one or both of the opportunities, the study would move to a second phase with the ultimate goal of developing a demonstration plant at a BC mill within the next 5 years that would be sized at ¼ to ½ the size of a gasifier that would meet the entire needs of the kiln. While both of the opportunities identified are new to British Columbia, syngas from biomass has been used in lime kilns in other parts of the world. While the initial cost of the technology scan is relatively small, if the project moves ahead, FEI currently lacks a mechanism to participate with the other partners in the project. This is one example of an area the proposed Innovation Fund would be helpful in moving technical innovation forward.

222.5 Please further explain the basis for FortisBC's statement in response to BCUC IR 74.3 that the "wood-waste process has the potential to increase RNG generation in BC to about 90 PJ annually."

Response:

The statement is based on a March 2017 RNG resource potential study by Hallbar Consulting Ltd. commissioned by the Province of British Columbia, FortisBC, and Pacific Northern Gas. The study estimated that based on a wood-waste feedstock estimate from a Natural Resources

Canada study the ultimate potential of RNG from wood-waste was 93.6 PJ/year (Figure 5, Page 23).[91]

[91] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

223.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-4, p. 2

Main Innovation Activities – Carbon Capture

On page 2 of Appendix C6-4 (Main Innovation Activities), FEI states the following:

> GHG emissions can be dramatically reduced through the utilization of carbon capture technologies in conjunction with end-use applications in both the build environment and industrial processes. FEI is exploring those end-use carbon capture technologies and is currently conducting a small-scale pilot with Clean 02 (a manufacturer of an end-use carbon capture device called Carbonix) to test and demonstrate energy efficiency and GHG reductions of up to 10 units.

FEI further states that it considers Clean 02 to be both a DSM and non-DSM activity. Specifically, FEI states the following:

> Funding for costs such as M&V Equipment to measure energy savings and incentives for the unit are eligible to receive DSM funds from the Innovative Technology Program while costs pertaining to measuring emission reductions and by-product production were covered from O&M.

In addition, FEI believes "additional Non-DSM funds will be required to explore and research carbon capture technologies similar to Clean 02 as well as supporting the commercialization of the technology category."

223.1 Please provide the TRL of Clean 02 and the historical actual costs which FEI has contributed towards the pilot by year.

Response:

CleanO2's carbon capture unit should be considered at TRL Level 9. Innovation Canada's definition of this TRL is *"Actual application of the technology in its final form and under real-life conditions, such as those encountered in operational tests and evaluations. Activities include using the innovation under operational conditions."* The unit is a commercially ready product in early adoption stage. FEI has made the following contributions towards this pilot program by year broken out by DSM and O&M:

Year	O&M	DSM
2017	$ 1,245	$ -
2018	$ 113,050	$ 123,861
2019	$ 16,100	$ 2,765
Total	**$ 130,395**	**$ 126,626**

Note: The 2018 O&M cost reported in the response to the BCUC IR 1.1.1 in FEI's Natural Gas Demand Side Management Annual Report filing was $112,312. This number did not include employee travel expenses, which are now included in the figure above

223.1.1 In the event that the Innovation Fund is approved, please explain whether the amount currently provided by O&M for Clean 02 will be removed (i.e. similar to FEI's proposal with respect to NGIF funding).

Response:

FEI expects that most of the O&M and DSM funding required to complete the CleanO2 pilot project will be paid out in 2019. As noted in the response to BCUC IR 2.223.1, FEI's cost is approximately $16 thousand in 2019, such that the 2018 funding has already been redeployed to address other priorities.

The funding of this project through O&M was appropriate at the time as there was no specific Innovation Fund and it helped to find solutions for customers that would help reduce emissions, reduce energy use while continuing to be a natural gas customer (as opposed to leaving the gas system for other fuels). O&M funds currently used for projects such as CleanO2 will continue to be used for projects and/or efforts to attract and retain customers that would be ineligible for grants from the Innovation Fund. If a new GHG reducing project like CleanO2 occurred in 2020, it would be funded from of the Innovation Fund.

223.1.2 Conversely, in the event that the Innovation Fund is not approved, please explain whether FEI intends to continue funding Clean 02, and if so, please explain where the funding would be recorded and how much the funding would be likely be annually during the proposed MRP term.

Response:

In the event that the Innovation Fund is not approved, FEI will provide the remaining funding required to complete the scope of the pilot as per its current funding structure. These amounts would be recorded in O&M Account 310-12 Energy Solutions. However, FEI expects that all the funding required to complete this pilot will have been recorded by the end of 2019.

223.2 Please explain how (i.e. by what process) the costs of Clean 02 are split between DSM funding and O&M funding.

Response:

The expenditures and costs associated with the measurement and evaluation of the energy efficiency aspects of the pilot were covered through FEI's DSM budget. The expenditures and costs associated with the measurement and evaluation of the carbon capture aspects of the pilot were covered by O&M.

223.3 Please confirm, or explain otherwise, that additional non-DSM funds required "to explore and research carbon capture technologies similar to Clean 02" noted in the preamble above will be funded by the Innovation Fund.

Response:

Confirmed. In the event that the Innovation Fund is approved, FEI expects to fund activities such as the exploration and research into carbon capture technologies through the Innovation Fund.

223.3.1 Please provide the number of projects FEI intends to initiate as part of the above activity, the expected project start/end dates, and the TRL of each project.

Response:

The carbon capture industry is presently at a very early stage of development, as is FEI's research into the area. FortisBC is aware of two additional carbon capture proposals that might be eligible for funding from the Innovation Fund; however, FEI does not have detailed information regarding the technology or if the proponents require funding. FEI can confirm that the proposals are seeking funding to develop new methods of capturing carbon from a variety of sources including natural gas powered engines, RNG upgrading and agricultural processing centers. Based on the information available, one is approximately TRL 4 and the other approximately TRL 9. FEI does not have information regarding expected start/end dates.

224.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-4, p. 2

Main Innovation Activities – Non-DSM Consumer End Use Technologies and Systems

On page 2 of Appendix C6-4 (Main Innovation Activities), FortisBC states:

> Often when working with builders and developers, a need is expressed for a heating or energy solution that is not commonly used or for a solution that is not yet developed… In these situations, FortisBC works with manufacturers, retailers, and HVAC contractors to devise a workable energy solution for the developer.
>
> An example of such a technology is Combined Heat and Power [CHP] technology that utilizes natural gas to generate electricity and supply heat… FortisBC is interested in furthering development of more efficient CHP units. However, CHP units are generally ineligible for DSM funding since the majority of installations are in new applications where natural gas use may actually increase. Despite this, FortisBC believes it is important to continue researching efficiency improvements in this technology. [Emphasis Added]

224.1 Please provide descriptions/objectives for all "Non-DSM Consumer End Use Technologies and Systems" that FortisBC is interested in furthering the development of, the expected timing of these projects (date of start/finish), and the TRL of each project.

Response:

FortisBC is continually researching end-use technologies that consumers could use to meet their energy requirements. Some of this activity is ad hoc through relationships with vendors, manufacturers, HVAC contractors and the building community, while other activity is more structured. Most of these related projects are with technology that is already in market, but is not commonly used in the region. The purpose of this type of investigation, research and project is to encourage the use of the equipment in different configurations and settings as well as to encourage the use in the region. Examples of this include wall furnaces, small-scale furnaces and boilers as well as micro CHP units.

In addition, FortisBC may fund research into non-DSM systems that could reduce the cost of energy for ratepayers. For example:

- FortisBC could fund innovation related to the use of aircraft or satellite imagery to identify vegetation management issues using machine learning techniques (potentially lowering costs for both FBC and FEI customers).

- FortisBC could also fund research into analytical techniques that use AMI meter data to derive a connectivity relationship between meters, transformers and distribution phases. This connectivity relationship is used for a variety of purposes including distribution system modeling, identifying the source of outages and notifying customers of outages. Analytical connectivity model corrections could save costs by avoiding having to send crews out to map connectivity relationships in the field. Customers could also benefit since outage location predictions and customer outage notifications would be more accurate.

If these or similar projects proceed, FortisBC will be providing information on timing and TRL during the Annual Review process.

224.1.1 Please explain whether FortisBC would likely undertake the above projects on its own or in collaboration with partner organizations. If FortisBC plans to collaborate with partner organizations, please specify the potential organization for each project and FortisBC's potential role in the project.

Response:

FortisBC would undertake projects in collaboration with partner organizations. FortisBC would evaluate potential collaboration opportunities on a project-by-project basis. The potential project opportunity, the customer benefit, the technology provider, and the interest of other parties would help determine and guide FortisBC in determining if FortisBC would undertake a project on its own or as a partner.

224.2 Please explain whether FEI or FBC will be researching more efficient CHP units and whether or not it will be in in collaboration with partner organizations (e.g. other utilities, academic institutions, BC Government, Federal Government).

Response:

Over the last decade or more, FEI has investigated and researched CHP units for commercial and residential use. In addition, the NGIF has a number of pilot projects that are CHP-based and as such have a variety of other partner organizations. Depending upon the opportunity including the interest from customers, availability of technology, complexity, and cost, FEI or FBC would partner with other organizations.

224.3 Given that new applications of CHP units may increase natural gas use, please elaborate on why FortisBC believes it is important to continue researching CHP technology and how research in this area is expected to contribute to meeting the CleanBC targets.

Response:

Combined heat and power units use natural gas as an energy source to produce both heat and electricity. The needs of customers vary with some customers focusing on reducing emissions, others focusing on operational issues and others focusing on costs. CHP units can offer a number of benefits to customers including increased resiliency, lower costs, valuable by-product (heat), greater manufacturing or operational efficiency, and the ability to use low carbon fuels such as RNG. CHP projects can run on RNG or hydrogen, thus they would be emission free and align with the Government of BC's Clean BC strategy.

225.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-4, pp. 6–8

Main Innovation Activities – EV and Charging Stations

On page 6 of Appendix C6-4 (Main Innovation Activities), FBC states that its focus is to support the expansion of EV charging infrastructure and it will provide the infrastructure necessary to catalyze the adoption of EVs in BC's Southern Interior. FBC states: "Incremental funding is required to support the operation of the EV stations. [However], <u>achieving these plans will depend in part on the outcome of the EV Charging Service Inquiry</u> currently being conducted by the BCUC." [Emphasis Added]

On June 24, 2019, the BCUC issued its Phase Two Report on the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service, outlining its findings and recommendations to Government with regard to non-exempt public utilities' participation in the EV charging services market.[92]

225.1 Please provide an update on FBC's plans with respect to EV charging stations subsequent to the issuance of the BCUC's Phase Two Report in its Inquiry into the Regulation of Electric Vehicle Charging Service.

<u>Response:</u>

FBC is currently awaiting the B.C. Government's response to the BCUC's recommendations contained in its Phase Two Report of the Inquiry into the Regulation of Electric Vehicle Charging Service and understands that the B.C. Government may be contemplating a new regulation relating to EV charging services based on the recommendations contained in the Phase 2 Report.

Given the implications of any new regulation on the regulatory framework for utility ownership and operation of EV charging stations, FBC's current plans with respect to construction and operation of EV stations are limited to:

- completing a deployment currently underway of 12 direct-current fast charging (DCFC) stations that were approved for partial funding under Natural Resources Canada's (NRCan) Electric Vehicle and Alternative Fuel Infrastructure Deployment Initiative; and
- the submission of an application to NRCan's Zero-Emission Vehicle Infrastructure Program later this year for additional funding to support the deployment of at least 20 DCFCs in 2020/21.

[92] Retrieved from: https://www.bcuc.com/Documents/Proceedings/2019/DOC_54345_BCUC-EV-Inquiry-Phase2-Report.pdf.

However, the decision to move forward with the additional 20 stations noted above will depend on the BC Government's response to the Inquiry recommendations.

In addition:

- FBC is partnering with the B.C. government and BC Hydro to administer a provincial rebate program for Level 2 charging installations for homes and workplaces later this year.
- FBC is exploring opportunities to provide incentives to customers for the EV charging equipment that may provide a demand-side benefit to FBC, and is presently conducting a feasibility study to examine different technology options and determine the technical potential of demand-side measures enabled by those technologies.
- FBC is examining opportunities to support educational activities related to electric vehicles including education regarding EV charging services and infrastructure requirements.
- FBC is considering how to support EV station deployments in multi-unit residential and commercial buildings.

225.2 Please provide the TRL and expected timing (date of start/finish) of each of the following RD&D opportunities listed in Appendix C6-4, supporting the development of EV charging infrastructure in BC: (i) Dynamic Load Control Research; (ii) Return to Base Charging Solutions Pilot; and (iii) Innovative DCFC Architectures Pilot.

Response:

As noted in the response to BCUC IR 2.207.7, pre-commercial activities are generally well-funded in the electric vehicle industry. As a result, FBC expects to only focus on late-stage TRL 9 and commercial demonstration and pilot projects related to EV-related innovation opportunities. FBC expects work on these innovation opportunities to occur throughout the term of the MRP.

RD&D Opportunity	Technology Readiness Level	Expected Timing (date of start/finish)
Dynamic Load Control Research	TRL 9 and commercial	Q1 2020 – Q4 2021
Return to Base Charging Solutions Pilot	TRL 9 and commercial	Q1 2021 – Q4 2023
Innovative DCFC Architectures Pilot	TRL 9 and commercial	Q1 2021 – Q4 2023

225.2.1 Please explain whether FBC plans to undertake each of the above projects on its own or in collaboration with partner organizations. If FBC plans to collaborate with partner organizations, please specify the organization for each project and FBC's role in the project.

Response:

Although FBC is still developing project plans for the EV-related innovation opportunities outlined in Appendix C6-4, it is expected that FBC will collaborate with partner organizations with FBC's role in the various initiatives yet to be determined. For certain initiatives, such as for return to base charging and innovative DCFC architectures, it is likely that FBC would lead the investment, deployment, and ownership of these charging solutions and would partner with a technology vendor as well as an existing fleet operator for the projects.

For other initiatives like dynamic load control research, it is likely that FBC would instead provide support for technical development, deployment, and data analyses with infrastructure ownership and operation left to a specific customer and/or partner organization. Some of the vendors that FBC may potentially work with on the EV-related innovation activities include ABB, Siemens, Wave, Momentum Dynamics, and AddEnergie.

226.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-4, p. 8

Main Innovation Activities – Developing Digital Natural Gas Feedstock

On Page 8 of Appendix C6-4 (Main Innovation Activities), FEI states that it “wants to gain a better understanding of ‘Digital Feedstock’ and, in particular, the barriers to broad-based adoption of digital feedstock as a basis for natural gas trading.”

> FEI explains that currently there is only one characteristic of natural gas that is measured and traded, however natural gas produced by different plants can vary on a number of other dimensions that customers might care about (such as, GHG content and ethane content).

FEI further states the following:

> Allowing for trading on these additional dimensions first requires data collection at the plant level. It then also requires a trading platform, possibly enabled by secure private or public ledger technology such as blockchain that can capture, verify, and disseminate this additional data about each unit of gas supplied to the market. Finally, it requires market participants to be willing to adopt or participate in this enhanced platform-based marketplace.

> RD&D investments in this technology will be focused on implementing demonstrations projects that would demonstrate to stakeholders, gas producers and gas purchasers how well the technology works and allow better assessment of the business and environmental benefits.

226.1 Please clarify and discuss whether FEI’s planned investment in this area relates to implementing “demonstrations projects” to market participants, building the technology (i.e. undertaking data collection, developing the trading platform), or a combination of both.

Response:

FortisBC intends to fund a white paper discussing: 1) how digital feedstock might incent an increase in production and usage of lower carbon fuels; 2) different platforms/architectures that could be used to more efficiently capture and transact RNG commodities; 3) how smart contracts might reduce operational costs and increase efficiency.

Depending on the results of this research, FortisBC may elect to fund pilot projects with willing market participants to further test the concept.

226.2 Please explain whether separate investments will be required for each (new) characteristic of natural gas that can be measured and traded on or if the investments are the same irrespective of the number or additional trading dimensions.

Response:

FortisBC does not expect to separately fund proposals for each characteristic of natural (or renewable) gas, and the investment will be similar regardless of the number of dimensions tracked. Additional dimensions may require additional funding for sensors and telemetry within a specific grant proposal however.

226.3 Please explain how FEI's planned investment in this area contributes to meeting the CleanBC targets.

Response:

If successful, digital feedstock would create a market price for additional attributes of natural and renewable gas. For example, a lower level of CO_2e emissions during conventional natural gas production may drive a higher price in the market. This would in turn provide a financial incentive for producers to lower their production CO_2e emissions and drive lower overall emissions from the industry.

227.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-4, pp. 9–10

Main Innovation Activities – Reducing Fugitive Emissions

On pages 9-10 of Appendix C6-4 (Main Innovation Activities), FEI states the following:

> With the innovation funding, FEI intends to invest in an optical gas imaging device, investigate welding options for residential meter sets, use new methane technology on vehicles to increase the frequency of leak detection on distribution pipelines, pursue decommissioning of high bleed pneumatic devices and conduct additional studies looking to improve our estimates on GHG emissions.

227.1 Please provide the number of projects FEI intends to invest in related to the RD&D activities noted in the preamble above. For each identified project, please provide the project descriptions/objectives, expected timelines (start to finish) and the TRL.

<u>Response:</u>

The emission reduction projects that FEI intends to invest in as part of the Clean Growth Innovation Fund are presently being identified and assessed. Project examples include research into optical gas imaging technologies, welding options for residential meter sets, vehicle-mounted methane detection technologies, decommissioning of high-bleed pneumatic devices and studies looking to improve estimates of GHG emissions. Project descriptions/objectives, expected timelines and TRL levels will not be known until specific initiatives and partnerships are identified.

227.1.1 Please explain whether FEI plans to undertake these projects on its own or in collaboration with partner organizations (e.g. other utilities, academic institutions, BC Government, Federal Government). If FEI plans to collaborate with partner organizations, please specify the organization for each project and FEI's role in the project.

<u>Response:</u>

The emission reduction projects that FEI intends to invest in as part of the Clean Growth Innovation Fund are presently being identified and assessed as outlined in the response to BCUC IR 2.227.1. As these projects are developed, opportunities for collaboration with partner organizations including other utilities, academic institutions, BC Government, Federal

Government and industry associations will be pursued. FEI's role with promising innovative initiatives is likely to be as an advisor, funding partner and testing site provider.

228.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-4

TRL Summary

228.1 Please summarize in a table the TRL of all projects described in the IRs above and any other projects referenced in Appendix C6-4.

Response:

The TRL levels of the projects referenced in Appendix C6-4 are generally provided in the heading for each of the Main Innovation Activities.

The TRL levels for the EV charging activities described in Appendix C6-4 Sections 1.8 (Dynamic Load Control Research - RD&D Stage), 1.9 (Return To Base Charging Solutions Pilot - RD&D Stage) and 1.10 (Innovative DCFC Architectures Pilot - RD&D Stage) are TRL 7-9 and possibly early-stage commercial.

Main Innovation Activity	TRL Level
Blending Hydrogen	3-6
Renewable Natural Gas	2-6
Carbon Capture	2-6
Non-DSM Customer End-Use Technologies & Systems	4-8
Natural Gas for Transportation	3-6
Hydrogen for Transportation	2-4
Electric Vehicles and Charging Stations	4-9 & Commercial
Dynamic Load Control	4-9 & Commercial
Return-to-Base Charging	Commercial
Innovative DCFC Architecture	4-9 & Commercial
Developing Natural Gas Feedstock	4-8
Reducing Fugitive Emissions	4-6
NGIF	2-8

229.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-1-1, Appendix C6-1, p. 8, Appendix C6-4

Concentric: Regulator Rationale for Ratepayer-funded Electricity and Natural Gas Innovation

On page 8 of Appendix C6-1 (Concentric: Regulator Rationale for Ratepayer-funded Electricity and Natural Gas Innovation), Concentric states the following:

> Government funding is most appropriate in the high-risk early research & development phase or where there are significant spillover benefits that discourage risk-taking. Utility customer funding is most appropriate where the benefits largely accrue to utility customers and where they are in a unique position to test new technologies and business models.

In Appendix C6-4 (Main Innovation Activities), FortisBC describes the main innovation activities that FortisBC intends to pursue with the Innovation Fund and the estimated range of TRLs of the activities.

229.1 Please confirm, or explain otherwise, that FortisBC considers that all of the innovation projects it intends to be pursue in Appendix C6-4 (as described in the IRs above) meet Concentric's requirements for innovation which is appropriately utility customer funded.

Response:

FortisBC believes the Main Innovation Activities in Appendix C6-4 align with Concentric's recommendations. Funding of research at lower TRL levels is likely to occur only with government co-funding, whereas funding of high-level TRL innovations will often include funding from other utilities and other organizations.

230.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 70.1; Exhibit B-1-1, Appendix C6-4

2020 Expenditure Level

In response to BCUC IR 70.1, FortisBC provided the following forecast for Innovation Fund expenditures by segment for 2020:

Segment	FEI ($ millions)	FBC ($ millions)
Supply	1.5	
T&D	0.5	
End-Use: Buildings	1.0	0.1
End-Use: Industry	0.5	
Transportation	1.5	0.4
Total	**$5.0**	**$0.5**

Appendix C6-4 (Main Innovation Activities) of the Application describes the main innovation activities that FortisBC intends to pursue and some of the related projects.

230.1 Please provide a further breakdown of the Innovation Fund expenditures by segment for 2020 into labour and non-labour cost components and by project. Please specify the relationship between each project and the specific innovation activity and explain whether it is for “pre-commercial” or “commercial” innovation.

Response:

It will not be possible to provide the requested information until Grant Proposals are received as contemplated in the governance proposal detailed in the response to BCUC IR 2.218.3. The forecast provided in the response to BCUC IR 1.70.1 is itself only a rough estimate of the expenditures in each segment.

However, a “rule of thumb” is that initiatives at a lower TRL level will generally have a higher labour proportion than those at a higher TRL level. This is because lower TRL levels tend to be focused on academic research and higher TRL levels on pilots of equipment. This is only a rule of thumb and will not always hold true.

230.2 With respect to labour costs, please clarify the extent to which the innovation work will be undertaken by existing FortisBC employees, new employees or contractors, or a combination of both.

Response:

Innovation work will be performed by the organizations that receive funding. FortisBC expects it will incur minimal internal labour costs, aside from governance costs. Please refer to the responses to BCUC IR 2.218.16 and 2.218.17 for details of the governance costs and the impact on FortisBC employees.

230.2.1 To the extent that innovation work is undertaken by existing FortisBC employees, please explain the impact (e.g. short-term, long-term) of the work on employees' existing areas of responsibility, including what work and departments are most likely to be impacted.

Response:

Please refer to the response to BCUC IR 2.230.2.

231.0 Reference: FORTISBC CLEAN GROWTH INNOVATION FUND

Exhibit B-10, BCUC IR 78.2, 80.1.1, 80.2, 80.2.4; Exhibit B-1, p. C-142; Ofgem Low Carbon Networks Fund Governance Document v.7,[93] pp. 10, 14

Key Success Indicators and Reporting

The regulation, governance and administration of projects funded by the Low Carbon Networks Fund (LCNF) established by Ofgem are set out in the "Low Carbon Networks Fund Governance Document v.7

On page 10 of the document (subsection 2.3), Ofgem states:

> 2.3 The Successful Delivery Reward Criteria are Project specific. A DNO [distribution network operator] must have set out the Successful Delivery Reward Criteria that it proposes for its Project as part of its Full Submission.[94] These proposed Successful Delivery Reward Criteria must comply with the following principles in that they must be:
>
> - linked to meeting identified targets for the outputs that will be expected to be delivered through the Project,
> - linked to meeting identified Project milestones, on at least an annual basis,
> - linked to achieving the proposals it puts forward for generation of new knowledge to be shared amongst all network operators, and
> - SMART objectives - specific, measurable, achievable, relevant and time bound…

2.6 If a Project is selected for funding, the DNO must submit to Ofgem a Project Progress Report at least every six months. The Project Progress Report must be of a standard considered by Ofgem as sufficient to provide Ofgem with the comfort that the Project is being successfully delivered and demonstrate progress against the agreed Successful Delivery Reward Criteria. [*Emphasis Added*]

In response to BCUC IR 80.1.1, FortisBC stated the following:

> Ratepayers will be able to evaluate success by looking at the leading indicators in terms of completing projects on time, on budget and within scope, additionally, at the lagging indicators specific to individual innovation projects that have been

[93] Retrieved from: https://www.ofgem.gov.uk/sites/default/files/docs/2015/04/lcnf_gov_doc_v7_-_final_clean_0.pdf

[94] Subsection 2.4 further notes that The Expert Panel and Ofgem may suggest changes to the Successful Delivery Reward Criteria proposed within the Full Submission as part of their consideration of the Full Submissions. The DNO can choose to accept these changes, which then forms part of the Full Submission.

completed and by the specific benefits that are expected to be achieved from each. [*Emphasis Added*]

231.1 Please discuss whether FortisBC would be amenable to adopting an approach similar to Ofgem in which: (i) lagging indicators specific to individual projects must be established during the "Evaluation and Selection" stage of projects; and (ii) the Innovation Working Group's evaluation of these targets would be reported to the BCUC in the proposed MRPs' annual reviews.

Response:

FortisBC has proposed lagging indicators similar to those required by Ofgem for specific projects for reporting to the BCUC. As described in the response to BCUC IR 2.218.3, governance of the fund includes establishing funding releases based on the project applicant meeting pre-funding conditions and milestone events. Pre-funding conditions and milestone events will be established during the Project Selection phase and will be based on SMART[95] principles. FortisBC expects to report on the selection criteria for each project in addition to the pre-funding conditions and milestone events at the MRP annual reviews.

In response to BCUC IR 78.2, FortisBC stated that "Project targets achievement evaluation" is the responsibility of the Innovation Working Group.

In response to BCUC IR 80.2, FortisBC stated the following:

> FortisBC expects to report on the following items related to the Clean Growth Innovation Fund at the Annual Reviews, plus any other items as directed by the BCUC:
>
> - Description and status of current projects;
> - New initiatives granted funding and current initiatives granted additional funding;
> - Completed project milestones; and
> - Project benefits (if successfully commercialized)

On page C-142 of the Application, FortisBC lists "Ensure Transparency" as the first out of six guiding principles underpinning the design and operation of the Innovation Fund

95 Specific, Measureable, Achievable, Relevant and Time-bound

and describes this principle as "The Companies will be accountable to the BCUC in and administration and oversight of the Fund."

231.2 Please discuss what FortisBC considers to be the BCUC's role in "the administration and oversight" of the Innovation Fund in the Annual Reviews. Specifically, in what way(s) does FortisBC anticipate it will be held "accountable" to the BCUC? For example, would the BCUC have the ability to review the prudency of the expenditures?

Response:

The BCUC will have the ability to review innovation projects that have received funding from the Clean Growth Innovation Fund including the project overview, expected benefits (as collected during the selection process described in the response to BCUC IR 2.218.3), the amount of co-funding secured, and expected and project milestones completed and planned, which will be reported at the Annual Review.

As with all innovation funding, there are inherent risks. Not all innovation projects will successfully lead to commercial innovations that will benefit customers. However, FortisBC believes that the evidence cited in the Application, along with the proposed governance structure, provides reasonable assurance that benefits will outweigh risks. If the BCUC finds that the Innovation Fund has not been effectively administered, it has a range of options it can exercise with respect to future funding and the ability to review the prudency of past expenditures.

231.3 Please compare and contrast the proposed content in the Annual Reviews for the Innovation Fund to the information that FortisBC provides to the BCUC with respect to the DSM Innovative Technologies program.

Response:

The information that FortisBC provides to the BCUC with respect to the DSM Innovative Technologies program area is included in the Natural Gas Demand-Side Management Programs Annual Report (DSM Annual Report). The DSM Annual Report outlines the actual energy savings results and expenditures for each year compared to the accepted DSM Plan. It details the Company's activities for the overall DSM Portfolio and in each DSM Program Area. It includes incentive and non-incentive expenditures at both the Portfolio and Program Area levels and reports overall cost effectiveness test results. The DSM Annual Report also includes an overview of activity in each Program Area.

The information that FortisBC expects to provide in the Annual Review regarding the Innovation Fund (as described in the preamble to this question and with further detail provided in the response to BCUC IR 2.218.3) is quite similar. It will not be possible to provide "actual" innovation project benefits (unless a specific innovation has become commercialized), but estimated benefits will be provided.

The Innovation Fund spending will be broken down in terms of the Main Innovation Activities described in Appendix C6-4 rather than by customer sector.

Similar to the DSM Program Area report, FortisBC will be providing an overview and description for each Innovation Fund project expenditure.

In response to BCUC IR 80.2.4, FortisBC stated that it "believes that the information that it will report in each of the Annual Reviews during the term of the proposed MRPs will be sufficient and that a final evaluation report and mid-term report would duplicate the information already provided."

On page 14 of the Ofgem "Low Carbon Networks Fund Governance Document v.7," Ofgem states:

> The DNO will be required to provide a detailed report, (the Project Progress Report), at least every six months, of sufficient detail to allow Ofgem to evaluate the progress of the Eligible LCN Fund Project. This must include information that will allow Ofgem to monitor how the DNO is performing against all of the Successful Delivery Reward Criteria. Ofgem may provide further guidance about the structure and contents of this report. Ofgem will publish the report on its website. If there is any confidential information in the Project Progress Report, this must be included in a separate confidential annex, which will not be published on Ofgem's website.

231.4 Please elaborate on the reasons why FortisBC believes that the information in an individual innovation project final evaluation report and mid-term report would duplicate the information it will report on in each of the Annual Reviews.

<u>Response:</u>

FortisBC believes that information provided for an individual innovation project in the Annual Review will be similar in many respects, but acknowledges that it may not be the same as the final report for that same innovation project. Therefore, information provided in a mid-term or final report for the Clean Growth Innovation Fund as a whole could differ from that provided in each of the Annual Reviews. FortisBC is willing to provide a mid-term or final report, although, as noted above, the information provided therein is not likely to differ materially from that provided in the Annual Reviews.

231.5 Please compare and discuss the pros and cons of the reporting proposed by FortisBC and the reporting requirements applied by Ofgem for the administration of projects funded by the LCNF for (i) FortisBC, (ii) the BCUC, and (iii) ratepayers.

Response:

FortisBC intends to prepare the same reporting for all three parties referenced in the question as described in the response to BCUC IR 2.218.3. The reporting as described in BCUC IR 2.218.3 is aligned to the reporting required by the LCNF. Due to the similarities in reporting requirements, "pros and cons" related to differences in reporting cannot be distinguished.

The Low Carbon Networks Fund is significantly larger than the fund being proposed by FortisBC. The fund could spend up to GBP 64 million on innovation and would be accessible to the tens of Distribution Network Operators (DNOs) established in the United Kingdom. The LCNF has since been replaced by the Network Innovation Competition and the Network Innovation Allowance funds as part of the performance-based RIIO framework.

Reporting in the RIIO framework is detailed. For example, reporting on innovation is categorized based on the type of solution being invested in. Categories include increasing network capacity/utilization, improving asset life cycle management, improving network performance, improving vegetation management, improving safety and improving environmental impact. Within each category DNOs report on a number of costs and benefits including gross avoided costs, estimated network losses, estimated customer interruptions, and estimated GHG emissions reductions.

FortisBC considers the Annual Review reporting described in the response to BCUC IR 2.218.3 to be similar to that required in the RIIO framework. Benefits are categorized by Main Innovation Activity, and the costs and benefits will be detailed to the extent possible.

232.0 Reference: INNOVATION FUND

Exhibit B-10, BCUC IR 74.1

Investment in RNG

In response to BCUC IR 74.1, FortisBC stated the following:

> The current CPCN threshold for non-GGRR biomethane projects appears to be inconsistent with the RNG objectives of the GGRR and the expanded CleanBC policy objective of achieving 15 percent renewable content in the gas supply stream. Given a $30/GJ ceiling price for RNG and very large supply targets, the current $5 million threshold for a non-GGRR CPCN is too low.

232.1 Please further explain why the existence of the $5 million CPCN threshold for non-GGRR biomethane projects is inconsistent with the RNG objectives of the GGRR and the expanded CleanBC policy.

Response:

While FEI is not seeking an increase to the non-GGRR CPCN threshold at this time, FEI believes that a higher threshold would allow for a more efficient review process for biomethane projects overall which will assist in expanding supply, consistent with the objectives of the GGRR.

Over the last two years, FEI has undertaken significant work to expand the biomethane supply funnel. In the course of that work, FEI's understanding of the cost of biomethane supply has grown through conversations with project proponents. The biomethane supply projects in the supply funnel, both direct investment projects where FEI is taking raw biogas and making the investment in the upgrading equipment and projects where third parties are proposing to provide FEI with finished biomethane have capital costs ranging from about $8 million to over $100 million.

232.2 Please clarify if FEI is requesting approval of a change to the CPCN threshold for non-GGRR biomethane projects in this proceeding. If no, please explain what actions or proposed actions FEI intends to take regarding the CPCN threshold.

Response:

FortisBC has not requested approval of a change to the CPCN threshold for non-GGRR biomethane projects in this Application but does expect to request a change to the threshold in the near future. Since the capital and operating costs to support the RNG program are forecast each year, a change in the CPCN threshold would not affect the level of capital expenditures included in the MRP or the approvals required to effect the MRP.

H. SERVICE QUALITY INDICATORS

233.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-10, BCUC IR 84.3, 84.5, 84.6, 90.7; FEI PBR Decision, p. 155

FEI and FBC Service Quality Indicators

In response to BCUC IR 84.3, FEI provided the current and proposed Service Quality Indicators (SQIs) with benchmarks as well as the 2016 through 2018 results and the average 2016 through 2018 results for each of these SQIs.

With regard to the Telephone Service Factor (TSF) (Emergency) SQI, FEI proposes to maintain the existing approved benchmark of “>=95%”, while the average 2016 through 2018 results show that 98% of calls were responded to within one hour.

FEI stated the following in response to BCUC IR 84.3 regarding the TSF (Emergency): “Three year average methodology not applicable. Proposed benchmark of 95% recognizes an appropriate balance between cost and service level as was determined in the PBR proceeding.”

On page 155 of the FEI PBR Decision, the BCUC stated that FortisBC and stakeholders should take into consideration the following factors when establishing the performance range for SQIs:

- The variance that has been experienced in the benchmark historically;
- The historic trend in the benchmark;
- The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;
- The sensitivity of the benchmark to external factors such as weather or economic conditions; and
- The impact of lower SQI levels on the provision of reliable, safe or adequate service.

In response to BCUC IR 84.5, FEI confirmed that in its review process to determine the appropriateness of continuing to use the existing thresholds, FEI considered the factors identified in the FEI PBR Decision and that it placed a “particular focus on considering the actual performance of the metric during the term of the Current PBR Plan.”

233.1 With specific reference to each of the five factors identified in the FEI PBR Decision (as provided in the above preamble), please provide a detailed assessment of FEI’s proposal to maintain the existing approved benchmark of “>=95%”for the TSF (Emergency) SQI.

Response:

Maintaining the TSF (Emergency) at 95 percent represents an appropriate balance between costs and service quality as was determined in the PBR proceeding. FEI's assessment of its proposal to maintain the existing approved benchmark is as follows.

Variance and Historical Trends

Although the recent three-year average may suggest 98 percent, actual history and results during the Current PBR Plan term indicate that FEI has been under 98.0 percent in 4 out of 5 years, with results ranging from 95.8 percent to 98.5 percent.

Type of Call [96]	2014	2015	2016	2017	2018
Emergency	95.8%	97.6%	98.5%	97.6%	97.9%

External Benchmarking

As mentioned in the Application on page B-54, for two of the SQIs (i.e., Emergency TSF and First Contact Resolution), there was insufficient peer group benchmarking data with which to compare FEI. Therefore, FEI has relied on its own experience and history in determining a proposed benchmark for Emergency TSF.

Impact of External Factors

External factors beyond FEI's control, such as extreme weather conditions, natural disasters (e.g., fire, flood) or atmospheric odors, can have significant impacts on the Emergency TSF. These external factors cannot be planned for and are challenging to recover from. This is because these types of events may drive a large volume of calls, which may create challenges meeting the benchmark at that point in time as well as for the month, depending on the ratio of total calls for the month.

Impact on Safe and Reliable Service

At the 95.0 percent Emergency TSF target, FEI is able to provide customers with reliable and safe service. In addition to the fact that FEI plans and schedules employees to answer 95 percent of these calls within 30 seconds or less, calls within the Emergency queue are answered on average in less than 12 seconds as per Table C7-4 in the Application. If FEI were to increase Emergency TSF to 98.0 percent, it would require an increase of approximately 2 to 3 FTE (approximately $113 to $170 thousand) per year to increase the likelihood that FEI could meet the target during all business hours.[97] Due to current average response time and already

96 Table A:C5-1-5 on page 6 of Appendix C5-1.
97 This additional FTE requirement has been calculated based on FEI's Emergency TSF as of July 2019 and the

high level of targeted service, FEI believes that an increase in service level targets and resourcing would not change the reliability of service or safety for our customers.

233.2 Please explain in detail how FEI determined that the proposed benchmark of 95% represents "an appropriate balance between cost and service level." Please specifically address how FEI determined that 95% was an acceptable service level and provide the cost required to maintain this service level.

Response:

Please refer to the response to BCUC IR 2.233.1.

FEI does not separate out the costs associated with supporting the Emergency queue and as such, the cost required to maintain this service on a stand-alone basis is not available. However, the current Base O&M for FEI includes the cost required to maintain a 95 percent service level for Emergency TSF. On incremental basis, approximately 2-3 FTE would be required to support an increase in the benchmark service of 3 percent.

233.3 Please explain how FEI determined that an additional amount of cost would be required in order to maintain a higher service level (i.e. maintain a benchmark of 98%). As part of this response, please estimate the additional cost required to maintain a benchmark of 98% and explain how FEI derived this estimated amount.

Response:

Please refer to the response to BCUC IR 2.233.1.

TSF target of 98.0 percent for the remainder of the year. Any unexpected external factors resulting in an increase in Emergency calls could impact FEI's ability to meet the Emergency TSF target of 98.0 percent.

With reference to the All Injury Frequency Rate (AIFR), FEI stated the following in response to BCUC IR 84.3:

> For AIFR, the current benchmark remains appropriate as the Company assesses the trend and sustainability of recent years' safety performance. The AIFR results have improved in recent years, but they should be monitored and reviewed on a longer term and trend basis, before the existing benchmark is adjusted to reflect recent historical performance.

With reference to First Contact Resolution, FEI stated the following in response to BCUC IR 84.3:

> The current benchmark approved by the BCUC at 78 percent based on setting a target that was above the industry average for call centre performance (i.e. 2012 SQM 71%). Recent industry average for call centre performance (i.e. 2018 was 70%) remains consistent with 2012 comparator.

With regard to FBC's First Contact Resolution SQI, as shown in response to BCUC IR 90.7, FBC proposes to maintain the existing approved benchmark of ">=78%" while the average 2016 through 2018 results were 80% and the results have consistently trended upwards since 2015.

233.4 Please explain why the AIFR results should be monitored and reviewed on a longer term and trend basis before the existing benchmark is adjusted. As part of this response, please provide, with rationale, the duration that FEI considers the AIFR results should be monitored.

<u>Response:</u>

AIFR results are inherently volatile in the short term. Contributing to the volatility of the AIFR performance in the short term is that the cause and nature and numbers of injuries in industrial, field type working environments, where workers may often conduct similar tasks for decades, are often unpredictable for short time periods. In addition, the AIFR results can be affected by a relatively low number of injuries (one or two) causing volatility in the results in the short term, but that are not necessarily indicative of either improvements or deficiencies in the safety management system. As the AIFR incorporates this inherent level of volatility, it requires a long-term perspective to be adopted to accurately evaluate trending and determination of the sustainability of recent years' safety performance.

As a result, safety results should be viewed on a longer term and trend basis, with the duration of longer term dependent on a sustained trend in performance materializing. The following are the historical AIFR results from 2009 to 2018. As evidenced by the Annual Results, the AIFR performance has been volatile, with performance ranging from 1.36 to 3.02 during the time frame 2009 to 2018.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Annual Results	2.49	2.66	1.66	1.91	3.02	1.73	2.52	2.13	1.36	1.74
Three year Rolling average	2.55	2.26	2.27	2.08	2.20	2.22	2.42	2.13	2.00	1.74
Benchmark	n/a	n/a	n/a	n/a	n/a	2.08	2.08	2.08	2.08	2.08
Threshold	n/a	n/a	n/a	n/a	n/a	2.95	2.95	2.95	2.95	2.95

FEI believes the current benchmark remains appropriate as FEI assesses the trend and sustainability of recent years' safety performance. While FEI has implemented programs in recent years like the Target Zero safety program and a focus on continuous improvement which have contributed to the improved results in recent years, the number of injuries in a given year is inherently unpredictable.

In its assessment of the continued use of the existing benchmark of 2.08, FEI considered a number of factors and provides the following discussion, referencing where applicable each of the five factors identified in the FEI PBR Decision for determination of SQI thresholds. FEI notes the five factors referred to in the preamble and identified in the FEI PBR Decision were not intended necessarily to be applied in the determination of appropriate benchmarks but instead were intended to be used in the development of acceptable performance ranges for SQIs. As a result, the factor "The historic trend in the benchmark" was not considered applicable to the determination of the benchmark itself.

In its proposal to maintain the benchmark at 2.08:

1. FEI reviewed the historical annual results for the variances and any sustained trends in performance. During the term of the Current PBR Plan, from 2014 to 2018, AIFR results have fluctuated from a low of 1.36 in 2017 to a high of 2.52 in 2015 with a similar performance of 2.13 observed in 2016. While recent years' performance has been lower, there have been years in the past (2009, 2010, 2015), as shown in the table above, that have been significantly higher demonstrating the inherent volatility with the AIFR results over a relatively short to mid-term period.

2. FEI did not specifically consider AIFR performance results in other utilities and jurisdictions, as AIFR performance may vary depending on the different operating conditions for each utility/jurisdiction, making AIFR difficult to compare with other companies on a like-for-like basis.

3. Regarding the sensitivity of the AIFR benchmark to external factors such as weather and economic conditions, it is difficult to determine what impact, if any, such conditions would have on AIFR performance. Any impact would likely be incorporated in the historical results.
4. Finally, concerning the impact of lower SQI levels on the provision of reliable, safe or adequate service, FEI believes that the benchmark of 2.08 represents a level that is reasonable, as suggested by performance during the term of the current PBR Plan.

233.5 With specific reference to each of the five factors identified in the FEI PBR Decision (as provided in the above preamble), please provide a detailed assessment of FEI's proposal to maintain the existing approved benchmark of "<=2.08" for the AIFR SQI.

Response:

Please refer to the response to BCUC IR 2.233.4.

233.6 With specific reference to each of the five factors identified in the FEI PBR Decision (as provided in the above preamble), please provide a detailed assessment of each of FEI's and FBC's proposal to maintain the existing approved benchmark of ">=78%" for the First Contact Resolution SQI.

Response:

FEI and FBC propose to maintain the existing approved benchmark at >=78% for First Contact Resolution (FCR) as it recognizes an appropriate balance between cost and service level as was determined in the PBR proceeding. Our assessment considering each of the five factors follows.

Variance and Historical Trends

When considering past performance, FBC has been higher than the approved benchmark performance in three of the five years, with a five-year average performance of 78 percent and FEI has been above the benchmark in all five years with a five-year average performance of 81 percent. Due to the relatively close performance and expected consistent level of experience between the Companies, FortisBC took the approach of setting a consistent FCR target for both companies that is achievable by both Companies at 78 percent. This benchmark level also recognizes that variances may occur due to the considerations described below.

First Contact Resolution [98]	2014	2015	2016	2017	2018
FBC [99]	73%	76%	79%	80%	82%
FEI [100]	80%	81%	81%	80%	83%

External Benchmarking

As mentioned in the Application on page B-54, for two of the SQIs (i.e., Emergency TSF and First Contact Resolution), there was insufficient peer group benchmarking data with which to compare FortisBC. Therefore, FortisBC relied on its own experience and history in determining a proposed benchmark for FCR. Although peer group data for benchmarking was not available, FortisBC did consider data available from Service Quality Metrics (SQM), a third party provider that FortisBC uses to review experiences with customers. Historically, FEI and FBC have performed higher than the Average Energy Company (70 percent) and Average Call Centre (72 percent) as demonstrated by the 2018 SQM results, further indicating that existing performance represents a very high level of service quality.

Impact of External Factors

Future technological changes and customer preferences may impact FCR in the near future as customers may resolve a variety of simpler transactions through self-serve options while complex issues will still be managed through real-time conversations between customer service representatives and customers. This shift may create fluctuations or variances FCR as more complex issues may be less likely to be resolved in the first interaction. FBC and FEI will continue to focus efforts in this area to determine what level of FCR is appropriate while balancing cost and service level.

Impact on Safe and Reliable Service

The Companies would need to conduct a review to determine opportunities (if any) that may exist to further improve FCR and accordingly, what resources and costs would need to be invested in order to achieve a higher overall benchmark. As noted above, due to the already high level of service experienced, the Companies did not believe it was necessary to conduct a review of this nature at this time. Further, the impact of external factors may create shifts in

[98] Note that as per SQM, the three-year average (2016 through 2018) margin of error is 3 percent for FBC and 1 percent for FEI.
[99] Table A:C 5-2-6 on page 7 of Appendix C5-2
[100] Table A:C 5-1-8 on page 9 of Appendix C5-1

FCR that the Companies will be monitoring and may require consideration and review of potential opportunities.

Thus, considering performance over the PBR term, SQM average energy company and call centre FCR results, and overall relatively high customer satisfaction levels, FEI and FBC believe that >=78 percent is the appropriate benchmark that allows the Companies to provide safe, adequate and reliable service to our customers for this MRP term.

233.7 Please discuss the likely factors which have contributed to FBC's upwards trend in the First Contact Resolution SQI since 2015 and what FBC's expectations are regarding First Contact Resolution during the proposed MRP term.

Response:

FBC's upward trend in the First Contact Resolution (FCR) SQI since 2015 can be attributed to process improvements and training that were implemented to address specific types of interactions that previously showed lower FCR. For example, high bill inquiries were reviewed and areas of opportunity were identified for improvement in FCR with these types of interactions.

First contact resolution is directly linked to high levels of customer satisfaction, and FBC has made significant efforts to empower its staff to achieve first contact resolution wherever reasonably possible; however, FBC also recognizes that not all interactions can be resolved on first contact. Some interactions require further investigation in order to get the right solution for the customer.

Please also refer to the response to BCUC IR 2.233.6.

In response to BCUC IR 84.6, FEI stated the following:

> In reviewing its existing SQIs, in addition to the replacement of the current informational SQI Telephone Abandonment Rate with the new informational SQI Average Speed of Answer, FEI considered adopting additional Safety related measures to complement the existing AIFR metric used to measure employee safety. FortisBC is looking into introducing other indicators of safety performance, which are leading indicators that capture the presence of "safety" and occurrence of proactive activities like safety observations and inspections. Further work on

investigating this new approach to measuring safety performance through both lagging and leading indicators is required. FortisBC has not progressed enough to be in a position to propose new safety related measures at this time.

233.8 Please explain when FortisBC expects to complete the investigation into the new approach for measuring safety performance.

Response:

FortisBC expects to complete the investigation into the new approach to measuring safety performance during 2019/20. This will entail participation in industry safety committee sub-groups that have recently been set up specifically to review safety performance metrics in the industry and the inclusion of leading indicators alongside lagging indicators such as AIFR.

233.8.1 Please confirm, or explain otherwise, whether FortisBC expects to propose the new measures during the proposed MRP term and, if so, whether this would be done as part of the Annual Review process.

Response:

Any proposed changes to safety related measures will be included as part of the Annual Review process.

I. TARGETED INCENTIVES

234.0 Reference: TARGETED INCENTIVES

Exhibit B-10, BCUC IR 96.1, 96.3

Targeted Incentives

In response to BCUC IR 96.3, FortisBC stated the following:

> FortisBC would pursue each of the targets in the absence of approval in order to address the emerging challenges and opportunities in its operating environment. However, the in the absence of approval of the Targeted Incentives, FortisBC would be less likely to achieve the targets or the same level of performance as it would with Targeted Incentives. This is due to the lack of an incentive to undertake the extraordinary efforts and investment of resources required to achieve these outcomes, the resulting shift in focus to traditional incentives and service quality, and the lack of BCUC endorsement of the targets as priorities to be addressed during the term of the MRPs.

234.1 Please further explain why, in the event that the BCUC does not approve FortisBC's targeted incentives as applied for, FortisBC would interpret such an outcome as a lack of BCUC endorsement of the targets as priorities to be addressed during the term of the MRPs.

Response:

The underlying purpose of an incentive is to promote and reward a desired outcome. As such, FortisBC's response to BCUC IR 1.96.3 was based on the premise that, if the BCUC did not approve the proposed targeted incentives, it would signal that the BCUC did not consider that it should promote or reward the proposed outcomes or that it places greater importance and priority on other outcomes. In particular, it may indicate that the BCUC believes that now is not the time for FortisBC to invest significant resources in addressing the longer-term challenges in its operating environment including responding to energy policy.

234.2 Please discuss in detail other components of each of FEI and FBC's proposed MRPs that, if approved, would be supportive of the goals identified by the targeted incentives.

Response:

The following describes in detail the other components of FEI and FBC's proposed MRPs that are supportive of the goals identified by the targeted incentives:

FEI	
Targeted Incentive	**MRP Components Supportive of the Identified Goal**
Growth in Renewable Gas	• Flow-through treatment of O&M and capital costs supports the ongoing growth of renewable gas supply. • The Clean Growth Innovation Fund supports the advancement of renewable gas technologies which promote increased supply and reduced costs for customers.
Growth in NGT	• Flow-through treatment of O&M and capital costs supports the ongoing growth of NGT demand. • The Clean Growth Innovation Fund supports the advancement of NGT technologies which strive to lower costs for customers which increases demand.
GHG Emission Reduction – Internal	• The Clean Growth Innovation Fund supports the advancement of technologies aimed at cost effective emissions reductions.
GHG Emission Reduction – Customer	• The incremental spending identified for Connect to Gas of $1.2 million supports, amongst other initiatives, increased customer conversions to natural gas from higher carbon fuel sources.
Customer Engagement	• FEI's capital requirements include enhancements to customer service-related systems. • FEI has commenced a bill redesign project focusing on increasing customer engagement and is also designing an online customer portal that will give customers access to various energy usage reports as well as creating a single sign on solution for customers.

FBC	
Targeted Incentive	**MRP Components Supportive of the Identified Goal**
Customer Engagement	• FBC's capital requirements include enhancements to customer service-related systems. • FBC has commenced a bill redesign project focusing on increasing customer engagement and is also designing an online customer portal that will give customers access to various energy usage reports as well as creating a single sign on solution for customers.

FBC	
Targeted Incentive	**MRP Components Supportive of the Identified Goal**
Growth in Electric Vehicle Transportation[101]	• Flow-through treatment of O&M and capital costs supports the ongoing growth of EV. • The Clean Growth Innovation Fund supports the advancement of technologies related to electric vehicles and charging stations which reduce costs for customers which increases demand.
Power Supply Incentive	• There are no other framework elements which support the achievement of the Power Supply Incentive.

In response to BCUC IR 96.1, FortisBC stated the following:

> The level of performance embedded in each of the Targeted Incentives listed inTable C8-1 of the Application represents performance above and beyond conventional service and creates positive value for customers. In other words, the Targeted Incentives have been designed to create outcomes above what is normally expected in the regular course of business.

234.3 Please describe in further detail how FortisBC has defined "performance above and beyond conventional service" and "outcomes above what is normally expected in the regular course of business." Please fully explain the basis for these definitions.

Response:

Generally speaking, conventional performance expectations are set through various means, including the requirement for prudent behavior, establishing spending envelopes through forecast or formulaic means, and implementing basic service quality metrics. FortisBC was referring to these conventional performance expectations that drive outcomes normally expected in the regular course of business.

In contrast to these basic expectations of performance, FortisBC has proposed a suite of targeted incentives which seek to enhance performance in specific areas. The level of performance built into these areas is not addressed through the conventional means noted above. Further, even if the proposed performance levels were mandated as opposed to incentivized, the utility could not be penalized for failing to achieve a target (such as the 20-fold

[101] FortisBC notes that a target has not been established for this incentive area; however, it anticipates that those framework elements identified in the response could reasonably support an EV Charging incentive.

increase in RNG supply by 2024[102]), considering the utility's right to recover its prudently incurred costs and earn a fair return. Therefore, in these important but emerging areas, an incentive-based approach is the most effective means to achieve the desired outcomes.

234.4 In the event that the proposed Targeted Incentives were not approved, please explain how each of FEI and FBC might alter its level of effort and investment in the areas related to the Targeted Incentives. Please explain in detail and quantify where possible.

Response:

As noted in the response to BCUC IR 2.234.1, FortisBC would interpret the denial of the proposed targeted incentives as a signal that other outcomes, such as achieving cost efficiencies should be prioritized before targeted incentives areas. FortisBC would continue to expend effort and investment towards targeted incentive areas, but would also place additional focus on achieving outcomes of higher priority first.

It is not known at this time what investments will be required to achieve the outcomes of the targeted incentives, or even if FortisBC will be able to be achieve the outcomes by the end of the MRP term. In other words, the level of effort and investment required has not been discovered yet. The purpose of the targeted incentives is to spur the Companies to focus efforts and resources on achieving the particular outcomes, so that the opportunities and investments needed to do so are discovered and pursued over the five-year MRP term.

[102] Exhibit B-10, FortisBC Response to BCUC IR 1.96.7.

235.0 Reference: TARGETED INCENTIVES

Exhibit B-10, BCUC IR 2.5, 74.3, 97.1, 97.3; Exhibit B-5, BCOAPO IR 92.3.1; Exhibit B-1, p. C-160; CleanBC Plan, Executive Summary, p. 5

Growth in Renewable Gas (RG)

On page C-160 of the Application, FEI states that the projected RNG production volume for 2018 is 342,300 GJs.

In response to BCOAPO IR 92.3.1, FEI provided the following table which it stated shows the actual RNG volumes each year from 2013 to 2018:

RNG Volume by Year	2013	2014	2015	2016	2017	2018
Supply (TJ)	93.1	105.4	132.8	133.6	155.0	178.1

235.1 Please clarify if, based on the table provided in response to BCOAPO IR 92.3.1, the actual RNG for 2018 was 164.2 TJs less than projected.

Response:

FEI clarifies that the 2018 RNG volume on page C-160 of the Application of 342.3 TJ is actually the projected sales volume, rather than the production volume[103].

FEI's 2018 production volume forecast was 275.4 TJ. Accordingly, the actual production volume variance for 2018 was approximately 100 TJ (275.4 TJ projected production volume minus 178.1 TJ actual production volume).

The variance of approximately 100 TJ was primarily due to lower than expected supply from four of the five RNG facilities. The four facilities individually produced between 15 percent and 45 percent less RNG than was originally anticipated over the 2018 year.

235.1.1 If yes, please explain the causes of the significant difference in RNG volumes from what was projected.

Response:

Please refer to the response to BCUC IR 2.235.1.

[103] Exhibit B-1, page C-160, lines 1-2.

235.2 Please provide the projected RNG production volume for 2019 and explain the basis for this projection.

Response:

FEI projects RNG supply of approximately 250 TJ for 2019. This is based on actual production to the end of July of approximately 147 TJ annualized to year end (147 / 7 x 12).

235.3 Please explain if the historical actual volumes of RNG provided in response to BCOAPO IR 92.3.1 represent the total volume of renewable gas produced by FEI in each of these years. If no, please provide a revised table showing the historical RG volume by year and explain where the other source(s) of RG were obtained.

Response:

FEI confirms that volumes provided in the response to BCOAPO IR 1.92.3.1 are actual historical volumes purchased or produced by FEI.

In response to BCUC IR 2.5, FEI stated the following:

> The GGRR [Greenhouse Gas Reduction (Clean Energy) Regulation] also includes recent amendments to the prescribed undertakings to include renewable natural gas (RNG) as a transportation fuel for natural gas transportation customers, which supports the policy statement quoted above regarding "increasing the production of renewable transportation fuels". The inclusion of RNG for transportation applications in the GGRR provides further opportunities for GHG emissions reductions due to the much lower carbon intensity of RNG as compared to conventional natural gas, and even more so, conventional diesel fuel.

235.4 Please explain whether the recent amendments to the GGRR regarding RNG were considered by FEI when developing its Growth in RG target.

Response:

FEI confirms that the recent amendments to the GGRR regarding RNG were considered when developing the Growth in RG target, but that this did not result in an "increase" to the targets, because the legislation was in place before the targets were developed.

235.4.1 If yes, please explain how and whether FEI increased its targets to reflect the amendments to the GGRR.

Response:

Please refer to the response to BCUC IR 2.235.4.

235.4.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.235.4.

235.5 Please discuss whether FEI considers the recent amendments to the GGRR coupled with the objectives outlined in the CleanBC Plan to be an endorsement from the Provincial Government of FEI's targets as priorities to be addressed during the term of the proposed MRP.

Response:

The amendments to the GGRR and the CleanBC Plan were both introduced prior to FortisBC's MRPs. Accordingly, FortisBC regards its MRPs as aligning with the objectives of the amended GGRR and CleanBC Plan.

235.6 Please explain if the recent amendments to the GGRR regarding RNG may increase FEI's ability to meet its proposed targets for other incentives beyond the "Growth in RG" incentive. If yes, please explain which incentives may be impacted. If no, please explain why not.

Response:

The recent amendments to the GGRR were introduced before setting the proposed target for Growth in NGT. Therefore, the amendments have no impact on the targets, but are nonetheless, generally supportive of growth in RG.

In response to BCUC IR 97.1, FEI provided the following table showing the percentage of renewable gas content in FEI's total natural gas throughput for each of the targets:

	2020	2021	2022	2023	2024
RG Target (PJs)	1.0	1.5	2.0	4.0	6.0
RG Target (%)	0.52	0.78	1.04	2.07	3.11

235.7 In consideration of the CleanBC Plan's goal of a minimum requirement of 15 percent of renewable content in natural gas by 2030, please explain if FEI considers its target of 3.11 percent by 2024 to be adequate.

Response:

RNG supply is projected at approximately 0.25 PJ for 2019. Given that RNG must increase by more than 10 times within the MRP term, considerable up-front effort is required to gain the necessary momentum to achieve the 2024 MRP target of 3.11 percent. This upfront effort not only includes the commercial aspects, but also the work required for the provincial government to develop enabling legislation supporting the 15 percent renewable gas target. These items will take time and FEI believes that the trajectory towards 2030 will be exponential and will not follow a straight line. Accordingly, FEI believes that the target of 6 PJ by 2024 is an appropriate five-year target.

235.7.1 As part of the above response, please explain how FEI might reasonably increase its RG content to a percentage closer to the

CleanBC Plan goal of 15 percent by 2030 if its target is to be at 3.11 percent as of 2024.

Response:

Please refer to the response to BCUC IR 2.235.7.

235.8 Please provide an update on the development of any Governmental regulations regarding RG. As part of this response, please discuss, based on information available to FEI, when it expects that regulations regarding RG may be issued.

Response:

Please refer to the response to BCUC IR 2.222.1.

235.9 Please explain why FEI does not consider it more appropriate to wait until Government regulations/mandates regarding RG are issued before implementing the Growth in RG Targeted Incentive. Please discuss the pros and cons of this approach.

Response:

Please refer to the response to BCUC IR 2.222.1.

In response to BCUC IR 97.3, FEI stated that it is “also pursing out-of-province and off-system options which may also increase annual volumes, but remain uncertain.”

FEI also stated the following in response to BCUC IR 74.3:

> FEI believes that it will need to source RNG from outside the province to achieve the 15 percent renewable gas policy goal by 2030. RNG sourced from outside of BC is both an expedient and an effective way to help reach the provincial government target. From a time-to-market perspective, there are shovel-ready

> projects in jurisdictions like Ontario that present an opportunity for BC and FEI's customers.

On page 5 of the CleanBC Plan, the Executive Summary states:

> Along with our actions to reduce greenhouse gas (GHG) emissions, CleanBC provides an effective blueprint to build our economy. Rising to meet the global challenge of climate change is an opportunity for British Columbia to mobilize our skilled workers, natural resources, and booming technology sector to reduce climate pollution and create good jobs and economic opportunities across B.C.
>
> …
>
> CleanBC describes how, together, we can make things more efficient, use less energy and waste less, while making sure that the energy we use is the cleanest possible and the greatest extent possible made-in-B.C.

235.10 Please explain in detail how pursuing out-of-province sources for RG would align with the CleanBC Plan. As part of this response, please specifically address the goal of creating economic opportunities across BC.

Response:

While the details of the CleanBC policy goal of 15 percent renewable content in the gas used by residential and industrial customers have not yet been determined, pursuing out-of-province RG meets the objectives of the CleanBC Plan for GHG emissions reduction and economic development:

- GHG Reduction: The CleanBC plan proposes a provincial target to achieve 15 percent renewable gas content by 2030. This target, which is calculated to be approximately 30 PJs per year, will require FEI to increase supply acquisition more quickly and broadly than the status quo. Out-of-province RNG provides an opportunity to capture greater emissions reductions at a reasonable acquisition price within a timeframe to support the provincial policy target.
- Economic Development: Clean and cost effective energy is a vital component of continued economic growth and opportunity in the province. RG remains competitively priced when compared to other forms of low-carbon energy. Expanding the RG supply by capturing out-of-province therefore creates greater economic opportunity while also reducing emissions. For example, out-of-province RG supply can help supplement the growing market for renewable gas for transportation. This increase in short-term supply increases confidence in RG supply, driving greater investment in fleet conversions and renewable gas infrastructure in BC.

235.11 Please clarify whether the sourcing of RG from out-of-province is a physical purchase or a notional purchase of RG.

Response:

FEI clarifies that RG purchased from out-of-province is a physical purchase of RG molecules including securing the rights to the associated environmental attributes and GHG emissions reduction benefits, which ensures that the full value of the RG will be received by FEI and its customers. While the purchase of RG is physical, transportation to a physical interconnection point on FEI's system may or may not be included as part of that purchase transaction. Accordingly, FEI assumes that the question is asking whether out-of-province RG will include transportation (physically delivered) or not (notionally delivered). FEI confirms that it is considering both delivery models with the only difference being that in the case of physically delivered RG, the cost of the RG would include additional tolls for transporting the RG to an interconnection point on FEI's system.

Further, RG that has been directly injected (i.e., on-system) or purchased and transported onto FEI's system (i.e. off-system or out-of-province) could both be considered notional in that the RG molecules are indistinguishable from conventional methane and cannot be physically traced to their individual point of delivery to the customer[104]. In that regard, the concept of notional delivery applies to all forms of RG and is no different whether the RG is on-system, off-system or out-of-province.

As a result, FEI contractually binds its RNG suppliers, both within and outside BC, to provide all environmental attributes benefits associated with RNG to FEI, which can then be passed on to FEI's customers. It is in this manner that the avoided GHG emissions can accrue within BC and be attributed to FEI's customers.

The opportunity to purchase out-of-province RG has primarily come about because some jurisdictions are not using the RG resources that have been developed or are being developed because they lack an established policy or regulatory framework for a carbon reduction regime. As a result, those jurisdictions are unable to include RG in the gas stream nor is there a regulatory construct that supports the sale of RG to customers in those jurisdictions. Due to the lack of competing demand and enabling policy in other jurisdictions, at this time FEI and its customers have an opportunity to procure RG supply from out-of-province at competitive prices while also securing the environmental attributes and GHG emissions reductions benefits. It is

[104] FEI's General Terms and Conditions of its Tariff, Section 28.1 (Notional Gas) states: Customers must recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but may instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

important to note that addressing GHG emissions is a global issue, rather than a local issue. In keeping with this principle, FEI believes that access to GHG emissions reduction opportunities should not be jurisdictionally constrained.

FEI is also of the view that using RG in BC to displace conventional natural gas, regardless of where the RG is produced, is an effective means of reducing GHG emissions and leveraging existing gas energy delivery infrastructure. FEI believes that out-of-province RG presents a valuable opportunity to reduce GHG emissions and contribute to procuring RG at the lowest possible price for our customers.

235.11.1 If it is a physical purchase, please explain the methods FEI would use to transport RG from out-of-province sources to BC, including the potential impact on FEI's costs of transporting from out-of-province sources versus obtaining RG from in-province sources.

<u>Response:</u>

Please refer to the response to BCUC IR 2.235.11. FEI notes that regardless of whether RG is from in-province sources or out-of-province sources, to qualify as a Prescribed Undertaking under the GGRR, FEI's costs to acquire RG must remain under the GGRR cap of $30.

236.0 Reference: TARGETED INCENTIVES

Exhibit B-10, BCUC IR 98.2; Exhibit B-5, BCOAPO IR 92.4.1; Exhibit B-1, pp. C-33, C-160

Growth in Natural Gas for Transportation (NGT)

On page C-160 of the Application, FEI states that annual NGT load has grown to approximately 2.0 PJs in 2018.

In response to BCUC IR 98.2, FEI provided the following table:

	2020	2021	2022	2023	2024
NGT Demand Contracted as of May 31, 2019 (PJ per year)	1.7	1.7	1.6	1.6	1.6
Uncontracted Projected Demand from Existing Customers (incremental to Demand Contracted)	0.07	0.2	0.5	1.1	1.7
Uncontracted Projected Demand from New Customers	0.0	0.0	0.0	0.0	0.0
Total	**1.77**	**1.9**	**2.1**	**2.7**	**3.3**

	2020	2021	2022	2023	2024
NGT Target (PJ per year)	3.0	4.0	5.0	6.0	7.0

236.1 Please update the applicable rows in the above table to reflect any additional contracted (or uncontracted) demand that has developed in the additional months that have elapsed since FortisBC completed its responses to IR1.

<u>Response:</u>

Below is a table that reflects additional contracted demand that has developed in the months that have elapsed since FortisBC completed its responses to the first round of information requests. Since that time, FEI has contracted with four additional fueling services customers totaling an incremental approximately 47,000 GJ per year.

	2020	2021	2022	2023	2024
NGT Demand Contracted as of August 20, 2019 (PJ per year)	1.75	1.75	1.65	1.65	1.65
Uncontracted Projected Demand from Existing Customers (incremental to Demand Contract)	0.07	0.20	0.50	1.10	1.70
Uncontracted Projected Demand from New Customers	0.00	0.00	0.00	0.00	0.00
Total	1.82	1.95	2.15	2.75	3.35
NGT Target (PJ per year)	3.0	4.0	5.0	6.0	7.0

236.2 Please provide the projected NGT load for 2019.

Response:

NGT demand was 2.04 PJ in 2018 and FEI is projecting approximately 2.23 PJ for 2019. Unlike the 2020-2024 forecast, the 2018 Actual and 2019 Projection both include uncontracted (spot) volumes. Spot volume was 0.70 PJ for 2018 and approximately 0.87 PJ for 2019 Projection. FEI's forecast reflects that a portion of this spot volume will become contracted in 2020 once marine vessels enter regular operational service.

For its 2020-2024 forecast included in the response to BCUC IR 1.98.2 and revised in response to BCUC IR 1.236.1, FEI included the contracted demand levels at the minimum annual quantities in the respective contracts as well as known increases in demand from those existing customers. As stated in FEI's response to BCUC IR 1.98.2, FEI did not include any volume for contracted demand from new customers or volumes for spot LNG loads because this value was unknown at the time of preparing the Application.

Finally, for clarity, the targeted incentive for NGT growth excludes non-transportation demand (i.e., demand for energy generation, export or other non-transportation uses is excluded).

In response to BCOAPO IR 92.4.1, FEI provided the following table:

TJ per year	2013	2014	2015	2016	2017	2018
Natural Gas for Transportation	0.37	0.77	1.02	1.16	1.52	2.04

236.3 Please clarify if the units in the above table provided in response to BCOAPO IR 92.4.1 are PJs, not TJs.

Response:

FEI confirms that the units in the table provided in response to BCOAPO IR 1.92.4.1 are PJs and not TJs.

236.4 Please explain why the Actual 2018 NGT demand was higher than what FEI currently forecasts for 2020.

Response:

Please refer to the response to BCUC IR 2.236.2.

On page C-33 of the Application, FEI provides Table C2-10 which breaks down FEI's requested $3.360 million incremental funding to Base O&M related to Engagement. Included in this amount is $2 million for "Raising Awareness for Consumers in a Lower Carbon Future" and $1 million for the "Climate Action Partners program".

236.5 Please explain in detail the ways in which the requested $2 million for "Raising Awareness for Consumers in a Lower Carbon Future" might contribute to FEI achieving its Growth in NGT target.

Response:

The objective of the "Raising Awareness for Consumers in a Lower Carbon Future" campaign is to increase British Columbians' overall knowledge about the relationship between natural gas, the environment and other energy sources. Through providing overall raised awareness and education on the benefits of natural gas for transportation along with all the other information the awareness campaign provides, it could contribute indirectly to FEI achieving its Growth in NGT target.

236.6 Please explain in detail the ways in which the requested $1 million for the "Climate Action Partners program" might contribute to FEI achieving its Growth in NGT target.

Response:

The Climate Action Partners program increases understanding and adoption of the services FortisBC provides. The purpose of the program is to assist governments and other stakeholders in understanding specific barriers and opportunities for utility infrastructure and energy services delivery so that gas utility interests are considered in future policy planning and development.

The program will not exclusively focus on developing the NGT business, but will be used to develop a number of lower carbon initiatives for FEI on a corporate-wide basis.

The requested $1 million for the Climate Action Partners program is expected to indirectly contribute to FEI achieving its Growth in NGT target by building new relationships and strengthening existing relationships with involved stakeholders. This would include, among other activities, facilitating conversations between partner organizations and FortisBC NGT representatives.

Climate Action Partners activities that may indirectly contribute to FEI achieving its Growth in NGT target include:

- Educating corporate and community stakeholders on the low and zero carbon transportation options for medium- and heavy-duty fleets, both their own fleets and commercial fleets operating in communities in B.C.;
- Educating the program's corporate and community stakeholders and providing analysis on the environmental, climate and cost benefits of using natural gas and RNG as transportation fuels;
- Identifying potential opportunities to convert diesel fleets to natural gas or renewable natural gas; and
- Identifying diesel truck or fleet owners potentially interested in exploring NGT opportunities, such as port drayage operators.

236.7 Please discuss whether the requested incremental funding for the Engagement activities listed in the above preamble might reduce the level of effort and investment of resources above and beyond the normal course of business required to achieve the Growth in NGT Targeted Incentive.

Response:

FEI's level of effort and investment of resources above and beyond the normal course of business will not be reduced if the above funding is approved.

As stated in response to BCUC IR 2.236.5 and BCUC IR 2.236.6, the funding for "Raising Awareness for Consumers in a Lower Carbon Future" and the "Climate Action Partners program" are broad-based initiatives not solely to be used to advance FEI's NGT initiatives.

Moreover, the funding for Engagement activities is allocated to a different department in FEI that is not involved in the development of NGT demand or in direct communication with customers to promote the adoption of NGT. FEI's initiative to achieve the Growth in NGT Targets Incentive will remain a top priority and will be a strategic focus for the utility. FEI believes this funding is complementary and will help further develop and grow the NGT program indirectly through raised awareness and partnerships for FEI's collective lower carbon future initiatives.

236.7.1 If yes, please discuss whether the annual targets should be increased if the incremental O&M funding is approved.

Response:

Please refer to the response to BCUC IR 2.236.7.

236.7.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.236.7.

236.8 Please explain how FEI intends to reach the targets in each of the years from 2020-2024, given the value for contracted demand from new customers is unknown. Does FEI have any plans in place to bridge the gap between the targeted volumes and the demand from existing customers? Please describe any such plans.

Response:

The targeted incentive related to growth in natural gas for transportation represents a stretch target; as discussed in the response to BCUC IR 1.96.7, the target requires a 3.5-fold increase in NGT demand. Accordingly, FEI will need to develop new and enhanced strategies to grow demand beyond current rates in order to achieve the targets. This will include ramping up market development efforts such as engaging with new customers by communicating the financial and environmental benefits of and opting for natural gas as a transport fuel and developing demand in new market segments by targeting new customers. This will be done using direct sales efforts, responding to Requests for Proposals for fleets considering adopting natural gas, and working with industry partners on developing compelling business cases for NGT for new and prospective customers.

236.8.1 Please describe the types, and amount of any additional investment that will be needed in order for FEI to achieve these targets.

Response:

Consistent with the current process, FEI will prepare an annual forecast of NGT investments as part of its Investment in a Clean Growth Future as per Section C4.4.2 of the Application. The amount of investment is unknown at this time and will depend on a number of factors, including market development. As such, FEI is not seeking approval of any amounts in this Application; they will be brought forward for review through the Annual Review process.

237.0 Reference: TARGETED INCENTIVES

Exhibit B-10, BCUC IR 30.9, 99.2; Exhibit B-1, pp. C-30, C-161–C-162

GHG Emissions Reductions – Customer

FEI states on page C-162 of the Application that its target for the annual number of natural gas conversions is 2,700 per year which reflects an increase over the five-year average.

Based on the historical conversions provided in Table C8-4 on pages C-161 and C-162 of the Application, the three-year average of conversions is 3,056.

237.1 Please confirm, or explain otherwise, that the majority of FortisBC's proposals in the Application which rely on historical averages (e.g. base growth capital, SQIs) utilize either a three-year average or a rolling three-year average.

Response:

FortisBC's proposals rely on a range of historical averages, but are commonly based on 3-year averages including:

- FEI growth capital base – 3 year average
- SQIs (FEI and FBC) – Combination of annual and 3 year rolling averages
- Targeted Incentive – GHG Emissions Reductions (Internal) – 5 year average
- Targeted Incentive – GHG Emissions Reductions (Customer) – 3 year average
- Targeted Incentive – Customer Engagement (FEI and FBC) – 3 year average

The number of years used is determined by the number of years required to achieve a base that is indicative of the trend going forward (for example, it may be necessary to add more years to the average to normalize for recent events that are not expected to continue into the future.

237.2 Please further explain why using a five-year average as a reference point in developing the GHG Emissions Reductions target is appropriate. As part of this response, please specifically address the reasonableness of relying on five years of historical data as a basis for setting future targets.

Response:

FEI interprets the question as referring to the GHG Emissions (Customer) target, which is measured by customer conversions. The metric uses a 5-year average primarily to normalize the effects of high growth levels in 2017 and 2018. FortisBC believes this approach is appropriate in this case given that high growth levels are not expected to persist, the target is a static figure which does not consider construction activity levels, and there are increased incentives for electrification of heating and hot water as noted in the CleanBC Plan.

FortisBC is not opposed to using a 3-year average (or rolling 3-year average), but suggests that it would be appropriate for the initial average to be based on the years 2017 to **2019** to address, in part, the objectives noted above.

237.3 Please discuss in detail the reasonableness of using either a three-year average or a rolling three-year average to set the target for natural gas conversions during the proposed MRP term. Please provide a detailed discussion for both options.

Response:

Please refer to the response to BCUC IR 2.237.2.

On page C-30 of the Application, FEI provides Table C2-9 which breaks down FEI's requested $1.200 million incremental funding to Base O&M related to the Connect to Gas program. Included in this amount is $0.600 million for Advertising.

In response to BCUC IR 30.9, FEI described its Advertising plans related to the Connect to Gas program for 2020, including the "Conversion Campaign" which FEI stated will "promote the benefits and simplicity of switching from other fuels such as oil or propane to natural gas."

In response to BCUC IR 99.2, FEI stated the following:

> While the requested incremental funding for the "Connect to Gas" program may assist in the achievement of the "GHG Emissions Reductions – Customer" incentive to the extent that it supports increased conversion customers, the O&M funding itself does not represent a reward. Rather the O&M funding only reflects FEI's costs of the program itself.

237.4 Please explain if one of the drivers for the requested incremental funding to Base O&M for the Connect to Gas program is to assist FEI in achieving the proposed GHG Emissions Reductions – Customer targeted incentive.

Response:

The drivers for the incremental funding to Base O&M for the Connect to Gas program do not include assisting FEI in achieving the proposed targeted incentive noted in the preamble. As noted in the response to BCUC IR 1.99.2, the Connect to Gas program may assist in the achievement of the targeted incentive; however, the purpose of the Connect to Gas program is broader in scope and promotes increased customer attachments as well as retention across all customer types.

237.5 Please discuss whether the requested incremental funding for the "Connect to Gas" program might reduce the level of effort and investment of resources above and beyond the normal course of business required to achieve the GHG Emissions Reductions – Customer Targeted Incentive.

Response:

FEI has proposed the incremental funding for the Connect to Gas program to expand its efforts to attach and retain customers across all customer types which mitigates rate pressures, contributes to keeping natural gas affordable, and maximizes the use of the gas delivery system.

The targeted incentive for GHG Emissions Reductions (Customer), which is more narrowly focused on natural gas conversions, is complimentary to the Connect to Gas program. FEI noted in its response to BCUC IR 1.99.2 that the Connect to Gas program may assist in the achievement of the targeted incentive. Accordingly, FEI does not believe that the incremental funding for Connect to Gas will reduce effort or investment of resources to achieve the targeted incentive.

237.5.1 If yes, please discuss whether the annual targets should be increased if the incremental O&M funding is approved.

Response:

Please refer to the response to BCUC IR 2.237.5.

237.5.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.237.5.

238.0 Reference: TARGETED INCENTIVES

Exhibit B-10, BCUC IR 72.2; Exhibit B-1, C-163

GHG Emissions Reductions – Internal

On page C-163 of the Application, FEI provides its targets for Greenhouse Gas (GHG) emissions reductions during the proposed MRP term.

FEI provided the following information on the CleanBC Industry Fund (CBCIF) in response to BCUC IR 72.2:

> The CBCIF is a component of the CleanBC Program for Industry. Industrial facilities emitting over 10,000 tonnes of CO2e are automatically included in the program. These facilities are eligible for the Industrial Incentive Program which rebates carbon tax payments above $30 per tonne to individual facilities provided they achieve a carbon intensity performance benchmark… Facilities in BC that meet or achieve the top performance benchmark will receive a full rebate of carbon taxes paid above $30 per tonne. For facilities that do not meet the performance benchmark they may receive a partial rebate.

238.1 Please explain if FEI's target for internal GHG emissions reductions is aligned with the targets established in the Government's CleanBC Program for Industry.

Response:

Based on forecasted natural gas demand, the framework associated with the MRP targets for FEI internal GHG emissions would be aligned with the CleanBC strategy; however the CleanBC benchmark targets are not yet known. In addition, since the response to BCUC IR 1.72.2 was submitted, the Government of BC has determined that FEI is not eligible for a rebate on carbon taxes paid above $30 per tonne on operational related emissions, should a performance benchmark be partially or fully met. The lack of rebate eligibility for FEI further emphasizes the importance of the FEI's Clean Growth Innovation Fund as proposed in the MRP and the ability to access capital to reduce operational GHG emissions.

238.1.1 As part of the above response, please provide a detailed comparison of the proposed GHG Emissions Reduction – Internal targeted incentive and the CBCIF.

Response:

Such a comparison is not available at this time. Please refer to the response to BCUC IR 2.238.1.

238.2 If the CleanBC Program for Industry's target is higher, please explain why it would not be more appropriate for FEI to align its target with the CleanBC program's target.

Response:

Please refer to the response to BCUC IR 2.238.1.

238.3 Please explain why the Government's identification of GHG emissions reductions as being a key goal is not adequate incentive for FEI to make extraordinary efforts to achieve GHG emissions reductions.

Response:

FortisBC's proposed targeted incentives related to reducing its emissions, and the emissions of its customers, help support a proactive approach to emissions reductions efforts in order to achieve greater and more cost effective reductions in advance of imposed standards. FortisBC recognizes emissions reductions as being a key goal of the provincial government and believes the proposed framework will assist in creating greater alignment and achievement of the provincial CleanBC objectives as compared to the status quo.

The identification of GHG goals by the Government (provincial or federal) requires sufficient capital and operating resources for organizations to meet such targets. Accordingly, the act of target setting may not be sufficient without the approval of necessary resources and a framework to support the achievement of such targets.

239.0 Reference: TARGETED INCENTIVES

TARGETED INCENTIVES

Exhibit B-1, pp. C-163–C-164

Customer Engagement

On page C-164 of the Application, FortisBC states: "In order to continue to increase adoption, FortisBC must continue to drive customer adoption of existing channels while also providing new and enhanced digital channel options."

239.1 Please explain in detail the ways in which FortisBC plans to increase customer adoption of existing channels.

Response:

The targeted incentive for enhancing customer engagement by increasing digital communication channel adoption represents a stretch target. As discussed in the response to BCUC IR 1.96.7, the target will require an increase of 1.4 and 1.9 fold increase for FBC and FEI, respectively. Accordingly, FortisBC will need to identify new and enhanced strategies, tactics and initiatives to increase customer adoption of existing and new channels above current rates in order to achieve the target. The development of strategies, tactics and initiatives will be informed by an analysis of existing channels and potential channels, customer and industry research, and industry best practices.

Specifically, FortisBC intends to undertake a review of channel options, including a comparison of the channels customers identify as preferred versus their actual channel use. This type of analysis may identify potential opportunities for improvement to existing digital and self-service channels as well as customer preference for expanded channel options. For example, this may identify changes to the existing IVR system (system, menu options, etc.) that could potentially increase adoption of self serve IVR options or lead to greater satisfaction and engagement with this particular channel.

It is expected that this channel option review and identification of next steps will occur by the end of 2020.

239.2 Please explain in detail the types of new and enhanced digital channel options which FortisBC intends to pursue and how it plans to go about identifying new and enhanced digital channel options.

Response:

Please refer to the response to BCUC IR 2.239.1.

239.3 Please discuss in detail the implications for FEI and FBC ratepayers if FortisBC only pursued a "normal course of business" level of increased digital channel adoption as opposed to the extraordinary level of digital channel adoption considered necessary to achieve the proposed targeted incentives.

Response:

Through the normal course of business, FortisBC intends to pursue increased adoption of digital channels to enhance the customer experience and increase customer engagement; however, progress towards this objective would be slower than compared to the incentivized approach. The extraordinary level of digital channel adoption considered as part of the targeted incentives encourages the Companies to invest in proactive approaches to accelerate the pace of adoption, find new opportunities beyond status quo and as a result, ultimately enhance the overall experience for customers.

The expected benefits of accelerated timing are increased engagement and satisfaction associated with the ability to use the channel that meets their needs, which may ultimately lead to better control and awareness of their specific energy needs and use. The normal course of business approach would delay such benefits.

239.3.1 As part of the above response, please discuss in detail the risks to ratepayers if the Customer Engagement targets are not achieved.

Response:

Please refer to the response to BCUC IR 2.239.3.

239.4 Please confirm, or explain otherwise, whether the need to develop new and enhanced digital options to respond to customer preferences is an issue facing most companies and is therefore not a challenge unique to FortisBC.

Response:

Confirmed.

240.0 Reference: TARGETED INCENTIVES

Exhibit B-1, pp. C-164–C-165

Growth in Electric Vehicle (EV) Transportation

On page C-165 of the Application, FortisBC states the following:

> On December 22, 2017, FBC applied for Approval of Rate Design and Rates for Electric Vehicle Direct Current Fast Charging (DCFC) Service. On January 12, 2018, FBC received approval of rates on an interim basis and the proceeding was adjourned until further notice as the BCUC established an inquiry to review the regulation of electric vehicle charging service in British Columbia (EV Charging Inquiry).
>
> Since FBC's role in supporting EV charging infrastructure in the province is among the issues that will be determined in the EV Charging Inquiry, FBC proposes to determine the appropriate targets following the conclusion of the Inquiry.

On June 24, 2019, the BCUC issued the Phase Two Report on the EV Charging Inquiry.

240.1 Please provide an update on FBC's proposal for setting a targeted incentive related to growth in EV transportation in consideration of the BCUC's issuance of the Phase Two Report on the EV Charging Inquiry.

Response:

As noted in the response to BCUC IR 2.225.1, FBC is currently awaiting the B.C. Government's response to the BCUC's recommendations contained in its Phase Two Report of the Inquiry into the Regulation of Electric Vehicle Charging Service, and understands that the B.C. Government may be contemplating new regulation relating to EV charging services based on the recommendations contained in the Phase 2 Report. As such, FBC submits that it will propose a target related to growth of EV transportation following the issuance of any new regulation pertaining to EV charging services.

240.1.1 As part of the above response, please clarify the timing and regulatory process proposed by FBC for reviewing its proposals for targets related to growth in EV transportation.

Response:

Please refer to the response to BCUC IR 2.240.1.

241.0 Reference: TARGETED INCENTIVES

Exhibit B-1-1, Appendix C7, p. 8; Exhibit B-10, BCUC IR 102.1, 102.2; Exhibit A2-2, FBC 2019/2020 Annual Electric Contracting Plan (AECP), Executive Summary

Power Supply Incentive (PSI)

On page 8 of Appendix C7 to the Application, FBC states the following:

> …the Eligible Mitigation Benefit will be calculated by comparing FBC's actual PPE [Power Purchase Expense] to the calculated PPE under a passive strategy in which FBC did not engage in any active optimization activity, and solely relied on its firm contracted resources to meet load. FBC is not suggesting that the passive strategy is something that would occur in absence of the PSI; rather, FBC is using the calculated passive strategy PPE as a floor from which to calculate Eligible Mitigation Benefit.

241.1 If the passive strategy is not something that would occur in the absence of the PSI, please explain why it would not be more reasonable to set a floor based on a baseline level of active optimization activity. For instance, if there are standard optimization activities that FBC performs each year, please explain why it would not be more appropriate to incorporate those activities into the floor from which to calculate the Eligible Mitigation Benefit.

Response:

The calculation of the passive strategy and the Eligible Mitigation Benefit under the Proposed PSI creates a baseline by which mitigation achieved by FBC can be measured. The proposed calculation method is useful in that it is transparent and easily verified.

FBC also proposed a fixed amount of Eligible Mitigation Benefit which would act as a floor to account for a base level of optimization activity. FBC has recommended that the first $7.5 million in benefits be solely for the customer. Once FBC has achieved $7.5 million in benefits, then FBC and the customer will begin to share in benefits, with the customer receiving 90 percent of all mitigation benefits achieved above the first $7.5 million.

Optimization of the power supply portfolio by FBC is a complex and integrated undertaking, making it difficult to determine the value created by individual activities. For example, forward market light load blocks may reduce PPA capacity requirements in the winter, and hourly peak demand purchases may increase surplus sales. The calculation of the Eligible Mitigation Benefit and the $7.5 million threshold under the proposed PSI incorporates all optimization activities undertaken by FBC and avoids the difficulties in attempting to break out the value created by individual activities.

241.1.1 Under a scenario where FBC was directed to incorporate a certain baseline level of mitigation activity into the floor, please provide a suggested amount and provide a detailed explanation for how this amount was determined.

Response:

Please refer to the response to BCUC IR 2.241.1.

In response to BCUC IR 102.1.1, FBC provided the following table:

Table 1

	2014	2015	2016	2017	2018	2019P
Approved PPE	$ 87.163	$ 117.837	$ 133.907	$ 136.216	$ 133.071	$ 145.065
Actual PPE	$ 86.337	$ 110.707	$ 123.169	$ 133.214	$ 123.842	$ 142.985
Variance (million)	$ (0.826)	$ (7.130)	$ (10.738)	$ (3.002)	$ (9.229)	$ (2.079)
Incremental Mitigation (beyond plan)	$ 2,168	$ 4,286	$ 7,015	$ 9,057	$ 14,236	$ 6,020

241.2 Please confirm, or explain otherwise, that based on the results in the above table, if FBC had set the floor for calculating the Eligible Mitigation Benefit at the "planned mitigation" level, it would still have received a share of the PPE savings in 2017 and 2018.

Response:

Confirmed. However, one of the benefits of the proposed PSI is that it is not based on a forecast of planned PPE, rather it is based on actual results and is therefore not impacted by variances from forecast, which can be caused by various factors beyond the control of FBC.

The calculation of the Eligible Mitigation Benefit is transparent and verifiable, and derives the total value of the mitigation activity achieved by FBC, regardless of the timing of the activity. From this calculation, a reasonable sharing of benefits between FBC and the customer can be determined. The proposed PSI results in a robust incentive plan that incorporates longer-term mitigation activity, and helps to ensure the best result for the customer by promoting a longer-term view for mitigation activities beyond a single forecast period.

In response to BCUC IR 102.1, FBC provided the following table detailing the historical actual PPE.

Table 2

Line No.	Description	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Actual 2018	Projected 2019
1	Brilliant	$ 35.742	$ 37.054	$ 38.775	$ 39.358	$ 39.618	$ 41.846
2	BC Hydro PPA	35.273	32.936	33.496	40.507	31.542	48.072
3	Waneta Expansion	-	25.361	36.174	37.454	35.133	38.604
4	Market and Contracted Purchases	16.048	15.300	13.663	16.768	18.137	13.868
5	Independent Power Producers	0.437	0.165	0.197	0.083	0.084	0.073
6	Self-Generators	-	-	-	0.101	0.049	0.087
7	CPA Balancing Pool	(1.090)	0.494	0.988	(1.049)	(0.684)	0.416
8	Sale of Surplus Power	(0.320)	(0.475)	-	-	-	-
9	Special and Accounting Adjustments	0.246	(0.129)	(0.124)	(0.008)	(0.036)	0.019
10	Total	$ 86.337	$ 110.707	$ 123.169	$ 133.214	$ 123.842	$ 142.985
11							
12	Gross Load (GWh)	3,451	3,385	3,387	3,594	3,530	3,615

In response to BCUC IR 102.2, FBC provided the following table showing the calculation of the Eligible Mitigation Benefit using the Actual 2018 PPE information:

Table 1: 2018 Eligible Mitigation Benefit

Line No.	Description	Actual 2018	Passive 2018	Variance
1	Brilliant	$ 39.618	$ 39.618	-
2	BC Hydro PPA	31.542	$ 63.446	$ 31.904
3	Waneta Expansion	35.133	$ 41.628	$ 6.495
4	Market and Contracted Purchases	18.137	$ 3.293	$ (14.844)
5	Independent Power Producers	0.084	$ 0.084	-
6	Self-Generators	0.049	$ 0.049	-
7	CPA Balancing Pool	(0.684)	$ (0.684)	-
8	Special and Accounting Adjustments	(0.036)	$ (0.036)	-
9	Incremental Wheeling	0.413	-	(0.413)
10	Total PPE plus Incremental Wheeling	$ 124.255	$ 147.397	$ 23.142
11				

241.3 Please confirm, or explain otherwise, that the Actual Gross Load is the same in both the Actual 2018 and the Passive 2018 column of the table in response to BCUC IR 102.2 and that the amount of the Actual Gross Load is 3,530 GWh, as shown in the table in response to BCUC IR 102.1.

Response:

Confirmed.

In response to BCUC IR 102.2, FBC stated the following:

> In 2018, FBC was able to displace 515 GWh of PPA [Power Purchase Agreement] energy purchases with a combination of forward and spot market purchases. Forward market purchases can be done up to two years in advance, while spot market purchases are executed on a day-ahead or hourly basis. Displacing PPA energy purchases resulted in a cost savings of $10.762 million as shown in line 1 of Table 2.
>
> FBC was also able to displace 355 MW/months of PPA Capacity in 2018 as a result of forward and spot market purchases. This resulted in a cost savings of $6.298 million as shown in line 2 of Table 2. PPA capacity savings can be achieved in three ways: by reducing PPA capacity required for energy, reducing PPA capacity required for peak demand, and saving on the PPA capacity ratchet.

241.4 Please provide a detailed breakdown of the energy displacement and cost savings described in response to BCUC IR 102.2. As part of this response, please also include the following:

- Actual BC Hydro PPA nomination for 2018. Please also confirm if FBC was required to pay any take-or-pay penalty under the BC Hydro PPA for 2018 and how the energy purchases and nomination under the PPA reconcile to the 515 GWh displacement calculated in the preamble above;
- Detailed calculations, including all inputs and assumptions, for the energy displacement of 515 GWh of PPA energy purchases; and
- Detailed calculations, including all inputs and assumptions, for the cost savings of $10.762 million.

Response:

The following table shows the detailed calculation of the 515 GWh of PPA energy purchases and the corresponding $10.762 million in PPA energy savings:

PPA Energy Displacements

Reference		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
[A]	Actual Market Purchases (GWh)	51	45	51	38	57	49	10	27	34	47	55	53	515
[B]	Actual Market Cost ($000)	$ 1,577	$ 1,433	$ 1,627	$ 642	$ 701	$ 1,127	$ 688	$ 930	$ 1,160	$ 1,422	$ 1,825	$ 1,712	$ 14,844
[C]	PPA Energy Rate ($/MWh)	$ 48.63	$ 48.63	$ 48.63	$ 50.09	$ 50.09	$ 50.09	$ 50.09	$ 50.09	$ 50.09	$ 50.09	$ 50.09	$ 50.09	
[D]=[A] x [C]	Cost if Supplied from PPA ($000)	$ 2,483	$ 2,191	$ 2,456	$ 1,892	$ 2,849	$ 2,472	$ 477	$ 1,352	$ 1,679	$ 2,350	$ 2,758	$ 2,646	$ 25,606
[E]=[C]-[B]	**Total PPA Energy Savings**	**$ 906**	**$ 758**	**$ 829**	**$ 1,250**	**$ 2,148**	**$ 1,345**	**-$ 212**	**$ 423**	**$ 519**	**$ 928**	**$ 933**	**$ 935**	**$ 10,762**

In response to BCUC IR 102.14, FBC stated the following:

> While the AECP outlines the annual plan, the PSI is expected to further align the interest of the Company and the customer by ensuring FBC is taking advantage of all the opportunities presented in the AECP, and spending sufficient resources to maximize performance in the area of power supply.

In response to BCUC IR 102.15, FBC stated the following:

> FBC currently has employees allocated to power supply operations, which include the power supply optimization activities, and is funded through formula O&M.
>
> FortisBC has proposed that employee-related expenses will be funded through index-based O&M, and will not form part of offsetting incremental costs in the Eligible Mitigation Benefit calculation.

Further in response to BCUC IR 102.17, FBC stated the following:

> As stated in the response to BCUC IR 1.96.3, this is due to the lack of an incentive to undertake the extraordinary efforts and investment of resources required to achieve these outcomes and the resulting shift in focus to traditional incentives and service quality.

241.7 Please clarify whether FBC is currently taking advantage of all the opportunities presented in its most recent AECP.

Response:

FBC is actively pursuing all opportunities presented in its most recent AECP. The optimization of the power supply portfolio continues to be a complex operation in an evolving market. The proposed PSI would help maximize performance while also creating incentive for FBC to find new opportunities and strategies to create additional value for the customer.

241.7.1 If FBC is not currently taking advantage of all of the opportunities presented in the AECP, please explain why not, with reference to each applicable opportunity.

Response:

Please refer to the response to BCUC IR 2.241.7.

241.8 Please provide a breakdown and description of all the costs of resources, including power purchase management expenses, incremental planning reserve margin, if any, and all related costs allocated for power supply operations, incurred in each year of the Current PBR Plan term. Please also explain where each of the identified costs are recorded (e.g. formula O&M, PPE, etc.)

Response:

The total cost of energy for the years 2014 to 2018 is provided below as well as the associated labour and non-labour O&M expenses. 2019 is not listed as the year is not complete and it would be inappropriate to compare 2019 YTD costs to 2014 to 2018 costs.

	2014	2015	2016	2017	2018
Power Purchase Expense					
Brilliant	$ 35,742	$ 37,054	$ 38,775	$ 39,358	$ 39,618
BC Hydro PPA	$ 35,273	$ 32,936	$ 33,496	$ 40,507	$ 31,542
Waneta Expansion	$ -	$ 25,361	$ 36,174	$ 37,454	$ 35,133
Independent Power Producers	$ 447	$ 165	$ 197	$ 184	$ 132
Market and Contracted Producers	$ 16,068	$ 15,300	$ 13,663	$ 16,768	$ 18,137
Surplus Sales	$ (320)	$ (475)	$ -	$ -	$ -
Balancing Pool/Other Adjustments	$ (873)	$ 366	$ 864	$ (1,057)	$ (720)
Weather Normalization		-	-	-	-
Total	$ 86,337	$ 110,707	$ 123,169	$ 133,214	$ 123,842
Water Fees	$ 9,600	$ 9,714	$ 10,182	$ 10,316	$ 10,264
Wheeling Expense					
Okanagan Point of Interconnect	$ 4,593	$ 4,184	$ 4,238	$ 4,356	$ 4,558
Creston	$ 474	$ 491	$ 497	$ 511	$ 554
Other	$ 64	$ 125	$ 80	$ 257	$ 411
Total	$ 5,132	$ 4,800	$ 4,815	$ 5,124	$ 5,523
Total Cost of Energy	$ 101,069	$ 125,222	$ 138,166	$ 148,654	$ 139,629
O&M Expenses to Manage PPE					
Labour	$ 530,555	$ 453,082	$ 490,513	$ 485,766	$ 523,617
Non-Labour	$ 129,460	$ 146,977	$ 132,230	$ 189,701	$ 181,404
Total	$ 660,015	$ 600,059	$ 622,743	$ 675,467	$ 705,021

The PPE, Water Fees and Wheeling expense are all included in the Power Supply costs. Any variance from forecast flows through to the customer under the terms of the Current PBR Plan. The O&M expense to manage PPE is funded through the formula O&M. There were no costs associated with Planning Reserve Margin during the Current PBR Plan.

241.9 In the event that FBC incurs additional costs, such as increased labour costs, in its efforts to achieve the proposed PSI target during the proposed MRP term, please explain where these costs would be recorded.

Response:

Any increased costs will be recorded in the various categories as provided in the response to BCUC IR 2.241.8. Increases in labour costs would flow through formula O&M.

On page 3 of the non-confidential Executive Summary of FBC's 2019/20 AECP, FBC stated the following:

> On January 28, 2019 Fortis Inc. entered into an agreement with Columbia Power Corporation (CPC) and Columbia Basin Trust (CBT) to sell its 51 percent interest in the Waneta Expansion project (WAX). The sale is expected to close within 90 days following satisfaction of closing conditions. As a result of the sale, the Waneta Expansion Capacity Purchase Agreement (WAX CAPA) will be assigned to the acquiring entity and there will be no changes to FBC's energy portfolio.

In response to BCUC IR 102.1.1, FBC stated: "Next, FBC also can maximize the value of WAX capacity by way of its day-ahead sales of capacity under the CEPSA agreement."

241.10 Please clarify whether FBC has any ownership interest in the Waneta Expansion project after the transaction described on page 3 of the non-confidential Executive Summary of FBC's 2019/20 AECP.

Response:

FBC does not, and has never had, an ownership interest in the Waneta Expansion project. FBC's parent company, Fortis Inc., was an owner, and sold its 51 percent interest to Columbia Power Corporation and Columbia Basin Trust in January 2019.

241.11 Please also clarify whether, after the above-mentioned transaction, FBC would continue to own the capacity entitlements under the WAX CAPA.

Response:

FBC continues to be a party to the Waneta Expansion Capacity Purchase Agreement, which is a 40-year agreement that terminates in 2055. Under the Waneta Expansion Capacity Purchase Agreement, FBC purchases all unused capacity that remains after the energy associated with the plant is delivered to BC Hydro.

241.11.1 If no, please further explain FBC's plan to maximize the value of WAX capacity, as stated in FBC's response to BCUC IR 102.1.1.

Response:

Please refer to the response to BCUC IR 2.241.11.

J. POLICIES AND SUPPORTING STUDIES

242.0 Reference: DEPRECIATION STUDY

Exhibit B-10, BCUC IR 108.1

Account 449.00 – LNG Plant – Other Equipment

In response to BCUC IR 108.1, FortisBC stated the following:

> While FortisBC considers the statistically indicated average service life as a strong indicator of the depreciation curve to apply, it does take into account other qualitative factors such as those mentioned in the interview notes. In addition, FortisBC considered that an estimated 27 year life was used for the past three depreciation studies (2009, 2014 and 2017). The depreciation rate for the account 449.00 has declined from 4.24 percent (2009) to 3.83 percent (2014) to 2.77 (2017) as a result of trueing up the "Book depreciation reserve" and to ensure proper future recovery of the remaining investment into this account.

242.1 Please confirm, or explain otherwise, whether the decline in the depreciation rate resulting from the trueing up of the "Book depreciation reserve" is due to higher depreciation collected than previous depreciation studies indicated.

Response:

The following response has been prepared by Concentric.

Concentric confirms that the decline in the depreciation rate is largely a result of trueing up the "Book depreciation reserve", however does not confirm that the decline in the depreciation rate is due to higher depreciation collected than what the previous depreciation studies had indicated.

The depreciation expense is collected based on the approved rates per the previous depreciation studies where the rates were developed based on the best available information at that time. A true up of the "Book depreciation reserve" is a normal course for depreciation studies and a reason why depreciation studies are recommended to be updated every 3 to 5 years. The true up ensures that the utility recognizes the appropriate amount of depreciation reserve for the period of time that the assets provide utility service.

242.1.1 If confirmed, please explain if using the statistically indicated average service life of 33 years in the last three depreciation studies would have resulted in a smaller true-up to the book depreciation reserve. Please also explain why a service life of 27 years is still a good representation of the average service life, if 33 years would have resulted in a smaller true-up to the book depreciation reserve.

Response:

This response has been provided by Concentric.

The requested scenario in this IR results in a total depreciation rate for Account 449.00, using an Iowa 33-R3 with -10 percent net salvage, of 2.34 percent. This is inclusive of any true up that may be required. The true up under the requested scenario would be calculated as follows:

(Calculated Accumulated Depreciation – Actual Accumulated Depreciation) / Remaining Life

In the circumstance of Account 449.00 with a 33-R3 and -10 percent salvage, the formula would be as follows:

(13,602,010 – 16,751,489) / 17.15 = -183,643.09

This indicates that Account 449.00 would have a negative true up of -$183,643.09 per year.

As filed, Account 449.00 using an Iowa 27-R3 with a -10 percent net salvage has a depreciation rate of 3.59 percent with a negative true up of -$75,006.57 per year. This indicates that the accumulated reserve position is closer to the theoretical reserve position using the recommended 27-R3 than with the statistically indicated average of 33-R3 as requested in this IR.

Concentric has provided the depreciation calculations for the Iowa 33-R3, in Attachment 242.1.1.

243.0 Reference: DEPRECIATION STUDY

Exhibit B-10, BCUC IR 115.1

Account 46400 – Other Structures

In response to BCUC IR 115.1, FortisBC stated the following:

> Account 464-00 has only experienced $38 thousand of retirement activity, resulting in approximately 97 percent still surviving at the oldest vintage. It is expected that the Residual Measure would not be accurate at this stage as more retirement history is needed before the retirement rate analysis for this account is considered relevant. Further, the majority of the investment in this account, $6.3M of the $6.8M total investment, has been installed since the year 2000….
>
> Based on the above, Concentric did not place any material weight on the curve fitting procedure for this account. Instead, Concentric relied on industry knowledge, discussions with FEI management, and peer comparisons to select the Iowa 30-R4.

243.1 Please further explain why it is reasonable to use an Iowa 30-R4 curve, given that 97 percent is still surviving at the oldest vintage. Please also explain why it would not be more appropriate to select an Iowa curve with a longer average service life.

Response:

The following response has been prepared by Concentric.

The majority of the assets in this account, $6.3 million of $6.8 million total, are less than 17 years old. Given that there have been very few assets reaching the age of 44.5 years, it is not significant enough to be representative of the account's average service life. The retirement dispersion pattern selected for this account, an Iowa R4, is considered appropriate for accounts experiencing minimal retirement activity at the early stages in the life of its assets. The R4 curve would anticipate that 97.02 percent of all investment is still in service at age 16.5. FortisBC has 99.48 percent still in service at that age interval which still aligns with the recommended R4 curve. As there have been no changes in the retirement patterns or management policies related to the assets in this account since the last depreciation study, it is still appropriate to maintain the currently approved average service life of 30 years.

243.2 Please provide a more detailed description of Concentric's discussions with FEI management which contributed to Concentric's selection of the Iowa 30-R4 curve. Please provide supporting documentation of these discussions, if available.

Response:

The following response has been prepared by Concentric.

The relevant interview notes for discussion of Account 464.00 – Other Structures are provided below.

"This account is the fencing, landscaping, small buildings associated with a transmission line. It is the miscellaneous expenses that go with the buildings. Mostly fencing."

Concentric notes that the types of assets as described in the quote from the interview notes above do not normally incur much interim retirement activity, but rather these types of assets are maintained through operating cost expenditures. As such, the observed life table as indicated at page 6-34 of the Concentric depreciation study report is not unusual in that the assets do not appear to have any significant interim retirement activity. Given the expected lack of interim retirement activity, Concentric has recommended a high moded R-30 curve Iowa curve, which is consistent with little retirement activity.

FortisBC provided the following part of the response:

FEI Operations also confirmed that an estimated 30 years' average life is still representative for this account as the type of assets in the account are similar to the assets under the TP Compressor structures (462.00) asset class that also have a 30 year average service life.

243.3 Please provide the peer comparisons Concentric used and explain how Concentric used these peer comparisons to select an Iowa 30-R4 curve.

Response:

The following response has been prepared by Concentric.

The peer comparison for all accounts was provided in response to BCUC IR 1.108.3. None of the peer utilities examined had a "Transmission Plant – Other Structures" account. The assets that are contained in FortisBC Account 464.00 are rolled into other accounts in peer utilities, thus making a comparison difficult. However, Concentric actively engages in the management and operation interviews as a general practice in virtually all assignments. During this process, assets similar in nature to the Account 46400 – Other structures are discussed, notwithstanding that the actual account structure of the peer group varies. As discussed in response to BCUC

IR 2.243.2, the assets of the type in this account have similar retirement characteristics within many utilities studied, notwithstanding that a peer comparison account is not available.

244.0 Reference: DEPRECIATION STUDY

Exhibit B-10, BCUC IR 117.2, 117.3

Account 47720 - Telemetry

In response to BCUC IR 117.1, FortisBC stated the following:

> Because this account has both buildings, with long lives, and technology assets, which are short lived, the average service life is expected to have a low-moded curve.
>
> …The original survivor curve, as plotted on page 6-78, shows a steady rate of retirement throughout the early life of this account indicating the need for a low moded curve. The previous estimate for this account was the Iowa 16-L1 which provides a poor fit to the historical data with a residual measure of 2.9050. Comments from operations and management suggest that there may be service life decreases in some assets in the future, however given the mix of assets in this account, it is not prudent to reduce the average service life at this time. As such, Concentric recommends the Iowa 20-R3 curve, with a residual measure of 2.6581, based on comments from operations and management staff, along with industry knowledge.

244.1 Please also explain further why FortisBC does not believe an Iowa curve with a longer average service life would not be more appropriate, given that 77 percent of assets are still surviving at age 20.5 years. What kind of weighting has FortisBC or Concentric placed on the long-lived assets in this account versus the short-lived assets? Please discuss.

<u>Response:</u>

The following response has been prepared by Concentric.

The currently approved life for Account 477.20 is Iowa 16-L1. The recommended life of 20-R3 represents a 25 percent increase in average service life. Concentric applies a theory of gradualism when selecting Iowa curves, and this theory played a large part in the selection of the 20-year average service life.

The use of gradualism and moderation in the development of depreciation parameters has a long history of use to avoid over-reacting to short term trends witnessed in the analysis of historical data. In terms of estimating average service life for long-lived accounts, gradualism has historically been used as a method to ensure that recent trends are indicative of long-term retirement patterns. For example, if the most recent five years of actuarial data indicates that an average service life estimate should be shortened significantly, the conventional theory is that the recent trend should be recognized but not to the full extent until at least one additional depreciation study confirms that the trend is indicative of the long terms expectations of the account.

With the use of the group accounting concept, individual assets are pooled together. While it is recognized there will be a mix of longer and shorter lived assets, the move to an Iowa R3 curve effectively deals with the fact the majority of assets will retire after the estimated average service life age, providing a reasonable expectation that the recommended Iowa 20-R3 curve will represent the entirety of the asset group. Discussions with management regarding the nature of the account assets were also considered in the determination of the right-moded (where the majority of retirements occur after the estimate average age) Iowa 20-R3 curve. It was noted during meetings with Operations that the technology component of the telemetry systems are experiencing a shorter service life, which would counteract the increased service lives of the assets surviving at age 20.5.

244.2 Please provide copies of discussions with FortisBC operations and management staff, if available, and indicate how these discussions contributed to the selection of an Iowa 20-R3 curve.

Response:

The following response has been prepared by Concentric.

Please refer to the response to BCUC IR 2.244.1.

The relevant interview notes for discussion of Account 477.20 – Distribution Telemetry are provided below.

- This is mostly just data going out, there is not a distribution SCADA system. Sensors and devices that allow data to leave a gate station site. This is mostly alarms and data collection systems to proactively deal with issues. Most is on regulating system assets and city gate systems.
- There are no lease costs for access to the communication path. Equipment in this account. The paths are accounted for in O&M.
- The telemetry systems are being installed to make it cheaper and easier to do upgrades as needed. The buildings and systems themselves are being built better and can be expected to last longer, however the technology part is seeing a shorter life.

- This account likely includes the Remote Terminal Units (RTUs), the Programmable Logic Controller (PLCs), etc. The life cycles on these assets are much shorter than they were even a few years ago.
- Sensors are run to fail, these last much longer than the other assets in this account
- Run the experience/placement band post 1994 for this account

The following is FortisBC's response:

The interview notes with Concentric above and the response to BCUC IR 1.117.1 in the preamble both make reference to buildings, however they are more appropriately described as systems. Therefore, the telemetry asset class has systems, with long lives, such as tubing, cables, supports/brackets, weatherproof boxes, antennas, as well as technology assets including RTUs, PLCs and transmitters.

244.3 Please provide the peer comparisons Concentric used and explain how Concentric used these peer comparisons to select an Iowa 20-R3 curve.

Response:

The following response has been prepared by Concentric.

The peer comparison for all accounts was provided in the response to BCUC IR 1.108.3. There was only one peer natural gas utility that has an account with a similar makeup to Account 477.20 which was based on a 17 year life curve. However, in the case of an account with such a limited peer group, there would be very little weighting applied to the peer comparison.

In response to BCUC IR 117.2, Concentric stated the following:

> Shown in the table below are three additional curves (Iowa 16-L1, 18-R3 and 19-R3), all of them having a residual measure higher than 2.6581, that Concentric considered before recommending the Iowa 20-R3 curve.

244.4 Did Concentric consider any curves with average service lives greater than 20 years?

Response:

The following response has been prepared by Concentric.

Concentric did not consider any lives longer than 20 years for Account 477.20.

244.4.1 If yes, please provide analysis similar to analysis given in the response to BCUC IR 117.2.

Response:

The following response has been prepared by Concentric.

Please refer to the response to BCUC IR 2.244.4.

244.4.2 If not, please explain why curves with average service lives greater than 20 years were not considered, considering there are over 77 percent of assets still surviving at the age 20.5 years.

Response:

The following response has been prepared by Concentric.

Please refer to the response to BCUC IR 2.244.1.

245.0 Reference: DEPRECIATION STUDY

Exhibit B-10, BCUC IR 120.2

Account 334.00 – Generation Plant – Accessory Electrical Equipment

In response to BCUC IR 120.2, Concentric provided interview notes which stated the following:

> The control equipment that makes up part of this account has been mostly switched to digital technology, which although provides better for better condition assessments, has a trade-off with lower service lives than older generation mechanical equipment. We are consequently evaluating whether a 50-R1.5 curve is more representative of the rate of depreciation in this account. In this case, we are not as concerned with trying to reduce the residual measure since that curve will fit the retirement of older technology which has largely been retired. A 40-year life with slightly higher mode (R2.5) would reflect the average shorter life because of the newer digital equipment.

Concentric then adds:

> The discussion with FBC Operations noted that newer technology is preferred to the older mechanical equipment, however it has a lower average life as a trade-off and as a result of the components in this class of equipment, the old 50-R1.5 curve was no longer representative of the average service lives and instead the Iowa 40-R2.5 curve is recommended as a better fit.

245.1 Please explain in further detail how Concentric determined that a 40-year average life is a more appropriate choice over using an average life of less than 40 years, given the switch to digital equipment. Were any lives shorter than 40 years considered?

Response:

The following response has been prepared by Concentric.

Concentric determined the 40-year estimate of average life as a composite of a variety of analyses and judgements. Statistical fit and visual fit to the historical retirements were only two criteria as pointed out on page 3-6 of the 2017 FBC depreciation study. There was recognition of a switch to shorter-life digital equipment for the control devices which would pull down the previous approved 51-R4 curve. The control equipment is one portion of accessory electrical equipment. Other considerations were discussions with operations staff about future procurement of accessory electrical equipment and any changes in asset management as influenced by run time, vendor support and other environmental factors that may influence condition assessments. Peer comparisons would be part of the evaluation if the field was representative enough.

Curves shorter than 40 years were not considered in preparing the study. It is essential that all average service life estimates incorporate the concept of gradualism when large changes are indicated. Frequent large scale changes to the life estimate risk the account getting over or under accrued if the life indications change between depreciation studies, as well as risk the potential for rate shock to toll payers. Consequently, Concentric does not recommend shortening the life for this account beyond 40 years at this time. Future depreciation studies will continue to monitor this account and may further shorten the life if the indications continue to suggest a shorter life is appropriate.

245.2 Please provide the peer comparisons Concentric used and explain how Concentric used these peer comparisons to select an Iowa 40-R2.5 curve.

<u>Response:</u>

The following response has been prepared by Concentric.

While there is a limited amount of data for this account, the recommended Iowa 40-R2.5 curve is within the peers range and was compared to Atco Electric with an Iowa 25-R1.5 curve and Manitoba Hydro with an Iowa 55-R4 curve.

246.0 Reference: DEPRECIATION STUDY

Exhibit B-10, BCUC IR 124.1, 124.1.2, 124.2

Net Salvage

In response to BCUC IR 124.1.2, FortisBC stated the following:

> The type of activities that are included in removal costs are those required to dispose of and remove the existing asset from the construction site. This may include expenditures for labour, material, and contract services required to demolish, dismantle, tear down, dispose of or otherwise remove the plant from service.

In response to BCUC IR 124.1, FortisBC stated the following:

> To expand on the comments above, FEI removes assets when they are in the way of other work being undertaken. For example, if a valve needs to be replaced because it no longer performs satisfactorily, it will have to be removed prior to installing a new valve as it would obstruct the space required to install the new valve. If a station requires piping or equipment upgrading due to insufficient capacity, the existing piping or equipment will have to be removed prior to installing the new piping or equipment, again, because the existing piping or equipment is an obstruction. Short sections of buried pipe are often replaced due to the replacement pipe being installed. Thus, generally, if there is a replacement of an existing asset, such as a valve, equipment or a short section of pipe, then the existing asset will need to be removed in order to allow the new asset to be installed.

246.1 Please explain how FEI distinguishes between those costs relating to removals, versus those costs relating to installation of the new assets, in the cases where removals are driven by the replacement of an existing asset.

<u>Response:</u>

In the cases where removals are driven by the replacement of an existing asset, FEI creates a separate charge number for the removal activities so that the costs associated with these activities are distinguishable and are reported separately from the installation costs. For example, for Distribution Mains and Services renewals, there is a time separation between the removal of the existing asset and the construction of the new assets and two charge numbers are raised to capture removal costs separately from installation costs.

There may be other instances where there is little separation in time between the removal and installation activities and, in those instances, an estimated percentage allocation is applied between the cost of removal and the installation costs within the same charge number, which then allocates the installation costs and removal costs out to two separate charge numbers. This estimated allocation is based on a combination of assessment of the removal and installation activities that actually occurred for the particular project, reference to any similar historical transactions and project manager forecasts of removal costs versus new asset installation in such circumstances.

In the cases of Meter renewals and exchanges, FEI continues to allocate 50 percent of the total costs to cost of removal and the remaining 50 percent to the new meter installed due to little separation in time between the two activities and the difficulty in separating out costs using different charge numbers. Other than replacing the existing meter with the new meter, all tasks associated with the meter exchange are assumed to apply equally to the removal and the installation of the meter.

These methodologies for distinguishing between the two activities have been FEI's established practice for many years and subject to review through various depreciation studies filed with the BCUC.

246.1.1 Please discuss, in detail, FEI's view on whether these removal costs, when driven by the replacement of an existing asset, should be considered a capital cost of installing the new asset.

<u>Response:</u>

While FEI acknowledges that there may be instances where the costs incurred with removal activities and new asset installations are similar in nature, it is important that FEI distinguishes between the costs in order to mitigate intergenerational inequity for customers, as well as to ensure compliance with US GAAP.

Asset removal costs incurred once an asset is no longer used and useful are collected through FEI customer rates as part of the net salvage provision, as determined through depreciation studies. The collection of net salvage in depreciation rates is intended to ensure that customers who are currently receiving the benefit of the assets, are also paying for the eventual removal costs of those assets over the life of those assets. This is intended to provide generational equity between customers by ensuring an even collection through customer rates. When costs are incurred to remove assets, such as in the examples provided in response to BCUC IR 1.124.1, the cash expenditures incurred are applied against the net salvage provision, not capitalized as part of the construction of the new asset. In many cases, these costs have already been collected through customer rates, and the eventual cash outlay closes off the timing difference that exists between collection of the costs and occurrence of the removal.

Therefore, these costs are not treated as a capital cost of installing the asset, but are extinguishing the net salvage liability that has already been collected.

Finally, US GAAP prescribes how the collection of removal costs through customer rates and the incurrence of the actual removal costs should be classified. US GAAP requires that removal costs be recognized separately from utility plant assets, as a regulatory liability (or regulatory asset). This is consistent with how FEI views the removal costs as a separate item from the capital cost of installing a new asset.

In response to BCUC IR 124.2, FortisBC stated the following:

> The main factors for the increase in the net salvage provision are the continuous need for ongoing retirements or replacement of the gas system, the continual increase in actual removal costs, inflation, and net salvage studies indicating that higher net salvage percentages are required in order to offset the cost incurred due to an increase in asset removal activities as compared to actual retirements.

246.2 Please explain how FEI distinguishes between those costs relating to removals, versus those costs relating to installation of the new assets, in the cases where removals are driven by the replacement of an existing asset.

Response:

Please refer to the response to BCUC IR 2.246.1. FortisBC notes that this question is a duplication of BCUC IR 2.246.1.

246.3 What proportion of removal costs are internal costs versus external contractor costs?

Response:

Over the Current PBR Plan period, approximately 67 percent of the removal costs were internal costs and 33 percent external contractor costs.

246.3.1 Please explain in detail how FEI chooses contractors for removal projects. Is it done through a bid process, previously used contractors, or other methods?

Response:

Contractors used for removal and installation projects are typically selected through a competitive bid process to establish rates for the associated work. Many smaller jobs are bid on a unit rate basis or on a time and materials basis using these established rates. Larger or complex jobs may be tendered individually using a competitive bid process.

246.3.2 How does FEI manage external contractor costs to ensure these costs are reasonable?

Response:

Work is conducted under competitively bid unit rates when possible. If unit rates are not applicable, contractors are typically asked to provide quotes or estimates for the work often based on competitively bid time and material rates. FEI reviews contractor quotes and estimates to ensure that labour, equipment and materials quantities are commensurate with the work being done. FEI monitors work execution and any contractor change requests to price or schedule during construction require FEI pre-approval.

247.0 Reference: DEPRECIATION STUDY

Exhibit B-10, BCUC IR 127.2

Net Salvage Change for Account 473.00 - Services

In response to BCUC IR 127.2, Concentric stated the following:

> No specific calculation was performed. As stated on page 3-9 of the FEI 2017 Depreciation Study and quoted above, the Summary of Book Salvage, shown on page 7-15, indicates progressive increases in the historical net salvage. With the total historical net salvage being negative 119 percent, Concentric views that negative 100 percent would be a reasonable expectation. However Concentric has recommended a more conservative move to a negative 70 percent until future studies continue to indicate a need for a larger increase.

247.1 Please clarify if “no specific calculation was performed” is the case for all FEI and FBC accounts where Concentric has recommended salvage changes. If no, please list the accounts where a specific calculation was performed, and provide the detailed calculation used to arrive at the recommended salvage rate.

Response:

The following response has been prepared by Concentric.

No specific calculation was performed for any of the recommended net salvage changes for all FEI and FBC accounts.

There is no specific calculation that can accurately weigh the historical indications, peer comparisons, opinions of management staff, professional judgement, and previous commission rulings. Instead, Concentric has applied its experience in the utility industry and professional judgement as a means in determining these changes. Consequently, there was no specific calculation performed for any account. Further, as no specific calculation is currently available in the depreciation literature, none of the depreciation studies that Concentric has performed throughout North America utilizes a calculation to weigh the various factors that are considered when making an estimate. Concentric is not aware of any depreciation consultants in North America who utilize such a calculation. One of the prominent texts on depreciation theory “Public Utility Depreciation Practices” contains the following discussion on the use of professional judgement:

> The use of informed judgement sometimes becomes a point of controversy in the regulatory setting because some of the analyst’s opinions cannot be quantified or easily supported. It is sometimes impossible to pinpoint the reasons for making a decision that diverges from a company’s historical data or standard reference material….It is the analyst’s responsibility to apply any additional known factors

that would produce the best estimate of the service life. The analyst's judgement, comprised of a combination of experience and knowledge, will determine the most reasonable estimate"[105]

247.2 Please explain why Concentric considers that negative 100 percent would be a reasonable expectation, if no specific calculation was performed. Please provide a detailed explanation for the appropriateness this percentage.

Response:

The following response has been prepared by Concentric.

The historical cost of removal calculation is negative 119 percent. Throughout Canada, services accounts are showing indications approaching and exceeding negative 100 percent. Further, discussions with management suggest that there are stricter requirements over time of work and working conditions to replace services in urban centers, where most services exist. Combined, these indications suggest that a rate of at least negative 100 percent is appropriate for this account.

247.3 Please explain how Concentric determined that negative 70 percent was appropriate when no specific calculation was performed, and why this is more appropriate than any other percentage below or above 70 percent.

Response:

The following response has been prepared by Concentric.

Please see the responses to BCUC IR 2.247.1 and BCUC IR 2.247.2. All net salvage estimates are derived through a combination of historical indications, peer comparisons, previous commission rulings, opinions of management staff, and professional judgement. In the case of Account 473.00, the estimate of negative 70 percent also incorporated the use of gradualism. The amount of weighting to put on gradualism ultimately becomes a matter of professional judgement, as is the selection of negative 70 as opposed to negative 69 percent or negative 71

[105] Staff Subcommittee of Depreciation of The Finance and Technology Committee of the National Association of Regulatory Utility Commissioners; Public Utility Depreciation Practices; August 1996; page 129

percent. One of the prominent texts on depreciation theory "Public Utility Depreciation Practices" contains the following discussion on the use of professional judgement:

> The use of informed judgement sometimes becomes a point of controversy in the regulatory setting because some of the analyst's opinions cannot be quantified or easily supported. It is sometimes impossible to pinpoint the reasons for making a decision that diverges from a company's historical data or standard reference material….It is the analyst's responsibility to apply any additional known factors that would produce the best estimate of the service life. The analyst's judgement, comprised of a combination of experience and knowledge, will determine the most reasonable estimate"[106]

247.4 Please explain why Concentric considers that its use of judgement and historical values to determine recommended salvage rates will accurately reflect future salvage requirements. As part of this response, please discuss any other methods used in other jurisdictions to determine future salvage requirements, and the merits and downsides of those methods.

Response:

The following response has been prepared by Concentric.

Concentric uses a combination of judgement and historical values to estimate and recommend salvage rates based on a combination of the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis are extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historical year. Additionally, a net salvage amount is also calculated for each historical three-year and five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year and five-year rolling bands.

[106] Staff Subcommittee of Depreciation of The Finance and Technology Committee of the National Association of Regulatory Utility Commissioners; Public Utility Depreciation Practices; August 1996; page 129

4. The annual, the three-year and the five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.

5. Each account is then compared to the net salvage percentage currently approved, compared to peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.

6. The net salvage percentage is then used in the depreciation rate calculations.

Steps one through four use mathematical methods to calculate the historical net salvage values. Step five is the only step in the determination of net salvage estimates that includes professional judgement. This step is essential to ensure that the historical data is properly interpreted, and trends are adjusted for accuracy. This adjustment allows Concentric to take into consideration changes to the types of assets in each account, historical or future retirement programs, commission orders, or other reasons that may cause the historical data to not be indicative of the future salvage requirements.

Concentric notes that the above method (commonly referred to as the “Traditional Method”) of developing estimates of future cost of removal expenditures is the most commonly used. However, Concentric also notes that accounting for net salvage and cost of removal expenditures is one of the greatest areas of divergence of regulated Canadian utilities. Utilities that account for net salvage recovery through the use of net salvage estimates use practices which include:

1. providing a provision for cost of removal in depreciation rates and booking the actual costs to the accumulated depreciation account (the “Traditional Approach” as described above);

2. providing a provision for cost of removal in depreciation rates based on a Constant Dollar approach and booking the actual costs to the accumulated depreciation account

3. expensing cost of removal in the year of occurrence or including the cost of removal of a replaced asset in the cost of the replacement asset; and

4. Asset Retirement Obligation (ARO) accruals.

A brief discussion of the above various options is presented below:

1. The Traditional Method

Allocating net salvage costs during the life of the related plant though the use of the Traditional Method (as described above) is an appropriate and equitable method and in accordance with authoritative texts[107] and most Uniform Systems of Accounts, and is the most widely accepted method within North America. However, because the historical ratio is developed by comparing cost of removal expenditures to original cost dollars retired, this method has an inherent level of inflation built in and cannot be considered to be time synchronized.

2. Use of a Constant Dollar Approach

The use of Constant Dollar approach is to determine a current cost to retire/remove assets through the use of normalizing the historic original cost of assets retired to the time period of the retirement transactions, and thereby removing the impacts of historical inflation from the traditional method. However, this current estimate needs to be adjusted to recognize the impacts of inflation over the period, from the current time to the estimated remaining life of the account using a forecasted rate of future inflation.

In order to recognize that the funds collected in current periods will not be expensed until potentially many years into the future, a discounted cash flow calculation is required. In this manner, the fact that the utility has received the benefit of the funds as working capital through the inclusion of the requirement into the current period revenue requirements, this calculation is consistent with the requirements of Asset Retirement Obligations.

3. Expensing Costs of Removal in Year of Occurrence and Including Costs of Removal in the installation of the new asset

This method of accounting for costs of removal, delaying collection until such costs are incurred, results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage.

The revenue requirements that result from any type of “expensing as incurred” option are greater than the revenue requirements that result from accruing for net salvage during the life of the related asset for a regulated utility that includes a rate of return in its revenue requirement. Although a comparison of the current revenue requirements related to a net salvage accrual and the current revenue requirements related to expensing of net salvage may indicate that the accrual is higher at a single point in time, over time the revenue requirements and the present value of those revenue requirements will be less if the net salvage cost is accrued over the life of the asset.

[107] Such as Depreciation Systems, Frank K. Wolf and W. Chester Fitch, Published, Iowa State University Press, 1994; and Introduction to Public Utility Accounting, American Gas Association/Edison Electric Institute, 1997.

4. Asset Retirement Obligations

The ARO approach to collecting costs of removal is used for a select number of asset groups in select circumstances. The pre-collection mechanism for AROs is often applicable for assets with a known retirement horizon and detailed decommissioning studies, such as nuclear generation sites. Toll payers benefit from the certainty of proper site remediation while utilities benefit from the pre-collection of removal costs.

However, the ARO approach to collecting costs of removal is not valid in the circumstances of distribution services. The large number of services that would each need to be considered individually and depreciated independently of one another would make an ARO calculation unworkable. As such, Concentric is unaware of any ARO calculations related to natural gas distribution services and other mass plant accounts.

248.0 Reference: LEAD-LAG STUDY FOR CASH WORKING CAPITAL

Exhibit B-10, BCUC IR 132.3

Management Review of FEI and FBC 2018 Lead-Lag Studies

In response to BCUC IR 132.3, FortisBC stated that internal management reviewed the FEI and FBC 2018 lead-lag studies based on their understanding of FortisBC's operations and regulatory practices.

248.1 Please provide details of the internal management involved in the review of the FEI and FBC 2018 lead-lag studies (e.g. department, roles, number of individuals). Please provide separate responses for FEI and FBC, if needed.

Response:

The review of the overall result of the study and its impact on FortisBC's cash working capital requirement involved management from the Regulatory and Finance departments as the primary reviewers of the study. The table below summarizes the department, role, and number of individuals included in the review.

Department	Roles	Number of Individuals
Regulatory	VP, Regulatory Affairs	1
Regulatory	Director, Regulatory Affairs	1
Regulatory	Manager, Cost of Service	1
Regulatory	Manager, Regulatory Affairs	1
Finance	Director, Finance and Accounting	1
Finance	Controller, Financial Accounting	1
Finance	Manager, Financial Planning & Control	1
Finance	Financial Accounting Manager	1
Total		8

In addition to the above internal management review of the lead-lag studies, various departments and managers were involved with the inputs and discussion for specific revenue and expense categories analyzed in the 2018 lead-lag studies. Over 20 managers or analysts from the Customer Service, Accounts Payable, Energy Supply, Human Resource, Procurement, Property Services, and Risk Management departments helped contribute to the results of the studies.

248.2 Please provide the steps internal management took to perform its "review" and conclude on the reasonableness of the FEI and FBC 2018 lead-lag studies. Please provide separate responses for FEI and FBC, if needed.

Response:

FortisBC's management took the following steps to review the 2018 lead-lag study within their responsible area(s) for FEI and FBC:

- Reviewed the methodology and revenue and expense categories in the 2018 lead-lag studies, as compared to the previously approved lead-lag study;
- Compared the lead-lag days from the 2018 lead-lag studies to the previously approved lead-lag days for each revenue and expense category and investigated any material differences arising between the two studies;
- Referenced the principles and approach discussed in the KPMG review of FEI's prior lead-lag study;
- Assessed the reasonableness of the results based on the knowledge of FortisBC's operations, industry, regulatory and legal requirements;
- Followed up on the changes expected as a result of changes in the business, examples which included the implementation of PST, as described in the response to BCUC IR 1.133.5 and the Summary of Methodology in Section D3.3 of the Application, as well as entering into new power purchase agreements, which were described in the response to BCUC IR 1.134.6;
- Researched and investigated other North American utilities lead-lag approach; and
- Compared the lead-lag days between FEI and FBC where applicable.

While the internal management review is an important process in preparing the lead-lag studies, the results of the 2018 lead-lag studies were primarily determined by financial transactions that have actually occurred within the Utilities' SAP system.

In response to BCUC IR 132.3, FortisBC also provided a list of eight KPMG findings as it relates to the KPMG's review of the FEI 2009 lead-lag study. BCUC Staff understand that this list was provided as FortisBC states:

> There was no review of FEI and FBC 2018 Lead-Lag Studies by an external consultant. However, the incremental external review and associated costs to be incurred were not necessary as FortisBC used the same model and methodology

consistent with the one established as part of the Terasen Gas Inc 2010-2011 Revenue Requirement Application. That 2009 Lead-Lag study was reviewed independently by KPMG and approved by the BCUC. With a previously established lead-lag model and no proposed change in methodology, the update to the lead lag study essentially required updating the model with more recent financial data and transactions derived from FortisBC's SAP system.

248.3 Please discuss internal management's findings, specifically as it relates to each of the eight KPMG findings from KPMG's review of the FEI 2009 lead-lag study, identifying the findings which management found: (i) remains appropriate, (ii) is no longer applicable, or (iii) requires update, with explanations. Given that KPMG's review in 2009 was for an FEI lead-lag study, please provide separate responses for FEI and FBC.

Response:

In relation to the 2018 lead-lag studies, FortisBC findings in relation to KPMG's review of the FEI 2009 lead-lag study are as follows:

FEI

No.	KPMG's Findings (FEI 2009 Study)	Internal Management's Findings (FEI 2018 Study)	Explanations
1	Is complete with respect to the inclusion of all major revenue and expense items as compared to the financial statements.	Remains appropriate	Major revenue and expense items in the FEI 2018 lead-lag study are consistent with those in the FEI 2009 lead-lag study.
2	Does not materially exclude any revenue or expense items as compared to the financial statements.	Remains appropriate	Major revenue and expense items in the FEI 2018 lead-lag study are consistent with those included in the FEI 2009 lead-lag study.
3	Appropriately uses the 2007 study period to reflect activity expected in 2010/2011 forecast years.	Remains appropriate	Relying on one year of data to reflect the expected activity remains consistent between the 2009 and 2018 lead-lag studies. The FEI 2018 lead-lag study uses 2017 data to reflect expected activity in the forecast years.
4	Appropriately and necessarily includes an adjustment for Carbon Tax introduced in 2008.	Not applicable	Carbon Tax was introduced in 2008 thus an adjustment was included in the FEI 2009 lead-lag study. The FEI 2018 lead-lag study continues to appropriately incorporate Carbon Tax.

No.	KPMG's Findings (FEI 2009 Study)	Internal Management's Findings (FEI 2018 Study)	Explanations
5	Uses averaging assumptions for some lag periods that are reasonable and correct in calculation.	Remains appropriate	Similar assumptions for most lag periods are used in the FEI 2018 lead-lag study.
6	Uses system generated data for the remaining lag periods that are reasonable and correct in calculation.	Remains appropriate	System generated data continues to be a driver in the determination of the FEI 2018 lead-lag study.
7	Is consistent with principles and guidance offered in FERC NOPR RM84-9-000, and in the approach used by other utilities jurisdictions.	Remains appropriate	The FEI 2018 lead-lag study is in alignment with the principles and guidance offered in FERC NOPR RM84-9-000 from 1984, and the approach used by other utilities.
8	Excludes financial items from its net revenue lag calculation, which KPMG does not find to be inappropriate.	Remains appropriate	The financial items that were excluded from its net revenue lag calculation remain consistent between the 2018 and 2009 FEI lead-lag studies.

FBC

No.	KPMG's Findings (FEI 2009 Study)	Internal Management's Findings (FBC 2018 Study)	Explanations
1	Is complete with respect to the inclusion of all major revenue and expense items as compared to the financial statements.	Required update	Major revenue and expense items in the FBC 2018 lead-lag study were updated to align with those in the FEI 2009 lead-lag study.
2	Does not materially exclude any revenue or expense items as compared to the financial statements.	Required update	Changes to the GST and interest expense assumptions were included in the FBC 2018 lead-lag study to align with the approach used in the FEI 2009 lead-lag study and other utilities.
3	Appropriately uses the 2007 study period to reflect activity expected in 2010/2011 forecast years.	Remains appropriate	The FBC 2018 lead-lag study uses 2017 data to reflect expected activity in the forecast years, similar to the methodology used in the FEI 2009 lead-lag study.
4	Appropriately and necessarily includes an adjustment for Carbon Tax introduced in 2008.	Not applicable	Carbon Tax is not a required tax for FBC.

No.	KPMG's Findings (FEI 2009 Study)	Internal Management's Findings (FBC 2018 Study)	Explanations
5	Uses averaging assumptions for some lag periods that are reasonable and correct in calculation.	Required update	More detailed averaging assumptions using actual system generated data were used in the FBC 2018 lead lag study.
6	Uses system generated data for the remaining lag periods that are reasonable and correct in calculation.	Required update	System generated data is used for the remaining lag periods in the FBC 2018 lead-lag study, as a result of aligning with the methodology used in the FEI 2009 lead-lag study.
7	Is consistent with principles and guidance offered in FERC NOPR RM84-9-000, and in the approach used by other utilities jurisdictions.	Remains appropriate	The FBC previously approved method was generally in alignment with the principles and guidance offered in FERC NOPR RM84-9-000 from 1984, and the approach used by other utilities.
8	Excludes financial items from its net revenue lag calculation, which KPMG does not find to be inappropriate.	Required update	The financial items that were excluded from its net revenue lag calculation were updated in the FBC 2018 lead lag study to align with the approach used in the FEI 2009 lead-lag study, and other utilities.

248.4 Please provide the cost and time associated with an external review of a lead-lag study, including the actual cost/time incurred in 2009 in current dollars and the expected cost/time if the FEI and FBC 2018 lead-lag studies were to be externally reviewed.

Response:

The external review of the FEI 2009 Lead-Lag study was performed by KPMG throughout 2009. The work provided by KPMG covered multiple utilities (FEI, FortisBC Energy Vancouver Island and FortisBC Energy Whistler) and was for a number of studies including a lead-lag study, capitalized overhead study, corporate services review report, transfer pricing methodology review, and shared services cost allocation review. Therefore, FEI is not able to provide a specific amount for the costs and hours of KPMG's review of the FEI 2009 Lead-Lag study. However, of the aggregate costs for all of these studies, FortisBC estimates the cost of the review work performed by KPMG for the FEI 2009 lead-lag study was approximately $25 thousand to $30 thousand.

It is reasonable to assume that the 2018 lead-lag studies would likely have similar or higher external review costs once inflation is taken into account. However, FortisBC continues to apply a previously established and approved lead-lag model with no proposed change in methodology, which could potentially mitigate or decrease the costs to have the lead-lag studies externally reviewed. The results of the 2018 lead-lag studies relied primarily on financial data and transactions derived from the Utilities' accounting systems, as well as incorporating FortisBC's employees' understanding of the nature of the transactions, all of which do not require an external review. The preparation of the lead lag studies requires the time and commitment of internal resources to explain, educate, discuss and review the various inputs and outputs of the studies, regardless of whether an external review is conducted.

249.0 Reference: LEAD-LAG STUDY FOR CASH WORKING CAPITAL

Exhibit B-10, BCUC IR 133.1, 133.2, 133.3; Exhibit B-5, BCOAPO IR 99.1; Exhibit B-1-1, Appendix D3-1, p. 6; Exhibit B-1-3, p. D-33; Exhibit B-3, Slide 39

FEI 2018 Lead-Lag Study

In response to BCUC IR 133.1, FortisBC stated that the change in revenue lag days from the FEI 2009 lead-lag study is primarily associated with updating the results in collection lag for Residential and Industrial customer classes.

BCUC Staff note that revenue lags days for “Bypass and Special Rates” changed from 45.9 days in the FEI 2009 lead-lag study to 37.6 days in the FEI 2018 lead-lag study, which is also a significant charge.

249.1 Please explain why revenue lag days for “Bypass and Special Rates” decreased from 45.9 days in the FEI 2009 lead-lag study to 37.6 days in the FEI 2018 lead-lag study. Please reference the three time frames assessed (i.e. service lag, billing lag and collection lag) in calculating the sales revenue lag days as part of the response.

Response:

FEI notes the Bypass and Special Rates revenue lag in the previous study was 43.9 days, rather than 45.9 days as referenced in the preamble. The Bypass and Special Rates revenue lag of 43.9 days used in the FEI 2009 lead-lag study was calculated as summarized in the table below.

($ millions)	Revenues	Lag days	Dollar days
RS 22 - firm service	788	45.2	35,618
RS 25	481	45.2	21,741
RS 46	13,489	41.7	562,491
Byron Creek	118	45.2	5,334
BC Hydro	15,736	45.2	711,267
VIGJV	4,689	45.2	211,943
Total Bypass & Special Rates	35,301	43.9	1,548,394

As per the above table, the determination of lag days for the prior study assumed the lag days for Rate Schedule 46 customers, which are a class of Bypass and Special Rate customer, was primarily based on the lag days of Rate Schedule 6 NGV Service customers (41.7 days). Additionally, the lag days for all other Bypass and Special Rate customer classes (such as RS 22, RS 25, Byron Creek, etc.) were based on the lag days for Large Industrial customers (45.2 days).

The updated 2018 lead-lag study result of 37.6 days was calculated by specifically isolating the actual 2017 lag data for the Bypass and Special Rates customers from Large Industrial customers. More specifically, using the more detailed billing lag data is the main driver of the 6.3 lag day decrease. Service lag and collection lag remained similar in the 2018 lead-lag study, as compared to the 2009 lead-lag study.

In response to BCUC IR 133.2, FortisBC provided actual Late Payment Charge data for 2018, showing that the 2018 weighted Collection Lag was 51.2 days. The 2018 weighted Collection Lag is greater than the Collection Lag used in the 2018 lead-lag study, however, FortisBC states "due to the relatively small weighting of Late Payment Charges in FEI's overall cash working capital calculation, FEI has not revised its proposals."

249.2 Given that revenue lag days are calculated using 2017 actual data in the FEI 2018 lead-lag study,[108] please provide a summary of the actual Late Payment Charge data for 2017 and the 2017 weighted Collection Lag.

Response:

The summary table below shows the weighted Collection Lag is 52.3 days for Late Payment Charges using the 2017 actual data, as compared to the 23.8 days Collection Lag using the average of Collection Lags for Residential and Commercial customers (refer to the response to BCUC IR 1.133.2.1).

Summary of 2017 Late Payment Charges

Payment Days	Sum of $ Amounts (000s)	% of $ Amounts	Weighted Collection Lag
Zero	13	0.5%	-
1 - 22 Days	864	31.2%	3.6
23 - 24 Days	91	3.3%	0.8
24 - 30 Days	243	8.7%	2.3
31 - 60 Days	824	29.7%	13.5
61 - 90 Days	392	14.2%	10.7
91 - 120 Days	175	6.3%	6.6
Over 120 Days	168	6.1%	14.8
Grand Total	**2,770**	**100.0%**	**52.3**

[108] Exhibit B-1-1, Appendix D3-1, p. 2.

Note: This table uses the same calculation method as explained in the response to BCUC IR 1.133.2.

As shown in the illustrative tables included below, there is no impact on the Total Revenues lag days or Cash Working Capital under the Proposed FEI 2018 Lead Lag Study, which includes 53.8 total lead lag days assuming 23.8 days Collection lag, as compared to the revised 82.3 total lead lag days assuming 52.3 days Collection Lag which utilized the methodology applied in the response to BCUC IR 2.249.2. Under both scenarios, the overall cash working capital calculation is the same due to the low overall weighting Late Payment Charges have on working capital.

Proposed FEI 2018 Lead-Lag Study

Line	Particulars	2019 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days
1	**Sales Revenue**			
2	Residential Tariff Revenue	709,672	40.3	28,566,207
3	Commercial Tariff Revenue	376,335	37.8	14,216,503
4	Industrial Tariff Revenue	92,131	47.7	4,390,990
5	Bypass and Special Rates	35,301	37.6	1,326,181
6				
7	**Total Sales Revenue**	1,213,439	40.0	48,499,881
8				
9	**Other Revenues**			
10	Late Payment Charges	2,549	53.8	137,173
11	Connection Charges	1,925	39.0	75,103
12	Other Utility Income	40,419	39.0	1,576,925
13				
14	**Total Other Revenues**	44,893	39.9	1,789,200
15				
16	**TOTAL REVENUES**	1,258,332	**40.0**	50,289,082
17				
18	Energy Purchases	369,282	40.0	14,770,730
19	Operation & Maintenance	246,088	31.8	7,827,635
20	Property Taxes	67,559	1.3	84,585
21	Operating Fees	7,851	352.9	2,770,525
22	Carbon Tax	273,822	30.7	8,409,712
23	GST	10,550	39.7	418,717
24	PST	4,320	45.8	197,659
25	Income Tax	52,972	15.2	805,174
26				
27	**TOTAL EXPENDITURES**	1,032,444	**34.2**	35,284,737
28				
29	**NET LEAD-LAG DAYS (Line 16 - Line 27)**		**5.8**	
30				
31	**CASH WORKING CAPITAL (Line 27/365 x Line 29)**		**$16,406**	
32				

Updated as per BCUC IR 2.249.2

Line	Particulars	2019 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days
1	**Sales Revenue**			
2	Residential Tariff Revenue	709,672	40.3	28,566,207
3	Commercial Tariff Revenue	376,335	37.8	14,216,503
4	Industrial Tariff Revenue	92,131	47.7	4,390,990
5	Bypass and Special Rates	35,301	37.6	1,326,181
6				
7	**Total Sales Revenue**	1,213,439	40.0	48,499,881
8				
9	**Other Revenues**			
10	Late Payment Charges	2,549	82.3	209,783
11	Connection Charges	1,925	39.0	75,103
12	Other Utility Income	40,419	39.0	1,576,925
13				
14	**Total Other Revenues**	44,893	41.5	1,861,810
15				
16	**TOTAL REVENUES**	1,258,332	**40.0**	50,361,692
17				
18	Energy Purchases	369,282	40.0	14,770,730
19	Operation & Maintenance	246,088	31.8	7,827,635
20	Property Taxes	67,559	1.3	84,585
21	Operating Fees	7,851	352.9	2,770,525
22	Carbon Tax	273,822	30.7	8,409,712
23	GST	10,550	39.7	418,717
24	PST	4,320	45.8	197,659
25	Income Tax	52,972	15.2	805,174
26				
27	**TOTAL EXPENDITURES**	1,032,444	**34.2**	35,284,737
28				
29	**NET LEAD-LAG DAYS (Line 16 - Line 27)**		**5.8**	
30				
31	**CASH WORKING CAPITAL (Line 27/365 x Line 29)**		**$16,406**	
32				

Note: For Late Payment Charges, total lag days of 82.3 days/53.8 days = service lag (0.0 days) + billing lag (30.0 days) + collection lag (52.3 days/23.8 days).

249.2.1 Does FortisBC consider that the Collection Lag used in the 2018 lead-lag study should be updated based on the 2017 weighted Collection Lag? Please explain why or why not.

Response:

FortisBC does not believe it is necessary to revise its proposals. Using the weighted collection lag based on either the 2017 or 2018 actual data does not have an impact on the Total Revenue lag days or Cash Working Capital due to the relatively small weighting of Late Payment Charges in FEI's overall cash working capital calculation. Please also refer to the response to BCUC IR 2.249.2.

249.2.2 Please provide the impact on FEI's overall cash working capital calculation if it were to revise the Collection Lag used in the 2018 lead-lag study based on the 2017 weighted Collection Lag.

Response:

Please refer to the response to BCUC IR 2.249.2.

On page 6 of Appendix D3-1, FortisBC defines the Service Lag as "the time from the deemed average receipt date of service to the average meter reading date" and the Billing Lag is "the time from the average meter reading date to the average date the customer is billed."

In response to BCUC IR 133.3, FortisBC stated the following:

> … the main driver of the increase in Late Payment Charge lag in the updated Lead-Lag Study is the billing lag, which is partly offset by the removal of the Service Lag… In the FEI 20019 Lead-Lag Study, the approach assumed the lags associated with Late Payment Charges would be similar to the lag seen across all tariff revenue classes, which assigned a lag to the Service. The Service Lag has been removed (now zero) in the FEI 2018 Lead-Lag Study.
>
> In response to BCOAPO IR 99.1, FortisBC stated: "While the determination of Late Payment charges involves an interest rate, Late Payment Charges are more appropriately considered a revenue stream pursuant to the applicable rate schedule under the current FBC Tariff, as well as under US GAAP."

249.3 Please provide the rationale for why removing the Service Lag for Late Payment Charges (and replacing it with a Billing Lag) is appropriate given that the Late Payment Charge is considered a revenue stream related to a service. Alternatively, would putting a Service Lag back into Late Payment Charges be appropriate? Please explain why or why.

Response:

Rather than applying a weighted average lag, there was an isolation of the values assigned to each of Service Lag, Billing Lag and Collection lag for Late Payment Charges. For FortisBC's lead-lag studies, there was a nil value assigned to the Service Lag. This is because there is no service provided to the customers for late payment charges (late payment charges occur immediately when the customers' accounts get overdue). It is more appropriate to assign zero days to the Service Lag and 30 days to the Billing Lag as the late payment charges get added to the customer's account on the next bill (approximately 30 days) after the charges are incurred.

249.3.1 If including a Service Lag would be appropriate, please provide the number of lag days that could be used with supporting rationale and the impact on the net lead-lag days and cash working capital for FEI.

Response:

Assigning zero to the Service Lag for Late Payment Charges revenue is appropriate as described in the response to BCUC IR 2.249.3.

In FortisBC's Errata filing (Exhibit B-1-3), FortisBC provided a revised page D-33 of the Application. In the revised page, FortisBC states:

- When applied to the 2019 approved data, the 2018 Lead-Lag Study results in a net lag of 5.8 days. This compares to a net lag of 6.2 days, as shown in the FEI Annual Review of 2019 Delivery Rates – Compliance Filing…
- When applied to the forecasted revenues and operating expense for 2019, this change in net days would have resulted in a decrease of approximately $1.1 million in cash working capital… [Emphasis Added]

In the Workshop Presentation (Exhibit B-3), FortisBC provided the following slide showing the revenue requirement impact of a change in net lead/lag days for cash working capital for FEI and FBC:

- Lead Lag Study for Cash Working Capital

Change in Net Lead/Lag Days	FEI	FBC
Approved	+6.2	+6.7
Proposed	+ 5.5	+ 9.5
Change	- 0.7	+ 2.8
Revenue Requirement Impact	**-$0.2 M**	**+$0.1 M**

249.4 Please provide the calculation of the revenue requirement impact of a decrease in cash working capital of $1.1 million (based on a proposed net lag of 5.8 days, instead of 5.5 days) for FEI in dollar and percentage point terms for 2020.

Response:

While 2020 revenue requirements have not yet been determined, the following table provides a calculation of the estimated 2020 revenue requirement impact that results from a decrease in Net Lead/Lag Days of 0.4 for FEI. The decrease in Net Lead/Lag Days decreases cash working capital by approximately $1.1 million which results in a revenue requirement decrease of $84 thousand or 0.01 percent.

Line No.	Particulars	$000	Reference
1	Change in Cash Working Capital	(1,100)	
2	Return on Rate Base	6.38%	
3	Earned Return	(70)	Line 1 x Line 2
4			
5	Earned Return	(70)	Line 3
6	Deduct Interest on Debt	33	
7	Accounting Income After Tax	(37)	Line 5 + Line 6
8	1 - Income Tax Rate	73.0%	1 - Line 10
9	Taxable Income	(51)	Line 7 / Line 8
10	Income Tax Rate	27.0%	
11	Tax Expense	(14)	Line 9 x Line 10
12			
13	Revenue Requirement	(84)	Line 3 + Line 11
14			
15	Approximate Delivery Margin	810,400	
16	Percent Change in Revenue Requirement	-0.01%	Line 13 / Line 15

Note: Approximate Delivery Margin is as shown on page C-173 of the Application.

250.0 Reference: LEAD-LAG STUDY FOR CASH WORKING CAPITAL

Exhibit B-10, BCUC IR 133.4, 134.7; Exhibit B-3, Slide 39

FBC 2018 Lead-Lag Study

In the Workshop Presentation (Exhibit B-3), FortisBC provided the following slide showing the revenue requirement impact of a change in net lead/lag days for cash working capital for FEI and FBC:

- Lead Lag Study for Cash Working Capital

Change in Net Lead/Lag Days	FEI	FBC
Approved	+6.2	+6.7
Proposed	+ 5.5	+ 9.5
Change	- 0.7	+ 2.8
Revenue Requirement Impact	**-$0.2 M**	**+$0.1 M**

250.1 Please provide the calculation of the revenue requirement impact of +$0.1 million for FBC (as shown in the table above) and also provide the impact in percentage point terms for 2020.

<u>Response:</u>

While 2020 revenue requirements have not yet been determined, the following table provides a calculation of the estimated 2020 revenue requirement impact that results from an increase in Net Lead/Lag Days of 2.8 for FBC. The increase in Net Lead/Lag Days increases cash working capital by approximately $1.3 million which results in a revenue requirement increase of $105 thousand or 0.03 percent. The calculation is shown below.

Line No.	Particulars	$000	Reference
1	Change in Cash Working Capital	1,300	
2	Return on Rate Base	6.71%	
3	Earned Return	87	Line 1 x Line 2
4			
5	Earned Return	87	Line 3
6	Deduct Interest on Debt	(40)	
7	Accounting Income After Tax	48	Line 5 + Line 6
8	1 - Income Tax Rate	73.0%	1 - Line 10
9	Taxable Income	65	Line 7 / Line 8
10	Income Tax Rate	27.0%	
11	Tax Expense	18	Line 9 x Line 10
12			
13	Revenue Requirement	105	Line 3 + Line 11
14			
15	Approximate Total Revenue Requirement	373,300	
16	Percent Change in Revenue Requirement	0.03%	Line 13 / Line 15

Note: Approximate Total Revenue Requirement is as shown on page C-174 of the Application.

In response to BCUC IR 134.7 for FBC, FortisBC stated the following:

> Payroll & Benefits increased by 8.5 days – the Payroll data in the FBC 2018 Lead-Lag Study was broken down between salaried and hourly payroll categories which gave rise to a different overall payment lead. Benefits data was also updated in the FBC 2018 Lead-Lag Study to reflect the actual payment terms and frequency for each benefit category. Both of these categories used high-level assumptions in the previously approved method.

In response to BCUC IR 133.4 for FEI, FortisBC stated the following:

> Payroll & Benefits increased the total expense lead by 11.2 days, primarily due to the 2018 study recognizing the service lead for incentive pay. This service lead is the result of employees providing service to FEI throughout the year while the related incentive is not paid unit the following year. The previous study did not account for this service lead.

250.2 Please elaborate on each of the reasons provided for FBC for the increase in total Payroll & Benefits expense lead by 8.5 days (e.g. how/why breaking out salaried and hourly payroll categories gave rise to a different overall payment lead) and separately provide the impact of each reason.

Response:

The previously approved method used to calculate the FBC payment lead assumed zero payment lead for both hourly and salaried payroll. In the FBC 2018 lead-lag study, this assumption was refined based on 2017 actual data to recognize that there are 7 to 8 lead days for hourly payroll rather than zero, while the payment lead continues to be zero for salaried payroll. Breaking out the salaried and hourly payroll categories increased the weighted lead days for Payroll & Benefits by 0.7 days.

A simple example of lead for hourly and salaried payroll is included below for illustrative purposes.

	Pay Period From	Pay Period To	Pay Date	Payment Lead (Lag)	Service Lead (Lag)
COPE/M&E (Salary)	16-Sep-2017	29-Sep-2017	29-Sep-2017	0.0	7.0
COPE/M&E (Hourly)	08-Sep-2017	21-Sep-2017	29-Sep-2017	8.0	7.0
IBEW (Hourly)	08-Sep-2017	21-Sep-2017	28-Sep-2017	7.0	7.0

Other reasons for the increase in the weighted lead days for Payroll & Benefits are as follows:

- Increase of 7.0 days and 1.2 days due to the inclusion of Incentive Pay and OPEB costs, respectively, in the FBC 2018 lead-lag study; and
- Increase of 0.6 days due to a longer service lead and payment lead for Pension costs in the FBC 2018 lead-lag study, as compared to those in the previously approved method; partially offset by
- Decrease of 1.2 days due to a change in the weighting of Payroll & Benefits compared to total O&M. The weighting decreased to 49 percent in the FBC 2018 lead lag study from 54 percent in the previously approved method.

250.2.1 Please clarify whether the reason for the increase in Payroll & Benefits expense lead for FEI is also applicable to FBC. Please explain why or why not.

Response:

For both FEI and FBC, the main reason for the increase in the Payroll & Benefits expense lead is related to incentive pay. However, the change related to FBC is due to incentive pay not being included in the previously approved method, while for FEI incentive pay was previously included, but assigned zero service lag. The previously approved method assumed that incentive pay was paid evenly throughout the year, rather than when the actual payments was made in the following year. Assigning service lag to incentive pay in FEI's 2018 lead-lag study is a refinement to more accurately reflect the effect of incentive pay in the determination of cash working capital. Please also refer to the response to BCUC IR 2.250.2.

251.0 Reference: SHARED SERVICES STUDY
Exhibit B-1, p. D-38
Cost Driver Approach

On page D-38 of the Application, FortisBC states: "A Cost Driver Approach would require minimal timesheets/journal entries to be processed, and the cost drivers would require only annual updating with a broader review of the shared services model on a longer-term basis."

251.1 Please explain what is meant by "annual updating" as described in the preamble above. What steps will FortisBC take with a "broader review of the shared services model"?

Response:

The "annual updating" process is in reference to the annual updating of the values of the cost drivers (for example the relative number of customers for the upcoming year) and for changes in the dollar value of the shared resource pools based on the upcoming year's budget (the total dollar value to which the cost driver is to be applied).

The statement "a broader review of the shared service model on a longer-term basis" is in reference to a periodic review to assess the continued applicability of the cost drivers in the shared services model. As part of the broader review, similar to the process undertaken to develop the proposed shared services model, a review of both FEI and FBC departments/functions will be undertaken to confirm the shared resources and allocation drivers.

251.2 In the event that changes to the cost drivers may be required during the Proposed MRP term, please clarify whether FortisBC will seek the BCUC's approval to make these changes and the expected regulatory review process, if any.

Response:

FortisBC does not expect to change the selection of the cost drivers (i.e., number of customers, number of employees, etc.) during the course of the Proposed MRP term as the chosen cost drivers provide a reasonable and representative basis for allocation of shared services costs between FEI and FBC. FortisBC will be updating, where required, the cost driver values annually in the shared services model to reflect the current values for use in upcoming year.

Changes to the choice of cost drivers may be required on a longer-term basis, but would be subject to review and approval by the BCUC.

252.0 Reference: SHARED SERVICES STUDY

Exhibit B-10, BCUC IR 135.2, Exhibit B-1-3

2018 Actual O&M Shared Services – Cost Driver Approach vs. Timesheet Approach

In response to BCUC IR 135.2, FortisBC noted in preparing the response that the total provided for 2018 actual O&M for FEI was misstated in the Application. FortisBC states that FEI actual O&M after cross charges should be referenced as $271,551 thousand instead of $276,511 thousand, and FEI actual O&M before cross charges should be referenced as $270,169 thousand instead of $275,129 thousand.

As a result, FortisBC filed the following corrected tables as part of an Errata filing (Exhibit B-1-3):

Table D4-1: 2018 Actual O&M Shared Services – Timesheet Approach

(in millions)	Gross O&M Actual	FEI to FBC Cross Charge	FBC to FEI Cross Charge	Net Cross Charge	Net O&M Actual
FEI	270.17	(2.55)	3.94	1.38	271.55
FBC	58.74	2.55	(3.94)	(1.38)	57.36
Total	**328.91**	**0.00**	**0.00**	**0.00**	**328.91**

Deleted: 275.13
Deleted: 276.51
Deleted: 333.87
Deleted: 333.87

Table D4-3: 2018 Actual O&M Shared Services – Cost Driver Approach vs Timesheet Approach

(millions)	O&M Actual Timesheet Approach	O&M Actual Cost Driver Approach	Allocations as per Timesheet Approach	Allocations as per Cost Driver Based	Difference in Approaches
FEI	271.55	276.17	1.38	1.04	0.34
FBC	57.36	57.70	(1.38)	(1.04)	(0.34)
Total	**328.91**	**333.87**	**0.00**	**0.00**	**0.00**

Deleted: 276.51
Deleted: 333.87

252.1 Given that FEI actual O&M before cross charges was misstated, please confirm that the amounts in column 2 (O&M Actual Cost Driver Approach) in Table D4-3 should have also been corrected, as follows (BCUC Staff corrected amounts are in red font):

(millions)	O&M Actual Timesheet Approach	O&M Actual Cost Driver Approach	Allocations as per Timesheet Approach	Allocations as per Cost Driver Based	Difference in Approaches
FEI	271.55	271.21	1.38	1.04	0.34
FBC	57.36	57.70	-1.38	-1.04	-0.34
Total	**328.91**	**328.91**	**0.00**	**0.00**	**0.00**

Response:

Confirmed. The amounts in Column 2 of Table D4-3 should have also been updated as presented. Column 2 will be updated in an Errata filed concurrently with these IR responses.

252.1.1 If not confirmed, please explain why total O&M actual using the Cost Driver approach ($333.87 million) is higher than total O&M actual using the Timesheet approach ($328.91 million) given that the difference in allocations between the two approaches is only $0.34 million.

Response:

Please refer to the response to BCUC IR 2.252.1.

253.0 Reference: SHARED SERVICES STUDY

Exhibit B-10, BCUC IR 135.2; Exhibit B-5, BCOAPO IR 101.1; Exhibit B-1, p. D-39

Exhibit B-1-1, Appendix D-4, p. 11

2013-2017 Actual O&M Shared Services – Cost Driver Approach vs. Timesheet Approach

In response to BCOAPO IR 101.1, FortisBC stated the following:

> As indicated by results in the study based on 2018 actuals, the Cost Driver approach generates similar results as the Timesheet approach, suggesting both are “accurate”.
>
> FortisBC is recommending the adoption of the Cost Driver approach as it is simpler to understand, easier to administer and more efficient and more stable over time, while providing an allocation methodology that reasonably represents the sharing of services.

In response to BCUC IR 135.2, FortisBC provided the following table showing the approximations of allocations using the Timesheet Approach compared to the proposed Cost Driver Approach, based on the actual labour cross charges observed from 2013-2017:

(millions)	O&M Actual Timesheet Approach	O&M Actual Cost Driver Approach	Allocations as per Timesheet Approach	Allocations as per Cost Driver Based	Differences in Approaches
2017					
FEI	259,631	260,186	657	1,212	(555)
FBC	55,821	55,266	(657)	(1,212)	555
Total	315,452	315,452	-	-	-
2016					
FEI	259,459	260,356	31	928	(897)
FBC	55,610	54,713	(31)	(928)	897
Total	315,069	315,069	-	-	-
2015					
FEI	260,034	261,978	(97)	1,847	(1,944)
FBC	57,785	55,841	97	(1,847)	1,944
Total	317,819	317,819	-	-	-
2014					
FEI	257,788	259,620	89	1,921	(1,832)
FBC	59,723	57,890	(89)	(1,921)	1,832
Total	317,511	317,511	-	-	-
2013					
FEI	264,923	269,789	133	4,999	(4,866)
FBC	56,696	51,830	(133)	(4,999)	4,866
Total	321,619	321,619	-	-	-

253.1 Please confirm that the amounts provided in the table above are in thousands of dollars (‘000’s) and not millions of dollars as indicated in the table.

Response:

Confirmed.

253.2 Please explain why there is a gradually decreasing trend in the “Differences in Approaches” from 2013 to 2018, where the “Differences in Approaches” is either $4.866 million or $4,866 million (depending on the IR response above) for 2013 and $0.34 million for 2018.

Response:

The decreasing trend in the “Difference in Approaches” from 2013 to 2018 is related to the evolving nature of shared services. In the earlier years, sharing was limited to only certain departments as the Companies evaluated opportunities for sharing of resources. A Timesheet Approach in these circumstances best captures the related shared services costs and appropriately represent the circumstances of the different shared services situations. As time passed, the Companies have expanded and broadened their sharing of services by pursuing integration opportunities. The broadening of shared services between the two Companies and the related shared costs are now reasonably represented by the proposed use of broad cost drivers such as the number of customers and number of employees for each Company.

The appropriateness of introducing a Cost Driver approach for Shared Services at this time is corroborated by the narrowing difference observed between the two approaches in recent years. The Cost Driver based allocation approach simplifies the administration of the cost allocation process, while providing an allocation methodology that reasonably represents the sharing of services provided.

253.3 Given the magnitude of the “Differences in Approach” from 2013 to 2017, please explain why FortisBC considers the Cost Driver Approach, as proposed, is appropriate. Please include FortisBC’s rationale for comparing the Cost Driver Approach results to the Timesheet Approach results for 2018 actuals only in the Application.

Response:

A stabilization in opportunities for O&M Shared Services and relatively small differences in allocations between the two approaches in the most recent two years (2017 and 2018) are conditions suggesting that introducing the Cost Driver Approach, as proposed, is now appropriate.

FortisBC has been pursuing integration opportunities for a number of years. As a result, FortisBC believes and anticipates that the opportunities for O&M related Shared Services have stabilized (i.e., identified areas for sharing) as all departments have integrated management. In the earlier years (i.e., 2013, 2014), sharing was limited to certain departments as the Companies evaluated opportunities for sharing of resources. As time passed, the Companies have expanded and broadened their sharing of services by pursuing integration opportunities.

In recent years, the differences between the two approaches have been relatively small. In 2017, the difference was $0.56 million and in 2018, the difference was even less at $0.34 million, providing support that the Cost Driver approach results in a representative allocation of costs compared to the Timesheet approach, and that sharing has stabilized to the point that now is the time to transition.

For the study, FortisBC used 2018 data as 2018 was the most recent year of actual data and represented the current level of integration between the utilities, and the expected level for the term of the MRPs.

Table D4-2 on page D-39 of the Application shows that the proposed cost driver for "Fleet Services" and "Regulatory" department/functions is "Time Estimates." To the extent that there are shared costs to be allocated, Table A:D4-4 on page 11 of Appendix D-4 shows that the proposed cost driver for "Legal", "Risk Management" and "Operations" department/functions is also "Time Estimates."

253.4 Please explain how the "Time Estimates" cost driver will be tracked and set (e.g. will FortisBC continue to use manual timesheets in these departments/functions to determine the allocation split between FEI and FBC, survey departments weekly/monthly/quarterly/annual, or use other methods?)

Response:

For departments following the "Time Estimate" approach, instead of requiring employees to complete timesheets, the allocated shared services costs will be based on time estimates for the upcoming year. For example, the Regulatory department will review the number and type of proceedings anticipated for the upcoming year as between FEI and FBC to determine the allocation of time.

In response to BCUC IR 137.1, FortisBC provided tables showing the calculation of allocated shared costs for 2013 to 2017 using the Cost Driver Approach by department.

253.5 Please explain the fluctuations in the split between FEI and FBC in the “Time Estimates” cost driver from 2013 to 2017.

Response:

The fluctuations of the Time Estimates split from 2013 to 2017 for the Regulatory and Fleet Services functions were influenced by the evolving nature and the level of integration between FEI and FBC. As integration efforts evolved from 2013 to 2017, a higher level of integration was achieved overall and that has stabilized in recent years. FortisBC notes that since 2015, as the Utilities became more fully integrated, the Time Estimate percentages split for Regulatory and Fleet Services have become more stable.

One of the reasons why Time Estimates was chosen as the driver for these groups is because there are annual fluctuations in the allocations due to differing priorities between the Companies year over year (for example, the number and type of regulatory proceedings for each of FEI and FBC).

253.5.1 Does FortisBC consider that the split between FEI and FBC the “Times Estimates” will be variable over the term of the Proposed MRP? Please explain why or why not.

Response:

For departments following the “Time Estimate” approach, the allocated shared services costs will be based on time estimates, which are reviewed annually. The time estimates are dependent on business priorities and can change over the proposed MRP term, but the impact of any variations on overall O&M for these departments should not be significant.

Please also refer to the response to BCUC IR 2.253.4.

253.6 Given the historical information provided in responses to BCUC IR 135.2 and 137.1, please explain why FortisBC considers that the Cost Driver Approach will be "more stable over time."

Response:

FortisBC believes the proposed cost driver approach will be more stable over time. Cost drivers such as the number of customers and number of employees are fairly consistent and stable over time and provide a representative basis to use in allocating shared services. While the overall level of shared services may change over time, the allocation of shared services costs between FEI and FBC is expected to remain relatively constant (i.e., stable) with the use of these cost drivers. As explained in the response to BCUC IR 2.253.3, sharing levels have stabilized in recent years and will remain stable over the MRP term.

254.0 Reference: SHARED SERVICES STUDY

Exhibit B-1, p. D-40

Revenue Requirement Impact

On page D-40 of the Application, FortisBC states the following:

> …as part of the transition to a Cost Driver Approach in this Proposed MRP, an adjustment is required to the Base O&M of FEI and FBC to recognize the difference in the overall allocation from the current Timesheet Approach to the Cost Driver Approach. Based on the 2018 actual O&M expenditures, the adjustment required would be an increase to FBC's Base O&M of $0.338 million with an equivalent offsetting reduction to FEI's Base O&M of $0.338 million.

254.1 Please provide the revenue requirement impact of transitioning to a Cost Driver Approach for shared services in percentage point terms for 2020.

<u>Response:</u>

The revenue requirement impact is an approximate delivery rate decrease of 0.04 percent for FEI and a 0.09 percent rate increase for FBC. The following table shows the calculation of the impact.

	FEI	FBC
Shared Service Study Impact	(0.338)	0.338
Margin (FEI) / Revenue (FBC)	810.4	373.3
Rate Change	**-0.04%**	**0.09%**

Note: Margin (FEI) and Revenue (FBC) are as shown on pages C-173 and C-174 of the Application.

255.0 Reference: CORPORATE SERVICES STUDY

Exhibit B-10, BCUC IR 139.1.2, 139.3.1

Comparison of Corporate Services Costs

In response to BCUC IR 139.1.2, FortisBC stated that historical comparison (2014-2018) of the total Actual corporate services charged directly by FI and FHI to FBC and the corporate services costs allocated to FBC using the proposed cost sharing methodology is not a meaningful comparison, and provides reasons.

FortisBC further stated: "Rather the expected impact of the proposed methodology is outlined in the revised Table C2-14 included in response to BCUC IR 1.34.1. Similarly, the overall impact for 2020 is expected to be approximately $383 thousand, as shown in Table D5-4 of the Application."

In response to BCUC IR 139.3.1, FortisBC stated the same for FEI, except that the revised table in response to BCUC IR 1.34.1 is Table C2-1 and the overall impact for 2020 is expected to be approximately $122 thousand, as shown in Table D5-4 of the Application.

FortisBC also stated in BCUC IR 139.3.1: "The FortisBC Utilities have recommended the proposed methodology due to the integration that exists between FEI and FBC at the end of the Current PBR Plan term that did not exist to the same degree at the beginning in 2014."

255.1 Please provide FortisBC's rationale for why comparing the expected impact of the proposed corporate services cost allocation methodology against the current methodology is meaningful for 2019 and 2020. Is it because FortisBC considers that O&M shared services between FEI and FBC have "stabilized"?[109]

Response:

To clarify, the sharing of services between FEI and FBC is not the same as allocating FI and FHI corporate services to FEI and FBC (as well as ACGS). Therefore, the O&M shared services between FEI and FBC that have "stabilized", as outlined in BCUC IR 1.136.1, is not the only basis for the recommendation to use the proposed methodology of allocating corporate services.

As stated in the preamble, the recommendation to use the proposed methodology of allocating corporate services is a result of the integration of FortisBC's departmental functions across the entire FortisBC group, which includes FHI's corporate departments. These corporate departments are providing the same services to both FEI and FBC (as well as ACGS) during the

[109] Exhibit B-10, BCUC IR 136.1.

MRP term, which did not exist to the same degree at the beginning of the Current PBR Plan term.

The reason for comparing the expected impact of the proposed methodology from 2019 to 2020 is to provide an approximate change that could be expected under the new methodology, beginning in 2020 as proposed, compared to the existing methodology of direct charging. Looking at prior years is not relevant, as described in the responses to BCUC IR 1.139.1.2 for FBC and BCUC IR 1.139.3.1 for FEI.

255.1.1 Please explain why the expected overall impact for 2019 and 2020 is meaningful to considering the proposed cost sharing methodology for the MRP term (2020-2024).

Response:

Please refer to the response to BCUC IR 2.255.1.

255.2 Please provide the 2020 revenue requirement impact of changing to the proposed cost sharing methodology for corporate services costs in percentage point terms for FEI and FBC, respectively.

Response:

While 2020 revenue requirements and costs of service have not yet been finalized, the following table provides a reasonable approximation of the impact of the proposed corporate services methodology on the estimated 2020 revenue requirement in terms of percentage points.

Estimated 2020 Revenue Requirement Impact of Proposed Cost Sharing Methodology ($millions)

	FEI	FBC
Corporate Services Cost Impact	(0.122)	0.383
Margin (FEI) / Reveue (FBC)	810.4	373.3
Rate Change	-0.02%	0.10%

Note: Margin (FEI) and Revenue (FBC) are as shown on pages C-173 and C-174 of the Application.

256.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-10, BCUC IR 149.1.1

Survey-based Approach – Pros and Cons

In response to BCUC IR 149.1.1, FortisBC stated that one of the “Cons” of the survey-based approach is “Potential for biased responses – Respondents may have biases to the survey questions.”

256.1 Please explain what the potential biases that respondents may have are and the potential motivations for these biases (e.g. to meet individual or corporate performance targets, to maintain or increase a departmental budget, etc.)

Response:

The reference to “potential for biased responses” in BCUC IR 1.149.1.1 as a con is in reference to surveys in general, and is not specific to a survey undertaken for capitalized overheads. As with any survey, there could be judgement incorporated in the responses and, therefore, the potential biases are inherent to the approach, but not to any particular motive.

Therefore, some of the biases that respondents may have had when being interviewed are:

- Confirmation bias, meaning the department manager answered in a way that confirmed their own preconceptions, instead of challenging what they believe through analysis of supporting data; or
- Courtesy bias, meaning the department manager answered in a way that they consider more acceptable than their true opinion to avoid disruption or further questioning, such as answering to be consistent with previous studies.

For each of the department heads and cost centre managers, there is no incentive or other motivation for trying to change the level of capitalized overhead related to their individual department. The allocation for capitalized overheads occurs outside of the O&M budgets and their responses would not change the overall costs for which they are responsible. Similarly, capital project managers were not directly involved in the input to the studies since they generally do not manage O&M and therefore, could not contribute to any bias within the studies. Additionally, the capitalized overheads allocated to specific projects is generally beyond the control of project managers, further reducing the potential bias included in the results of the study.

In order to ensure an appropriate level of diligence on the responses, as well as to eliminate the potential for some of the above biases to occur, the following actions were performed:

- Independent advisory firm KPMG, who were engaged to review the methodology and prepare the study, made objective challenges to survey responses.

- Results of survey responses were evaluated against the results in the capitalized overhead studies prepared in 2013, and follow up inquiries were made where required.
- Comparisons to business trends, capital expenditure profiles, and quantitative data supporting cost drivers of the department, such as proportions of employees, were used in certain surveys to corroborate the responses provided.

256.2 Please describe the mitigating actions taken by FortisBC in consideration of the potential for biased responses.

Response:

Please refer to the response provided in BCUC IR 2.256.1.

257.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-10, BCUC IR 149.3; Exhibit B-1, Section B2.4

External Survey

In response to BCUC IR 149.3, FortisBC stated the following:

> Since 2013, fewer utilities in Canada and the United States have publicly filed capitalized overhead studies. It is understood that there are more instances where utilities are internally updating capitalized overhead studies and implementing the results as part of their multi-year revenue requirements applications, rather than publicly filing studies and explicitly requesting approval for a rate… As such, both KPMG and FortisBC had difficultly locating the required information and an external survey of other utilities across the US and Canada was not included as part of the 2018 FEI and FBC Capitalized Overhead Studies (2018 Studies).

In Section B2.4 of the Application, FortisBC explains that Concentric was selected as the consultant to prepare a separate benchmarking study for each of FEI and FBC.

257.1 To the extent possible, please provide the overhead capitalization methodology and rate for each utility identified in the Canadian peer group for FEI and FBC, respectively, in the Concentric benchmarking studies.

Response:

The following response was provided by Concentric.

Overhead capitalization rates were requested from those utilities that participated in the benchmarking study in order for Concentric to better understand what factors might be affecting the administrative and general (A&G) expenses comparison across utilities. To maintain confidentiality between the utilities and Concentric, each utility surveyed was designated by letter, which is summarized below.

Utility	Overhead Capitalization Rate for Each Year of the Benchmarking Study (i.e., 2012 through 2017)
A	The overhead capitalization follows the actual labour distribution of that year. Historically that capitalization rate has been approximately 60/40 O&M/capital.
B	Since 2011 the Company has been charging the majority of overhead costs (mainly internal labour costs) directly to the related capital work projects. As a result, there is a very small amount being charged to overheads (just purchasing and inventory labour and maintenance that remain in overheads) annually: 2012 - 1.18% 2013 - 1.58% 2014 - 1.46% 2015 - 1.75% 2016 - 1.68% 2017 - 1.53% Prior to 2011, overheads ran in the 9.5-10.5% range.
C	Payroll loading is 34% added to labour , vehicle costs are allocated to construction labour at 25% and material loading is 10%. This has been consistent over the 2012 to 2017 period.
D	The overhead capitalization rate will vary from year to year and will also vary for each Distribution and Transmission based on the level of capital spending. The rate has typically ranged between 6 and 9% of total capital expenditures.
E	The percentage of our operating costs charged to capital is not a number that we publicly report.
F	As a % of Gross O&M: 2017 – 14% 2016 – 14.1% 2015 – 13.8% 2014 – 13.1% 2013 – 12% 2012 – 11.7%
G	Apply capital overhead to capital projects based on loading rates by function. The loading rates for F13 – F17 are shown in the table below. Actual Overhead Capitalization rate information is not available for Fiscal 2012. Transmission - Distribution - Generation Fiscal 2013 - 1.9% - 18.5% - 2.1% Fiscal 2014 - 1.3% - 16.4% - 1.9% Fiscal 2015 - 2.2% - 14.7% - 2.7% Fiscal 2016 - 3.3% - 13.3% - 3.1% Fiscal 2017 - 4.8% - 11.3% - 3.2%
H	No Response
I	No Response
J	No Response
K	No Response
L	No Response
M	No Response

257.1.1 Please discuss and explain which of these capitalized overhead methodologies and rates FortisBC would consider to be indicators of the appropriate rate to be implemented for FEI or FBC.

Response:

The capitalized overhead methodologies and rates for other utilities summarized in the table in the response to BCUC IR 2.257.1 are not indicators of the appropriate capitalized rate to be implemented for FEI or FBC.

The capitalized overhead rates proposed for the FortisBC regulated entities are based solely on the historical and projected capital expenditures, business departments' activities, operating environment and accounting processes specific to FEI and FBC, which have been described in section D6 of the Application and Appendices D6-1 and D6-2. Without a better understanding of the historical and projected capital programs, regulatory mechanisms and accounting processes of the other utilities included in Concentric's benchmark study, comparing capitalized overhead rates is not as relevant.

Further, there is minimal consistency in rates and several different capitalization methodologies provided for those utilities surveyed by Concentric. Accordingly, rates ranged from lower than 2 percent, as shown for Utility B and up to 18.5 percent for distribution services, as shown for Utility G. Similarly, the capitalized overhead methodologies were not consistent across the respondent utilities. As an example, Utility B acknowledges that it charges its overhead costs directly to capital which then distorts how it methodology and rate can be comparable to other utilities that do not direct charge such overhead costs.

Due to these varying capitalized overhead methodologies and rates, FortisBC does not view comparative rate and methodology data from other utilities as appropriate or relevant compared to the overhead study developed by an independent advisory firm, KPMG, that was reviewed and corroborated by management. FortisBC's Corporate Overhead Studies have been prepared based on the historical, current and future capital activities, operating environment, business departments' activities and accounting processes that are relevant for FortisBC, which may not be comparable to other utilities.

FortisBC notes that, while the responses from those utilities surveyed by Concentric are not necessarily comparable, the results of the Capitalized Overhead Studies for FEI and FBC, which recommend rates of 16 percent and 15 percent applied to gross O&M respectively, appear to be in the same range as utilities F and G.

258.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-10, BCUC IR 150.2, 153.2

Nature of Capital-related O&M Costs (FEI and FBC)

In response to BCUC IR 150.2 and 153.2, FortisBC explained the nature of capital-related costs in the FEI and FBC O&M by department. As part of that response, FortisBC stated: "included in operations O&M are operations support representatives, dispatch coordinators and field operations assistants who support and enable the capital activities performed by the group."

258.1 Please elaborate and provide examples of the type of work which Operations O&M undertakes to "support and enable" capital activities performed by the Operations group.

Response:

Operations Support Representatives, Dispatch Coordinators, and Field Operations Assistants provide support to all activities performed by Operations, which includes capital-related activities. The job duties considered to support and enable capital activities are outlined below:

Operations Support Representatives

- Process and support capital and O&M work orders
- Respond to inquiries and requests related to capital and O&M
- Process initial meter and service line installations for new customers in growth capital projects
- Provide a wide range of detailed capital and O&M job information to crews

Dispatch Coordinators

- Coordinate the scheduling and dispatching of FortisBC resources (people, tools, equipment and time) to meet capital and O&M work requirements
- Determine the complexity and priority of capital and O&M work and allocate appropriate field resources
- Provide assistance to management in monitoring annual capital and O&M work plans for field operations
- Develop annual work and long-term capital forecast plans, including all planned and unplanned activities
- Collaborate with Supervisors, Managers, Planners, and Field Staff in order to achieve operational and capital targets

Field Operations Assistants

- Assists management to research, gather information and compile reports & variance reviews on capital and O&M projects
- Checks and codes documents such as invoices and expense claims for capital and O&M projects

Without these supportive functions in place, capital projects cannot be initiated or constructed. Therefore, these costs are examples of the type of administrative activities that should be included as part of the capitalized overhead rate as supported by the BCUC Uniform System of Accounts and US GAAP ASC 980 rate regulated operations. The capital activities of the above mentioned functions have been appropriately incorporated into the proposed rate and results of the KPMG study per Appendix D6-1.

FortisBC also stated: "Energy Supply and Resource Development involve future energy resource planning, which requires coordination with capital project planning."

258.2 Please explain why FortisBC considers "coordination with capital project planning" a capital-related activity given that the coordination is required for future energy resource planning, which is not a capital activity.

Response:

To clarify, the reference to "coordination with capital project planning" represents the Energy Supply and Resource Development departments' portion of O&M incurred for FortisBC's future energy resource planning that relates to the development of potential future capital projects. This O&M includes activities that identify and develop gas and power supply infrastructure, major capacity initiatives, new regional projects, and system infrastructure projects including pipeline, compressor, storage, transmission, and/or electric generation projects. The early stage identification of these potential capital projects by Energy Supply and Resource Development are required for system reliability and resiliency, as well as to meet demand growth. Accordingly, this department incurs O&M that indirectly supports capital activity and is appropriately incorporated in the determination of the capitalized overhead rate.

259.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-10, BCUC IR 150.3, 150.3.1, 150.8; Exhibit B-1-1, Appendix D6-1, p. 15

FEI Capitalized Overhead Study Results

BCUC Staff prepared the following table showing the change in the capitalization rate for the FEI departments from the 2013 FEI Capitalized Overhead Study to the 2018 FEI Capitalized Overhead Study:

Department	(1) FEI 2013 Overhead Study Grouped to 2018 Departments - Capitalization Rate (Reference: Exhibit B-10, BCUC IR 150.3)	(2) FEI 2018 Overhead Study - Capitalization Rate (Reference: Exhibit B-1-1, Appendix D6-1, p. 15)	(2)-(1) Change in Capitalization Rate
Operations	18%	14%	-4%
Engineering	10%	50%	40%
Customer Service and Information Systems	9%	10%	1%
Market Developments and External Relations	2%	23%	21%
HR, Environment, Health & Safety, and Facilities	11%	14%	3%
Finance and Corporate	7%	12%	5%
Regulatory, Legal and Operations Support	16%	14%	-2%
Energy Supply and Resource Development	17%	3%	-14%
Total	12%	16%	4%

In response to BCUC IR 150.3.1, FortisBC provided explanations for significant changes in capital-related activity, based on dollar value, by department.

259.1 Please confirm, or correct otherwise, that the table prepared above by BCUC Staff is correct.

Response:

Confirmed.

As stated in the responses to BCUC IRs 1.150.3 and 1.150.3.1, O&M costs used in the 2013 FEI Capitalized Overhead Study reflected only those O&M costs relating to FEI Mainland, as the study was prepared prior to the amalgamation of FEI with FEVI and FEW.

As requested in BCUC IR 2.259.2, FortisBC has provided explanations for all variances greater than +/- 3 percent between the 2013 and 2018 FEI Capitalized Overhead Studies as follows:

- **Operations (-4 percent)**

  The individual rate for this department, which represents Operations, Project Management and LNG Operations, has decreased primarily due to an increase in O&M that did not all support capital projects. The higher overall 2018 Operations O&M primarily relates to LNG operations, which had a lower proportion of O&M activities estimated as supporting capital activities. There was a much smaller portion of LNG

Operations O&M at the time of preparing the 2013 FEI Capitalized Overhead Study as compared to the 2018 FEI Capitalized Overhead Study.

While the proportion of O&M that does not support capital projects has increased, this department's O&M activities incurred to support capital expenditures has increased. There is an increased need for maintenance and investment in FEI's aging infrastructure to continue to provide safe, reliable services, along with increased need to provide physical security, all of which requires a greater amount of activities from Project Management and Operations. These O&M activities include those operational support functions that enable the capital activities performed by the group of employees who charge directly to capital.

- **Engineering (+40 percent)**

  The increase is primarily due to this department's increasing activities to support growth and sustainment capital expenditures, as well as the increased need for investment in FEI's aging infrastructure. These capital expenditures requirements place increasing demand on the Engineering department to perform a higher amount of upfront planning and feasibility activities. Such O&M activities must be incurred prior to construction of capital projects. For example, the labour and consultant costs for the early stage planning of capital projects are not directly charged to specific capital projects.

  The Engineering O&M activities also includes the review, evaluation and updating of design standards which are incurred to support not only operating activities, but are required to be incurred prior to the construction and implementation of a new asset. This department has had to reassess and redesign its processes to provide class 3 estimates for capital expenditures and the nature of these costs, while necessary for capital projects, is recorded in O&M.

- **Market Developments and External Relations (+21 percent)**

  The increase in this department's O&M activities that support capital expenditures is driven by the capital effect of "Influence 3: Increased need for engagement with stakeholder and Indigenous communities as a result of stakeholder activism and provincial and federal policy changes", as described in the response to BCUC IR 1.1.1. As discussed in that response, the failure to engage effectively will negatively impact planned capital programs.

  The activities of this department required for capital projects include:

  - enhancing engagement practices, including modernizing Indigenous operating arrangements and committing additional staff and resources to building capacity in Indigenous communities, which will assist in gaining vital support for required capital projects.

- expanding efforts on project consultation, in terms of the scope and number of stakeholder and rights holder consultations, to maintain and build positive relationships to secure broad support and certainty for projects.

The increase in this department's O&M activities that support capital expenditures are also driven by the capital effect of "Influence 1: Policy direction and mandate from all levels of government towards decarbonization", as described in the response to BCUC IR 1.1.1. A discussed in that response, climate-related policies create new requirements for capital expenditures to comply with increasingly stringent emissions requirements and to meet customers' changing energy needs.

There are new compliance and communication requirements with municipalities and other levels of government related to FEI's capital projects, which are managed by this department. Where FEI's services are provided, high volumes of upfront communication and public hearings are required for construction projects. These requirements have increased over the last five years and currently are requiring more effort than what was required at the time of the 2013 Corporate Overhead Study.

- **HR, Environment, Health & Safety, and Facilities (+3 percent)**

There has been an increase in activities for all of these departments as a result of the level of capital expenditures incurred over the Current PBR Plan term and forecast for the term of the MRP. Increased capital expenditures requires a greater proportion of hiring practices and human resource requirements. Certain capital projects will continue to form part of the corporate sustainability programs and requirements, which are at a higher level as compared to the timing of the last study.

Environment, Health & Safety O&M that relates to both operating and capital activities includes an increase in assessments, investigations, permitting, approvals, monitoring, inspecting and auditing to ensure compliance with evolving regulatory requirements for capital projects. Capital projects require safety enhancements through the implementation of safety programs that focus on high risk, contractor management, road safety, leading safety indicators, human and organization performance, and further development of frontline safety leadership. FEI has also been increasing its focus on employee and customer health and safety by implementing the Target Zero program, with an increased focus on both capital and operating activities.

The Facilities department O&M includes activities that indirectly supports FEI Facilities Capital, including approved facilities are built to meet internal standards, build codes and regulations, as well as larger projects to address muster replacements, and provide a long-term solution toward meeting the business requirements.

- **Finance and Corporate (+5 percent)**

  This function primarily consists of Financial Accounting, Capital Asset Accounting, Financial Reporting, Corporate Finance, Internal Audit, and FI Corporate Services. The increase in Regular capital expenditures and Major Projects since the 2013 Capitalized Overheads Study required an increase in compliance, accounting, financial reporting, tax and financing requirements, which are managed by FortisBC's Finance department.

  Finance and Corporate supports the capital program by the following:

  - Managing the financial forecasting and budgeting of capex;
  - Accounting for capex within the capital asset module;
  - Complying with the external financial reporting requirements for capex;
  - Preparation of accounting analyses relating to capex in accordance with US GAAP;
  - Providing analysis and review of certain CPCN application and capital forecasts in annual rate filings;
  - Providing tax planning opportunities and support around capex;
  - Ensuring compliance with tax regulations for corporate income tax and commodity tax related specifically to capital projects;
  - Testing and evaluation of controls and accounting processes around capital projects by both Internal Audit and capital asset accounting group;
  - Testing and evaluation of Internal Controls for Financial Reporting (ICFR) specific to the property, plant and equipment processes, which represents a significant portion of the audit conducted by the external auditors;
  - Processing accounts payable transactions, of which a significant amount relate to invoices and purchase orders related to capital projects;
  - Managing cash requirements to ensure timely payment of invoices to capital expenditures;
  - Arranging cost-effect debt financing for the Company's capital projects, either through its operating credit facility agreements or debt offerings;
  - Coordinating with credit rating agencies around assessments of FortisBC's current and projected capital expenditures and the evaluation of credit metrics;
  - Oversight of all the above mentioned capital related activities by FortisBC's Executive and Board of Director by providing stewardship, governance, capital budget approvals, and strategic direction that largely involves investment in utility infrastructure;

- Arranging equity financing of FortisBC's capital expenditures through the FI corporate services;
- Sharing of best practices amongst the group of FI companies relating to various functional areas which support capital projects, such as joint procurement activities, which are provided by way of the FI corporate services; and
- Benefiting from the FI administered company-wide group insurance program which supports FortisBC's capital projects.

- **Energy Supply and Resource Development (-14 percent)**

  The capitalization rate decreased primarily due to the increase in overall department O&M while the capital related activities did not increase at the same proportion. The increase in O&M for this department not supporting capital projects was due to the activities incurred to prioritize the development of initiatives to reduce greenhouse gas emission due to current or future changes in environmental regulations. While the rate decreased by 14 percent, the value of forecasted capital related costs identified in this department have only slightly deceased from approximately $600 thousand to $500 thousand, which is driving the change in the percentage.

While the comparison to the overall prior capitalized overhead study rates provides a reasonableness assessment of whether the 2018 recommended overhead rate reflects the shift in business activities, FEI focused on whether the FEI 2018 Overhead Study, included in Appendix D6-1 of the Application, appropriately reflected the activities that are required to support its capital expenditures over the term of the MRP.

259.2 Please provide explanations for each change in the capitalization rate by department greater than +/- 3 percent between the 2013 FEI Capitalized Overhead Study and the 2018 FEI Capitalized Overhead Study, including how the nature of each department's indirect capital-related work has changed since 2013 and why.

Response:

Please refer to the response to BCUC IR 2.259.1.

260.0 Reference: CAPITALIZED OVERHEAD STUDY

Exhibit B-10, BCUC IR 153.3, 153.3.1; Exhibit B-1-1, Appendix D6-2, p. 18

FBC Capitalized Overhead Study Results

BCUC Staff prepared the following table showing the change in the capitalization rate for the FBC departments from the 2013 FBC Capitalized Overhead Study to the 2018 FBC Capitalized Overhead Study:

Department	(1) FBC 2013 Overhead Study Grouped to 2018 Departments - Capitalization Rate (Reference: Exhibit B-10, BCUC IR 153.3)	(2) FBC 2018 Overhead Study - Capitalization Rate (Reference: Exhibit B-1-1, Appendix D6-2, p. 18)	(2)-(1) Change in Capitalization Rate
Operations	15%	17%	2%
Engineering	32%	10%	-22%
Customer Service and Information Systems	9%	13%	4%
Market Developments and External Relations	8%	22%	14%
HR, Environment, Health & Safety, and Facilities	17%	13%	-4%
Finance and Corporate	17%	17%	0%
Regulatory, Legal and Operations Support	12%	9%	-3%
Energy Supply and Resource Development	5%	10%	5%
Total	15%	15%	0%

In response to BCUC IR 153.3.1, FortisBC noted that there were no significant increases or decrease in total O&M or capital-related activity, based on dollar value, by department.

260.1 Please confirm, or correct otherwise, that the table prepared above by BCUC staff is correct.

Response:

Confirmed.

As requested in BCUC IR 2.260.2, FortisBC provides the explanations below for all variances greater than +/- 3 percent between the 2013 and 2018 FEI Capitalized Overhead Studies:

- **Engineering (-22 percent)**

  The decrease in the capitalization rate is primarily due to an increase in overall Engineering O&M costs for which a portion did not qualify as being categorized as indirectly supporting the capital program. FBC's Engineering department O&M continues to include activities relating to the upfront planning activities required to construct capital projects, but also includes an increase in the system reliability and maintenance activities as compared to the 2013 Capitalized Overhead Study. These activities identify potential component failures on both new and existing equipment and implements the appropriate maintenance strategy to manage those risks. Due to increasing requirements pursuant to the North American Electric Reliability Corporation (NERC), FBC has increased its O&M to meet these reliability standards. While a relatively minor portion of the increased O&M associated with these reliability standards indirectly support capital and are appropriately included in the capitalization rate, the remaining balance has been evaluated as remaining outside of the capitalized overhead as an operating activity.

- **Customer Service and Information Systems (+4 percent)**

  Customer service is incurring a greater proportion of activities to support capital that will address rising customer expectations with respect to service, engagement channels and keeping pace with other service providers. This includes enhancements to customer service-related systems, online customer portal to provide customers access to their various energy usage, review of the customer information system. Customer service O&M activities are also necessary to handle the increase in customer engagement and communication requirements related to new capital expenditures. Additionally, the overall Customer Service O&M has decreased compared to the 2013 Capitalized Overhead Study due to the ongoing department integration between FEI and FBC, thus increasing the relative proportion of activities incurred to support capital expenditures.

  There is an increase in Information Systems (IS) O&M activities, which are the result of replacing, adding or improving information systems and technologies, that are specifically utilized to support capital projects. These activities include the labour and non-labour incurred to support capital planning tools, dispatch and scheduling of capital projects, reconfiguration of capital asset accounting module, capital project planning and execution software, time entry and procurement systems to support capital projects.

- **Market Developments and External Relations (+14 percent)**

  The increase in this department's O&M activities that support capital expenditures is driven by the capital effect of "Influence 3: Increased need for engagement with stakeholder and Indigenous communities as a result of stakeholder activism and provincial and federal policy changes", as described in the response to BCUC IR 1.1.1. As discussed in that response, the failure to engage effectively will negatively impact planned capital programs.

  The activities of this department required for capital projects include:

  - enhancing engagement practices, including modernizing Indigenous operating arrangements and committing additional staff and resources to building capacity in Indigenous communities, which will assist in gaining vital support for required capital projects.
  - expanding efforts on project consultation, in terms of the scope and number of stakeholder and rights holder consultations, to maintain and build positive relationships to secure broad support and certainty for projects.

The increase in this department's O&M activities that support capital expenditures are also driven by the capital effect of "Influence 1: Policy direction and mandate from all levels of government towards decarbonization", as described in the response to BCUC IR 1.1.1. As discussed in that response, climate-related policies create new requirements for capital expenditures to comply with increasingly stringent emissions requirements and to meet customers' changing energy needs.

There are new compliance and communication requirements with municipalities and other levels of government related to FBC's capital projects, which are managed by this department. Where FBC's services are provided, high volumes of upfront communication and public hearings are required for construction projects. These requirements have increased over the last five to ten years and are requiring more effort than what was required at the time of the 2013 FBC Corporate Overhead Study.

- **HR, Environment, Health & Safety (EH&S), and Facilities (-4 percent)**

The capitalization rate for this department decreased primarily due the decrease in Facilities O&M, partially offset by an increase in Human Resources and EH&S activities to support capital projects. The Facilities O&M decreased as a result of lower capital and maintenance costs that resulted from the new Kootenay Operation Centre. This decrease was partially offset by the HR and EH&S departments, which have experienced an increase in effort and resources required to support capital related activities. FBC has also been increasing its focus on employee and customer health and safety by implementing the Target Zero program, which consists of both capital and operating activities, the former which has been incorporated into the 2018 FBC Capitalized Overhead Study.

- **Regulatory, Legal and Operations Support (-3 percent)**

This department continues to provide activities that are critical to the execution of capital expenditures, including the management of the associated regulatory processes, assessment of construction contracts, obtaining adequate insurance and property services; however, the proportion has changed from the last study. This has resulted in relatively insignificant changes, as the dollar amount of capital related activities and overall O&M costs have decreased since the 2013 Capitalized Overhead Study by $100 thousand and $200 thousand, respectively. These changes have resulted in an overall 3 percent decrease.

- **Energy Supply and Resource Development (+5 percent)**

This department continues to provide activities for FBC's future energy resource planning that relates to the development of potential future capital projects, although the proportion has changed from the last study, resulting in relatively insignificant changes. This O&M includes activities that identify and develop power supply infrastructure, major capacity initiatives, new regional projects, and system infrastructure projects including transmission, and/or electric generation projects. The early stages identification of these potential capital projects by Energy Supply and Resource Development are required for system reliability, as well as to meet demand growth. Accordingly, this department incurs O&M that indirectly supports capital activity. The dollar amount of capital related activities and overall O&M costs have slightly increased since the 2013 Capitalized Overhead Study by $70 thousand and $120 thousand respectively, which has resulted in a 5 percent increase.

While the comparison to the overall prior capitalized overhead study rates provides a reasonableness assessment of whether the 2018 recommended overhead rate reflects the shift in business activities, FBC focused on whether the FBC 2018 Overhead Study, included in Appendix D6-2 of the Application, appropriately reflected the activities that are required to support its capital expenditures over the term of the MRP.

260.2 Please provide explanations for each change in the capitalization rate by department greater than +/- 3 percent between the 2013 FBC Capitalized Overhead Study and the 2018 FBC Capitalized Overhead Study, including how the nature of each department's indirect capital-related work has changed since 2013 and why.

Response:

Please refer to the response to BCUC IR 2.260.1.

Attachment 161.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 163.3

Provided in electronic format only due to
document size and in order to conserve paper

Refer to Live Spreadsheet Model provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

IRM Framework for the Proposed Merger of Enbridge and Union Gas

Revised May 4, 2018

Mark Newton Lowry, Ph.D.
President

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin, Suite 601
Madison, Wisconsin USA 53703
608.257.1522 608.257.1540 Fax

Table of Contents

1. Introduction and Summary

1.1. Introduction

Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("Enbridge") (collectively the "Applicants") filed a merger, acquisitions, amalgamations and divestitures ("MAADs") application on November 2, 2017 with the Ontario Energy Board ("OEB").[1] On November 23, 2017 the Applicants proposed a new incentive rate-setting ("IR") mechanism ("IRM") for distribution, transmission, and storage services of the amalgamated company ("Amalco").[2] The proposal follows guidelines in the *OEB Handbook to Electricity Distributor and Transmitter Consolidations* ("MAADs Handbook"), which Enbridge and Union propose to extend to their merger in the natural gas sector.[3]

The filing includes evidence on the productivity trends of North American energy distributors by Dr. Jeff Makholm of NERA Economic Consulting ("NERA"). This study includes some methods for measuring productivity which are uncommon in previous OEB proceedings on IRM design. Most notably, a volumetric index was used to measure output and a one hoss shay ("OHS") approach was used to measure capital quantities.

Enbridge and Union are the two largest gas distributors in Ontario. Assuming approval of the MAADs application, the merged company will become one of North America's largest gas distributors, serving most of Ontario's customers and areas that have gas supply. This increases the importance of a careful appraisal of the Applicants' IRM proposal and supportive productivity research. Controversial technical work and IRM provisions should be highlighted and, where warranted, challenged to avoid undesirable precedents for the Applicants and other Ontario utilities in the future. Staff of the OEB have retained Pacific Economics Group Research LLC ("PEG") to prepare analysis and commentary on NERA's productivity research and testimony and some features of the Applicants' IRM proposal.

This is the report on our work. Following a brief summary of our findings, Section 2 reviews pertinent background information. We discuss in Section 3 the nature of productivity research and its

[1] EB-2017-0306, Exhibit A, Tab 2, November 2, 2017.

[2] EB 2017-0307, Exhibit A, Tab 2.

[3] EB 2017-0307, Exhibit B, Tab 1, p. 2.

role in IRM design, emphasizing the output and capital specifications. There follows in Section 4 our critique of NERA's productivity evidence, and results obtained by PEG using alternative methods. We present results of a study of US gas utility productivity we prepared for this proceeding in Section 5. There follows in Section 6 a discussion of the stretch factor and our X factor recommendations. We conclude in Section 7 with a discussion of other aspects of the Applicants' IRM proposal. Appendices address some of the more technical issues raised in the report in more detail.

1.2. Summary

The Applicants have proposed to operate under a Price Cap IRM for ten years, without rebasing, following the conclusion of their current rate plans this year. The proposed new IRM would have a price cap index and an X factor of zero. NERA provided supportive productivity research and testimony on the total factor productivity ("TFP") trends of Union, Enbridge, and a large sample of American power distributors. Rate growth would be further accelerated for the trend in the Normalized Average Consumption/average use of gas by general service customers. A lost revenue adjustment mechanism ("LRAM") would compensate the Amalco for lost revenue due to conservation and demand management ("CDM") programs for contract customers.

X Factor

Since this filing applies to a gas utility and is being made towards the end of the OEB's 4th generation IRM for Ontario power distributors, PEG understands the Applicants' interest in an updated TFP growth target. The Applicants have hired a well-known TFP practitioner, and the 0% base TFP growth trend that Dr. Makholm proposes is in our view reasonable.

PEG nonetheless has serious concerns about the methods used in NERA's productivity work. We question the appropriateness of submitting a study of US power distribution productivity that excludes customer (e.g., billing and collection) services and administrative and general costs when satisfactory data are available for a gas utility productivity study that includes these costs. Because of the Normalized Average Consumption/average use adjustment and the LRAM, the volumetric output index NERA used is inappropriate for a study intended to calibrate the Applicants' X factor. The OHS method used to measure capital quantities has several disadvantages, including its sensitivity to the assumption made about the average service life of assets. Errors seem to have been made in the measurement of

Enbridge and Union's productivity, and the chosen asset price deflator for this exercise was inappropriate.

We made some corrections for key deficiencies in NERA's productivity research. With improved methods, we find that the TFP trends of U.S. power distributors averaged **0.49%** from 2001 to 2016. Over a similar 2001-2016 sample period, the TFP trend of Enbridge averaged a **-0.76%** annual decline, while the TFP of Union averaged **1.04%** growth.

We also prepared a study of the recent TFP trends of a sample of US natural gas utilities. Over the full 1999-2016 period that we examined, the TFP of sampled utilities averaged a **-0.23%** annual decline. Based on the range of evidence available in this proceeding, we recommend **0.0%** as the base productivity growth target for the Amalco.

We disagree with Dr. Makholm's 0% stretch factor recommendation, which is based on the premise that stretch factors are only appropriate in first generation IRMs. The Board is correct to reconsider stretch factors for all utilities on a regular basis using statistical benchmarking. A utility is no more certain to be efficient after one or even several terms of IR than firms in unregulated markets are certain to be efficient. Several other regulators have approved stretch factors after the first generation of IR.

In the absence of suitable benchmarking evidence, we believe that the Amalco should be assigned a 0.30% stretch factor. Combined with a 0.00% base productivity growth trend, we arrive at a recommendation of a 0.30% X factor. The PCI Formula would then be growth inflation – 0.30%, net of Y and Z factors.

Other Plan Provisions

When a power distributor operating under a price cap IRM consolidates with a distributor operating under Custom IR, the MAADs Handbook permits the distributors to operate for as long as 10 years under price cap IR without rebasing. However, as noted by the OEB in its Decision [on the Issues List] and Procedural Order No. 3, the applicability of the provisions of the MAADs Handbook are an open issue with the exception of the "no harm" test. The proposed IRM for the most part follows *Rates Handbook* 4th GIRM guidelines. It features a price cap index, Y factors, and Z factors. The Applicants have not asked for Y factor treatment of pension and other benefit expenses. An earnings sharing mechanism would be operational for the last five years. An incremental capital module ("ICM") would be available to provide supplemental capital revenue.

We are concerned about some features of the Company's proposal.

- The Board is not obliged to follow MAADs Handbook guidelines. The Applicants' proposed IRM is, in any event, not fully consistent with 4th GIRM.
- Since the Board is free to deviate from MAADs rules, it can require a rebasing of each Applicant's revenue to their recent and normalized historical costs followed by their formulaic escalation to 2019 values. This would sidestep problems of performance incentives and merger-related costs. Since the Applicants are in the last year of their respective IRMs and Custom rate-setting plans, skipping a rebasing in 2019 will do little to spur the Applicants' incentives.
- The proposed ratemaking treatment of capital cost is problematic. The ICM would weaken the Amalco's cost containment incentives and raise regulatory cost. The PCI would effectively apply chiefly to revenue for operation, maintenance, and administrative ("OM&A") expenses and provides only a floor for revenue growth even though it is designed to play neither of these roles. The materiality and dead zone provisions of the ICM merit reconsideration. Alternatively, or in addition, the PCI for operation, maintenance, and administrative cost could reflect the OM&A productivity trend, while the ICM could be calculated using the capital productivity trend.
- An industry price index ("IPI") which averages growth in the GDPIPIFDD and the average weekly earnings in Ontario Industry would likely track gas utility input prices. The IPI also sidesteps the need for a complicated input price differential calculation such as NERA provided.
- The proposed materiality threshold for the Z factor is low. A higher threshold is warranted that is appropriate for the Amalco's large size. The threshold should be escalated for PCI and customer growth.

1.3. PEG Credentials

PEG is an economic consulting firm with headquarters in Madison, Wisconsin USA. We are a leading consultancy on the economics of regulation and statistical research on the performance of gas and electric utilities. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. IRM design and the measurement of utility productivity trends are company specialties. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing utility issues. He has prepared productivity research and testimony in more than 30 separate proceedings. His most recent study of power distributor productivity was published by Lawrence Berkeley National Laboratory in 2017. Author of dozens of professional publications, Dr. Lowry has chaired numerous conferences on performance measurement and utility regulation. In the last five years, Dr. Lowry has played a prominent role in IR proceedings in Alberta, British Columbia, Maine, Massachusetts, and Quebec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin. The resume of Dr. Lowry is attached.

2. Background

Under the Applicants' proposal, Enbridge and Union would operate in 2018 under their current rate setting plans (a Custom IR plan for Enbridge and a "price cap" IRM for Union). These plans are scheduled to expire this year. The new IRM would then begin without rebasing revenue to the Amalco's costs (with the exception of certain adjustments proposed to deal with the expiration of certain costs or to reflect certain tax-related or policy-related factors).[4] The new IRM would have the following notable provisions:

- The term would be the ten-year period from January 1, 2019 to December 31, 2028.[5] By 2028, customers of Amalco would therefore have waited from 10 up to 15 years for revenues to be fully rebased to costs.

- The attrition relief mechanism, described as a price cap index ("PCI"), is similar to that in the current Union Gas IRM.[6] This mechanism would not directly escalate rates like those used in the default 4th GIRM. Instead, the revenue requirement would be escalated each year for inflation less an X factor with further Y factor and Z factor adjustments. The updated revenue requirements for volumetric charges of general service customers would be converted to rates using predetermined formulas like

  $$[Revenue_t^{Required}/(Volume_{t-2}^{Normalized}/Customers_{t-2})] \times Customers_t^{Forecasted}.$$

  The term in parentheses is called Normalized Average Consumption ("NAC") and is based on an OEB-approved volume normalization procedure.

  Revenue from general service customers would later be adjusted to yield the amount that would have occurred had normalized average consumption in year *t-1* been used to set rates. Since the number of customers is rising and average use is trending downward, this mechanism

[4] EB 2017-0307, Exhibit B, Tab 1, p. 16.

[5] EB 2017-0307, Exhibit B, Tab 1, p. 4.

[6] EB 2017-0307, Exhibit B, Tab 1, p. 7.

provides additional rate escalation and reduces risk of cost under-recovery for the utility and its shareholders.

- The proposed PCI inflation measure is the gross domestic product implicit price index for final domestic demand for Canada ("GDPIPIFDD^{Canada}").[7]
- The proposed X factor of zero is supported by TFP testimony by Dr. Jeff Makholm of NERA. NERA's research used a monetary "one hoss shay" approach to measuring capital cost that has never to our knowledge been used in Ontario IR proceedings.[8] Dr. Makholm also recommended a 0.0% stretch factor.[9]
- The Applicants propose to maintain most existing deferral and variance accounts.[10] These would include an LRAM to compensate them for lost margins due to conservation programs for contract service customers.
- The plan also features the availability of an ICM for incremental capital funding.[11,12] The capital cost for capex accorded ICM treatment would be eligible for an updated weighted-average cost of capital ("WACC").[13]
- The applicants also propose a Z factor mechanism. The Applicants have indicated the possibility of seeking an increase to the WACC for other capital using the Z factor process.

---

[7] EB 2017-0307, Exhibit B, Tab 1, p. 8.

[8] However, physical asset capital quantity treatments that are purported to be approximations to the OHS monetary approach have been filed and reviewed in two prior OEB proceedings (EB-2007-0679 and EB-2013-0152).

[9] EB 2017-0307, Exhibit B, Tab 2, pp. 33-34.

[10] EB 2017-0307, Exhibit B, Tab 1, pp. 22-23 and Exhibit B, Tab 1, Attachments 3 and 4.

[11] EB 2017-0307, Exhibit B, Tab 1, pp. 12-16.

[12] While the ICM was designed for IRM rate-setting plans for electricity distributors, the OEB's *Handbook for Utility Rate Applications* (the Rate Handbook) issued October 13, 2016, extends the ICM option to all rate-regulated utilities operating under Price Cap IR plans. Further, the MAADs Handbook also makes the ICM available to an amalgamated utility operating under a Price Cap IR plan prior to rebasing.

[13] EB 2017-0307, Exhibit B, Tab 1, pp. 15-16.

- After five years, an earnings sharing mechanism would come into effect and equally share earnings which are more than 300 basis points above the allowed rate of return on equity (on a regulated basis) between the Amalco and customers.[14]
- The proposal also includes a scorecard with 18 metrics by which various aspects of the Amalco's performance would be measured.[15]

[14] EB 2017-0306, Exhibit B, Tab 1, pp. 43-44.

[15] EB 2017-0307, Exhibit B, Tab 1, pp. 20-22.

3. Principles for X Factor Calibration

3.1. Index Research and its Use in Regulation

Productivity Indexes

The Basic Idea

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The trend in a productivity index is the difference between the trend in an index of outputs ("*Outputs*") and the trend in an input quantity index ("*Inputs*").

$$\textit{trend Productivity} = \textit{trend Outputs} - \textit{trend Inputs.} \qquad [1]$$

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. *Partial* factor productivity ("*PFP*") indexes measure productivity in the use of a particular input class such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple kinds of inputs. These are sometimes called *total* factor productivity indexes even though such indexes rarely address the productivity of all inputs.

Output Indexes

The output (quantity) index of a firm summarizes the scale of its operation. If this index is multidimensional, growth in each output dimension which is itemized is measured by a subindex. Growth in the summary output index is a weighted average of the growth in the subindexes.

In designing an output index, choices concerning subindexes and weights should depend on the manner in which the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindexes should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[16] A productivity index calculated using a revenue-weighted output index ("$Outputs^R$") will be denoted as $Productivity^R$.

$$\textit{trend Productivity}^R = \textit{trend Outputs}^R - \textit{trend Inputs}. \qquad [2a]$$

[16] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

Another possible objective of output research is to measure the impact of growth in scale on *cost.* In that event, the output variable(s) should measure dimensions of "workload" that drive cost.[17] A productivity index calculated using a cost-based output index ("$Outputs^C$") will be denoted as $Productivity^C$.

$$trend\ Productivity^C = trend\ Outputs^C - trend\ Inputs. \qquad [2b]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[18] The research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are another important productivity growth driver. These economies are realized in the longer run if cost has a tendency to grow less rapidly than operating scale. Incremental scale economies (and thus productivity growth) will typically be lower the slower is output growth.

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency level.

---

[17] If there is more than one output variable, the weights for these variables should reflect the relative impacts of these drivers on the cost of producing the outputs (the products and services produced by the firm or sector). The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes. These have been used on several occasions in PEG's previous research for the OEB. For example, PEG used an elasticity-weighted output index in its research on the TFP growth of Ontario power distributors in the 4th GIRM proceeding. The output variables were delivery volume, peak demand, and the number of customers served. These variables are billing determinants as well as cost drivers.

[18] A classic early discussion of the drivers of productivity growth can be found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

System age can drive productivity growth in the short and medium run. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility has a need for unusually high replacement capex, capital productivity growth can plunge. On the other hand, productivity growth tends to surge in the aftermath of unusually high capex as the surge capital depreciates.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a gas distributor is a change in safety regulations. This has recently affected the productivity of US gas distributors.

A productivity index with a *revenue*-weighted output index has an important driver that doesn't affect a cost efficiency index. This is true since

$$\begin{aligned} \textit{trend Productivity}^R &= \textit{trend Outputs}^R - \textit{trend Inputs} + (\textit{trend Outputs}^C - \textit{trend Outputs}^C) \\ &= (\textit{trend Outputs}^C - \textit{trend Inputs}) + (\textit{trend Outputs}^R - \textit{trend Outputs}^C) \\ &= \textit{trend Productivity}^C + (\textit{trend Outputs}^R - \textit{trend Outputs}^C). \qquad [3] \end{aligned}$$

Equation [3] shows that growth in $\textit{Productivity}^R$ can be decomposed into the growth in a cost efficiency index and an "output differential" that measures the difference between the impact that growth in operating scale has on revenue and cost.

The output differential is sensitive to changes in external business conditions.[19] For example, the revenue of a gas distributor may depend chiefly on system use due to high usage (e.g., volumetric) charges while cost depends chiefly on system capacity. In that event, increasingly mild winter weather, higher appliance efficiency standards, and/or large, mandated CDM programs can, by slowing growth in system use, reduce the output differential and slow growth in Productivity^R and earnings.

Gas distributors have long considered the number of customers served to be a more pertinent driver of their cost than their delivery volumes. The number of customers served is highly correlated

---

[19] Note also that companies can sometimes bolster their output differential and accelerate TFP^R and earnings growth with better marketing. For example, they can try to bolster sales of products that raise revenue more than cost. An example would be the substantial effort of MacDonald's restaurants in recent years to build a breakfast business.

with peak day demand and is an important cost driver in its own right. A declining trend in use per customer (aka "average use") has therefore been highlighted by many distributors as an important source of financial attrition. In the United States, many distributors operate under revenue decoupling systems that escalate allowed revenue each year by the number of customers served and use balancing accounts to ensure that this revenue is ultimately received.[20]

Use of Index Research in Regulation

Price Cap Indexes

Index logic supports the use of index research in price cap index design. We begin our demonstration by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[21] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\textit{trend Revenue} = \textit{trend Cost.} \qquad [4]$$

The trend in the revenue of any firm or industry can be shown to be the sum of the trends in revenue-weighted indexes of its output prices ("*Output Prices*^{R}") and billing determinants ("*Outputs*^{R}")

$$\textit{trend Revenue} = \textit{trend Outputs}^R + \textit{trend Output Prices}^R. \qquad [5]$$

The trend in cost can be shown to be the sum of the trends in a cost-weighted input price index ("*Input Prices*") and input quantity index.

$$\textit{trend Cost} = \textit{trend Input Prices} + \textit{trend Inputs} \qquad [6]$$

It follows that the trend in output prices that permits revenue to track cost is the difference between the trends in the input price index and a total factor productivity index of *TFP*^{R} form.

$$\begin{aligned}\textit{trend Output Prices}^R &= \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) \qquad [7]\\ &= \textit{trend Input Prices} - \textit{trend TFP}^R.\end{aligned}$$

---

[20] Lowry, M. N., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, for Edison Electric Institute, 2015.

[21] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

The result in equation [7] provides a conceptual framework for the design of PCIs of general form

$$\textit{trend Rates} = \textit{trend Inflation} - X. \qquad [8a]$$

Here X, the "X factor," reflects a base productivity growth target ("$\overline{TFP^R}$") that is typically the trend in the TFP^R of the utility industry or some peer group. A "stretch factor" is often added to the formula which slows PCI growth in a manner that, appropriately designed, shares with customers the financial benefits of performance improvements that are expected under IRMs.[22]

$$X = \overline{TFP^R} + \textit{Stretch} \qquad [8b]$$

Since the X factor often includes a stretch factor it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

Average Use Adjustment

Equations [3] and [7] imply that

$$\textit{trend Output Prices}^R = \textit{trend Input Prices} - [\textit{trend TFP}^C + (\textit{trend Outputs}^R - \textit{trend Outputs}^C)] \qquad [9]$$

When the X factor is calibrated using a $\overline{TFP^R}$ index (i.e., a TFP index constructed from billing determinants), it follows that it compensates the subject utility for any tendency in the industry for $Outputs^R$ to grow more slowly than $trend\ Outputs^C$.

Suppose, now, that an IRM with a price cap index includes a *separate* adjustment to rates for the difference between the trends in volumes and the number of customers served by the subject utility. A variant on equation [7] is

$$\textit{trend Output Prices}^R$$

$$= \textit{trend Input Prices} - (\textit{trend Outputs}^R - \textit{trend Inputs}) + (\textit{trend Customers} - \textit{trend Customers})$$

$$= \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) - (\textit{trend Outputs}^R - \textit{trend Customers})$$

---

[22] Mention here of the stretch factor option is not meant to imply that a positive stretch factor is warranted in all cases.

$$= \textit{trend Input Prices} - \textit{trend } TFP^N - (\textit{trend Outputs}^R - \textit{trend Customers}) \qquad [10]$$

This implies that, if a rate plan combines a price cap index with an average use adjustment, the number of customers should be used to measure output in the supportive productivity research.

3.2. Capital Specification

The Monetary Approach to Capital Cost and Quantity Measurement

The capital cost specification is of central importance in research on the productivity trends of energy distributors because their technology is capital intensive. The cost of capital ("*CK*") includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in North American productivity research. These are so-called because they are based on the value of utility plant. A monetary approach decomposes capital cost into a consistent capital quantity index ("*XK*") and capital service price index ("*WKS*") such that

$$CK = WKS \cdot XK. \qquad [11]$$ [23]

In rigorous cost research, it is customary to assume that a capital good provides a stream of services over a period of time that is called the service life of the asset. The capital service price index measures the trend in the price of a unit of capital service. The capital quantity index is constructed by deflating the value of plant additions using an asset price index and subjecting the resultant quantity estimates to a mechanistic decay specification. In research on the productivity of US energy utilities, Handy Whitman utility construction cost indexes have traditionally been used for this purpose. The product of the capital service price index and the capital quantity index is the annual cost of using the flow of services.

[23] The *growth rate* of capital cost is thus the sum of the growth rates of the capital price and quantity indexes.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized decay specification for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

Alternative Monetary Approaches

Several monetary methods have been established for measuring capital quantity trends. A key issue in the choice of a monetary method is the pattern of decay in the capital service flow. The pattern of decay over time is sometimes called the age-efficiency profile. Another issue is whether plant is valued in historic dollars or replacement dollars.

Three monetary methods have been used in X factor calibration research.

- Under the geometric decay ("GD") specification, the flow of services from investments in a given year declines at a constant rate ("*d*") over time. The quantity of capital at the end of each period *t* ("XK_t") is related to the quantity at the end of *last* period and the quantity of gross plant *additions* ("XKA_t") by the following "perpetual inventory" equation

$$XK_t = XK_{t-1} \bullet (1-d) + XKA_t. \quad [12a]$$

$$= XK_{t-1} \bullet (1-d) + \frac{VKA_t}{WKA_t}. \quad [12b]$$

where *d* is the (constant) rate of decay in the quantity of older capital. In equation [12b], the quantity of capital added each year is measured by dividing the reported value of gross plant additions by the contemporaneous value of a suitable asset price index ("*WKA*"). In research on the productivity of US energy utilities a Handy Whitman Construction Cost Index is conventionally used for this purpose.

The GD method assumes a replacement (i.e., *current* dollar) valuation of plant. Replacement valuation differs from the historical (aka "book") valuation used in North American utility accounting and requires consideration of capital gains.

- Under the one hoss shay specification, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. The quantity of plant at the end of the year is the sum of the quantity at the end of the prior year plus the quantity of gross plant additions less the quantity of plant retirements ("XKR_t").

$$XK_t = XK_{t-1} + XKA_t - XKR_t. \qquad [13a]$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \qquad [13b]$$

Since utility retirements are valued in historical dollars, the quantity of retirements in year *t* can be calculated by dividing the reported value of retirements by the value of the asset price index for the year when the retired assets retired were added.

Plant is once again valued at replacement cost. The one hoss shay method has nonetheless been used occasionally in research intended to calibrate utility X factors.

- The cost of service ("COS") method is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review. PEG has used this approach in several X factor calibration studies, including two for the OEB.[24]

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost were discussed at some length in the OEB's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).[25] Based on our experience as witnesses in that and other recent proceedings we believe that the following considerations are relevant.

1. *The goal of productivity research in X factor calibration is to find a just and reasonable means to adjust rates between rate applications.*

Productivity studies have many uses, and the best methodology for one use may not be best for another. One use of productivity research is to measure the trend in a utility's operating efficiency. Another is to calibrate the X factor in a price-cap or revenue-cap index.

Price-cap indexes in most IRMs for energy utilities, including the IRM proposed by the Applicants, are intended to adjust utility rates between general rate cases that employ a cost of service approach to capital cost measurement. In North America, the calculation of capital cost for ratemaking typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of each asset shrinks over time as depreciation reduces net plant value and the return on rate base.

2. *One-hoss shay is not preferable to geometric decay as the foundation for a monetary approach to capital quantity measurement.*

[24] See Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007); Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

[25] See, for example, Exhibit M2, Tab 11.1, Schedule OPG-002, Attachment A of the OEB's EB-2016-0152 proceeding.

The OHS specification is sometimes argued to better fit the service flows of *individual* utility assets. OHS has been used in some productivity studies filed in proceedings to determine X factors. In Alberta, for example, power distribution productivity studies using OHS have been accepted in two proceedings to inform the choice of X factors in rate and revenue-cap indexes for energy distributors. A study with an OHS capital cost specification recently provided the sole basis for the choice of a base productivity trend for Eversource Energy, a large Massachusetts power distributor.

Other evidence suggests that the OHS specification is disadvantageous. Here are some notable problems.

OHS is More Difficult to Implement Accurately than GD. A comparison of equations [12b] and [13b] shows that implementation of GD and OHS both require a deflation of gross plant *additions*. This is straightforward since the years of the additions are known exactly. The challenge with OHS is that it requires, additionally, deflation of plant *retirements.* The vintages of reported retirements are generally unknown to a scholar measuring productivity. OHS practitioners commonly deflate the value of retirements by the value of the construction cost index for a year in the past that reflects the assumed average service life of the assets.

Examining equation [13b], It can be seen that the quantity of capital in a given year will be smaller the larger is the quantity of retirements. The quantity of retirements will be larger the older is the average service life of the assets. Thus, TFP growth will tend to be more rapid under the OHS approach the higher is the average service life.

Our empirical research over the years suggests that productivity results using OHS are also quite sensitive to the average service life assumption. Seemingly reasonable service life estimates can produce negative capital quantities for some utilities. In recent power distribution productivity research for the Consumers' Coalition of Alberta, PEG found results using the OHS capital cost specification to be much more sensitive to the assumed average service life of assets than those using geometric decay. [26,27]

---

[26] See, for example, Lowry, M.N. and Hovde, D., *PEG Reply Evidence*, Exhibit 20414-X0468, AUC Proceeding 20414, revised June 22, 2016, pp. 15-18.

[27] See also our discussion in Exhibit M2, Tab 11.1, Schedule OPG-002, Attachment A of the OEB's EB-2016-0152 proceeding for our attempt to implement an established form of OHS for hydroelectric power generation.

The sensitivity of OHS results to service life assumptions can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Unfortunately, itemizations of FERC Form 1 plant addition and retirement data are not publicly available before 1994.

It should also be noted that the mathematical coding for GD is particularly intuitive and easy to implement and review. The OHS specification involves a complicated capital service price that lacks intuition.

Prices in Many Used Asset Markets are Inconsistent with an OHS Assumption Alternative patterns of *physical* asset decay involve different patterns of asset value *depreciation*. Trends in used asset prices can therefore shed light on asset decay patterns. Several statistical studies of trends in used asset prices have revealed that they are generally not consistent with the OHS assumption.[28] Instead, depreciation patterns like that commensurate with GD appear to be the norm for machinery and are also generally the case for buildings.[29]

An OHS Assumption Does Not Make Sense for Heterogeneous Groups of Assets In real-world productivity studies, capital quantity trends are rarely if ever calculated for *individual* assets. They are instead calculated from data on the value of plant additions (and, in the case of OHS, retirements) which encompass multiple assets of various kinds. Even if each individual asset had an OHS age/efficiency profile, the age/efficiency profile of the *aggregate* plant additions could be poorly approximated by OHS for several reasons.

- Assets of the same kind could end up having different service lives. The light bulbs installed by homeowners in a given year, for example, will burn out at different times.
- Different kinds of assets can have markedly different service lives.

[28] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts*," Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

[29] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 101.

- Individual assets, in any event, frequently have components with different service lives. The tires in a motor vehicle, for example, can need replacement before the wheels of the vehicle do.

Alternative capital cost specifications such as GD can provide a better approximation of the service flow of a group of assets that individually have OHS patterns or which are composites of assets with OHS patterns.

Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[30] [italics in original]

Gas Distributor Assets Do Not Exhibit a Constant Flow of Services A common sign of decline in the flow of services from an asset is a rise in the expenses to operate and maintain it. Another sign of a diminishing flow of services is a continual stream of "refurbishment" capital expenditures that do not boost volume or capacity. Gas utilities tend to experience rising OM&A expenses and refurbishment capex as their assets age.

The OHS Approach is Rarely Used. These disadvantages of the OHS specification help to explain why alternative specifications are more the rule than the exception in capital quantity research. For

[30] OECD, *op. cit.*, p. 12.

example, GD is used to calculate capital quantities in the National Income and Product Accounts of the US and Canada. Statistics Canada also uses GD in its multifactor productivity studies for sectors of the economy.[31] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand assume hyperbolic decay, not OHS, in their sectoral TFP studies.

GD has also been the capital cost specification most widely used in productivity studies intended for X factor calibration in the North American energy and telecommunications industries. PEG personnel have used the GD approach in most of their more than 30 productivity studies for the OEB and other clients. PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used GD.[32] Laurits R Christensen, major professor in the PhD committee of Dr. Makholm, and his colleague Dr. Mark Meitzen of Christensen Associates used GD in virtually all of their numerous studies of *telecommunications* utility productivity. Christensen Associates Energy Consulting has to our knowledge also used GD in most of their studies over the years of *energy* utility productivity, including one for Union Gas.[33] The Brattle Group and Concentric Energy Advisors used GD in their gas utility productivity studies for Enbridge.[34] Mr. Steven Fenrick used GD in the recent productivity study he filed in testimony for Hydro One Networks in a proceeding that is currently before the OEB.[35]

The OEB has never to our knowledge appraised a productivity study that used an OHS *monetary* method but has twice expressed skepticism about studies that used a physical asset approximation to an

[31] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program," *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14., p. 41 and Statistics Canada, *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204, January 2001.

[32] Lowry, M.N., Deason, J., and Makos, M. (2017), "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,", Lawrence Berkeley National Laboratory, July, p. B.12.

[33] See, for example, Hemphill, R., and Schoech, P. (1999), An Evaluation of the Union Gas Limited Performance-Based Regulation Proposal, p. 25.

[34] James Coyne, James Simpson, and Melissa Bartos, Concentric Energy Advisors, Inc., Incentive Ratemaking Report*, Prepared for Enbridge Gas Distribution*, OEB Proceeding EB-2012-0459, Exhibit A2, Tab 9, Schedule 1, June 28, 2013, p. B-11 and Jeffrey Bernstein and Paul Carpenter, X Factor Guideline and Measurement for Ontario's Natural Gas Distribution Industry, OEB Proceeding EB-2007-0615, Exhibit B, Tab 3, Schedule 6, November 6, 2007.

[35] EB-2017-0049, Exhibit A-3-2, Attachment 1, pp. 22-24.

OHS monetary method. In the recent OPG IRM proceeding to establish an IRM for Ontario Power Generation, for example, the OEB stated that

> Although many hydroelectric generation assets have very long useful lives, the OEB is not convinced that there is no functional depreciation until end of life. In fact, reviews of capital projects to sustain, refurbish and replace hydroelectric stations and assets in OPG's prior payment amount applications confirm that capital expenditures and operating costs are needed to maintain capacity to the end of a station's life. Absent ongoing capital and operating expenditures, hydroelectric generation assets will depreciate over time. In the OEB's view, LEI's physical method, which assumes no depreciation until the end of life, is not a realistic basis for the analysis of productivity of hydroelectric generation facilities.[36]

Conclusions In summary, there are many general arguments against the use of the OHS approach to measure capital quantities in productivity research. The OHS approach seems especially *disadvantageous* in productivity studies of US gas utilities managing mature assets, not especially *advantageous*. That is because the requisite plant value data used in the calculations are insufficiently itemized; depreciation has an important impact on gas distributor cost trends today, and gas utility assets do not in any event seem to have conformed to an OHS service flow pattern in recent years.

The GD approach is preferable based on the data and other information available at this time. Most of these arguments also apply to power distribution. This helps to explain why PEG frequently uses the GD approach in its studies of gas and electric power distribution productivity.

[36] OEB (2017), Decision and Order EB-2016-0152 Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021, December 28, p. 127.

4. Critique of NERA's Productivity Research and Testimony

4.1. US Power Distribution

NERA calculated the TFP trend of a large sample of US utilities in the provision of power distribution services over the lengthy 1973-2016 period.[37] This is an update of a study they have undertaken on three prior occasions, including 2010-2012 research and testimony for the Alberta Utilities Commission ("AUC") in its first Alberta generic IRM proceeding.[38] Both their original Alberta study and the updated study filed in this application found a materially *positive* productivity trend before 2000 and a materially *negative* trend since 2000.

Dr. Makholm reported a **0.54**% TFP trend over his full sample period in his work for the Applicants.[39] While in past proceedings he has argued in favor of calibrating X factors using the trend in his index for his *full* sample period, as a witness for the Applicants he is recommending a **0.0%** base TFP growth trend for the Amalco reflecting the slowing growth of his TFP indexes in the latter part of the time period.

PEG was a witness for the Consumers' Coalition of Alberta in the AUC's first generic IRM proceeding, as well as in the second proceeding that concluded in 2016. Although there was no NERA witness in the second proceeding, their methodology was used by two utility witnesses.[40] Based on this experience, and our review of NERA's evidence in this proceeding, we have numerous concerns about their methodology. To facilitate the Board's review, we first discuss our major concerns before detailing other concerns.

---

[37] EB 2017-0307, Exhibit B, Tab 2, pp. 110 and 113.

[38] This proceeding established IRMs for several gas and electric power distributors in Alberta.

[39] EB 2017-0307, Exhibit B, Tab 2, p. 113.

[40] Written Evidence of Dr. Toby Brown and Dr. Paul R. Carpenter for Altagas Utilities Inc, ATCO Electric, ATCO Gas, Enmax Power Corporation, and FortisAlberta, filed as Exhibit 20414-X0056 in Alberta Utilities Commission Proceeding 20414, pp. 26-32 (Brattle) and filed as Appendix B of Exhibit 20414-X0074 in Alberta Utilities Commission Proceeding 20414, pp. 18-20 (Christensen Associates Energy Consulting).

Major Concerns

Relevance of Research

Our first concern is that the Applicants, who will run one of North America's largest *gas* utilities, would submit a study of *power* distribution industry TFP in this proceeding but not a study of *gas* utility industry productivity. While there are admittedly similarities, power and natural gas distribution have noteworthy differences, and the Amalco IRM would apply to gas transmission and storage services of the Amalco as well as its distributor services. In two previous Ontario rate plan proceedings, Enbridge submitted studies (by the Brattle Group and Concentric Energy Advisors) of US gas utility industry productivity.[41] Studies of gas utility industry productivity have also been presented, usually by utilities, in numerous jurisdictions including Alberta, British Columbia, California, Colorado, Georgia, Massachusetts, New York, Québec, and Australia in IRM applications.

A further concern about the relevance of NERA's power distribution productivity study is that it needlessly excludes customer care and administrative and general ("A&G") costs. These costs will be incurred by the Amalco and are a likely source of merger-related productivity gains. While Dr. Makholm often argues against customizing productivity studies used to calibrate X factors, NERA *did* include these costs in their earlier productivity research and testimony for two power distributors but excluded them from their study for the AUC, presumably because many customer services are provided by independent companies in Alberta.[42]

A related concern is that NERA is not in the habit of reporting trends in the productivity of OM&A inputs and has denied their relevance in IRM design. It follows that, even though the proposed PCI would, due to the ICM, chiefly apply to the *OM&A* expenses of a utility engaged in gas storage, transmission, and distribution, the Applicants have retained a consultant to prepare a study of *power*

---

[41] James Coyne, James Simpson, and Melissa Bartos, Concentric Energy Advisors, Inc., *Incentive Ratemaking Report*, Prepared for Enbridge Gas Distribution, OEB Proceeding EB-2012-0459, Exhibit A2, Tab 9, Schedule 1, June 28, 2013 and Jeffrey Bernstein and Paul Carpenter, *X Factor Guideline and Measurement for Ontario's Natural Gas Distribution Industry*, OEB Proceeding EB-2007-0615, Exhibit B, Tab 3, Schedule 6, November 6, 2007.

[42] Jeff Makholm, *Updated and Rebuttal Testimony* on behalf of Central Maine Power Company, June 22, 2000 pp. 6-7; Jeff Makholm, *A Productivity Offset for a Proposed PBR Plan* on behalf of UtiliCorp Networks Canada, Attachment B to EDTI-NERA-1(c), September 1, 2000, pp. 12, 32-33; and Jeff Makholm, *Total Factor Productivity Study for Use in AUC Proceeding 566-Rate Regulation Initiative*, December 30, 2010, p. 6.

distribution productivity which excludes many pertinent OM&A expenses and does not consider OM&A productivity trends.

If NERA's power distribution TFP study were accepted by the OEB as the basis for setting X for the Amalco, it could become a precedent in Ontario power distribution regulation as well, just as the OEB nears commencement of its work to develop the next generation of IRM for power distributors. If it becomes a precedent, some electricity distributors could argue, as they have in recent Alberta, Massachusetts, and Quebec proceedings, that results using NERA's methods and a truncated sample period (producing a materially negative productivity trend) are most appropriate. This increases the importance of reviewing and considering this study carefully.

Reliance on power distribution research might nevertheless be needed to calibrate the Amalco's X factor if abundant data of good quality were unavailable to calculate *gas* utility productivity. In fact, however, good quality and reasonably standardized data are available for numerous US gas distributors since the mid-1990s and can be purchased from commercial vendors.[43] Moreover, the gas data have several advantages (e.g., better data on system age and materials used in line construction) over the analogous power industry data. PEG personnel have done numerous gas utility industry productivity studies over the years for various clients that include the OEB, two Canadian consumer groups, and several US gas utilities.[44] A productivity study we prepared using US data was published in an American Gas Association professional journal.[45]

<u>Methodological Concerns</u>

NERA's methodology for measuring power distribution productivity is, in any event, controversial. To facilitate the Board's review of the numerous and sometimes complicated issues that

---

[43] Requisite data are available for a smaller group of more than 30 utilities since the mid-1980s, making possible more accurate capital cost and quantity calculations.

[44] See, for example, Lowry, M., Hovde, D., Getachew, L., and Fenrick, S., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities* in EB-2006-0606/0615, (2007). Lowry, M.N. (2016), *Next Generation PBR for Alberta Energy Distributors,* filed in Alberta Utilities Commission Proceeding 20414 as Exhibit 20414-X0082, and Lowry, M., Hovde, D., and Rebane, K., (2013), "X Factor Research for Fortis PBR Plans," in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia.

[45] Lowry, M.N. and Kaufmann, L. (1996) "Forecasting the Productivity Growth of Natural Gas Distributors," *AGA Forecasting Review*, Vol. 5, March.

arise in productivity studies, we begin by highlighting our most important concerns with NERA's methodology.

Output Specification Consider first that NERA measures output growth as a revenue-weighted average of the growth in sales volumes to different service classes. Even though the Applicants propose a price cap index, NERA's volumetric output index is inappropriate for use in the calibration of the Amalco's X factor because of the Normalized Average Consumption adjustment and LRAM that the Applicants have and propose to continue using. The NAC effectively causes customers rather than volumes to drive general services revenue growth. Our analysis in Section 3 showed that the number of customers served is a more appropriate scale variable in the presence of a rate adjustment like the NAC adjustment.

The output specification would matter less if trends in the volumetric index and the number of customers served were similar. However, they are not. Volume growth differs from customer growth by growth in volume *per customer*, and this varied greatly for US electric utilities over NERA's lengthy sample period. The average use of residential and commercial customers is particularly important in a power distributor productivity study.

NERA did not provide data on the number of customers served by the utilities in their sample, and these data are difficult (although not impossible) to obtain for their lengthy sample period. Thus, it is difficult to demonstrate the consequences of using their volumetric index without doing an alternative study or gathering and importing extensive customer data for use with their other index formulae.

Faced with this challenge, we gathered the necessary customer data for utilities in NERA's sample. Residential and commercial volume and customer trends for these utilities are compared in Table 1 below. It can be seen that residential and commercial average use by customers of the utilities in Dr. Makholm's sample averaged 1.6% annual growth from 1973 to 2000, but averaged a 0.3% annual decline from 2001 to 2016. The decline in average use has accelerated since 2008. This is clearly the main reason for the slowing growth in NERA's TFP indexes after 2000, but has limited relevance to the calibration of an X factor for the proposed IRM of the Applicants.

Capital Specification We also have concerns about the simple one hoss shay approach that NERA used to measure capital cost. We discussed several *general* disadvantages of the OHS approach in Section 3.2

Table 1-revised

Comparison of Electric Utility Customer and Volume Trends[1,2]

	Average Volume Growth			Average Use Growth	
Year	Total Volume [A]	Residential and Commercial Volume [B]	Average Total Customer Growth [C]	Total Volumes [A-C]	Residential and Commerical Volumes [B-C]
1973	7.7%	7.7%	3.0%	4.7%	4.7%
1974	-0.1%	0.5%	2.5%	-2.6%	-2.0%
1975	1.1%	5.6%	1.7%	-0.6%	3.9%
1976	5.6%	3.5%	1.9%	3.7%	1.6%
1977	4.4%	5.0%	2.1%	2.4%	2.9%
1978	4.0%	3.8%	2.4%	1.6%	1.5%
1979	3.2%	2.5%	2.3%	0.9%	0.2%
1980	1.2%	3.7%	1.8%	-0.6%	1.9%
1981	1.1%	0.2%	1.4%	-0.3%	-1.2%
1982	-1.1%	2.4%	1.2%	-2.3%	1.2%
1983	3.0%	3.0%	1.4%	1.6%	1.6%
1984	4.9%	3.9%	1.5%	3.4%	2.4%
1985	1.7%	2.2%	1.8%	-0.1%	0.4%
1986	2.2%	3.8%	1.8%	0.4%	2.0%
1987	4.2%	4.3%	1.9%	2.3%	2.4%
1988	4.8%	5.6%	1.8%	3.0%	3.8%
1989	2.3%	1.9%	1.6%	0.7%	0.2%
1990	1.7%	2.3%	-0.2%	1.8%	2.5%
1991	2.2%	3.6%	1.3%	1.0%	2.3%
1992	0.0%	-1.2%	1.2%	-1.2%	-2.3%
1993	3.7%	5.2%	1.3%	2.4%	3.9%
1994	2.6%	2.7%	1.4%	1.2%	1.3%
1995	2.5%	4.2%	1.5%	1.0%	2.6%
1996	2.4%	2.7%	-0.1%	2.6%	2.9%
1997	1.1%	0.5%	1.3%	-0.2%	-0.8%
1998	2.7%	3.5%	1.3%	1.4%	2.2%
1999	1.8%	2.8%	3.7%	-1.9%	-0.9%
2000	3.4%	3.9%	1.3%	2.0%	2.6%
2001	-0.7%	1.1%	3.6%	-4.2%	-2.4%
2002	1.9%	4.2%	1.2%	0.7%	2.9%
2003	0.4%	0.5%	0.7%	-0.2%	-0.1%
2004	1.6%	1.0%	1.1%	0.5%	-0.2%
2005	2.4%	3.4%	1.4%	1.1%	2.1%
2006	-1.1%	-1.5%	0.3%	-1.4%	-1.8%
2007	3.1%	3.9%	0.9%	2.2%	2.9%
2008	-1.6%	-1.0%	0.7%	-2.2%	-1.7%
2009	-4.8%	-3.4%	0.2%	-5.0%	-3.6%
2010	3.8%	3.6%	0.5%	3.2%	3.1%
2011	-0.7%	-1.0%	0.4%	-1.1%	-1.3%
2012	-2.0%	-1.9%	0.5%	-2.4%	-2.4%
2013	0.6%	0.3%	0.6%	0.1%	-0.3%
2014	-0.3%	0.5%	0.6%	-0.9%	0.0%
2015	-0.7%	-0.6%	0.8%	-1.5%	-1.4%
2016	-0.5%	-0.1%	0.7%	-1.3%	-0.9%
Average Annual Growth Rate					
1973 - 2000	**2.7%**	**3.2%**	**1.6%**	**1.0%**	**1.6%**
1973 - 2016	**1.7%**	**2.2%**	**1.4%**	**0.4%**	**0.9%**
2001 - 2016	**0.1%**	**0.6%**	**0.9%**	**-0.8%**	**-0.3%**
2008 - 2016	**-0.7%**	**-0.4%**	**0.6%**	**-1.2%**	**-1.0%**

Notes

[1]All growth rates are calculated logarithmically. For example, growth rate of V = $\ln(V_t/V_{t-1})$.

[2]Average growth rates in a given year are the mean of the respective annual growth rates for all companies in NERA's sample with plausible customer data available.

above. Our focus in this section is that NERA's particular approach to executing OHS is flawed. Since they do not itemize quantities of different kinds of distributor assets, their OHS approach is particularly sensitive to the choice of an average service life used to estimate the quantity of retirements.

NERA assumes a 33-year average service life.[46] In response to an undertaking, NERA showed that this is the average ratio of power distribution gross plant value to power distribution depreciation expenses for a large sample of US electric utilities from 1988 to 2009.[47] For each company in the sample, PEG divided the end of year gross value of distribution plant by distribution depreciation expenses to replicate NERA's average service life calculations. We removed observations that were zero or negative, and then calculated the mean and standard deviation of average service life for all companies in a given year. We recalculated the mean average service life in each year by filtering out all observations that were more than two standard deviations from the initial mean. By repeating this process for each year, we generated a time series of average service lives. From 1988 to 2009, the period that NERA uses in determining an average service life of 33 years, we found that the mean average service life was 32.7 years. The mean average annual service life grew over this period from 31.1 in 1988 to 35.4 in 2009. Growth continued between 2009 and 2016, from 35.4 to 38.3 for our screened observations.

We demonstrate mathematically in Appendix A.1 that NERA's calculation is appropriate for the analysis of *depreciation expenses*, not for *retirements.* This matters doubly since the 33-year average service life that NERA assumes is on the low end of the range of reasonableness, based on our research and experience. Other research suggests that average service life is higher.

Table 2 summarizes data we have gathered from utility filings on the average service lives of US power distributors today. It can be seen that they typically exceed 40 years. In response to an undertaking, Enbridge and Union report average service lives of about 38 years and 36 years in 2016, respectively.[48] As explained further in Appendix 1, we calculated an alternative average service life that

---

[46] Exhibit B, Tab 2, p. 84 (Exhibit JDM-2).

[47] Exhibit JT 2.2, Attachment 1.

[48] Exhibit JT 2.3, Attachments 1 and 2.

Table 2

Estimated Service Lives of Electric Distribution Assets of Select U.S. and Canadian Utilities

	FERC Account											
	360	361	362	364	365	366	367	368	369	370	371	373
Studies (date):	Land and Land Rights	Structures and Improvements	Station Equipment	Poles, Towers and Fixtures	Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters	Installations on Customers Premises	Street Lighting and Signal Systems
Non-FERC Accounting												
Hydro Quebec, (2017)				47 (Lignes Aeriennes)		35 (Lignes souterraines)						
OEB (2010)		50	45	52.5	47.1	60	35	45	50.3	30		
EDTI (2010)		50	35	45	45	41	41	35		18		20
FortisBC (2014)	75		50	50	49			45	75	20	20	27
FERC Accounting												
Public Service of Colorado (2010)	90	60	55	50	50	60	45	45	48	22	26	33
San Diego Gas and Electric (2014)		63	51	47	55	57	45	34	54	48	34	36
San Diego Gas and Electric (2012)		54	49	44	48	53	40	33	49	48	19	32
Black Hills Power (2012)	40	40	45	50	50	37	40	36	62	21	30	25
Northwest Territories Power Corp (2015)		40	25	50	55	30	30	50	55	18	18	48
PECO (2016)		50	50	53	52	65	53	46	52	15	35	24
Florida Power and Light (2016)		65	45	45	48	60	39	34	49	29	30	35
PECO (2013)		50	50	53	52	65	53	46	52	25	25	24
Consolidated Edison (2014)		52	50	60	60	80	50	34	65		60	60
Duke Energy Carolinas (2008)		45	38	43	40	45	45	36	38	20	35	29
PPL (2012)	65	65	50	55	45	55	53	39	42	19	27	30
Idaho Power (2006)		65	50	44	47	60	50	37	35	18	13	25
Oklahoma Gas and Electric (2009)	60	60	35	50	50	55	55	36	55	25	30	40
Southern California Edison (2015)		50	65	55	55	59	43	33	45	20		48
Western Massachusetts Electric (2016)		65	47	56	55	65	60	34	56	18	25	25
NSTAR (2016)		70	60	58	48	75	45	36	58	23		20
Entergy Mississippi (2008)	65	60	61	30	35	52	50	25	36	32	35	17
Ameren Missouri (2013)		60	62	47	50	70	56	41	49	26	25	36
Rockland Electric Company (2015)		55	45	65	48	70	65	50	70	23	45	45
Duquesne Light (2013)		55	44	50	48	70	50	44	65	21		27
Pacific Gas and Electric (2014)	60	65	46	44	46	62	47	32	49	20	40	29
Rochester Gas and Electric (2007)	75	60	58	50	50	70	50	48	50	41		29
US Summary Statistics[3]:												
Average	**65**	**57**	**49**	**50**	**49**	**60**	**48**	**39**	**51**	**25**	**31**	**33**
Max	**90**	**70**	**65**	**65**	**60**	**80**	**65**	**50**	**70**	**48**	**60**	**60**
Median	**65**	**60**	**50**	**50**	**50**	**60**	**50**	**36**	**51**	**22**	**30**	**30**
Min	**40**	**40**	**25**	**30**	**35**	**30**	**30**	**25**	**35**	**15**	**13**	**17**
Mean / Median	**1.00**	**0.95**	**0.98**	**1.00**	**0.99**	**1.00**	**0.97**	**1.07**	**1.01**	**1.15**	**1.02**	**1.10**
Mean without Max and Min	**65.0**	**57.0**	**49.5**	**50.2**	**49.6**	**60.3**	**48.4**	**38.7**	**51.3**	**24.6**	**29.9**	**32.0**
Adjusted / Normal Mean	**100%**	**100%**	**101%**	**100%**	**100%**	**101%**	**100%**	**100%**	**100%**	**97%**	**98%**	**98%**
Weight Calculation:												
Aggregate Gross Value of Distribution Plant, Major US electric utilities, 1996[1,2]	**1,540,088**	**1,888,296**	**19,827,510**	**23,309,900**	**24,740,492**	**10,167,804**	**24,422,026**	**27,727,740**	**14,765,567**	**8,726,051**	**1,246,649**	**4,892,033**
Share of Total Distribution Plant, 1996 (%)	**0.94%**	**1.16%**	**12.15%**	**14.28%**	**15.15%**	**6.23%**	**14.96%**	**16.98%**	**9.04%**	**5.35%**	**0.76%**	**3.00%**
Weighted Average Life of Distribution Plant	**46.6**											

Footnotes:
[1] Thousands of dollars
[2] Source: Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996, EIA. Page 43.
[3] Service life studies that are not consistent with FERC Accounts are excluded from these calculations.

Notes:
Missing value indicates no service life estimate provided in corresponding study.

is commensurate with retirements using a better formula and detailed retirement data from FERC Form 1. Our alternative estimate was 42 years. We demonstrated in the second Alberta IRM proceeding that, with an average service life of even 37 years, TFP growth using NERA's methodology is much higher.[49]

NERA's capital cost treatment and volumetric index together explain why TFP growth using their index has been materially negative in recent years. They obtain a reasonable TFP trend (e.g., +0.54%) over their lengthy full sample period because brisk (but, in an Application to the Applicants' proposed IRM, irrelevant) growth in average use in the early years offsets the productivity declines in later years. In recent years, their TFP indexes have been declining due to a combination of declining average use and an inappropriate average service life assumption.

The slowdown in TFP growth using NERA's method invites controversy over the appropriate sample period when their methodology is used. In testimony for North American power distributors, the Brattle Group (in Alberta), Christensen Associates Energy Consulting (in Alberta and Massachusetts), and Concentric Energy Advisors (in Quebec) have as utility witnesses embraced most aspects of NERA's methodology but only for recent years of their full sample period when productivity growth was negative.[50] All of these witnesses have, like NERA in this proceeding, cited the AUC's embrace of NERA's work in the first Alberta IRM proceeding. Truncation of the sample period, using NERA's methodology in other respects, was actually never embraced by the AUC but was accepted in a recent decision by the Massachusetts Department of Public Utilities.[51] Note that in the second Alberta generic proceeding, the AUC's chosen 0.3% X factor was informed by utility studies using OHS but also by a study by PEG that used geometric decay.

---

[49] Lowry, M.N. and Hovde, D. (2016), *PEG Reply Evidence*, Exhibit 20414-X0468 in AUC Proceeding 20414, pp. 15-19.

[50] Written Evidence of Dr. Toby Brown and Dr. Paul R. Carpenter for Altagas Utilities Inc, ATCO Electric, ATCO Gas, Enmax Power Corporation, and FortisAlberta, filed as Exhibit 20414-X0056 in Alberta Utilities Commission Proceeding 20414, pp. 26-32 (Brattle), Meitzen, M.E. (2016) *Determination of the Second-Generation X Factor for the AUC Price Cap Plan for Alberta Electric Distribution Companies*, filed as Appendix B of Exhibit 20414-X0074 in Alberta Utilities Commission Proceeding 20414, pp. 27-42 (Christensen Associates Energy Consulting), and Concentric Energy Advisors (2018), *Performance Based Regulation: Recommended X Factor*, Report filed as Exhibit B-0178 in Regie de l'Energie file R-4011-2017, pp. 5-9.

[51] See Massachusetts Department of Public Utilities, DPU-17-05, *Order Establishing Eversource's Revenue Requirement*, November 30, 2017, pp. 383-384. PEG did not participate in the Massachusetts proceeding.

Other Concerns

A number of smaller problems with NERA's US power distribution research also merit mention.

- Recall from Section 3 that the computation of a capital quantity index starts with a benchmark year adjustment. We believe NERA's calculations of capital quantity indexes in their initial benchmark year were also incorrect. OHS is sometimes characterized as a method for calculating the quantity associated with gross plant value. Yet NERA deflated *net* plant values by an average of past values of a construction cost index. As a consequence, we believe that the initial quantities of capital for each utility in their sample were understated. Their method effectively removed accumulated depreciation associated with older capital twice. It was first removed when calculating net plant value and then removed again when the original value of plant is retired. When an alternative and higher average service life is used to calculate capital quantities, this can result in negative capital quantities for some utilities. Utility witnesses in Alberta used these negative capital quantities as an argument against a higher average service life.[52]

- NERA's volume data were drawn entirely from FERC Form 1, which requests volumes of utility *sales* and not *deliveries*. With respect to residential volumes, for example, the instructions in the Uniform System of Accounts for Account 440, which is labeled "Residential Sales", state that

    A. This account shall include the net billing for electricity supplied for residential or domestic purposes.

    B. Records shall be maintained so that the quantity of electricity sold and the revenue received under each rate schedule shall be readily available.[53]

  It is easy to understand why these instructions might prompt a utility experiencing retail competition to report power *sales* volumes even when its power *delivery* volumes are larger.

[52] Brattle Undertaking #4 as filed in Alberta Utilities Commission Proceeding 20414 as Exhibit 20414-X0564 and Transcript Volume 8, pp. 2808-2809 from Alberta Utilities Commission Proceeding 20414.

[53] Code of Federal Regulations (2017), Title 18, Volume 1, Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, p. 488-491.

There are, as a consequence, marked declines in the reported volumes of some utilities that lost retail merchant business to competitors.

- There is too much weight on the trend in industrial volumes in NERA's volumetric index. NERA acknowledged in response to an information request that many large industrial customers of US electric utilities take service directly from the transmission system.[54]
- NERA failed to correct for some mergers.
- There were no controls for transfers of costs of assets and other inputs between the transmission and distribution operations of utilities.
- A Törnqvist/Thiel multilateral form was used for the productivity indexes. This form is not the best available for measuring productivity *trends.* Chain-weighted Törnqvist and Fisher Ideal forms are preferable for trend studies. PEG conventionally uses chain-weighted Törnqvist forms for input price and productivity indexes used in productivity trend studies.
- We are also concerned that NERA's documentation of their research for the Applicants in his direct evidence is substandard for an IRM filing in Ontario. For example, he did not discuss his methods for calculating the TFP trends of Enbridge and Union. To describe NERA's US power distribution productivity research, Enbridge attached his *first* report in the 2012 Alberta proceeding even though NERA revised their methodology during the proceeding and presented new results.[55] For example, Dr. Makholm acknowledged at the technical conference that he revised his labor cost specification during this Alberta proceeding at the recommendation of Dr. Lowry.[56]

[54] EGDI_Union_IRR_Staff_20180323, Exhibit C, Staff 40(d), p 3.

[55] The second report filed in AUC proceeding 566 was filed in response to an interrogatory response Exhibit C/Staff-34 b), Attachment 2.

[56] Technical Conference Transcript March 29, 2018, pp. 7-9.

Alternative Results

To illustrate the problems with NERA's power distributor productivity research, PEG has undertaken several alternative runs. Results of this exercise are presented in Table 3. We focus here on results for the 2001-2016 part of the sample period. The table also presents results for the full sample period.

- We first revised the benchmark year capital quantity calculation to deflate *gross* plant value by a 33-year average of past construction cost index values. This raised the estimated TFP trend for the sample by about 30 basis points, from -1.21% to -0.91%.
- We next corrected for a small problem with NERA's labor quantity calculation. This raised the estimated TFP trend by about 8 basis points, to -0.83%.
- We next removed some merged companies from the sample. This lowered the estimated TFP trend by 3 basis points, to -0.86%.
- We next raised the average service life from 33 to 37 years. This raised the estimated TFP trend by a remarkable 68 basis points, to -0.18%.
- Finally, we replaced NERA's volumetric output index with the number of customers served. This raised the estimated TFP trend by another 67 basis points, to **+0.49%.** With all of these upgrades and corrections, the estimated TFP trend using OHS for the *full* (1973-2016) sample period was **+0.85%.**

4.2. Enbridge and Union

NERA also calculated the TFP trend of Enbridge over the 1993-2016 period and that of Union over the 2001-2016 period. NERA reported a **-0.21%** average annual growth rate for Enbridge and a **-0.23%** trend for Union.[57] Our review of his work revealed several concerns. Here are the major ones.

[57] EB 2017-0307, Exhibit B, Tab 2, pp. 26-27.

Table 3

Summary of Corrections and Modifications to NERA's Productivity Calculations

	1973-2016			1973-2000			2001-2016		
	TFP Trend	Incremental Change	Cumulative Change	TFP Trend	Incremental Change	Cumulative Change	TFP Trend	Incremental Change	Cumulative Change
As Reported	0.54%			1.53%			-1.21%		
Modifications									
33 year TWA	0.55%	0.02%	0.02%	1.55%	0.02%	0.02%	-1.19%	0.02%	0.02%
Gross Plant 20 Year TWA	0.67%	0.12%	0.13%	1.65%	0.10%	0.11%	-1.04%	0.15%	0.16%
Gross Plant 33 Year TWA	0.78%	0.11%	0.24%	1.75%	0.10%	0.21%	-0.91%	0.13%	0.30%
Labor Quantity Calculation	0.81%	0.03%	0.27%	1.75%	0.00%	0.21%	-0.83%	0.08%	0.38%
Remove Merged Companies	0.79%	-0.03%	0.25%	1.73%	-0.02%	0.19%	-0.86%	-0.03%	0.35%
Average Service Life = 37 Years	1.23%	0.45%	0.69%	2.04%	0.29%	0.50%	-0.18%	0.73%	1.03%
Customers as Output	**0.85%**	**0.06%**	**0.31%**	**1.06%**	**-0.67%**	**-0.48%**	**0.49%**	**1.34%**	**1.69%**

- The Handy Whitman Index for *electric power distribution* construction costs in the Northeast US was used to deflate the asset values of these two *natural gas* utilities. We believe that the Statistics Canada's implicit price index for the capital stock of the utility sector is a more appropriate asset price deflator for the Applicants.

- NERA's benchmark year adjustment deflated the plant values of each applicant by an average of construction cost index values for a period ending in *1964* when the average should end in a year around the turn of the 21st century, when plant additions for each applicant become available. This is an apparent error in NERA's research.

- The number of customers served should be the output variable if the goal is to calibrate the X factor of the Applicants.

We recalculated these indexes using the number of customers served, our preferred asset value deflator, and benchmark year adjustments that are appropriate for Union in 1992 and Enbridge in 2000.

The OHS approach to measuring capital quantity and the 33-year average service life assumed by NERA were not changed.

Results of our calculations are presented in Tables 4a and 4b. Over the full 1993-2016 sample period for which data were gathered for Enbridge, its TFP growth averaged 0.31% annually while its OM&A productivity averaged 1.95% growth and its capital productivity averaged a 1.70% annual decline. Over the full 2001-2016 period for which data were gathered for both companies, Enbridge averaged a 0.76% annual TFP decline while Union averaged 1.04% annual growth. Both companies experienced brisk OM&A productivity growth.

Table 4a
Corrected Union TFP Results

Yearly Estimates:	TFP				O&M Productivity		Capital Productivity			
	NERA Results	Corrected Benchmark Year Adjustment	Plus Canadian Asset Price Index	Plus Customers as Output	NERA Results*	Plus Customers as Output	NERA Results*	Corrected Benchmark Year Adjustment	Plus Canadian Asset Price Index	Plus Customers as Output
2001	-6.89%	-6.80%	-6.64%	2.30%	-6.41%	2.53%	-7.00%	-7.37%	-7.02%	1.92%
2002	7.08%	7.82%	7.85%	3.26%	3.41%	-1.19%	7.81%	12.80%	13.60%	9.00%
2003	5.43%	8.73%	9.10%	7.30%	11.67%	9.87%	3.82%	3.83%	4.09%	2.28%
2004	-4.91%	-6.29%	-6.35%	0.30%	-9.77%	-3.12%	-3.94%	-2.43%	-1.92%	4.73%
2005	0.83%	2.11%	2.21%	3.95%	2.25%	3.99%	0.49%	1.87%	2.07%	3.81%
2006	-8.23%	-8.28%	-8.46%	1.27%	-8.11%	1.63%	-8.24%	-8.48%	-9.10%	0.63%
2007	6.96%	6.97%	6.62%	1.33%	6.40%	1.12%	7.08%	7.71%	6.96%	1.67%
2008	2.33%	2.04%	1.65%	0.69%	3.19%	2.24%	2.20%	0.67%	-0.99%	-1.95%
2009	-4.00%	-3.70%	-4.45%	0.84%	-4.12%	1.17%	-3.95%	-3.16%	-4.87%	0.41%
2010	-4.06%	-5.50%	-6.37%	-1.50%	-8.60%	-3.73%	-3.25%	-2.11%	-3.33%	1.54%
2011	6.34%	6.14%	5.33%	0.11%	6.10%	0.88%	6.38%	6.18%	4.17%	-1.05%
2012	-8.29%	-8.49%	-9.38%	0.21%	-9.51%	0.08%	-8.07%	-7.40%	-9.25%	0.33%
2013	12.52%	13.08%	11.99%	1.12%	13.39%	2.52%	12.35%	12.66%	9.78%	-1.08%
2014	6.62%	7.03%	6.32%	1.36%	8.72%	3.76%	6.17%	4.78%	2.52%	-2.44%
2015	-8.30%	-9.65%	-10.80%	-1.84%	-9.66%	-0.71%	-8.06%	-9.75%	-12.05%	-3.10%
2016	-7.13%	-10.26%	-11.36%	-4.04%	-9.94%	-2.62%	-6.64%	-10.81%	-13.42%	-6.10%
Average Annual Growth Rates										
2001-2016	**-0.23%**	**-0.31%**	**-0.80%**	**1.04%**	**-0.69%**	**1.15%**	**-0.18%**	**-0.06%**	**-1.17%**	**0.66%**

*PEG calculated O&M and capital productivity based on summary results calculated by NERA.

Table 4b
Corrected Enbridge TFP Results

Yearly Estimates:	TFP				O&M Productivity		Capital Productivity			
	NERA Results	Corrected Benchmark Year Adjustment	Plus Canadian Asset Price Index	Plus Customers as Output	NERA Results*	Plus Customers as Output	NERA Results*	Corrected Benchmark Year Adjustment	Plus Canadian Asset Price Index	Plus Customers as Output
1993	1.22%	-2.85%	-3.05%	-3.67%	-2.16%	-2.78%	2.38%	-4.40%	-4.86%	-5.48%
1994	1.87%	0.25%	0.19%	0.64%	0.82%	1.27%	2.29%	-0.58%	-0.51%	-0.06%
1995	-4.21%	-5.63%	-5.55%	1.17%	-4.87%	1.85%	-3.88%	-6.59%	-6.55%	0.16%
1996	7.04%	4.90%	4.88%	-0.81%	3.33%	-2.35%	8.24%	6.03%	6.18%	0.50%
1997	-3.65%	-4.69%	-4.43%	2.14%	-4.35%	2.23%	-3.63%	-6.17%	-5.83%	0.75%
1998	-4.68%	-3.13%	-2.68%	7.23%	2.22%	12.13%	-7.36%	-11.07%	-10.94%	-1.03%
1999	3.35%	2.88%	3.05%	2.92%	4.17%	4.04%	3.04%	1.11%	1.24%	1.11%
2000	8.10%	11.33%	11.73%	9.83%	18.22%	16.31%	4.57%	2.49%	2.58%	0.67%
2001	-0.18%	-2.16%	-2.09%	0.12%	-2.25%	-0.04%	0.38%	-2.30%	-2.16%	0.05%
2002	-0.93%	-2.08%	-2.05%	1.03%	0.18%	3.26%	-1.28%	-4.44%	-4.58%	-1.50%
2003	6.78%	3.63%	3.39%	-2.71%	0.66%	-5.44%	8.56%	6.21%	6.07%	-0.03%
2004	-2.85%	-3.11%	-3.07%	2.82%	-2.47%	3.43%	-2.98%	-3.83%	-3.75%	2.14%
2005	0.08%	-0.69%	-0.87%	1.83%	2.08%	4.78%	-0.62%	-3.77%	-4.65%	-1.95%
2006	-9.30%	-10.37%	-10.72%	0.29%	-8.57%	2.44%	-9.50%	-11.96%	-13.13%	-2.12%
2007	8.39%	7.44%	6.94%	0.04%	7.63%	0.73%	8.59%	7.30%	6.03%	-0.86%
2008	0.03%	-0.24%	-0.59%	1.50%	2.04%	4.14%	-0.50%	-1.69%	-2.98%	-0.88%
2009	-2.78%	-2.65%	-3.02%	1.15%	0.10%	4.27%	-3.46%	-4.45%	-5.66%	-1.49%
2010	-3.08%	-3.23%	-3.86%	1.05%	-2.11%	2.81%	-3.39%	-4.37%	-5.80%	-0.89%
2011	3.56%	2.87%	2.20%	-0.23%	3.99%	1.56%	3.38%	1.82%	0.22%	-2.21%
2012	-10.33%	-12.31%	-13.42%	-3.18%	-14.65%	-4.41%	-9.23%	-10.60%	-12.53%	-2.29%
2013	9.33%	7.29%	6.42%	-3.10%	7.19%	-2.33%	9.89%	7.36%	5.60%	-3.92%
2014	6.16%	5.73%	5.07%	0.13%	10.08%	5.15%	5.00%	2.19%	0.33%	-4.60%
2015	-7.94%	-9.92%	-11.05%	-3.24%	-11.91%	-4.10%	-6.79%	-7.59%	-9.04%	-1.24%
2016	-11.07%	-15.62%	-17.49%	-9.58%	-10.02%	-2.11%	-11.36%	-19.52%	-23.44%	-15.53%
Average Annual Growth Rates										
1993-2016	**-0.21%**	**-1.35%**	**-1.67%**	**0.31%**	**-0.03%**	**1.95%**	**-0.32%**	**-2.87%**	**-3.67%**	**-1.70%**
2001-2016	**-0.88%**	**-2.21%**	**-2.76%**	**-0.76%**	**-1.13%**	**0.88%**	**-0.83%**	**-3.10%**	**-4.34%**	**-2.33%**

*PEG calculated O&M and capital productivity based on summary results calculated by NERA.

5. New Research on U.S. Gas Utility Productivity

PEG has prepared a study of the recent OM&A, capital, and total factor productivity trends of a sizable sample of US gas distributors. This study uses productivity research methods which are more appropriate for calculating the Amalco's X factor than some of the methods that NERA used. We describe the research at a high level in this section. Some additional details of the research can be found in Appendix A.2.

5.1. Productivity Trends of US Gas Distributors

Data

US Gas Distributors

The chief source of our data on the costs of US gas utilities was reports to state regulators. These reports are fairly standardized since they often use as templates the Form 2 that interstate gas pipeline companies file with the FERC. A Uniform System of Accounts is available for this form. The chief source for our data on gas utility customers was Form EIA 176. Data from both of these sources are compiled by respected commercial venders. We obtained most of the gas operating data used in this study from SNL Financial.[58]

Other data sources were also employed in our productivity research. These were used primarily to measure input price trends. The supplemental sources of price data were Whitman, Requardt & Associates, the Regulatory Research Associates unit of SNL Financial, the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor, and the U.S. Department of Commerce.

Our calculations of the productivity trends of US gas distributors are based on quality data for 58 utilities. The sample includes most of the larger distributors in the United States. Some of the sampled distributors (e.g., Southern California Gas) also provided gas transmission and/or storage services but all were involved more extensively in gas distribution. The sampled distributors are listed in Table 5.

[58] For a few of the sampled companies, the SNL data were deemed insufficient in some of the earliest years of the sample period. In such cases, we used data from sources we have used in the past such as the GasDat service of Platts.

Table 5
Companies in PEG's Gas Utility Indexing Sample

Avista	Northwest Natural Gas
Baltimore Gas and Electric	NSTAR Gas
Berkshire Gas	Ohio Gas
Cascade Natural Gas	Ohio Valley Gas
Central Hudson Gas & Electric	Orange and Rockland Utilities
Citizens Energy Group	Pacific Gas and Electric
Columbia Gas of Kentucky	PECO Energy
Columbia Gas of Maryland	Peoples Gas Light and Coke
Columbia Gas of Ohio	Peoples Gas System
Columbia Gas of Pennsylvania	Public Service of Colorado
Columbia Gas of Virginia	Public Service Electric and Gas
Connecticut Natural Gas	Puget Sound Energy
Consumers Energy	Questar Gas
Corning Natural Gas	Rochester Gas and Electric
Duke Energy Ohio	San Diego Gas & Electric
East Ohio Gas	Sierra Pacific Power
Hope Gas	South Carolina Electric & Gas
Indiana Gas Company	South Jersey Gas
Louisville Gas and Electric	Southern California Gas
Madison Gas and Electric	Southern Connecticut Gas
Mountaineer Gas	Southern Indiana Gas and Electric
National Fuel Gas Distribution	Spire Alabama
New Jersey Natural Gas	St. Joe Natural Gas
New York State Electric & Gas	St. Lawrence Gas
Niagara Mohawk Power	Vermont Gas Systems
North Shore Gas	Virginia Natural Gas
Northern Illinois Gas	Washington Gas Light
Northern Indiana Public Service	Wisconsin Gas
Northern States Power - Wisconsin	Yankee Gas Services

Note: Sample comprises 58 utilities

Index Details

Scope

We calculated indexes of trends in the OM&A, capital, and total factor productivity of each sampled utility in the provision of gas transmission, storage, and distributor services. Costs of administrative and general functions and many customer services (e.g., billing and collection) were included in the study. The costs considered also encompassed taxes and pension and other benefit expenses.

Itemized costs attributed to electric services provided by combined gas and electric utilities in the sample were excluded from the analysis. We also excluded certain costs that are itemized on U.S. data forms and are unlikely to be subject to indexing in the IRM of the Applicants. The costs excluded for this reason included expenses for gas supply, gas transmission by others, and compressor station fuel.

We also excluded customer service and information expenses. These costs grew briskly during the sample period for many utilities due to the growth in utility CDM programs. The cost of these programs is not itemized in the U.S. data for easy removal. CDM programs are not covered by the indexing provisions of the Applicants' proposed IRM.

The applicable total cost was calculated as the sum of applicable O&M expenses and the costs of gas plant ownership. The index calculations required the breakdown of cost into two input categories: capital and OM&A inputs. OM&A inputs comprised labor, materials, and services. Material and service ("M&S") inputs is a residual input category that includes the OM&A services of contractors, insurance, real estate rents, equipment leases, materials, and miscellaneous other goods and services. The calculation of capital cost is discussed further in Appendix Section A.2.

Output Measure

The number of customers served was the output metric in our gas productivity study. We show in Section 3.1 above that this is the output specification that is relevant to the calibration of an X factor for the Applicants.

Input Quantity Index

The growth rate in the input quantity index of each sampled distributor was a weighted average of quantity subindexes for capital and OM&A inputs.

Sample Period

In choosing a sample period for an indexing study used in X factor calibration, it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2016. It is also desirable for the sample period to reflect the long-run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest technology trend. Moreover, the accuracy of the measured capital quantity trend is enhanced by having a start date for the indexing period that is several years after the first year that good capital cost data are available. We attempt to balance all of these considerations by presenting productivity results for the eighteen-year 1999 to 2016 period.

Index Results and Analysis

Table 6 reports annual growth rates in the total and partial factor productivities of US gas utilities for each year of the full sample period. Inspecting the results, it can be seen that the sampled distributors averaged **-0.23%** annual TFP growth.[59] Output growth averaging **1.03**% annually was outpaced by multifactor input quantity growth averaging **1.26**% annually. OM&A productivity growth averaged **0.88**% annually whereas capital productivity growth averaged a **0.98%** annual decline.

Table 6 also shows that, in the last 5-6 years of the sample period, there was a decline in OM&A, capital, and total factor productivity growth. Increased OM&A expenses and capex seem to have partly resulted from the distributors' response to regulations that were enacted by the US Pipeline and Hazardous Materials Safety Administration ("PHMSA") and by a high-profile gas transmission pipeline explosion in San Bruno, California. The new regulations mandated that distributors have and implement a Distribution Integrity Management Program ("DIMP") with a written integrity management plan by August 2, 2011.[60]

OM&A expenses of gas utilities increased due in part to the cost of developing and implementing the DIMP and addressing the findings of major incident investigations. Some of the increased OM&A expenses would be temporary. For example, in the aftermath of the San Bruno incident, Pacific Gas and Electric requested nearly $400 million for various activities related to upgrading

---

[59] All growth trends in this report were included logarithmically.

[60] Gas transmitters already operated under a requirement that they implement a Transmission Integrity Management Program ("TIMP") for many of the pipelines they operate by December 17, 2004.

Table 6-revised
Productivity Results for Sampled Gas Distributors[1]

	Output	Input Quantities			Productivity		
Year	Customers [A]	OM&A [B]	Capital [C]	Total [D]	OM&A [A-B]	Capital [A-C]	TFP [A-D]
1999	2.16%	-0.24%	2.10%	1.45%	2.40%	0.07%	0.71%
2000	2.67%	1.25%	2.37%	1.79%	1.41%	0.29%	0.88%
2001	1.30%	-7.89%	2.71%	-1.25%	9.19%	-1.40%	2.55%
2002	0.82%	-2.13%	1.70%	0.25%	2.96%	-0.88%	0.58%
2003	2.21%	3.92%	1.62%	2.33%	-1.70%	0.59%	-0.12%
2004	0.94%	0.92%	1.87%	1.39%	0.02%	-0.93%	-0.44%
2005	1.39%	1.58%	1.54%	1.56%	-0.18%	-0.14%	-0.17%
2006	0.77%	-6.99%	1.23%	-2.23%	7.75%	-0.47%	3.00%
2007	0.62%	6.25%	1.28%	3.39%	-5.64%	-0.66%	-2.78%
2008	0.33%	-0.72%	1.06%	0.29%	1.05%	-0.73%	0.05%
2009	0.29%	5.35%	1.28%	3.13%	-5.06%	-0.99%	-2.84%
2010	0.34%	0.00%	1.46%	0.76%	0.34%	-1.12%	-0.42%
2011	0.56%	0.75%	1.69%	1.30%	-0.19%	-1.13%	-0.74%
2012	0.87%	1.29%	1.56%	1.98%	-0.43%	-0.70%	-1.11%
2013	0.66%	3.21%	2.46%	2.40%	-2.55%	-1.81%	-1.74%
2014	0.85%	2.87%	2.97%	2.85%	-2.02%	-2.12%	-2.00%
2015	0.94%	-2.33%	3.66%	1.16%	3.27%	-2.72%	-0.22%
2016	0.88%	-4.38%	3.75%	0.14%	5.27%	-2.87%	0.75%
Average Annual Growth Rates							
1999-2016	**1.03%**	**0.15%**	**2.02%**	**1.26%**	**0.88%**	**-0.98%**	**-0.23%**

Notes

[1]Research used geometric decay and a 1994 benchmark year for capital quantity.

their transmission pipeline records.[61] OM&A expenses may also increase if a distributor finds that it needs to implement or alter its leak management program to meet the PHMSA's requirements.

Capex increased in subsequent years, as distributors relied on the data compiled from implementing the DIMP and addressing the findings of major incident investigations to identify assets needing replacement due to a high risk of failure. To help ensure that DIMP and TIMP costs would be funded, regulators in several states (e.g., Colorado, Connecticut, and Michigan) have approved trackers to address some, if not all, of these costs.

Surges in capex that result from these programs slow TFP growth in the short run. Once a surge ends, however, TFP growth can accelerate as these assets depreciate.

[61] The regulator disallowed the costs not due to concerns about their level but rather because it believed that Pacific Gas & Electric had followed deficient document management procedures that required this work to be undertaken. California Public Utilities Commission (2012), *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders and Requiring Ongoing Improvement in Safety Engineering*, Decision 12-12-030, December 20, pp. 89-97.

6. Stretch Factor and X Factor Recommendations

6.1 Stretch Factor

The Applicants adopted NERA's recommendation of a 0% stretch factor.[62] No benchmarking evidence was presented by the Applicants to substantiate this proposal. The evidence in hand is that Enbridge had a TFP growth trend well below the U.S. norm, while Union's TFP growth was above the norm.[63] Both companies have been operating for several years under rate plans that provide supplemental capital revenue.

Dr. Makholm maintained in his direct evidence that stretch factors are appropriate only for first generation IRMs. The AUC embraced this principle in its decision in its first generic IRM proceeding.[64] However, the AUC in in its second generation IRM decision seemed to include a stretch factor in its 0.30% X factor decision.[65] Stretch factors have been included explicitly in some other second generation or later IRMs.[66] For example, *three* generations of IRMs for power distributors in Ontario have included a stretch factor, including the current plan. The OEB explained why it continues to include stretch factors in IRMs in a decision on 4th GIRM, stating that:

> The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.[67]

---

[62] EB 2017-0307, Exhibit B, Tab 1, pp. 8-9.

[63] However, better methods for measuring the MFP trends of the Applicants may yield faster TFP growth.

[64] EB 2017-0307, Exhibit B, Tab 2, p. 14.

[65] Alberta Utilities Commission (2017), *Errata to Decision 20414 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities*, pp. 38-40.

[66] Numerous IRMs, including most established through settlements, do not itemize the components of the X factor and thus do not indicate whether a stretch factor is included. This likely includes some second generation or later IRMs which had previously included an explicit stretch factor.

[67] Ontario Energy Board (2013), EB-2010-0379, *Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,* Issued on November 21, 2013 and as corrected on December 4, 2013, p. 18-19.

This logic applies to investor-owned utilities as well as publicly-owned utilities. Stretch factor assignments in the 3rd and 4th generation Ontario power distribution IR plans have been updated annually to reflect company performance in cost benchmarking studies. Utilities that have operated under one or even several IRMs have not necessarily eliminated all inefficiencies. Moreover, operation under an IRM will typically generate stronger performance incentives than the regulatory systems of the typical utility in the productivity sample. Consider also that the Ontario stretch factor and benchmarking system works as an efficiency carryover mechanism that rewards distributors for sustained reductions in cost and penalizes them for sustained increases.

Similarly, after several generations of IRMs, the British Columbia Utilities Commission approved stretch factors of 0.2% for FortisBC Energy Inc. (formerly Terasen Gas) and 0.1% for FortisBC (formerly West Kootenay Power) for their current plans. The BC Commission also endorsed the possibility of including stretch factors in future generations of IR plans that are based on benchmarking evidence. The Commission believed that there was

> a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.**[68] [Emphasis in original]

Telecommunications precedents are also of interest. The US Federal Communications Commission approved stretch factors in second-generation IRMs for AT&T and the interstate services of incumbent local exchange carriers.[69] Dr. Lowry has advocated for the inclusion of stretch factors in

---

[68] British Columbia Utilities Commission (2014), *Decision,* In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, p. 86.

[69] Federal Communications Commission, FCC 93-326, Report Adopted June 24, 1993 in CC Docket 92-134. Federal Communications Commission, FCC 97-159, Fourth Report and Order Adopted May 7, 1997, in CC Dockets, 94-1 and 96-262. The latter decision was subsequently overturned by the US Court of Appeals for the District of Columbia Circuit in 1999.

second generation or later IR plans in testimony for several utility clients.[70] Hydro One Networks, Ontario's largest power distributor, is proposing a 0.45% stretch factor in its current IRM proposal.[71]

Since the Applicants have not submitted benchmarking evidence, a 0.30% stretch factor seems in order for the Amalco. In the 4th GIRM this is the standard stretch factor for Ontario power distributors with average cost performance. Also, in EB-2016-0152, OPG proposed, and the OEB approved, a 0.30% X factor for the hydroelectric generation payment amounts Price Cap plan, on the basis of cost benchmarking evidence of how OPG compared with a sample of other hydroelectric generators filed in that proceeding.

6.2 X Factor

Our review of the assembled productivity evidence reveals the following facts.

- The TFP trends of sampled U.S. gas utilities over the 1999-2016 sample averaged **-0.23%.**
- When Dr. Makholm's research was corrected and upgraded to be more pertinent to the Applicants' IRM proposal, the TFP trends of sampled U.S. power distributors averaged **+ 0.49%** from 2001-2016.
- PEG obtained a similar **+0.23%** average trend in the TFP of U.S. power distributors from 2001 to 2014.[72] OM&A productivity growth averaged **0.40%** while capital productivity growth averaged **0.18%.**
- The IRM favors the Applicants in many respects. For example, the company will be compensated for a substantial portion of its capital revenue shortfalls.

Based on the assembled evidence, we recommend a **0.0%** base TFP trend for the Amalco. Adding this to a 0.30% X factor, we recommend a **0.30%** X factor.

---

[70] See, for example, his X factor recommendations for Central Maine Power in 2007 and Gaz Metro in 2012. A full listing of Dr. Lowry's X factor recommendations for clients during the 2006-2015 period were detailed in Alberta Utilities Commission Proceeding 20414, Exhibit 20414-X0205 (CCA-EDTI Attachment 1b).

[71] EB-2017-0049, Exhibit A, Tab 3, Schedule 1, p. 21.

[72] Lowry, M.N., Deason, J., and Makos, M., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,", Lawrence Berkeley National Laboratory, July 2017.

7. Other IRM Provisions

When a power distributor operating under a price cap IRM consolidates with a distributor operating under Custom IR, the MAADs Handbook permits the distributors to operate for as long as 10 years under a price cap IRM without rebasing. However, as noted by the OEB in its Decision [on the Issues List] and Procedural Order No. 3, the applicability of the provisions of the MAADs Handbook are an open issue with the exception of the "no harm" test. The proposed IRM for the most part follows *Rates Handbook* guidelines. It features a price cap index, Y factors, and Z factors. The Applicants have not asked for Y factor treatment of pension and other benefit expenses. An earnings sharing mechanism would be operational for the last five years. An incremental capital module ("ICM") would address the need for supplemental capital revenue.

We have concerns about some features of the Applicants' proposed plan. Here are the most notable.

7.1. Adherence to MAADs

The Applicants propose to use MAADs provisions that the OEB designed to encourage consolidation of Ontario's power distributors, with their balkanized power distribution service territories. Consolidation of smaller power distributors can streamline OEB regulation and produce economies of scale and contiguity that can be passed on to customers. The regulatory and efficiency benefits of merging the Applicants is less obvious. Thus, the OEB should not feel obliged to apply all MAADs provisions to the Applicants' proposal. The panel in this proceeding has agreed that the applicability of the MAADs Handbook to gas utilities, and the Enbridge-Union merger specifically, is an unresolved issue in this proceeding. This means that the IRM for the Amalco does not need to closely resemble 4th GIRM.

The proposed IRM, in any event, deviates from the OEB's 4th GIRM in several ways. In addition to a 0% stretch factor proposal that lacks empirical substantiation, for instance, the inflation measure is GDPIPIFDD^{Canada} and not an industry price index that more accurately tracks a utility's cost by averaging the inflation of the GDPIPIFDD^{Canada} and the average weekly earnings of workers in Ontario industry. The Normalized Average Consumption/average use adjustments are also not part of 4th GIRM.

7.2. Rebasing

Since the Board is free to deviate from MAADs rules, it can require a rebasing of each Applicant's revenue to their recent and normalized historical costs followed by their formulaic escalation to 2019 values. This would sidestep problems of performance incentives and merger-related costs. Since the Applicants are in the last year of their respective IRMs and Custom rate-setting plans, skipping a rebasing in 2019 will do little to spur the Applicants' incentives. In the extra time that the rebasing requires, the Applicants can prepare a more appropriate asset management plan for use in ICM applications.[73]

7.3. Capital Cost Treatment

The Applicants' proposed ratemaking treatment of capital cost is in line with 4th GIRM but nonetheless raises several concerns. The ICM would weaken the Amalco's capex containment incentives. Incentives to contain capex and OM&A expenses are imbalanced, creating perverse incentives to incur excessive capex to reduce OM&A costs. The Applicants would also be incentivized to "bunch" their capex so that it maximizes revenue. The Applicants would have some incentive to exaggerate capex needs since this helps to legitimize the need for an ICM and reduces pressure for capex containment.

Exaggeration of capex needs may reduce the credibility of the Applicants' forecasts in future proceedings. However, utilities can always claim that they "discovered" ways to economize under the force of stronger incentives. British distributors operating under several generations of IR have repeatedly spent less on capex than they forecasted.

Another problem with the ICM is that customers must compensate the Amalco for most of the expected capital revenue shortfalls when capex is high even though most of the capex in question is likely to be similar in kind to that made by distributors in the productivity research sample.[74] Utilities can then be compensated twice for the same capex: once via the ICM and then again by a low X factor.

[73] Alternatively, the Applicants could use the rebasing to request an Advanced Capital Module in lieu of potentially repeated ICM filings.

[74] The Amalco would not, however, be compensated for unexpected capex overruns.

A similar concern about "double dipping" arises concerning distribution capex costs that are Z factored due to exogenous events such as severe storms and highway construction programs. These costs are also incurred by distributors in the productivity sample and slow their productivity growth.

PEG has shown in other proceedings that the TFP growth of gas and electric power distributors alike rises considerably if a portion of their capex is removed from the calculations. In 2016 Alberta testimony, for instance, PEG showed that excluding 10% of capex from a study of the productivity of US power distributors raised their estimated TFP trend over the full 1997-2014 sample period by 23 basis points, from 0.48% to 0.71%.[75]

Consider also that the Company is asking for supplemental revenue now, when its TFP growth is slowed by high capex, but could in the future operate under a standard IRM in which its price growth is limited by the industry's *long run* productivity trend. The trend in I-X mechanism thus effectively provides only a *floor* for the escalation of allowed revenue, and arguably applies chiefly to OM&A revenue, when the X factor was not designed to play either of these roles. Customers are not ensured the benefit of industry productivity growth even in the long run and even when it is achievable.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and Applicants' incentives to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Applicants' capex proposal. This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals complicates price cap IR proceedings and is one of the reasons why the Board must review asset management plans --- a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB Staff and stakeholders are sometimes hard-pressed to effectively challenge capex proposals.

Following an unhappy experience with capital cost trackers, a number of possible reforms to the ratemaking treatment of capital were discussed in the recent Alberta generic proceeding on second generation IR for energy distributors in that province. Based on the record, the Alberta Utilities Commission eventually chose a means for providing supplemental capital revenue that was less

[75] Lowry, Mark N., Pacific Economics Group Research, *Next Generation PBR for Alberta Energy Distributors*, Exhibit 20414-X0082 in Alberta Utilities Commission Proceeding 20414, March 23, 2016, pp. 63-66.

dependent on distributor capex forecasts. Regulatory cost was reduced thereby, and capex containment incentives were strengthened.[76]

A number of possible reforms to the capital cost tracker process were proposed by PEG in the Alberta proceeding which could also make sense in Ontario.

- The capex eligible for supplemental revenue could be subject to materiality thresholds and dead zones. Dead zones could also be added to materiality thresholds for Z-factored capex.
- The X factor could be raised in this and future plans to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. Knowledge that there is a price to be paid in the long run from asking for extra revenue now would strengthen the Amalco's capex containment incentives.
- Eligibility of capex for ICM treatment could be scaled back. For example, capex in the last year of the plan term could be declared ineligible because this involves only one year of underfunding.
- The ICM threshold can be escalated using the productivity trend of capital, while the X factor for OM&A revenue can reflect the productivity trend of OM&A. This could reduce the need for supplemental ICM revenue and make escalation of OM&A revenue more reflective of industry OM&A cost trends.

The OEB already embraces one of these strategies, since the ICM has a materiality threshold and dead zone. However, it is not clear whether the 10% threshold is appropriate, and under current ICM policy the Amalco would be funded for 100% of its marginal capex once it exceeds the threshold. An alternative is to disallow a fixed share of the total capex excess once capex exceeds the ICM threshold. Separate X factors for OM&A and capital revenue is another idea meriting consideration. If the OEB does not wish to deviate from the ratemaking treatment of capital in the 4th GIRM, the favorable treatment of capital should be kept in mind when considering other plan provisions.

[76] PEG nonetheless does not endorse the AUC's chosen approach.

7.4. Other Recommendations

Here are some other recommended modifications to the Applicants' proposal.

- An IPI is consistent with 4Th GIRM and sidesteps the need for a complicated input price differential calculation such as NERA provided. The OHS and GD capital cost specifications that NERA and PEG have used in this proceeding are very different from the methodology the Board uses to calculate capital costs in rate applications. This reduces the relevance of input price differential calculations that might be made using GD or OHS.
- If the OEB approves the Normalized Average Consumption/average use adjustments and LRAMs, the number of customers should be used in supportive TFP calculations to calibrate the X factor.
- The materiality threshold for Z factors plays an important role in IR. It reduces regulatory cost and can increase cost containment incentives.
- The proposed materiality threshold for the Z factor is low. A higher threshold is warranted that is appropriate for the Amalco's large size. The threshold should be escalated for PCI and customer growth.

Appendix

A.1 Calculating the Average Service Life

Estimation of the quantity of retirements was noted in Section 3.2 to be a special challenge when the one hoss shay approach is used in a TFP study to estimate the quantity of capital. We seek the quantity of capital ("XK_t^R") that corresponds to the value of plant retirements ("VKR^R") that utilities report. The value of retirements is the sum of the values of the gross plant additions of each asset type j that were made in year t-N_j ("$VKA_{j,t-N_j}$"), where N_j is the actual service life of the asset. The value of the asset price index in the year that each such addition was made can be denoted as $WKA_{j,t-N_j}$. Then

$$XK_t^R = \sum_j \frac{VKA_{j,t-N_j}}{WKA_{j,t-N_j}} = VK^R \cdot \sum_j \frac{VKA_{j,t-N_j}}{VK_t^R} \cdot \frac{1}{WKA_{j,t-N_j}} \qquad [A1]$$

Please note the following:

- The quantity of retirements depends on the service life of each kind of asset and the share of each kind in the value of retirements.
- Since utilities report plant value in historical dollars, assets with shorter service lives tend to get a little more weight because they tend to have been installed more recently. On the other hand, these are typically assets, such as meters, that tend to involve a small share of total plant value.
- It is reasonable to approximate equation [A1] with the following

$$XK_t^R = \frac{VK_t^R}{WKA_{t-ASL^R}} \qquad [A2a]$$

where

$$ASL^R = \sum_j \frac{VKA_{j,t-N_j}}{VK_t^R} \cdot N_j. \qquad [A2b]$$

- ASL^R may change over time.

NERA estimated average service life by taking the ratio of the gross value of all distribution assets ("VK^{gross}") to total distribution depreciation expenses ("CKD"). Suppose now that, in each year t, the depreciation expense for each asset *j* is the ratio of the gross value of the corresponding plant addition in year *t-s* to the expected service life of the asset ("N_j"). Then

$$\frac{VK_t^{gross}}{CKD_t} = \frac{VK_t^{gross}}{\sum_j \sum_s \frac{VKA_{j,t-s}}{N_j}}$$

$$= \frac{\cancel{VK_t^{gross}}}{\cancel{VK_t^{gross}} \sum_{j,s} \frac{VKA_{j,t-s}}{VK_t^{gross}} \cdot \frac{1}{N_j}}$$

$$= \frac{1}{\sum_{j,s} \frac{VKA_{j,t-s}}{VK_t^{gross}} \cdot \frac{1}{N_j}}$$

$$= ASL_t^D. \qquad [A3]$$

Please note the following.

- ASL^D is a reasonable approximation to an average service life. However, it is the average *expected* service life that corresponds to *depreciation* expenses, not the average *actual* service life corresponding to reported *retirements*.
- The formula places a particularly heavy weight on lives of all assets that have been added in recent years (not just short-lived assets such as meters) since these are less depreciated and, with book valuation of capital, are valued in more inflated dollars.
- ASL^D may change over time.
- There were no depreciation expenses corresponding to assets that are fully depreciated but remained a part of gross plant value for several years because they were still serviceable. Thus, ASL_t^D is not a true average.

We calculated our own estimate of the average service life corresponding to power distribution plant retirements. We began by reviewing the service life studies of utilities and compiling the service lives for 12 power distribution asset classes that are reported on the FERC Form 1. For each asset class, we took the arithmetic average of the 23 studies to determine an average service life. Next, we pulled down detailed retirement value data from FERC Form 1. This allowed us to determine what fraction of total retirements corresponded to each asset category. We used this to calculate a mean average service life of the asset categories weighted by the fractions. We did this for each year and company in the sample, except for NSTAR LLC for which we had no data. Then, we dropped all observations that had a mean average service life that was zero or negative. Additionally, there were instances where the sum of the retirement asset categories does not match the total distribution retirements reported by the company. When the difference between the sum and the reported total was more than 1 percent of the summation, we dropped the observation. Some companies reported negative retirements in individual asset categories. This results in negative service lives for those assets, so we dropped these observations as well. After this winnowing process of retirements, we had 1295 observations between 1995 and 2016. The average service life over the full period is 41.9. Furthermore, we observed that the average service life barely changed between 1995 and 2016, falling from 41.9 to 41.8.

A.2 Details of the US Gas Utility Productivity Research

This Appendix contains more technical details of our gas productivity research. We first discuss our input quantity and productivity indexes, respectively. We then address our method for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary quantity index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

The growth of the gas distribution O&M quantity input index was the difference between the growth in applicable total cost and the growth of an O&M input price index. Each summary input quantity index was of chain-weighted Törnqvist form.[77] This means that its annual growth rate was determined by the following general formula:

$$\ln\left(Inputs_{t} \Big/ Inputs_{t-1} \right) = \sum_{j} \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(X_{j,t} \Big/ X_{j,t-1} \right). \quad \text{[A4]}$$

[77] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

Here in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends

The annual growth rate in each productivity index is given by the formula

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \quad [A5]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Input Price Indexes

The trend in the OM&A input quantity of each sampled distributor was calculated as the difference between the trend in its applicable OM&A expenses and an OM&A input price index. The growth rate of an input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

Price Index Formulas

The OM&A input price indexes used in this study were of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula. For any asset category *j*,

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}} \right). \qquad [A6]$$

Here in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Input Price Subindexes

The OM&A input price indexes summarized trends in the prices of labor and M&S inputs. Regionalized employment cost indexes from the BLS were used to measure labor quantity trends. The gross domestic product price index ("GDPPI") was used to measure the trend in material and service prices. A price subindex for capital was required to calculate the capital quantity and is discussed further below.

Capital Cost and Quantity Specification

A monetary approach was chosen to measure the capital cost of each utility. Recall from Section 3.2 that under this approach capital cost is the product of a capital quantity index and a capital (service) price index.

$CK = WKS \cdot XK.$

Geometric decay was assumed. We took 1964 as the benchmark year for the capital quantity index. The values for the capital quantity indexes in the benchmark year were based on the net value of plant as reported in the FERC Form 1. We estimated the benchmark year (inflation adjusted) value of net plant by dividing this book value by an average of the values of an index of utility construction cost for a period ending in the benchmark year.

The construction cost indexes (WKA_t) were developed from the applicable regional Handy-Whitman Index of Cost Trends of Gas Utility Construction.[78] We adjusted these indexes to better reflect the changing composition of materials.

The following formula was used to compute values of the capital quantity index in subsequent years. For any asset category *j*,

$$XK_{j,t} = (1-d)\cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [A7]$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [A8]$$

The first term in the expression corresponds to taxes and franchise fees. The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

[78] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

References

Baldwin, J.R., Gu, W., and Yan, B. (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program", Canadian Productivity Review, Catalogue no. 15-206-XIE – No. 14. p. 41.

Baldwin, J.R., Liu, H. and Tanguay M. (2015), "An Update on Depreciation Rates for the Canadian Productivity Accounts", The Canadian Productivity Review, Catalogue No. 15-206-X, January 2015.

Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., Productivity Measurement in Regulated Industries, (Academic Press, New York) pages 172-218.

Fraumeni, B. (1997), "The Measurement of Depreciation in the U.S. National Income and Product Accounts," Survey of Current Business, for the Bureau of Economic Analysis.

Frayer, J., Chow, I., Leslie, J., and Porto, B. of London Economics International LLC, (2016), "Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry," filed in OEB proceeding EB-2016-0152.

Handy-Whitman Index of Public Utility Construction Costs, Baltimore, Whitman, Requardt and Associates, various issues.

Hulten, C. and F. Wykoff, (1981), "The Measurement of Economic Depreciation," in Depreciation, Inflation, and the Taxation of Income From Capital, C. Hulten ed., Washington D.C. Urban Institute.

Kaufmann, L., Hovde, D., Kalfayan, J., and Rebane, K., (2013), "Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board," in OEB Proceeding EB-2010-0379.

Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., (2008), "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario," in OEB Proceeding EB-2007-0673.

Lowry, M. N. and Hovde, D. (2016), PEG Reply Evidence, Exhibit 468, AUC Proceeding 20414, revised June 22.

Lowry, M. N., Makos, M., and Waschbusch, G. (2015), "Alternative Regulation for Emerging Utility Challenges: 2015 Update," for Edison Electric Institute.

Lowry, M. N., Hovde, D., and Rebane, K., (2013), "X Factor Research for Fortis PBR Plans," in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia.

Lowry, M. N., Getachew, L., and Fenrick, S., (2008), "Benchmarking the Costs of Ontario Power Distributors," in OEB Proceeding EB-2006-0268.

Lowry, M. N., Hovde, D., Getachew, L., and Fenrick, S., (2007), "Rate Adjustment Indexes for Ontario's Natural Gas Utilities," in OEB Proceeding EB-2006-0606/0615.

Ontario Energy Board, (2008), "Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors," Proceeding EB-2007-0673.

Organisation for Economic Co-Operation and Development (2009), Measuring Capital, OECD Manual, Second Edition.

Sing, M. (1984), The Cost Structure of the Gas Distribution and Electricity Industries, University of Wisconsin PhD Thesis.

Statistics Canada (2001), "The Statistics Canada Productivity Program: Concepts and Methods", Catalogue no. 15-204, January.

Tornqvist, L. (1936), "The Bank of Finland's Consumption Price Index," Bank of Finland Monthly Bulletin, 10, pages 1-8.

US Department of Energy, Financial Statistics of Major US Investor-Owned Electric Utilities, various issues.

US Energy Information Administration (1997), Financial Statistics of Major US Investor-Owned Electric Utilities 1996, U.S. Department of Energy.

RESUME OF
MARK NEWTON LOWRY

April 2018

Home Address 1511 Sumac Drive
Madison, WI 53705
(608) 233-4822

Business Address 44 E. Mifflin St., Suite 601
Madison, WI 53703
(608) 257-1522 Ext. 23

Date of Birth August 7, 1952

Education High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Applied Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position President, Pacific Economics Group Research LLC, Madison WI

Chief executive and sole proprietor of a consulting firm in the field of utility economics. Leads internationally recognized practice performance-based regulation and utility performance research. Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 Partner, Pacific Economics Group, Madison, WI

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 Vice President
January 1989-December 1992 Senior Economist, Christensen Associates, Madison, WI

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political

Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
4. Customer Response to Interruptible Service Programs. Southern California Edison, 1989.
5. Measuring Load Relief from Interruptible Services. New England Electric Power Service, 1989.
6. Design of Time-of-Use Rates for Residential Customers. Iowa Power, 1989.
7. Incentive Regulation: Can it Pay for Interstate Gas Companies? Southern Natural Gas, 1989.

8. Measuring the Productivity Growth of Gas Transmission Companies. Interstate Natural Gas Association of America, 1990.
9. Measuring Productivity Trends in the Local Gas Distribution Industry. Niagara Mohawk Power, 1990.
10. Measurement of Productivity Trends for the U.S. Electric Power Industry. Niagara Mohawk Power, 1990-91.
11. Comprehensive Performance Indexes for Electric and Gas Distribution Utilities. Niagara Mohawk Power, 1990-1991.
12. Workshop on PBR for Electric Utilities. Southern Company Services, 1991.
13. Economics of Electric Revenue Adjustment Mechanisms. Niagara Mohawk Power, 1991.
14. Sales Promotion Policies of Gas Distributors. Northern States Power-Wisconsin, 1991.
15. Productivity Growth Estimates for U.S. Gas Distributors and Their Use in PBR. Southern California Gas, 1991.
16. Cost Performance Indexes for Gas and Electric Utilities for Use in PBR. Niagara Mohawk Power, 1991.
17. Efficient Rate Design for Interstate Gas Transporters. AEPCO, 1991.
18. Benchmarking Gas Supply Services and Testimony. Niagara Mohawk Power, 1992.
19. Gas Supply Cost Indexes for Incentive Regulation. Pacific Gas & Electric, 1992.
20. Gas Transportation Strategy for an Arizona Electric Utility. AEPCO, 1992.
21. Design and Negotiation of a Comprehensive Benchmark Incentive Plans for Gas Distribution and Bundled Power Service. Niagara Mohawk Power, 1992.
22. Productivity Research, PBR Plan Design, and Testimony. Niagara Mohawk Power, 1993-94.
23. Development of PBR Options. Southern California Edison, 1993.
24. Review of the Southwest Gas Transportation Market. Arizona Electric Power Cooperative, 1993.
25. Productivity Research and Testimony in Support of a Price Cap Plan. Central Maine Power, 1994.
26. Productivity Research for a Natural Gas Distributor, Southern California Gas, 1994.
27. White Paper on Price Cap Regulation For Electric Utilities. Edison Electric Institute, 1994.
28. Statistical Benchmarking for Bundled Power Services and Testimony. Southern California Edison, 1994.
29. White Paper on Performance-Based Regulation. Electric Power Research Institute, 1995.
30. Productivity Research and PBR Plan Design for Bundled Power Service and Gas Distribution. Public Service Electric & Gas, 1995.
31. Regulatory Strategy for a Restructuring Canadian Electric Utility. Alberta Power, 1995.
32. Incentive Regulation Support for a Japanese Electric Utility. Tokyo Electric Power, 1995.
33. Regulatory Strategy for a Restructuring Northeast Electric Utility. Niagara Mohawk Power, 1995.
34. Productivity and PBR Plan Design Research and Testimony for a Natural Gas Distributor Operating under Decoupling. Southern California Gas, 1995.
35. Productivity Research and Testimony for a Natural Gas Distributor. NMGas, 1995.
36. Speech on PBR for Electric Utilities. Hawaiian Electric, 1995.
37. Development of a Price Cap Plan for a Midwest Gas Distributor. Illinois Power, 1996.
38. Stranded Cost Recovery and Power Distribution PBR for a Restructuring U.S. Electric Utility. Delmarva Power, 1996.
39. Productivity and Benchmarking Research and Testimony for a Natural Gas Distributor. Boston Gas, 1996.
40. Consultation on the Design and Implementation of Price Cap Plans for Natural Gas Production, Transmission, and Distribution. Comision Reguladora de Energia (Mexico), 1996.
41. Power Distribution Benchmarking for a PJM Utility. Delmarva Power, 1996.
42. Testimony on PBR for Power Distribution. Commonwealth Energy System, 1996.

43. PBR Plan Design for Bundled Power Services. Hawaiian Electric, 1996
44. Design of Geographic Zones for Privatized Natural Gas Distributors. Comision Reguladora de Energia (Mexico), 1996.
45. Statistical Benchmarking for Bundled Power Service. Pennsylvania Power & Light, 1996.
46. Presentation on Performance-Based Regulation for a Natural Gas Distributor, Northwestern Utilities, 1996.
47. Productivity Research and PBR Plan Design (including Service Quality) and Testimony for a Gas Distributor under Decoupling. BC Gas, 1997.
48. Price Cap Plan Design for Power Distribution Services. Comisión de Regulación de Energía y Gas (Colombia), 1997.
49. White Paper on Utility Brand Name Policy. Edison Electric Institute, 1997.
50. Generation and Power Transmission PBR for a Restructuring Canadian Electric Utility, EPCOR, 1997.
51. Statistical Benchmarking for Bundled Power Service and Testimony. Pacific Gas & Electric, 1997.
52. Review of a Power Purchase Contract Dispute. City of St. Cloud, MN, 1997.
53. Statistical Benchmarking and Stranded Cost Recovery. Edison Electric Institute, 1997.
54. Inflation and Productivity Trends of U.S. Power Distributors. Niagara Mohawk Power, 1997.
55. PBR Plan Design, Statistical Benchmarking, and Testimony for a Gas Distributor. Atlanta Gas Light, 1997.
56. White Paper on Price Cap Regulation (including Service Quality) for Power Distribution. Edison Electric Institute, 1997-99.
57. White Paper and Public Appearances on PBR Options for Power Distributors in Australia. Distribution companies of Victoria, 1997-98.
58. Research and Testimony on Gas and Electric Power Distribution TFP. San Diego Gas & Electric, 1997-98.
59. Cost Structure of Power Distribution. Edison Electric Institute, 1998.
60. Cross-Subsidization Measures for Restructuring Electric Utilities. Edison Electric Institute, 1998.
61. Testimony on Brand Names. Edison Electric Institute, 1998.
62. Research and Testimony on Economies of Scale in Power Supply. Hawaiian Electric Company, 1998.
63. Research and Testimony on Productivity and PBR Plan Design for Bundled Power Service. Hawaiian Electric and Hawaiian Electric Light & Maui Electric, 1998-99.
64. PBR Plan Design, Statistical Benchmarking, and Supporting Testimony. Kentucky Utilities & Louisville Gas & Electric, 1998-99.
65. Statistical Benchmarking for Power Distribution. Victorian distribution business, 1998-9.
66. Testimony on Functional Separation of Power Generation and Delivery in Illinois. Edison Electric Institute, 1998.
67. Design of a Stranded Benefit Passthrough Mechanism for a Restructuring Electric Utility. Niagara Mohawk Power, 1998.
68. Workshop on PBR for Energy Utilities. World Bank, 1998
69. Advice on Code of Conduct Issues for a Western Electric Utility. Public Service of Colorado, 1999.
70. Advice on PBR and Affiliate Relations. Western Resources, 1999.
71. Research and Testimony on Benchmarking and PBR Plan Design for Bundled Power Service. Oklahoma Gas & Electric, 1999.
72. Cost Benchmarking for Power Transmission and Distribution. Southern California Edison, 1999.
73. Cost Benchmarking for Power Distribution. CitiPower, 1999.
74. Cost Benchmarking for Power Distribution. Powercor, 1999.

75. Cost Benchmarking for Power Distribution. United Energy, 1999.
76. Statistical Benchmarking for Bundled Power Services. Niagara Mohawk Power, 1999.
77. Unit Cost of Power Distribution. AGL, 2000.
78. Critique of a Commission-Sponsored Benchmarking Study. CitiPower, Powercor, and United Energy, 2000.
79. Statistical Benchmarking for Power Transmission. Powerlink Queensland, 2000.
80. Testimony on PBR for Power Distribution. TXU Electric, 2000.
81. Workshop on PBR for Gas and Electric Distribution. Public Service Electric and Gas, 2000.
82. Economies of Scale and Scope in an Isolated Electric System. Western Power, 2000.
83. Research and Testimony on Economies of Scale in Local Power Delivery, Metering, and Billing. Electric distributors of Massachusetts, 2000.
84. Service Quality PBR Plan Design and Testimony. Gas and electric power distributors of Massachusetts, 2000.
85. Power and Natural Gas Procurement PBR. Western Resources, 2000.
86. Research on the Cost Performance of a New England Power Distributor. Central Maine Power, 2000.
87. PBR Plan Design for a Natural Gas Distributor Operating under Decoupling. BC Gas, 2000.
88. Research on TFP and Benchmarking for Gas and Electric Power Distribution. Sempra Energy, 2000.
89. E-Forum on PBR for Power Procurement. Edison Electric Institute, 2001.
90. Statistical Benchmarking for Power Distribution, Queensland Competition Authority, 2001.
91. Productivity Research and PBR Plan Design. Hydro One Networks, 2001.
92. PBR Presentation to Governor Bush Energy 2000 Commission. Edison Electric Institute, 2001.
93. Competition Policy in the Power Market of Western Australia, Western Power, 2001.
94. Research and Testimony on Productivity and PBR Plan Design for a Power Distributor. Bangor Hydro Electric, 2001.
95. Statistical Benchmarking for three Australian Gas Utilities. Client name confidential, 2001.
96. Statistical Benchmarking for Electric Power Transmission. Transend, 2002.
97. Research and Testimony on Benchmarking for Bundled Power Service. AmerenUE, 2002.
98. Research on Power Distribution Productivity and Inflation Trends. NSTAR, 2002.
99. Benchmarking and Productivity Research and Testimony for a Western Gas and Electric Power Distributor operating under Decoupling. Sempra Energy, 2002.
100. Future of T&D Regulation, Southern California Edison. October 2002.
101. Research on the Incentive Power of Alternative Regulatory Systems. Hydro One Networks, 2002.
102. Workshop on Recent Trends in PBR. Entergy Services, 2003.
103. Workshop on PBR for Louisiana's Public Service Commission. Entergy Services, February 2003.
104. Research, Testimony, and Settlement Support on the Cost Efficiency of O&M Expenses. Enbridge Gas Distribution, 2003.
105. Advice on Performance Goals for a U.S. Transmission Company. American Transmission, 2003.
106. Workshop on PBR for Canadian Regulators. Canadian Electricity Association, 2003.
107. General consultation on PBR Initiative. Union Gas, 2003.
108. Statistical Benchmarking and PBR Plan for Four Bolivian Power Distributors. Superintendencia de Electricidad, 2003.
109. Statistical Benchmarking of Power Transmission. Central Research Institute for the Electric Power Industry (Japan), 2003.
110. Statistical Benchmarking, Productivity, and Incentive Power Research for a Combined Gas and Electric Company. Baltimore Gas and Electric, 2003.

111. Advice on Statistical Benchmarking for Two British Power Distributors. Northern Electric and Yorkshire Electricity Distribution, 2003.
112. Testimony on Distributor Cost Benchmarking. Hydro One Networks. 2004.
113. Research, Testimony, and Settlement Support on the Cost Efficiency of O&M Expenses for a Canadian Gas Distributor. Enbridge Gas Distribution. 2004.
114. Research and Advice on PBR for a Western Gas Distributor. Questar Gas. 2004.
115. Research and Testimony on Power and Natural Gas Distribution Productivity and Benchmarking for a U.S. Utility Operating under Decoupling. Sempra Energy. 2004.
116. Advice on Productivity for Two British Power Distributors. Northern Electric and Yorkshire Electricity Distribution. 2004.
117. Workshop on Service Quality Regulation for Regulators. Canadian Electricity Association. 2004.
118. Advice on Benchmarking Strategy for a Canadian Trade Association. Canadian Electricity Association. 2004.
119. White Paper on Unbundled Storage and the Chicago Gas Market for a Midwestern Gas Distributor. Nicor Gas. 2004.
120. Statistical Benchmarking Research for a British Power Distributor. United Utilities. 2004.
121. Statistical Benchmarking Research for Three British Power Distributors. EDF Eastern, EDF London, and EDF Seeboard. 2004.
122. Benchmarking Testimony for Three Ontario Power Distributors. Hydro One, Toronto Hydro, and Enersource Hydro Mississauga. 2004.
123. Indexation of O&M Expenses for an Australian Power Distributor. SPI Networks. 2004.
124. Power Transmission and Distribution PBR and Benchmarking Research for a Canadian Utility. Hydro One Networks, 2004.
125. Research on the Cost Performance of Three English Power Distributors, EDF, 2004.
126. Statistical Benchmarking of O&M Expenses for an Australian Power Distributor. SPI Networks. 2004.
127. Testimony on Statistical Benchmarking of Power Distribution. Hydro One Networks. 2005.
128. Statistical Benchmarking for a Southeastern U.S. Bundled Power Service Utility. Progress Energy Florida. 2005.
129. Statistical Benchmarking of a California Nuclear Plant. San Diego Gas & Electric. 2005.
130. Explaining Recent Rate Requests of U.S. Electric Utilities: Results from Input Price and Productivity Research. Edison Electric Institute. 2005.
131. Power Transmission PBR and Benchmarking Support and Testimony. Trans-Energie. 2005.
132. Power Distribution Benchmarking Research and Testimony. Central Vermont Public Service. 2006.
133. Benchmarking and Productivity Research and Testimony for Western Gas and Electric Utilities Operating under Decoupling. San Diego Gas & Electric and Southern California Gas. 2006
134. Consultation on PBR for Power Transmission for a Canadian Transco. British Columbia Transmission. 2006.
135. Research and Testimony on the Cost Performance of a New England Power Distributor, Central Vermont Public Service, 2006.
136. White Paper on Alternative Regulation for Major Plant Additions for a U.S. Trade Association. EEI. 2006.
137. Consultation on Price Cap Regulation for Provincial Power Distributors. Ontario Energy Board. 2006.
138. Statistical Benchmarking of A&G Expenses. Michigan Public Service Commission. 2006.
139. Workshop on Alternative Regulation of Major Plant Additions. EEI. 2006.

140. White Paper on Power Distribution Benchmarking for a Canadian Trade Association. Canadian Electricity Association. 2006.
141. Consultation on a PBR Strategy for Power Transmission. BC Transmission. 2006.
142. Consultation on a Canadian Trade Association's Benchmarking Program. Canadian Electricity Association. 2007.
143. Testimony on PBR Plan for Central Maine Power, 2007.
144. Report and Testimony on Role of Power Distribution Benchmarking in Regulation. Fortis Alberta, 2006.
145. Consultation on Alternative Regulation for a Western Electric & Gas Distributor Operating under Decoupling. Pacific Gas & Electric. 2007.
146. Consultation on Revenue Decoupling and Revenue Adjustment Mechanisms for a Consortium of Massachusetts Electric and Gas Utilities. National Grid. 2007.
147. Gas Distribution Productivity Research and Testimony in Support of Decoupling and Other PBR Plans for a Canadian Regulator. Ontario Energy Board. 2007.
148. Testimony on Tax Issues for a Canadian Regulator. Ontario Energy Board. 2008.
149. Research and Testimony in Support of a Revenue Adjustment Mechanism for Central Vermont Public Service. 2008.
150. Consultation on Alternative Regulation for a Midwestern Electric Utility. Xcel Energy. 2008.
151. Research and Draft Testimony in Support of a Revenue Decoupling Mechanism for a Large Midwestern Gas Utility. NICOR Gas, 2008.
152. White Paper: Use of Statistical Benchmarking in Regulation. Canadian Electricity Association. 2005-2009.
153. Statistical Cost Benchmarking of Canadian Power Distributors. Ontario Energy Board. 2007-2009.
154. Research and Testimony on Revenue Decoupling for 3 US Electric Utilities. Hawaiian Electric, 2008-2009.
155. Benchmarking Research and Testimony for a Midwestern Electric Utility. Oklahoma Gas & Electric, 2009.
156. Consultation and Testimony on Revenue Decoupling for a New England DSM Advisory Council. Rhode Island Energy Efficiency and Resource Management Council, 2009.
157. Research and Testimony in Support of a Forward Test Year Rate Filing by a Vertically Integrated Western Electric Utility. Xcel Energy, 2009.
158. Research and Report on the Importance of Forward Test Years for U.S. Electric Utilities. Edison Electric Institute, 2009-2010.
159. Research and Testimony on Altreg for Western Gas and Electric Utilities Operating under Decoupling. San Diego Gas & Electric and Southern California Gas, 2009-2010.
160. Research and Report on PBR Designed to Incent Long Term Performance Gains. Client Name Withheld, 2009-2010.
161. Research and Report on Revenue Decoupling for Ontario Gas and Electric Utilities. Ontario Energy Board, 2009-2010.
162. Research and Report on the Performance of a Western Electric Utility. Portland General Electric, 2009-2010.
163. Research and Report on the Effectiveness of Decoupling for a Western Gas Distributor. Client Name Withheld, 2009-2010.
164. White Paper on Alternative Regulation Precedents for Electric Utilities. Client Name Withheld. 2010-2011.
165. Statistical Cost Benchmarking for a Midwestern Electric Utility, Oklahoma Gas & Electric, 2010.

166. Research and Testimony in Support of a Forward Test Year Rate Filing by a Western Gas Distributor. Xcel Energy, 2010.
167. Research and Testimony in Support of Revenue Decoupling for a Power Distributor. Commonwealth Edison, 2010-2011.
168. Research and Report on the Design of an Incentivized Formula Rate for a Canadian Gas Distributor. Gaz Metro Task Force. 2010-2011.
169. White Paper on Alternative Regulation Precedents for Electric Utilities. Edison Electric Institute. 2010-2011.
170. Benchmarking Research and Report on the Performance of a Midwestern Electric Utility, Oklahoma Gas & Electric, 2011.
171. Research and Testimony on Approaches to Reduce Regulatory Lag for a Northeastern Power Distributor, Potomac Electric Power. 2011.
172. Assistance with an Alternative Regulation Settlement Conference for a Northeastern Power Distributor, Delmarva Power & Light. 2011.
173. Research and Testimony on the Design of a Attrition Relief Mechanisms for power and gas distributors on behalf of a Canadian Consumer Group, Consumers' Coalition of Alberta. 2011-2012.
174. Research and Testimony on Remedies for Regulatory Lag for 2 Northeastern Power Distributors, Atlantic City Electric & Delmarva Power & Light. 2011-2012.
175. Research and Testimony on Projected Attrition for a Western Electric Utility, Avista. 2011-2012.
176. Productivity and Plan Design Research and Testimony in Support of a PBR plan for Canadian Gas Distributor, Gaz Metro. 2012-2013.
177. Testimony for US Coal Shippers on the Treatment of Cross Traffic in US Surface Transportation Board Stand Alone Cost Tests. 2012
178. Survey of Gas and Electric Altreg Precedents. Edison Electric Institute. 2012-2013.
179. Research and Testimony on the Design of an Attrition Relief Mechanism for a Northeast Electric Utility, Central Maine Power. 2013.
180. Research and Testimony on Issues in PBR Plan Implementation for a Canadian Consumer Group, Consumers' Coalition of Alberta. 2013.
181. Consultation on an Altreg Strategy for a Southeast Electric Utility (client name withheld). 2013.
182. Consultation on an Altreg Strategy for a Midwestern Electric Utility, Oklahoma Gas & Electric. 2013.
183. Research and Testimony on the Design of an Attrition Relief Mechanism for a Northeast U.S. Electric Utility, Fitchburg Gas & Electric. 2013.
184. Consultation on Regulatory Strategy for a California Electric and Gas Utility, San Diego Gas & Electric. 2013.
185. Research on Drivers of O&M expenses for a Canadian Gas Utility, Gaz Metro. 2013.
186. Research on the Design of Multiyear Rate Plans for a Midwest Electric & Gas Distributor, (client name withheld). 2013-2014.
187. Research on the Design of Multiyear Rate Plans for a Southeast Electric Utility, (client name withheld). 2013-2014.
188. Research and Testimony on Productivity Trends of Gas and Electric Power Distributors for a Canadian Consumer Group, Commercial Energy Consumers of BC, 2013-2014.
189. Research and Testimony on Productivity Trends of Vertically Integrated Electric Utilities, Client Name Withheld, 2014.
190. Research and Testimony on Statistical Benchmarking and O&M Expense Escalation for a Western Electric Utility, PS Colorado, 2014.

191. Transnational Benchmarking of Power Distributor O&M Expenses, Australian Energy Regulator, 2014.
192. Research and Testimony on Statistical Benchmarking and O&M Cost Escalation for an Ontario Power Distributor, Oshawa PUC Networks, 2014-2015.
193. Assessment of Statistical Benchmarking for three Australian Power Distributors, Networks New South Wales, 2014-2015.
194. Research and Testimony on Merger of Two Midwestern Utility Holding Companies, Great Lakes Utilities, 2014-2015.
195. White Paper on Performance-Based Regulation for a Midwest Electric Utility, Xcel Energy, 2015.
196. Research and Support in the Development of Regulatory Frameworks for the Utility of the Future, Powering Tomorrow, 2015.
197. Survey of Gas and Electric Alternative Regulation Precedents. Edison Electric Institute, 2015.
198. White Paper on Multiyear Rate Plans for US Electric Utilities, Edison Electric Institute and a consortium of US electric utilities, 2015.
199. White Paper on Performance-Based Regulation in a High Distributed Energy Resources Future, Lawrence Berkeley National Laboratory, January 2016.
200. White Paper on Performance Metrics for the Utility of the Future, Edison Electric Institute and a consortium of US electric utilities, 2016.
201. Research and Testimony on Performance-Based Regulation for Power Transmission and Distribution, Association Québécoise des Consommateurs Industriels d'Electricité.
202. Testimony on Revenue Decoupling for Pennsylvania Energy Distributors, National Resources Defense Council, March 2016.
203. Research and Testimony on Multiyear Rate Plan Design and U.S. Power Distribution Productivity Trends, Consumers' Coalition of Alberta. 2016.
204. Development of a Revenue Decoupling Mechanism and Supporting Testimony for a Midwestern U.S. Environmental Advocate, Fresh Energy. 2016.
205. Research and Testimony on Hydroelectric Generation Total Factor Productivity and Multiyear Rate Plan for a Canadian Regulator, Ontario Energy Board. 2016.
206. White Paper on Utility Experience and Lessons Learned from Performance-Based Regulation Plans, Lawrence Berkeley National Laboratory, 2016-2017.
207. Workshop on Performance-Based Regulation for Regulators in Vermont, 2016.
208. Consultation on Alternative Regulation trends for a Vertically Integrated Utility, 2016.
209. Statistical Benchmarking and Multiyear Rate Plan Testimony for a Western Gas Utility, Public Service of Colorado, ongoing.
210. Transnational Benchmarking of Power Distribution Cost, Productivity and Rates for the Consumer Advocate of a Canadian province, Alberta Utilities Consumer Advocate, 2017.
211. Presentation on PBR and Distribution System Planning for a U.S. Government Workshop, Lawrence Berkeley National Laboratory, 2017.
212. Statistical Benchmarking and Multiyear Rate Plan Testimony for a Western Electric Utility, Public Service of Colorado, ongoing.
213. Development of a Multiyear Rate Plan for an Northeastern Power Distributor, Green Mountain Power, ongoing.
214. Productivity Research and Report for an Northeastern Power Distributor, Green Mountain Power, 2017.
215. White Paper on Multiyear Rate Plans and U.S. Power Distributor Productivity Trends, Lawrence Berkeley National Laboratory, 2017.
216. Research and Testimony on Power Distributor Cost Performance and Productivity for a Canadian Regulator, Ontario Energy Board, ongoing.

217. Research and Testimony on Performance-Based Regulation for a Midwest Utility, Northern States Power (MN), ongoing.
218. Research and Testimony on Gas Utility Productivity for a Canadian Regulator, Ontario Energy Board, ongoing.
219. Research on Granular Power Distributor Cost Benchmarking for a Canadian Regulator, Ontario Energy Board, ongoing.

Publications

1. Public vs. Private Management of Mineral Inventories: A Statement of the Issues. Earth and Mineral Sciences 53, (3) Spring 1984.
2. Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). Energy Journal 6 (4), 1986.
3. The Changing Role of the United States in World Mineral Trade in W.R. Bush, editor, The Economics of Internationally Traded Minerals. (Littleton, CO: Society of Mining Engineers, 1986).
4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. Materials and Society 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).
6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November 1987.
7. Storage, Monopoly Power, and Sticky Prices. les Cahiers du CETAI no. 87-03 March 1987.
8. Monopoly Power, Rigid Prices, and the Management of Inventories by Metals Producers. Materials and Society 12 (1) 1988.
9. Review of Oil Prices, Market Response, and Contingency Planning, by George Horwich and David Leo Weimer, (Washington, American Enterprise Institute, 1984), Energy Journal 8 (3) 1988.
10. A Competitive Model of Primary Sector Storage of Refined Oil Products. July 1987, Resources and Energy 10 (2) 1988.
11. Modeling the Convenience Yield from Precautionary Storage: The Case of Distillate Fuel Oil. Energy Economics 10 (4) 1988.
12. Speculative Stocks and Working Stocks. Economic Letters 28 1988.
13. Theory of Pricing and Storage of Field Crops With an Application to Soybeans [with Joseph Glauber (senior author), Mario Miranda, and Peter Helmberger]. University of Wisconsin-Madison College of Agricultural and Life Sciences Research Report no. R3421, 1988.
14. Competitive Speculative Storage and the Cost of Petroleum Supply. The Energy Journal 10 (1) 1989.
15. Evaluating Alternative Measures of Credited Load Relief: Results From a Recent Study For New England Electric. In Demand Side Management: Partnerships in Planning for the Next Decade (Palo Alto: Electric Power Research Institute, 1991).
16. Futures Prices and Hidden Stocks of Refined Oil Products. In O. Guvanen, W.C. Labys, and J.B. Lesourd, editors, International Commodity Market Models: Advances in Methodology and Applications (London: Chapman and Hall, 1991).
17. Indexed Price Caps for U.S. Electric Utilities. The Electricity Journal, September-October 1991.
18. Gas Supply Cost Incentive Plans for Local Distribution Companies. Proceedings of the Eight NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).

19. TFP Trends of U.S. Electric Utilities, 1975-92 (with Herb Thompson). Proceedings of the Ninth NARUC Biennial Regulatory Information Conference, (Columbus: National Regulatory Research Institute, 1994).
20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
21. The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann), Applied Economics Letters 2 1995.
22. Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (with Lawrence Kaufmann). Palo Alto: Electric Power Research Institute, December 1995.
23. Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann). AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. Price Caps for Distribution Service: Do They Make Sense? (with Eric Ackerman and Lawrence Kaufmann), Edison Times, 1999.
29. "Performance-Based Regulation for Energy Utilities (with Lawrence Kaufmann)," Energy Law Journal, Fall 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas and Electricity, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, Forthcoming.
32. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
33. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), PEG Working Paper, November 2004.
34. "Econometric Cost Benchmarking of Power Distribution Cost" (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
35. "Assessing Rate Trends of U.S. Electric Utilities", Edison Electric Institute, January 2006.
36. "Alternative Regulation for North American Electric Utilities" (With Lawrence Kaufmann), Electricity Journal, July 2006.
37. "Regulation of Gas Distributors with Declining Use Per Customer" USAEE Dialogue August 2006.
38. "Alternative Regulation for Infrastructure Cost Recovery", Edison Electric Institute, January 2007.
39. "AltReg Rate Designs Address Declining Average Gas Use" (with Lullit Getachew, David Hovde, and Steve Fenrick), Natural Gas and Electricity, 2008.
40. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009
41. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods," (with Lullit Getachew), Energy Policy, 2009.
42. "Alternative Regulation, Benchmarking, and Efficient Diversification", USAEE Dialogue, August 2009.

43. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), in Lester C. Hunt and Joanne Evans, eds., International Handbook on the Economics of Energy, 2009.
44. "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" (With Lullit Getachew), Review of Network Economics, December 2009
45. "Forward Test Years for US Electric Utilities" (With David Hovde, Lullit Getachew, and Matt Makos),
Edison Electric Institute, August 2010.
46. "Innovative Regulation: A Survey of Remedies for Regulatory Lag" (With Matt Makos and Gentry Johnson), Edison Electric Institute, April 2011.
47. "Alternative Regulation for Evolving Utility Challenges: An Updated Survey" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, 2013.
48. "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, November 2015.
49. "Performance-Based Regulation in a High Distributed Energy Resources Future," (With Tim Woolf), Lawrence Berkeley National Laboratory, January 2016.
50. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," (With Jeff Deason), Lawrence Berkeley National Laboratory, July 2017.

Conference Presentations

1. American Institute of Mining Engineering, New Orleans LA, March 1986
2. International Association of Energy Economists, Calgary AL, July 1987
3. American Agricultural Economics Association, Knoxville TN, August 1988
4. Association d'Econometrie Appliqué, Washington DC, October 1988
5. Electric Council of New England, Boston MA, November 1989
6. Electric Power Research Institute, Milwaukee WI, May 1990
7. New York State Energy Office, Saratoga Springs NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell MT, May 1994
12. Edison Electric Institute, Washington DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando FL, March 1995
14. Illinois Commerce Commission, St. Charles IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco CA, April 1996
18. AIC Conferences, Orlando FL, April 1996
19. IBC Conferences, San Antonio TX, June 1996
20. American Gas Association, Arlington VA, July 1996
21. IBC Conferences, Washington DC, October 1996
22. Center for Regulatory Studies, Springfield IL, December 1996
23. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton AL, July 1997
26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving TX, Sept. 1997

27. American Gas Association, Washington DC [national telecast], September 1997
28. Infocast, Miami Beach FL, Oct. 1997
29. Edison Electric Institute, Arlington VA, March 1998
30. Electric Utility Consultants, Denver CO, April 1998
31. University of Indiana, Indianapolis IN, August 1998
32. Edison Electric Institute, Newport RI, September 1998
33. University of Southern California, Los Angeles CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio TX, April 2000
38. Infocast, Chicago IL, July 2000 [Conference chair]
39. Edison Electric Institute, July 2000
40. IOU-EDA, Brewster MA, July 2000
41. Infocast, Washington DC, October 2000
42. Wisconsin Public Utility Institute, Madison WI, November 2000
43. Infocast, Boston MA, March 2001 [Conference chair]
44. Florida 2000 Commission, Tampa FL, August 2001
45. Infocast, Washington DC, December 2001 [Conference chair]
46. Canadian Gas Association, Toronto ON, March 2002
47. Canadian Electricity Association, Whistler BC, May 2002
48. Canadian Electricity Association, Montreal PQ, September 2002
49. Ontario Energy Association, Toronto ON, November 2002
50. Canadian Gas Association, Toronto ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge LA, February 2003
52. CAMPUT, Banff, ALTA, May 2003
53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax NS, May 2004
56. Edison Electric Institute, eforum, March 2005
57. EUCI, Seattle, May 2006 [Conference chair]
58. Ontario Energy Board, Toronto ON, June 2006
59. Edison Electric Institute, Madison WI, August 2006
60. EUCI, Arlington VA, September 2006 [Conference chair]
61. EUCI, Arlington VA September 2006
62. Law Seminars, Las Vegas, February 2007
63. Edison Electric Institute, Madison WI, August 2007
64. Edison Electric Institute, national eforum, 2007
65. EUCI, Seattle WA, 2007 [Conference chair]
66. Massachusetts Energy Distribution Companies, Waltham MA, July 2007.
67. Edison Electric Institute, Madison WI, July-August 2007.
68. Institute of Public Utilities, Lansing MI, 2007
69. EUCI, Denver, 2008 [Conference chair]
70. EUCI, Chicago, July 2008 [Conference chair]
71. EUCI, Toronto, March 2008 [Conference chair]
72. Edison Electric Institute, Madison WI, August 2008
73. EUCI, Cambridge MA, March 2009 [Conference chair]
74. Edison Electric Institute, national eforum, May 2009

75. Edison Electric Institute, Madison WI, July 2009
76. EUCI, Cambridge MA, March 2010 [Conference chair]
77. Edison Electric Institute, Madison WI, July 2010
78. EUCI, Toronto, November 2010 [Conference chair]
79. Edison Electric Institute, Madison WI, July 2011
80. EUCI, Philadelphia PA, November 2011 [Conference chair]
81. SURFA, Washington DC, April 2012
82. Edison Electric Institute, Madison WI, July 2012
83. EUCI, Chicago IL, November 2012 [Conference chair]
84. Law Seminars, Las Vegas NV, March 2013
85. Edison Electric Institute Washington DC, April 2013
86. Edison Electric Institute, Washington DC, May 2013
87. Edison Electric Institute, Madison WI, July 2013
88. National Regulatory Research Institute, Teleseminar, August 2013
89. EUCI, Chicago IL April 2014 [Conference chair]
90. Edison Electric Institute, Madison WI, July 2014
91. Financial Research Institute, Columbia MO, September 2014
92. Great Plains Institute, St. Paul MN, September 2014
93. Law Seminars, Las Vegas NV, March 2015
94. Edison Electric Institute, Madison WI, July 2015
95. Lawrence Berkeley National Laboratory, Vermont Future of Electric Utility Regulation Workshop
    January 2016
96. Great Plains Institute, Minneapolis MN, February 2016
97. Wisconsin Public Service Commission, Madison WI, March 2016
98. Society of Utility Regulatory Financial Analysts (SURFA), Indianapolis IN, April 2016
99. Edison Electric Institute, Madison WI, July 2016
100. Lawrence Berkeley National Laboratory, Webinar, November 2016
101. Washington State House of Representatives, Technology and Economic Development Committee, January 2017
102. National Regulatory Research Institute, Webinar, May 2017
103. National Conference of Regulatory Attorneys, Portland OR, May 2017
104. Edison Electric Institute, Madison WI, July 2017
105. Lawrence Berkeley National Laboratory, Webinar, August 2017
106. New England Conference of Public Utilities Commissioners, Hallowell ME, September 2017
107. Wisconsin Public Utilities Institute, Madison WI, October 2017
108. University of Wisconsin Department of Applied Economics, October 2017
109. NARUC, St Paul MN, January 2018

Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

Association Memberships (active)

International Association of Energy Economist
Wisconsin Public Utilities Institute

IN THE MATTER OF

EB-2017-0307

Expert Report and Direct Testimony

PREPARED BY

JEFF D. MAKHOLM, PH.D.

NATIONAL ECONOMIC RESEARCH ASSOCIATES INC
200 CLARENDON STREET
BOSTON, MA 02116
USA

ON BEHALF OF

Enbridge Gas Distribution and Union Gas Limited

November 23, 2017

Contents

I. Qualifications and Findings

Q1. Please state your name, business address and current position.

A1. My name is Jeff D. Makholm. I am a Senior Vice President/Managing Director at National Economic Research Associates, Inc. ("NERA"). NERA is a firm of consulting economists with offices in a number of cities in North America and around the world. My business address is 200 Clarendon Street, Boston, Massachusetts, 02116.

Q2. Please describe your academic background.

A2. I have M.A. and Ph.D. degrees in economics from the University of Wisconsin-Madison, with a major field of Industrial Organization and a minor field of Econometrics/Public Economics. My 1986 Ph.D. dissertation is entitled "Sources of Total Factor Productivity in the Electric Utility Industry." I also have B.A. and M.A. degrees in economics from the University of Wisconsin-Milwaukee. Prior to my latest full-time consulting activities, I was an Adjunct Professor in the Graduate School of Business at Northeastern University in Boston, Massachusetts, teaching courses in microeconomic theory and managerial economics.

Q3. Please describe your work experience pertinent to this proceeding.

A3. My work involves pricing, regulation and market issues for regulated infrastructure industries, including natural gas, electricity, water and telecommunications utilities, natural gas and oil pipelines, airports, toll roads and passenger and freight railroads. More specifically, I have consulted for firms, governments, regulatory agencies or interest groups on the issues of competition, rate/toll design, cost of capital, regulatory rulemaking, incentive ratemaking, load forecasting, least-cost planning, cost measurement, contract obligations and bankruptcy. As shown in Exhibit JDM-1, my Curriculum Vitae, I have appeared as an expert witness in public utility rate cases and have testified before administrative and civil law courts on more than 250 occasions.

I have directed studies on behalf of utility companies, governments and the World Bank in many countries. In these countries, I have drafted regulations, established tariffs/tolls, recommended financing options for major capital projects, advised on industry restructurings, and assisted in the privatization of state-owned gas utilities.

Q4. What is your experience in performing Total Factor Productivity (TFP) growth studies that lead to an independent recommendation of the *X-factor*?

A4. I have been involved in the study and application of TFP growth studies for regulated industries for more than three decades. For my Doctoral work in the 1980s, I performed the first scholarly investigation into the measurement and econometric investigation of the sources of energy utility TFP growth—the model for empirical TFP growth research and application for PBR plans around the world. I have performed TFP growth studies used to set regulated tariffs for energy utilities in Canada, the United States, New Zealand, Mexico, and Argentina.

In 1999, I was involved in Ontario's first investigation of performance-based regulation. Responding to a request for proposal, I directed a project for Ontario Hydro Services Company (OHSC) in 1999 regarding the transition from cost-of-service regulation to the OEB's newly designed PBR framework. OHSC at the time was looking for advice and assistance from an experienced party in developing and supporting its transmission and distribution PBR applications for the next rate order period starting in 2001.

Most recently, I was retained as an independent expert by the Alberta Utilities Commission (the AUC) in its 2011-2012 generic "Rate Regulation Initiative" to identify common regulatory practices or industry standards, compare key provisions in plans proposed by the utilities in Alberta against industry standards, deal with areas where a common standard exists, and analyse the pros and cons of all plans (whether proposed by the utilities or supported by industry standards generally). Working independently, I directed the preparation of a TFP growth study to use for Alberta's electricity and gas distribution companies. The conclusions in that study were accepted by the AUC, in its Decision 2012-237, on all major conclusions of that PBR initiative (methods, data, transparency, output measure, time periods and possible advanced statistical methods). The AUC also adopted my "capital tracker" proposal to ensure the collection of necessary capital expenditures not covered by other elements of an incentive regulation plan. Subsequently, I provided testimony for ATCO Gas in 2013 before the AUC on the implementation of that company's capital tracker mechanism.

Q5. What is your experience with Canadian regulation generally?

A5. I have provided evidence a number of times before federal and provincial regulatory boards in Canada. I presented testimony before the National Energy Board (NEB) on behalf of FortisBC Energy Inc. with respect to the proposals of NOVA Gas Transmission Ltd. to construct the proposed "Komie North," "North Montney," and "Towerbirch" facilities into the shale gas fields of northeast British Columbia (Hearing Orders GH-001-2012, GH-001-2014, and GH-003-2015, respectively). In those proceedings, I focused on three issues: the economic feasibility of the proposed facilities, the potential commercial impacts of the proposed projects, and the appropriateness of the proposed NGTL toll treatment.

I also appeared before the NEB in three cases regarding TransCanada Pipelines on behalf of the Market Area Shippers (MAS). For the MAS Group—a group comprising Enbridge Gas Distribution, Inc., Union Gas Limited, and Société en commandite Gaz Métro—I was involved in the following proceedings: Hearing Orders RH-003-2011 (restructuring); RH-001-2013 (proposed toll amendments); and RH-001-2014 (toll settlement). I also appeared before the NEB on behalf of Enbridge and Union with regard to TransCanada's abandonment cost methodology (MH-001-2013).

In 2010, I was retained by Hydro-Québec TransEnergie ("HQT") to give evidence before the Régie de l'énergie in Québec on the application of traditional regulatory principles to HQT's cost allocation practices and electricity transmission rates. In 2015, on behalf of Société en commandite Gaz Métro, I provided evidence before the Régie de l'énergie regarding the approval and pricing of transmission system capacity additions on the company's Saguenay and the Eastern Township networks.

In 2014, I served as an expert witness for Alliance Pipeline Ltd. in its application to the NEB for approval of New Services and Related Tolls and Tariffs (RH-002-2014). My analysis comprised a review of the proposed tolling methodology and a study to examine market power in Alliance's origin and destination markets.

Q6. In addition to the above, have you published articles or written papers on issues related to the regulation and economics of public utilities—including the measurement of productivity and efficiency in regulated firms?

A6. Yes. Listed on my Curriculum Vitae (attached as Exhibit JDM-1) are many published (or forthcoming) articles, working papers and two books pertaining to economic and regulatory issues associated with natural gas and oil pipelines around the world. Included in those papers is a recent publication (October 2017, *Natural Gas and Electricity*), entitled "Regulating Utility Efficiency 'Fast and Slow': The Current Australian Problem" that comments on the noteworthy problems that Australia is having assessing efficiency in the regulation of electricity distributors there.

Q7. What is the purpose of your testimony in this proceeding?

A7. I have been asked by Enbridge Gas Distribution (EGD) and Union Gas Ltd (Union) to provide testimony in support of the productivity offset (the *X-factor*) to be used in the price cap formula that will apply to its distribution business in the upcoming deferred rebasing periods for each company. I provide independent TFP growth studies for EGD and Union to use with those companies' next incentive regulation application before the Ontario Energy Board (OEB).

Q8. How do you approach the calculation of a productivity offset?

A8. I use a TFP growth analysis to determine empirically the magnitude of the *X-factor* as part of the *RPI-X* regulatory model. I employ data from the US FERC Form 1 and data from EGD and Union to derive the TFP growth for the companies' distribution services.

Q9. What do you conclude from your analysis?

A9. I recommend, on the basis of my customary empirical analysis in such cases, that EGD and Union should be subject to a zero *X-factor* with a zero "stretch factor." Throughout my testimony, I will explain the basis for my recommendations.

Q10. How do you organize your testimony?

A10. My testimony has five sections to follow. In **Section II**, I provide a brief re-cap of the source of *RPI-X* regulation and the essential, intuitive role played by the *X-factor* in that model of regulation. In **Section III**, I present the theoretical model that describes what the *X-factor* is meant to measure as it serves to mimic a competitive pricing constraint over defined rate formula periods for regulated firms. In **Section IV**, I describe the empirical methods for measuring the various inputs and outputs called for by that theory. In **Section V**, I present my TFP computations for EGD, Union and the US energy distribution companies covered by the Form 1 data that served as the basis for my recommendations that were accepted by the AUC in its Rate Regulation Initiative in 2012, updated to include data through 2016. In **Section VI**, I present my conclusions.

II. Economic Intuition Behind the *X-factor*

Q11. What is the purpose of this part of your testimony?

A11. I describe, with references to the literature on the subject, what the *X-factor* is for, including if and when it requires adjustment by means of a "stretch" factor.

Q12. Where does the *X-factor* come from?

A12. The basic *RPI-X* price cap incentive regulation model is a UK import, implemented there to speed that country's rapid privatization under the Margaret Thatcher government in the 1980s. Its allure to the UK government lay in its promise both to bypass the perceived inefficiencies of, what was described there as, "cost plus" regulation in North America (an unfortunately simplistic label in my opinion) and to avoid what it also perceived to be various difficult regulatory institutions and procedures—the creation of which would necessarily slow down quick privatization (which is what the Thatcher government demanded).[1] The 1980s also was a time to reassess the longstanding regulatory model in North America, given changes in the telecom market (because of the mandated 1982 breakup of AT&T that produced the regional Bell operating companies) and the evident problems of rising electricity and gas rates.[2] As a result, *RPI-X* regulation attracted considerable scholarly interest.[3] It came to North America first in the regulation of those

---

1 As an example of the press for rapid privatization (regarding British Gas), see Makholm, *The Political Economy of Pipelines*, University of Chicago Press, Chicago and London (2012), pp. 57-58.
2 Makholm, "Electricity Deregulation under Siege," Natural Gas and Electricity, Volume 34, No. 5 (August 2017), p. 29.
3 Littlechild, S.C., "The regulation of privatized monopolies in the United Kingdom, *The Rand Journal of Economics*, Vol. 20,No. 3 (1989), p. 457.

regional Bell operating companies—and then to a few US electricity and gas companies in a small number of states (e.g., California, Maine, New York and Massachusetts). It also attracted attention in Ontario, British Columbia and Alberta.

In US telecommunications, *RPI-X* regulation of local services in the 1990s was a bridge to deregulation and is generally no longer applied in that industry. In US energy regulation, *RPI-X* regulation with a specific *X-factor* did not spread outside the few states that originally pursued it. In Canada, Alberta initiated a generic *RPI-X* "Rate Regulation Initiative" in 2010-2012 with a major emphasis on an empirically-derived *X-factor*, now in its second generation.[4] Ontario is on its fourth generation plan—all of which have referred to an empirically-derived *X-factor*.

Q13. What are the institutions underlying *X-factors*?

A13. *RPI-X* was supposed to be a more efficient alternative than North American utility regulation—permitting rates to rise at a government index of inflation minus an unspecified adjustment factor, called "*X*." As originally conceived in 1983 by its author, Stephen Littlechild, *X* would be part of a "package of measures" in the license responsibilities offered as the UK's public enterprises would be offered to investors through privatization.[5] As such, the government had wide freedom in setting *X*, and Littlechild offered no guide for how to do so. For resetting *X*, or in cases where the package of measures had already been determined, Littlechild admits "there are thus fewer degrees of freedom in resetting *X*," but provides no other guide for its determination.[6] Indeed, where he described the re-setting of *X* in the UK at all, Littlechild emphasizes the broad peremptory powers of regulators that do not translate to Canada or the United States.[7]

---

4 NERA was retained as an independent expert by the Alberta Utilities Commission (AUC) to present the procedures and data for the purpose of computing the *X-factor*. The AUC adopted NERA's methods in their entirety. See AUC, Decision 2012-237, September 12, 2012.

5 Littlechild, S.C., "Regulation of British Telecommunications' Profitability, London: Department of Industry, (1983).

6 Littlechild, S.C., "The regulation of privatized monopolies in the United Kingdom, The Rand Journal of Economics, Vol. 20, No. 3 (1989), p. 457.

7 "…in setting *X* the U.K. regulator has more discretion and less need to reveal the basis of his decisions than does his U.S. counterpart. … In the U.K., there is less pressure for due process, [and] neither governments nor regulators have given detailed reasons for their decisions on *X*." Littlechild (1989), p. 461.

As originally conceived and written about in the UK, *RPI-X* did not deal with any deeper institutions such as administrative procedures, uniform systems of accounting, or the prudence standard involved in the regulation of investor-owned utilities—institutions important to Canadian and US regulation that the UK did not have.[8] Partly for those institutional reasons and partly because of the political nature of UK regulation generally, the implementation of *RPI-X* turned out to be much more difficult and contentious than anticipated. After a notable retrospective on its perceived failures, the UK abandoned that form of regulation in favor of another regulatory model labelled "RIIO" (Revenue = Incentives + Innovation + Outputs).[9]

Q14. How did such regulation translate to North America?

A14. North American regulation has a deep and longstanding institutional foundation inherent in accounting regulation, the "prudence standard," and the *Northwestern Utilities* and *Hope* cases geared toward safeguarding private property in regulated industries.[10] Where *RPI-X* regulation initially resonated best in North America, given such institutions, was in the application to regulated local and interstate telecom companies in the wake of their divestiture from AT&T. The regulated telecom industry could readily define "baskets" of disparate services (which could be subject to the single weighted-average price cap). The industry also was in a period of rapid productivity growth due to new technologies (e.g., electronic switches, digitization, fiber optics). Thus, *RPI-X* regulation gave telecom regulators tools to lighten regulatory burdens both by specifying average price caps and permitting regulated prices to move after being set—taking away the need to persistently update individual regulated service rates.[11] *RPI-X* regulation was a reasonably successful part of the transition to deregulation of that industry.[12]

[8] See Makholm (2015) for a description of the institutional differences between UK and US utility regulation, and Makholm (2008) for a similar description of the institutional similarities between US and Canadian regulatory institutions.

[9] See Makholm (2015). Also see: https://www.ofgem.gov.uk/ofgem-publications/51870/decision-docpdf.

[10] *Northwestern Utilities v. City of Edmonton, S.C.R. 186 (NUL 1929)* and *Federal Power Commission et al v. Hope Natural Gas Co*, 320 U.S. 591 (1944).

[11] The Federal Communications Commission (FCC) issued a price cap order with an *X-factor* in 1989 (See: FCC 95-132, CC Docket No. 94-1 "In the Matter of Price Cap Performance Review for Local Exchange Carriers," Appendix D). California issued a price cap decision in 1989 (decision D.89-10-031). Massachusetts issue a price cap decision in 1995 (New Eng. Tel. & Tel. Co. dba NYNEX, D.P.U. 94-50, May 12, 1995). NERA assisted with all three efforts.

[12] There was a lot more to the deregulation of the telecommunications industry—involving great economic and regulatory controversies. My late NERA colleague Alfred Kahn wrote about those controversies at length. See: Kahn, A.E., *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness*, MSU Public Utility Papers, Michigan State University, East Lansing (1998).

RPI-X regulation did not resonate as well for electric and gas distribution utilities. Companies with a single product (i.e., distribution services) had no telecom-like "basket" of diverse services, no telecom-like rapid technological progress and no prospect of deregulation. Thus, *RPI-X* regulation for energy distribution utilities in North America generally came to be seen as less of an alternative to cost-based regulation (as originally conceived in the UK) than a means to lengthen "regulatory lag" for pricing services that were never foreseen as candidates for deregulation. The AUC echoed such a conclusion in Alberta's generic 2012 "Rate Regulation Initiative" proceeding:

> As NERA emphasized, this concept corresponds to the underlying theory behind the PBR plans in Canada and the United States: to permit regulated prices to change to reflect general price changes and industry productivity movements without the need for a base rate case. The effect is to lengthen regulatory lag and better expose regulated utilities to the type of incentives faced by competitive firms.[13]

Q15. Why is an *X-factor* necessary in a price cap model?

A15. Before I answer your question, let me say something about what I call the UK "*X"* as opposed to the North American "*X-factor*."

When I refer to the *X* in Littlechild's *RPI-X* formula, it is just "*X"*—something for the regulator to choose without any need for quantitative justification. North American regulators do not generally have such powers to act without some due process trail—they need some sort of evidentiary support that fits in with the general boundaries on their discretion designed to safeguard investor property (i.e., the *Northwestern Utilities* case). That is, North American regulators cannot simply pull *X* out of the air as their UK colleagues have done. They need evidence: an empirically-derived "*X-factor*" relating to an acceptable theoretical foundation.

Consistent with more longstanding, due process based regulatory institutions designed to produce evidence-based (and hence legally defensible) results, the derivation of the *X-factor* in Canada and the United States moved away from the UK regulatory choice model described originally by Littlechild and into a productivity measurement model designed to mimic a competitive constraint. The measurement of TFP mirrored

[13] AUC Decision 2012-237, page 58 (quoting Exhibit 391.02, NERA second report, paragraph 2).

theoretical advances in the construction of theoretically suitable index numbers coming out of scholarly study on industrial productivity at the University of California-Berkeley and the University of Wisconsin, Madison, including my own work.[14] With such techniques for reliably constructing productivity indexes, the *X-factor* became a regular part of *RPI-X* cases in most of the jurisdictions in Canada and the United States that continue to pursue such a regulatory model.

Q16. But why is an *X-factor* even necessary?

A16. The answer is that the regulatory lag that drives the company incentives, in such incentive-based regulation, requires some sort of allowance for inflation. But the available economy-wide published inflation indexes do not necessarily capture the inflation that is relevant *for the specific regulated business in question*. The *X-factor* comprises those adjustments that *may be required* to permit published inflation indexes to work for a price adjustment formula as applied to a particular regulated company. That is all the *X-factor* does in its application to North American energy utilities: square published inflation indexes to the output price trends of the regulated business in question.

Whether an *X-factor* may be required is an empirical matter. If the utility in question is part of an industry that is growing in productivity in line with the economy as a whole (suitably measured) and faces the same kind of input cost inflation as other firms in the economy (again, suitably measured), then the use of published economy-wide inflation indexes will work—we do not need an *X-factor*. But if the growth in productivity for the industry in question is *different* than the economy's, or input cost inflation for the utility is *different* from that for the economy's businesses generally, then the published economy-wide inflation index will not work to track fairly the inflation to be applied as the cap for the utility's prices.

For example, telecom companies just prior to deregulation displayed considerably greater measured productivity growth than the economy at large—defined as the way they produced their products for the costs they incurred. As such, a price cap plan that used economy wide inflation would not reasonably track regulated telecom prices driven down

[14] See: Makholm. J.D., *Sources of Total Factor Productivity in the Electric Utility Industry*, Unpublished Ph.D. Dissertation, University of Wisconsin-Madison, 1986.

by the industry's greater relative productivity growth. An *X-factor*, drawing on measured productivity in the telecom industry vis-à-vis the economy, would reflect the telecom industry's greater relative productivity growth. The *X-factors* in telecommunications price cap plans at that time tended to be in the 2-5 percent range.[15]

With respect to the sign of the *X-factor* as part of a price cap index for a defined regulatory period, the following is a reasonable summary:

- A positive *X-factor* indicates expected *lower input cost growth* or *higher productivity growth* for the regulated enterprise, vis-à-vis the economy as a whole, which means that economy-wide inflation indexes would overstate the regulated firm's price inflation during the rate formula period.
- A zero *X-factor* means that the economy-wide inflation index is expected to fairly track the regulated firm's price inflation during the rate formula period.
- A negative *X-factor* means that the economy-wide inflation index is expected to be insufficiently large for the purpose of tracking the regulated firm's price inflation during the rate formula period.

Q17. Can an RPI-X performance-based regulatory plan work without a positive *X-factor*?

A17. Yes, of course it can. The *X-factor* is there only to square the deemed inflation index to the relative input growth and TFP growth of the company in question. Whether the result of that squaring is positive or negative has no effect on the incentives provided by such a regulatory regime.

Q18. How has the OEB conducted performance-based regulation for electric distributors?

A18. The Board described the purpose of implementing its first generation of PBR for Ontario's electric distributors as a means to shift away from historical cost of service regulation to a rate mechanism that "provides the utilities with incentive for behavior

[15] See: FCC 95-132, CC Docket No. 94-1 "In the Matter of Price Cap Performance Review for Local Exchange Carriers," Appendix D.

which most closely resembles that of competitive, cost-minimizing, profit-maximizing companies."[16]

As I understand it, the OEB implemented its first generation PBR plans for electric and gas distributors in the time period between 2000 and 2003, depending on the utility.[17] For electric distributors, the OEB's price cap mechanism utilized an industry-specific inflation measure and a productivity measure of 1.5 percent inclusive of a 0.25 percent stretch factor.[18] The Board's second generation plan for electric distributors in the 2007-2009 period was to be a "transitional mechanism" while the Board determined a "formulaic rate adjustment method that will return distributors to incentive regulation, without creating any major hardships for them or for their ratepayers."[19] It is my understanding that all electric distributors would be subject to a price cap form of rate adjustment using GDP-IPI FDD and a fixed one percent *X-factor* for the three-year term without a stretch factor.[20]

In the third generation PBR plans for electric distributors, I understand that the OEB decided to retain GDP-IPI FDD as the inflation factor and an input price differential of zero.[21] The Board concluded 0.72 as the appropriate TFP growth value for this third generation IR plan, meaning that it found those electric distributors productivity growth higher than the rest of the economy, and grouped distributors using a benchmarking exercise to assign stretch factors.[22] In the next generation, I understand that the Board identified three options for the price cap adjustment mechanism, as a way to address differing capital investment requirements: 4th Generation Incentive Rate-setting ("4th Generation IR"), Custom Incentive Rate-setting ("Custom IR"), and Annual Incentive

---

16 Ontario Energy Board, Decision with Reasons RP-1999-0034.
17 Ontario Energy Board, Decision with Reasons in RP-1999-0034, Decision with Reasons in RP-1999-0017, and RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005.
18 Ontario Energy Board, Decision with Reasons RP-1999-0034, pp. 35-41.
19 Ontario Energy Board, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006., p.23
20 GDP-IPI FDD stands for Gross Domestic Product Input Price Index Final Domestic Demand. Ontario Energy Board, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, pp. 26-33.
21 Ontario Energy Board, Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008, p. 11.
22 Ontario Energy Board, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008, pp. 12, 22.

Rate-setting Index ("Annual IR").[23] The Board adjusted the stretch factor component of the *X-factor* as described in the third generation to evaluate distributors based on total cost benchmarking. I also understand that the OEB adopted a two-factor input price index using 70 % GDP-IPI FDD and 30% change in average weekly earnings ("AWE").[24]

Q19. What is the "stretch factor"?

A19. The AUC, in its 2010-2012 "Rate Regulation Initiative," dealt with the concept of the stretch factor in a comprehensive fashion as part of its new initiative.[25] The AUC made three important determinations regarding the stretch factor that I conclude are reasonable: (1) it does not have a "definitive analytical source" like a TFP growth study, but relies on a regulators' judgment and regulatory precedent; (2) it has no influence by itself on the incentives for regulated companies to reduce costs; and (3) it serves to reflect the "immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime."[26]

Most of the parties in the AUC's proceeding, through the various witnesses, as cited by the AUC in its decision, agreed with these opinions of the AUC. To the extent there was disagreement, it focused mostly on whether there was a strong enough change in incentives under the new AUC's PBR regime to warrant a stretch factor. One witness, Dr. Charles J. Cicchetti, noted that the OEB has used a sliding scale of stretch factors for its third-generation PBR regime applied to its electricity distributors for perceived absolute measures of efficiency (as opposed to productivity growth differences that inform TFP growth studies).[27]

The consensus among a broad cross-section of economists, as reflected by the AUC's discussion in that case, is that the foundation for the stretch factor lies in the *transition* to a PBR regime and away from cost-of-service regulation. When historical productivity

[23] Ontario Energy Board, Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012.

[24] Ontario Energy Board, Report of the Board Rate Setting Parameters and Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors, EB-2010-0379, December 4, 2013.

[25] Decision 2012-237, Rate Regulation Initiative, September 12, 2012, pp. 98-104.

[26] AUC Decision 2012-237, pp. 100, 104. The AUC has confirmed its "transition" perspective in 2016, stating that: "Given that current generation PBR plans include a COS-based capital trackers mechanism, which will be mostly replaced in the next generation PBR plans by the K-bar mechanism, the Commission expects that next generation PBR plans will be largely devoid of any significant COS elements. Therefore, the Commission finds merit in including a stretch factor component in the X factor for the next generation PBR plans for all distribution utilities." (Decision 20414, p. 40).

[27] AUC Decision 2012-237, p. 56 (footnote 276).

growth measurements reflect cost-of-service incentives, any heightened incentives under a PBR regime will only show up prospectively. The stretch factor merely anticipates the result of imposing the price cap regime. Its level represents regulators' judgement regarding the effect the new regime will have on the incentives of the firms subject to it.

As such, I propose a stretch factor of zero for EGD and Union in this proceeding, as the transition in Ontario to price cap regulation for these two companies is long in the past.[28]

Q20. What about the OEB's use of stretch factors for its electricity distributors—which exist even though what you label the "transition" to incentive regulation happened long ago. Does that contradict your conclusions about the stretch factor for EGD or Union?

A20. For Ontario, as the subject was raised before the AUC in 2012, the question is whether the stretch factors applied by the OEB to the province's electricity distributors (of 0.2, 0.4 and 0.6) for the then-third generation PBR plan contradicts my opinion that the foundation for the stretch factor lies in the *transition* from cost-of-service regulation to PBR.

I conclude that it does not, in the unique context of Ontario's electricity distribution industry, because of a focus on relative productivity *levels* among the numerous electricity distributors as opposed to the productivity *growth rates* involved in the justification for applying an *X-factor*. My discussion and recommendations for EGD and Union deal strictly with the latter—while the OEB, for what I conclude are good reasons, has included assessments of the former for its business of regulating the prices of the electricity distributors it oversees.

Considerable effort has been expended in North American price cap plans on matters of "statistical benchmarking" of regulated company productivity, or econometric forecasting of what a proper price index should be for a particular firm as part of a broader rate plan. Indeed, Ontario has unique experience with such issues because of its unusually disaggregated electricity sector—comprising many different distribution companies.

[28] See Ontario Energy Board, Decision with Reasons in RP-1999-0034, Decision with Reasons in RP-1999-0017, and RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005.

Q21. In that respect, does an *RPI-X* price cap model imply anything about the particular production technology of the regulated firm or allow a regulator to judge whether any particular company is "efficient" compared to its peers?

A21. No, except in unusual circumstances (like needing to regulate the price paths of numerous different electricity distributors). The focus of a PBR plan involving an *RPI-X* formula involves productivity *growth*, and not productivity *levels* (as I show in the next section of my testimony). The AUC dealt with the issue at length in the matter of its electricity and gas distribution utilities, quoting me regarding proposals to determine whether a firm is or is not efficient by looking at benchmark data alone:

> So if you get into the business of drawing a productivity frontier and concluding that you know why a company is not on that frontier, that is, it's inefficient, you're making two errors. One, the error is concluding that you've actually measured a frontier, and we contend that, to a certain extent, you're measuring errors. And the second is that we economists have anything to say about whether a firm is or is not productive with the scarcity of data we have before us. Could be that you don't lie on the efficiency frontier because your utility is in a swamp. But if we can't measure swampiness, we have no way of correcting for that.[29]

The AUC observed that in the productivity studies it considered, because the "focus is on rates of change in productivity within an industry, not levels," the unique cost features for particular companies cancel each other out in the process.[30]

Q22. Do you have particular experience with the quality of available objective data that inform utility productivity analyses?

A22. Yes. In addition to my academic work and Dissertation, I have elsewhere written at length for publication about the difficulties of trying to measure efficiency levels of regulated companies under price cap plans with the kind of data that is available.[31] In one 2007 publication, I note the following:

---

29 AUC Decision 2012-237, p. 57.

30 Ibid.

31 See: "Elusive Efficiency and the X-factor in Incentive Regulation: The Törnqvist v. DEA/Malquist Dispute," in Voll, S.P., and King, M.K. (Eds.), *The Line in the Sand: The Shifting Boundaries Between Markets and Regulation in Network Industries*, National Economic Research Associates, White Plains, New York (2007), pp. 95-115; and "Regulating Utility Efficiency "Fast and Slow": the Current Australian Problem, *Natural Gas and Electricity*, Volume 34, No. 5 (October 2017), pp. 28-32

> Empirical data from academic TFP studies show that even the highest quality data (from the U.S. Uniform System of Accounts) produces TFP index growth rates for individual companies that are highly sensitive to vagaries and judgments on how company data is reported to government agencies. Individual data points for specific companies and years in industry-wide TFP analysis are notoriously unstable, even in the best of circumstances.[32]

None of this instability materially undercuts TFP growth studies that encompass many years of data (when the errors cancel each other out)—as in the TFP studies that I presented in Alberta and present in this proceeding.

Q23. Are Ontario's gas distributors in a period of "transition" regarding the move to PBR, as you describe above?

A23. No. It is my understanding that the OEB has pursued PBR regulation for all of its utilities since 1999. Thus, with the proposal in this application, both companies enter into their fourth generation IR plan. I understand that EGD's first PBR plan in the early 2000s was applicable only to the operations and maintenance portion of its costs and was termed "targeted PBR."[33] For Union's first generation plan, the Board identified GDPPI as the inflation factor and 2.5 percent as the applicable *X-factor*.[34] I understand that both utilities resumed filing cost-of-service applications upon expiration of their initial PBR plans.[35]

I also understand that for the 2008-2012 time frame, the Board approved settlement agreements for incentive rate regulation of EGD and Union, with EGD using a "revenue per customer" framework and Union using a price-cap approach. The parties in the EGD settlement could not agree on an *X-factor*, so instead used an inflation coefficient with which to adjust rates.[36] Similarly for the 2014-2018 period, Union came to a settlement agreement with stakeholders and the parties agreed to an inflation coefficient rather than

32 Makholm, "Elusive Efficiency" (2007), p. 105.
33 Ontario Energy Board, RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005, p. 14.
34 Decision with Reasons, RP-1999-0017, pp. 79, 90.
35 Ontario Energy Board, RP-2004-0213, Natural Gas Regulation in Ontario: A Renewed Policy Framework, March 30, 2005, p. 14.
36 Ontario Energy Board, Decision EB-2007-0615, Schedule A, Enbridge Gas Distribution Revised Settlement Agreement, pp. 10-13; Ontario Energy Board, Decision EB-2007-0606, Schedule A, Union Gas Settlement Agreement, pp. 10-12.

an explicit *X-factor*.[37] EGD utilized the Custom IR option as described for electricity distributors above for its rate adjustment mechanism over the 2014-2019 timeframe.[38]

For Ontario's gas distributors—in contrast to the numerous electric distributors which face altogether different regulatory challenges given the makeup of the industry in the province—I do not find it reasonable to impose a stretch factor for a PBR regime that will be nearly 20 years old when the next price cap framework period begins.

Q24. What about the merger between EGD and Union? Isn't that a "transition" that conceptually could lead to the consideration of a stretch factor?

A24. No. I conclude that that would be "stretching" the meaning of the stretch factor beyond its generally accepted definition. It would also, in my opinion, confuse cause and effect. Let me explain.

Changing the form of regulatory control, away from traditional cost of service regulation to performance-based regulation, applies to regulated utility prices whether the enterprises subject to the new regime remain independent or merge. The change of regime causes the deviation from what would otherwise be straightforward ($I - X$), to include a stretch factor. But the new, performance-based regime is specifically designed to incentivize efficiency, whether lowering costs or enhancing output, so as to increase earnings for the firms involved. There are myriad and inherently unpredictable ways for companies to respond to such a new regime. One of those ways can be to investigate the merger of long-separate utility enterprises, which, if it saves money in the service of consumers, is a good thing. Consumers will share in those saving at future rebasing (and along the way with an earnings sharing scheme, if there is one).

Of course, the considerations for merging utility operations take place in a complex context, and it would be a mistake to draw a straight line between incentive regulation and any particular utility merger. The extent to which anything associated with the change in regulatory regimes incentivized such a merger, it is one of the salutary effects of the new regime. It is not the cause of heightened expectations that drive the stretch factor. It would be a misuse of the stretch factor, as that term is commonly understood, to

[37] Ontario Energy Board, Decision EB-2013-0202, October 7, 2013.
[38] Ontario Energy Board, Decision EB-2012-0459, July 17, 2014.

base it on any particular money-saving or efficiency-enhancing move by the utilities subject to the performance-based regime.

Q25. Is your opinion about measuring productivity growth as opposed to levels a problem for the OEB as it relates to its regulated *electricity distributors*?

A25. No. The issues facing the OEB in the regulation of its wide array of electricity distributors are unique.

My own published criticisms of stochastic frontier analyses and statistical benchmarking of productivity levels do not apply to the challenges of regulating many distributors—most of which are small, municipally-owned enterprises. Indeed, the literature on using statistical techniques to gauge efficiency levels across different operations points to the usefulness of using such methods for gauging efficiency levels "in the public sector, as contrasted with the private sector."[39] Most of Ontario's electricity distribution utilities are in the public sector. As such, I have no criticism of the use of such techniques to gauge the efficiency of the electricity firms that the OEB oversees.

The stretch factors that the OEB used for its third or fourth generation PBR plans for its electric distribution sector, which I understand embody such benchmarking, are different than the type of stretch factors that I and the AUC discussed as part of its 2012 Rate Regulation Initiative decision.[40] The label ("stretch") is the same, but the foundation and function of those factors is different.

III. Economic Theory behind the *X-factor*

Q26. What is this part of your testimony about?

A26. This section serves to provide the theory-oriented reader with the mathematical derivation of the *X-factor.* I explain how the *X-factor* fits into the theory of incentive

[39] Charnes, A., Cooper, W.W., and Rhodes, E., Measuring the Efficiency of Decision Making Units," *European Journal of Operational Research*, Vol. 2 (1978), pp. 429-444 (quoted passage is from p. 433); and Sena, V., "The Frontier Approach to the Measurement of Productivity and Technical Efficiency," *Economic Issues*, Vol. 8, Part 2 (2003), pp. 71-97.

[40] Ontario Energy Board, Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008 and Ontario Energy Board, Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012.

regulation. I present this theory simply to emphasize that, if an economy wide inflation index is the choice for the inflation factor in *RPI-X* regulation, the *X-factor* has two identifiable components: (1) an input price differential, and (2) a productivity *growth* differential, both compared to the economy as a whole. Because the OEB has accepted the GDP-IPI FDD for the *RPI* part of the formula for Union and EGD in the past, my empirical study focusses on those two elements of the *X-factor*. Having set out the mathematical derivation of the *X-factor* in this section, the next section explains the empirical results of this theory.

Q27. Please proceed.

A27. The annual PBR price cap adjustment formula is designed to emulate competitive markets so that if a company exceeds industry average productivity growth, its earnings will increase, and if it falls short of industry average productivity growth, its earnings will decline. Assume the price cap plan begins with appropriate prices so that the value of total inputs (including a normal return on capital) equals the value of total output for the company as well as the industry. For the industry, we can write this relationship as follows:

$$\sum_{i=1}^{N} p_i Q_i = \sum_{j=1}^{M} w_j \ R_j \ ,$$

where the industry has N outputs ($Q_i, i = 1,\ldots,N$) and M inputs ($R_j, j = 1,\ldots,M$) and where p_i and w_j denote output and input prices, respectively. We want to calculate a productivity target for a company based on industry average productivity growth.

Focusing on rates of changes (that is, differentiating this identity with respect to time) yields the following relationship:

$$\sum_{i=1}^{N} \dot{p}_i Q_i + \sum_{i=1}^{N} p_i \dot{Q}_i = \sum_{j=1}^{M} \dot{w}_j R_j + \sum_{j=1}^{M} w_j \dot{R}_j \ ,$$

where a dot ($\cdot$) indicates a derivative with respect to time. Dividing both sides of the equation by the value of output ($Rev = \sum_i p_i Q_i$ or $C = \sum_j w_j R_j$), we obtain this:

$$\sum \dot{p}_i\left(\frac{Q_i}{REV}\right)+\sum \dot{Q}_i\left(\frac{p_i}{REV}\right)=\sum \dot{w}_j\left(\frac{R_j}{C}\right)+\sum \dot{R}_j\left(\frac{w_j}{C}\right),$$

where *REV* and *C* denote revenue and cost. If rev_i denotes the revenue share of output *i* and c_j denotes the cost share of input *j*, then

$$\sum_i rev_i dp_i = \sum_j c_j dw_j - \left[\sum_i rev_i dQ_i - \sum_j c_j dR_j\right],$$

where *d* denotes a *percentage* growth rate: $dp_i = \dot{p}_i / p_i$. The first term in the equation just above is the revenue-weighted average of the rates of growth of output prices, and the second is the cost-weighted average of the rates of growth of input prices. The term in brackets is the difference between weighted averages of the rates of growth of outputs and inputs. It thus is a measure of the change in TFP. Rewriting the equation to simplify things, we get the following:

$$dp = dw - dTFP.$$

The theory underlying the annual adjustment formula implies that the rate of growth of a revenue-weighted output price index is equal to the rate of growth of an expenditure-weighted input price index plus the change in TFP. This equation demonstrates that TFP is the appropriate foundation for a productivity target in the price cap plan. If the plan begins with revenues which just match costs—and if a company attains the same productivity growth as the industry does (measured in terms of TFP), then the company's revenues will continue to match its costs.

Applying this rule, we write the following:

$$dp^* = dw - dTFP$$

where dp^* represents the annual percentage change in industry output prices and dw represents the annual percentage change in input prices. To raise or lower industry output prices in order to track exogenous changes in cost, we write

(1) $$dp = dw - dTFP + Z^*$$

where dp represents the annual percentage change in industry output prices adjusted for exogenous cost changes and Z^* represents the unit change in costs due to external circumstances.[41] Thus, to keep the revenues of the industry equal to its costs, despite changes in input prices, the price cap formula should (i) increase industry output prices at the same rate as its input prices less the target change in productivity growth, and (ii) directly pass through exogenous cost changes.

Equation (1) just above sets the allowed price change as input price changes less TFP growth adjusted for exogenous cost pass-through costs. If the economy-wide inflation rate were taken as a measure of the industry's input price growth and X was its TFP growth target, equation (2) would indeed be the basis for the ideal price adjustment formula. However, there are two potential problems with such an interpretation:

1. Broad inflation measures capture economy-wide *output* price growth, not the industry's input price growth. So even if the industry is a microcosm of the whole economy, a measure that captures economy-wide output price growth would not be an appropriate measure of its input price growth.[42]

2. X is a target TFP growth rate relative to the economy as a whole (or relative to the TFP growth already embodied in economy-wide output price growth). The change in TFP in equation (2) is the absolute TFP growth for the industry. Again, unless economy-wide TFP growth is zero, X is not equal to $dTFP$.

To get from the equation just above the price adjustment formula, we must compare the productivity growth of the industry with the productivity growth of the whole economy. It is difficult to measure input price growth objectively. No agency in Canada (or the United States) maintains an objective index of input prices, industry by industry. A productivity adjustment based on company-provided calculations of changes in their own input price index could be controversial and would not necessarily be based on information outside the company's control. However, by comparing productivity growth of the industry with that of the whole economy, one avoids the difficulty of measuring input price growth.

---

41 Note that Z^* can be positive or negative.

42 Recall that input price growth differs from output price growth by the growth in TFP. Only if national productivity growth were zero could GDP-PI be a good measure of national input price growth.

For the economy as a whole, the relationship among input prices, output prices, productivity, and exogenous cost changes can be derived in the same manner as it was derived in equation (2) above

$$(2) \qquad dp^N = dw^N - dTFP^N + Z^{*N}$$

where dp^N is the annual percentage change in an economy-wide index of output prices; dw^N is the annual percentage change in an economy-wide index of input prices $dTFP^N$ is the annual change in the economy-wide total factor productivity and Z^{*N} represents the change in economy-wide output prices caused by the exogenous factors included in equation (1). Subtracting equation (2) from equation (1) gives

$$dp - dp^N = \left[dw - dw^N\right] - \left[dTFP - dTFP^N\right] + \left[Z^* - Z^{*N}\right] \ ,$$

or

$$(3) \qquad dp = dp^N - \left[dTFP - dTFP^N + dw^N - dw\right] + \left[Z^* - Z^{*N}\right] \ ,$$

which simplifies to

$$(4) \qquad dp = dp^N - X + Z \,.$$

Where the productivity factor (*X*) equals the following:

$$X = (dTFP - dTFP^N) - (dw - dw^N)$$

This equation just above shows that *X* arises if the growth in productivity for the industry in question is *different* than the economy's (the first time), or input cost inflation for the utility is *different* from that for the economy's businesses generally (the second term).

Thus, if the industry achieves a productivity target of *X* and experiences exogenous inflationary cost changes given by *Z*, then the price change that keeps earnings constant is given by equation (4). This price change is given by:

1. the rate of inflation of economy-wide output prices dp^N,
2. less a fixed productivity offset, *X*, which measures the difference in TFP growth, and the difference in input price growth, for the industry and the economy,

3. plus exogenous unit cost changes.

Using the formula (4) to limit price increases has the property that earnings remain the same if a company's achieved productivity differential just meets the historical target *X*. If a company exceeds its productivity target, its earnings will rise; if it falls short of its productivity target, its earnings will fall. This system of rewards and punishments sets up the same incentives that an unregulated company would face in a competitive market, where failure to match industry-average productivity growth results in lower earnings and exceeding industry average productivity growth leads to increased earnings.

IV. Empirical Methods behind the *X-factor*

Q28. What is this section of your testimony about?

A28. I briefly describe my methods for computing TFP growth for the regulated distribution component of local utility operations. Those methods include isolating the distribution component of such utilities and then measuring the various inputs and outputs that result in TFP growth measures. For a longer and more comprehensive explanation of my methodology, please see my report in Alberta Proceeding 566, attached as Exhibit JDM-2. I provide a list of all documents I relied upon as Exhibit JDM-5.

Q29. Please briefly explain your TFP methodology.

A29. My TFP studies for EGD, Union and the distribution industry all utilize the Tornqvist/Theil index methodology to construct output, input and TFP indexes using the various components of outputs and inputs. For my study of the distribution industry I use a population of 65 US electric and combination electric and gas distributors over the time period 1973-2016.[43] I create individual TFP indexes and growth rates for each company and year and then take a weighted average of these growth rates to calculate average TFP

[43] The productivity of electric and gas distribution companies is similar. For one, both industries are highly capital intensive. Further, I examined the difference between TFP growth for both industries using data from Statistics Canada and found no statistically significant difference between the two using both value-added and gross output as the output measure. The data used for this test was taken from Statistics Canada: Table 383-0032. The data series on Multifactor Productivity for the electric and natural gas industry were terminated in 2010.

growth over the time period.[44] For EGD and Union, I use their own company-specific data to calculate average TFP growth for each company. The EGD study spans the years 1993-2016, while the Union study covers the time period 2001-2016.

Q30. How did you measure output in your calculation of TFP growth?

A30. For the distribution industry I use sales volume as the output quantity. I create an output index by combining sales volume for several different customer categories as follows: Residential, Commercial, Industrial and Public. EGD provided sales volume (10^6 m^3) data for roughly the same customer categories. However, I measure sales volume (10^6 m^3) for Union using two customer categories, a General Service category and a Contract category. Union's output quantity measure does not include any output related to its ex-franchise transmission business.

Q31. How did you deal with EGDs and Union's unregulated activities in storage and Union's ex-franchise transmission business when calculating the input costs for labor and materials?

A31. For EGD, I gathered data from its representatives as well as the company's rate filings. It is my understanding that EGD spun off a portion of its unregulated business in 1999. As such, prior to 1999, I use data on wages and salaries and operations and maintenance expense that the company reported were only associated with the distribution business. After 1999, the company ceased reporting its operations in its rate filings in this way. Therefore, I use company total values EGD, as reported in its historic rate filings, for the remaining years.

Further, it was necessary to deal with Union's upstream transmission assets. For O&M and labor costs, I average the historic transmission allocation factors from Union's 2007 and 2013 cost study to estimate the proportion of costs associated with transmission in each year of my study.[45] I then exclude these transmission costs, isolating for only distribution O&M and labor.

---

[44] I use each company's total mWh for each year as the weight.

[45] These cost studies can be found in cases EB-2005-0520 and EB-2011-0210, respectively. For labor, this method allocates about 10% of Union's costs to transmission. For O&M expenses about 9% of Union's costs are allocated to transmission.

Q32. How did you deal with these aspects of EGD's and Union's business in your measurement of each company's capital quantity?

A32. I count only EGD's regulated storage plant and distribution plant as distribution capital. I do the same for Union, excluding any aspect of Union's capital associated with its transmission business. Union provided data on its total capital additions and retirements, making it necessary to adjust these data to exclude its transmission lines and other unregulated assets. I did this by first taking out any additions and retirements associated with its transmission business.[46] I then allocate a pro rata share of the remaining capital to distribution using the proportion of distribution plant to total plant (excluding transmission).

V. TFP Results for EGD, Union and the US Energy Distribution Industry

Q33. What are your TFP growth results for EGD?

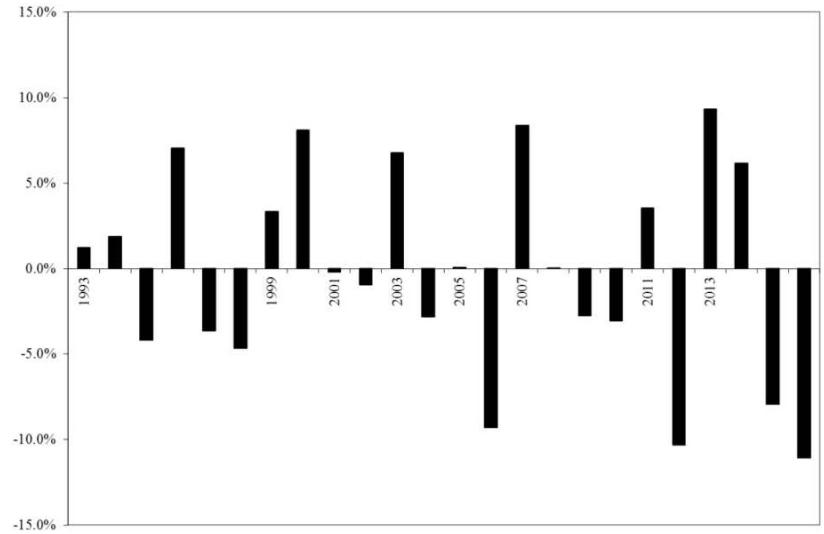
A33. I find that EGD's average TFP growth over the time period 1993-2016 to be **-0.21 percent**. Comparing this to the Canadian economy wide productivity growth over this same time period results in a relative TFP growth compared to the Canadian economy of **-0.50 percent**.[47] **Figure 1** below summarizes EGD's yearly TFP growth (please see Exhibit JDM-3 for further summary tables and results from each of my three TFP studies).

---

46 Union's representatives informed me that none of its retirements over the relevant time period were due to the Dawn to Parkway transmission line.

47 Note that Statistics Canada has not yet published a measure of TFP growth for the Canadian economy for 2016. As such, for this year I use the average economy-wide TFP growth for the time period 1993-2015.

Figure 1. EGD TFP growth, 1993-2016

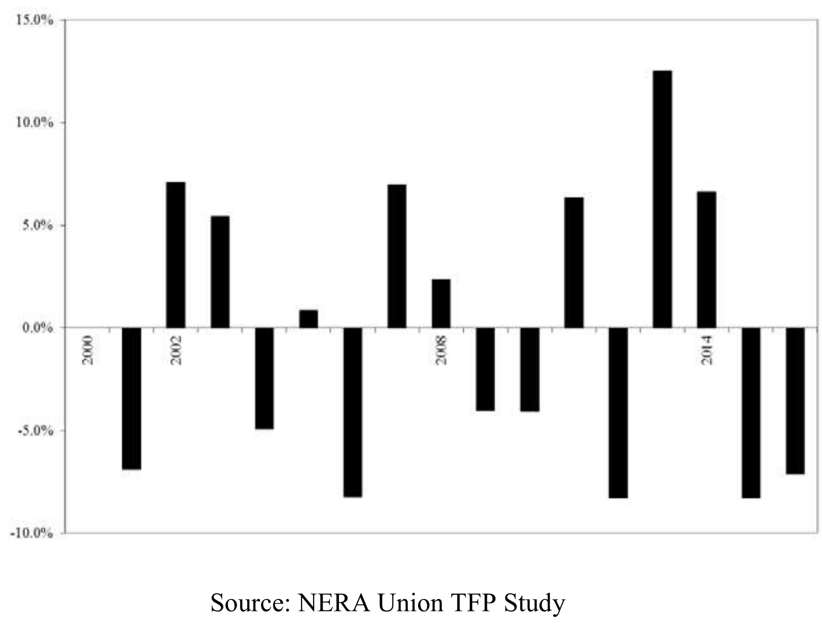


Source: NERA EGD TFP Study

Q34. What are your TFP growth results for Union?

A34. For Union, TFP growth over the time period 2001-2016 averaged **-0.23 percent**, which produces a relative TFP growth factor vis-à-vis the Canadian economy of **-0.06 percent**.[48] **Figure 2** below summarizes Union's yearly TFP growth.

Figure 2. Union TFP growth, 2001-2016



Source: NERA Union TFP Study

48 For Union, economy-wide TFP growth in 2016 is equal to TFP growth over the time period 2001-2015.

Q35. What about the US regulated energy distribution industry?

A35. I calculate a TFP growth of **0.54 percent** for my population of 65 US electric distribution (and combination electricity and gas) companies over the time period 1973-2016. Comparing this to Canadian economy-wide TFP growth produces an *X-factor* of **0.35 percent**.[49] **Figure 3** below illustrates TFP growth over this time period.

Q36. Do you have any observation on the usefulness of that US data to straight gas distribution companies in Canada?

A36. Yes. That issue was heard at length before the AUC when it accepted my study as the basis for its first generation *X-factor*.[50] Considering the unique quality of the FERC Form 1 data involved, the lack of such data in Canada, the commonality of the distribution tasks for both electricity and gas distributors, and the commonality of the regulatory institutions in Canada and the United States, the AUC accepted the use of that data set over other sources of data for both electricity and gas distributors in the province. It was a decision supported by various other parties in that proceeding who stressed the quality and transparency of that data set for the purpose of close scrutiny. Comparing the TFP growth from that US data to Canadian economy TFP growth is proper, as I discussed previously regarding the fundamental purpose of the *X-factor* (to square Canadian inflation indexes to experienced industry TFP growth).

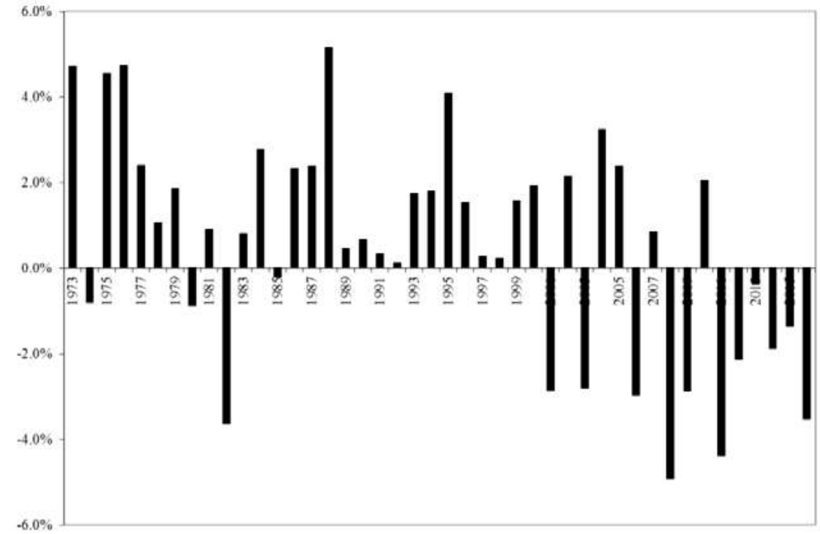
Q37. Do you do a study of input price differences for your analysis of the US regulated energy distribution industry?

A37. Yes. Doing a standard difference in means test, I show that it is not possible to conclude that the data on US distributors input prices and economy wide input prices in the United States come from different series. Exhibit JDM-4 collects my results from this case as well as those I conducted for the AUC proceeding in 2010, for Central Maine Power Company in Maine PUC Docket No. 99-666 and for Utilicorp Networks Canada in Alberta in 2000. The results of my comparison of the input price series' have been consistent over time.

---

49 I use the average TFP growth for the time period 1973-2015 to estimate TFP growth in 2016 for the economy.
50 AUC, Decision 2012-237, September 12, 2012, pp.67-72.

Figure 3. Industry TFP growth, 1973-2016



Source: NERA Industry TFP Study

Q38. Do you have any observations about Figures 1, 2 and 3?

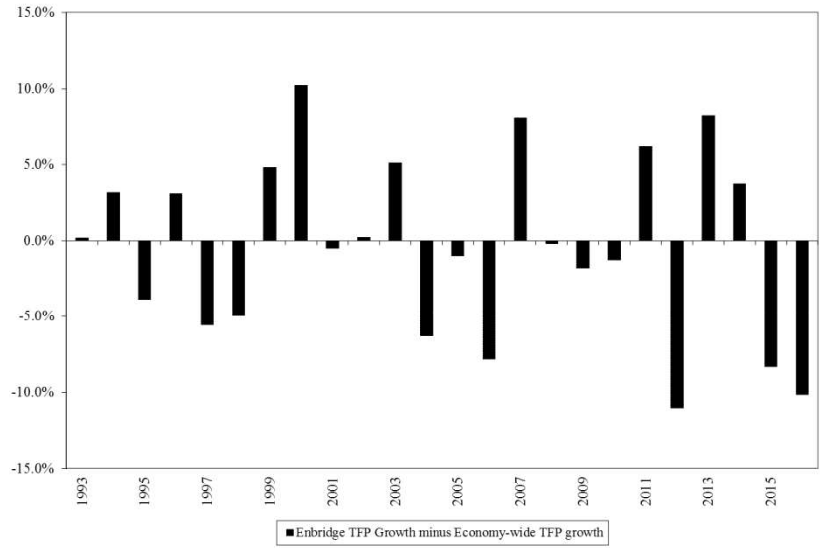
A38. Yes. Those figures are where the rubber meets the road, so to speak, regarding a TFP growth study. They conform to a similar bar chart that I first presented for the years 1971-1980 in my 1986 Dissertation.[51] My TFP growth computations for EGD and Union show no reasonably discernable trend—either by themselves or in comparison with the Canadian economy wide TFP growth, as shown in **Figures 4 and 5**, below. Visually examining such results (there is nothing technical in such a visual examination) shows only dispersion around zero—no size or trend to the TFP growth results.

The same is not true of the longer time series results for the US regulated energy distribution companies. There is a definitive trend there that is impossible to overlook. The past six years show negative TFP growth (as do 8 of the last 10 years). Indeed, only 5 of the past 15 years have shown positive TFP growth, whereas 15 of the 15 years before showed positive TFP growth. There is a lot going on with these data that points to a downward trend in measured TFP growth for that population of companies—either by themselves or in relation to the Canadian economy as a whole (shown in **Figure 6**).

---

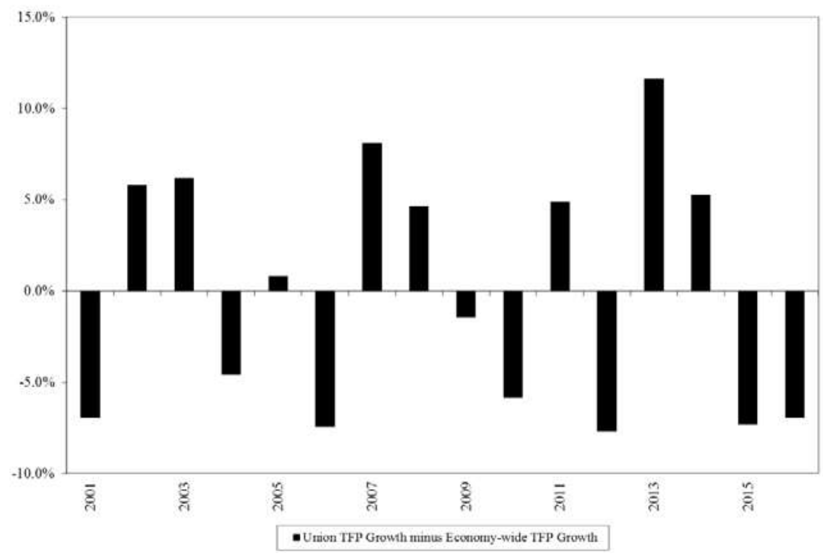
[51] *Sources of Total Factor Productivity in the Electric Utility Industry*, Unpublished Ph.D. Dissertation, University of Wisconsin-Madison, 1986, p. 79.

Figure 4. EGD TFP Growth minus Canadian economy TFP growth, 1993-2016



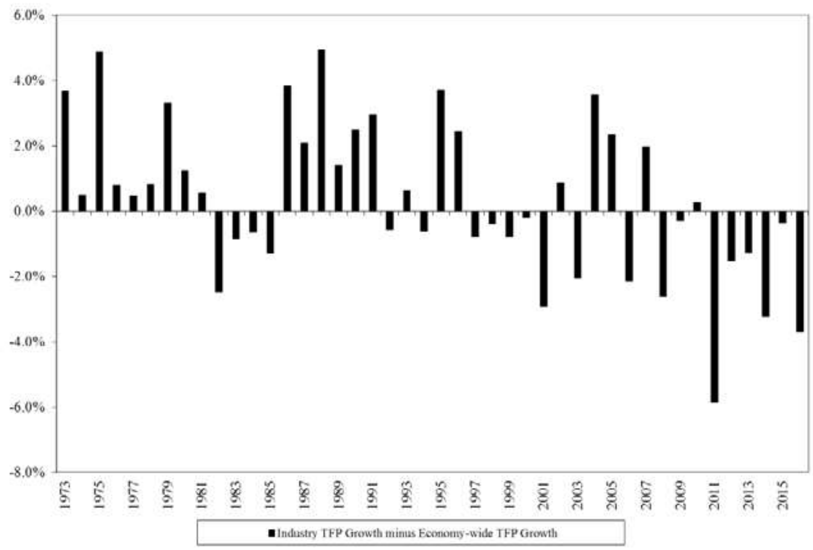
Source: NERA EGD TFP Study and Statistics Canada

Figure 5. Union TFP Growth minus Canadian economy TFP growth, 2001-2016



Source: NERA Union TFP Study and Statistics Canada

Figure 6. Industry TFP Growth minus Canadian economy TFP growth, 1973-2016



Source: NERA Industry TFP Study and Statistics Canada

Q39. Could there be some "structural break" or other economic explanation for such an apparent visual trend?

A39. That is a complicated question. Generally, I recommend against (as I did in the AUC proceeding) making conclusions about economic "structural breaks" based only on the visual examination of data. Indeed, the question of the time period was heavily discussed in that proceeding (including in the Decision), and the AUC supported my conclusion, stating: "NERA's approach of using the longest time period available allows a smoothing out of the effects of various in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle."[52]

I do not recommend splitting the period of measurement. But the analysis since 2009, when I last performed such TFP computations, shows a definitive trend. Given the long-term changes in the energy utility industry since the early 1970s, including the unbundling of distribution services and competition in energy supply, there may well be trends behind such TFP results, for the industry as a whole or for particular objective regions of the United States that disinterested researchers have not yet discovered. I do not hold the opinion that electricity restructuring, as such, necessarily led to a change in

[52] Decision 2012-237, p. 66.

the TFP growth exhibited by the distribution portion of the industry. I also do not have an objective explanation for that apparent trend or knowledge of any scholarly analysis that would do so.[53]

But that trend does inform my conclusions in this case—which is to recommend a simple average TFP growth estimate as applicable to EGD and Union in this case would be unwise. The trend, in a type of analysis that has proven highly credible and has been relied upon in the past, is too apparent for that. Whereas any split in the data would produce a negative TFP growth figure, I determine that it is better to conclude that I cannot definitively reason that there is a prospect for any reliable positive TFP growth for that group of firms for the rebasing period applicable to EGD and Union.

VI. Conclusions on the *X-factor* for EGD and Union

Q40. What do you conclude from your TFP analysis regarding an *X-factor* for the upcoming rebasing period for EGD and Union?

A40. Based on my TFP growth study for the large group of US distribution companies, supported by my comparable analysis of TFP growth for both EGD and Union, I do not recommend an *X-factor* for EGD or Union for their upcoming 10-year rebasing periods. I explain in my testimony that the theory underlying *RPI-X* regulation gives only two reasons for having an *X-factor* in the inflation formula for regulated prices: (1) input price growth differences, or (2) TFP growth differences between the industry and the economy as a whole from which the inflation index comes. For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set). For TFP growth, my analysis of the growth trends in the industry over the period 1973 to 2016, either for the US data set or the data for EGD or Union, does not support an *X-factor* either. Thus, I conclude that the Canadian output

[53] There are scholarly reviews of the past decades of the US electricity industry that I respect, and to some extent they point to possible reasons for poor performance over the past 20 years ("By the mid-2000s the relationship between average and margin cost has largely reversed, and many states expressed a great deal of regret about the decision to restructure"). But those reviews are not sufficient means by which to definitively to change the elements of such a TFP study as I have presented here. See: "The U.S. Electricity Industry after 20 Years of Restructuring," Severin Borenstein and James Bushnell, Energy Institute at Haas Working Paper (May 2015), p. 26.

inflationary index proposed in this case and accepted by the OEB for the companies in the past—GDP-IPI FDD—fairly represents a competitive-like constraint on the output prices for EGD and Union that the *RPI-X* form of regulation calls for.

Q41. What do you conclude regarding any possible "stretch factor?"

A41. I also do not recommend the imposition of a stretch factor. It is fair to say that the consensus, among economists performing productivity studies in PBR plans in North America, is that the purpose of a stretch factor is to reflect the expected productivity growth due to the heightened incentives that accompany a *transition* from a cost-of-service regime to PBR. The OEB has pursued PBR regulation for its utilities consistently since 1999. For *gas distribution* in the province there is nothing, in my opinion, in the generally-accepted foundation for price cap regulation to justify the imposition of a stretch factor for a PBR regime that will turn 20 years old at the start of the upcoming price cap periods.

This is as opposed to *electricity distribution*, which faces distinct industrial, ownership and regulatory challenges that call for different types of regulatory effort on the part of the OEB. Nothing in my testimony is meant as criticism of the measurement of productivity *levels* (as opposed to *growth*), for Ontario's electricity distribution sector or the use of statistical or econometric targets, including their own "stretch" factors, for the many companies, both investor- and municipally-owned, in that sector. Indeed, as discussed in my testimony, the productivity literature provides support for the use of such methods in the presence of such a large number of similarly-situated public enterprises.

Q42. Please explain again why you consider it a misuse of a stretch factor to predicate it on the merger between EGD and Union?

A42. As I said before, it is reasonable to believe that a new, performance-based, regulatory regime will incent different types of utility behavior. As such, there is some merit to concluding that measured productivity over historical periods will not reflect the relative TFP growth capability of a regulated enterprise if it is subject to the new regime. That is the commonly-understood basis for the stretch factor, and such a reason goes away after a number of generations of the new regime.

The stretch factor is not there to anticipate and/or appropriate the gains from any particular efficiency move that utilities may pursue—from more efficient meter reading, to re-organized scheduling and reporting methods, to changes in acquisition procedures, to anything that utilities may re-think and do differently because of the new regime, including merging adjacent service territories. If such actions drive earnings upward and cost downward during a rebasing period, consumers will be the ultimate beneficiaries. But if the stretch factor is repurposed to be a way of trying to take those efficiencies before they happen, then it will undermine the basis for incentive regulation.

Q43. What, in your analysis of the input price differential, lends support for your recommendation of a zero *X-factor* for EGD and Union's next incentive rate setting period?

A43. Using the largest possible TFP data set for North American energy distribution companies, I have consistently never found a statistically significant difference in input prices for the energy distribution industry versus the economy as a whole. I confirm that same result here. That is, I have always found that there is no reason to conclude that the input price inflation faced by the energy utility distribution sector differs from the input price inflation facing the rest of the economy.

Q44. What in your TFP growth analysis for US distribution companies lends support for your recommendation of a zero *X-factor*?

A44. My recommendation rests on the rapidity of the falling measured TFP growth for that group of distribution utilities, since the last time I performed that analysis in 2010—supported by my analysis of consistent EGD and Union data.

For the TFP growth study in that case, I computed average annual TFP growth for the entire population of US distribution companies to be 0.96 percent over the 37 years from 1973 to 2009. Lengthening the period by seven years to 2016, with no methodological changes, reduced the average TFP growth of 0.54 percent—or a growth rate relative to the Canadian economy of 0.35 percent—a precipitous drop that is evident in **Figure 3**. Because of that decline, where the past six years show negative TFP growth (as do 8 of the last 10 years), I cannot conclude that there is a prospect for any reliable positive TFP growth for that group in the next 10 years—either by themselves or in relation to the Canadian economy as a whole. Given the trend evident in such a rapidly-falling TFP growth measurement, and also the unmistakable visual trend in the annual TFP growth measures shown in **Figure 3**, I think that there is no reasonable basis upon which to recommend an *X-factor* based on the difference between distribution TFP growth and economy wide TFP growth, grounded in that data set and the transparent computations applied to it.

My analogous computations for EGD and Union similarly show no TFP growth for the periods over which the companies supplied me with consistent data. The EGD data shows an average TFP growth of -0.21 (for 1993-2016), compared to average TFP growth of -0.23 (for 2001-2016) for Union. Compared to the Canadian economy TFP growth, those numbers remain negative: -0.50 for EGD and -0.06 for Union.

Q45. Does this conclude your testimony at this time?

A45. Yes.

OEB Rule 13A

FORM A

Proceeding: EB-2017-0307

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Jeff D. Makholm. I live at 40 Mount Vernon Street, Boston, in the state of Massachusetts.

2. I have been engaged by or on behalf of Enbridge Gas Distribution and Union Gas Limited to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: November 23, 2017

Jeff D. Makholm

JEFF D. MAKHOLM
Senior Vice President/Managing Director

National Economic Research Associates, Inc.
200 Clarendon Street
Boston, Massachusetts 02116
(617) 927-4540

Dr. Makholm specializes on the issues of valuation, damages and proper regulated pricing in hard commodity markets and energy industries. With respect to hard commodities (including mining, processing, transport and sale in international markets), he assess production and lease contracts, economic transport costs, and values in local and international markets according to the accepted economic principles of vertical relationships in complex, multi-stage hard commodity production markets. Another of Dr. Makholm's areal of specialty involves the privatization, regulation and deregulation of energy and transportation industries—those that operate networks (such as oil and gas pipelines, electricity transmission and gas distribution systems, telecommunications and water utility systems, railroads and toll roads) and those operating infrastructure business at specific sites, such as oil refineries, electricity generation plants, gas treatment plants, commodity mines, sewage treatment plants and airports. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory and contracting practices. On such issues among others, Dr. Makholm has prepared expert testimony, reports and statements, and has appeared as an expert witness in court proceedings, arbitral tribunals, regulatory bodies and Parliamentary panels on more than 250 occasions.

Dr. Makholm's clients in North America include privately held oil, gas and utility corporations, public corporations and government agencies. He has represented dozens of gas and electric distribution utilities, as well as both intrastate and interstate oil and gas pipeline companies and oil, gas and electricity producers. Dr. Makholm has also worked with many leading law firms engaged in issues pertaining to the local and interstate regulation of energy utilities.

Internationally, Dr. Makholm has directed an extensive number of projects in the mining, utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), oil pipeline transport financing and regulation (Russia), and valuating in hard commodity mining (Russia, Peru, Colombia, New Zealand). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published many papers in various peer-reviewed and editor-reviewed publications (*Economics of Energy & Environmental Policy, Public Utilities Fortnightly*, *Natural Gas and Electricity*, *The Electricity Journal*, *The Energy Law Journal, and Competition and Regulation in Network Industries*)—involving a wide range of subjects pertaining to his research work. He is a frequent speaker in the U.S., Europe and elsewhere at conferences and seminars addressing market, pricing and regulatory issues for the energy, commodity and transportation sectors. His latest book, *The Political Economy of Pipelines: A Century of Comparative Institutional Development*, was published by the University of Chicago Press in 2012.

EDUCATION

UNIVERSITY OF WISCONSIN-MADISON,
MADISON, WISCONSIN
Ph.D., Economics, 1986
Dissertation: Sources of Total Factor Productivity in the Electric Utility Industry
M.A., Economics, 1985

BROWN UNIVERSITY
PROVIDENCE, RHODE ISLAND
Graduate Study, 1980-1981

UNIVERSITY OF WISCONSIN-MILWAUKEE
MILWAUKEE, WISCONSIN
M.A., Economics, 1980
B.A., Economics, 1978

EMPLOYMENT

1996-present	Senior Vice President/Managing Director. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1986-1996	Vice President/Senior Consultant. National Economic Research Associates, Inc., (NERA) Boston, Massachusetts.
1987-1989	Adjunct Professor. College of Business Administration, Northeastern University, Boston, Massachusetts
1984-1986	Consulting Economist. National Economic Research Associates, Inc., (NERA) Madison, Wisconsin.
1983-1984	Consulting Economist. Madison Consulting Group, Madison, Wisconsin.
1981-1983	Staff Economist. Associated Utility Services, Inc., Moorestown, New Jersey.

RECENT TESTIMONY (SINCE 2000)

Before the International Court of Arbitration, Case No. 1976/CA/ASM, Drummond Coal Mining LLC (DCM), et al, Respondents/Counterclaimants, vs. Ferrocarriles del Norte de Colombia S.A.., Claimant/Counter-Respondent, Expert Report, 20 June 2017. Subject: Market values of mining export losses due to imposed constraints on capacity.

Before the National Energy Board, Expert Report and Reply Testimony on behalf of Plains Midstream Canada ULC. Hearing Order RH-002-2016, May 15, 2017. Subject: Proper cost allocation for liquid fuel pipeline tariffs.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of Plains Midstream Canada ULC. Hearing Order RH-002-2016, November 2016. Subject: Proper cost allocation for liquid fuel pipeline tariffs.

Before the Supreme Court of the State of New York, County of New York, Expert Testimony on behalf of plaintiffs in: S.A. de Obras y Servicios, Copasa and Cointer Chile, S.S. and Azvi Chile, S.A. Agencia en Chile, Plaintiffs v. The Bank of Nova Scotia and Scotiabank Capital, IAS Part 49, Index No. 651649/2013 and 651555/2012. August 10, 2016, Subject: Value of P3 toll road enterprise in Chile.

Before the National Energy Board, Expert Testimony on behalf of FortisBC Energy Inc., Hearing Order Number GH-003-2015, March, 2016. Subject: Tolling for pipeline extensions

Before the Superior Court of the State of Delaware in and for New Castle County, Expert Report on behalf of Deere & Company, in C.A. No. N13C-07-330 MMJ CCLD. December 2, 2015. Subject: Value of Power Purchase Agreements in the wind power industry.

Before the Superior Court of the State of California for the County of Los Angeles in the Matter of GAF Materials Corporation v. Paramount Petroleum Corporation, Opinion given September 3, 2015. Case No: BC 481673. Subject: Oil price indexing to set asphalt prices.

Before the United States District Court for the Northern District of Oklahoma, Expert Report on behalf of SFF-TIR, LLC, the Stuart Family Foundation (et al), Case No. 14-CV-369-TCK-FHM, June 30, 2015. Subject: Fair value of shares in a pipeline industry services firm.

Before the International Chamber of Commerce Expert Report on behalf of STP Energy Pte Ltd. Subject: Valuation of offshore oil and gas exploration permit, April 29, 2015.

Before the Régie de l'énergie, Written Evidence on behalf of Gaz Métro. Subject: Pricing of gas distribution system expansion, January 20, 2015

Before the Supreme Court of Western Australia, Filed Statement on behalf of North West Shelf Pty Ltd, Subject: Value and interpretation of gas swaps agreement, December 24, 2014.

Before the District Court of Tarrant County, Texas, 17th Judicial District, Expert Report of Jeff D. Makholm on behalf of OAO Gazprom, et al, Subject: Valuation of failed LNG import project, November 14, 2014.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of MAS (Market Area Shippers Group), Hearing Order RH-001-2014, July 2014. Subject: Effectiveness of toll design//regime in settlement.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the National Energy Board, Expert Testimony on behalf of FortisBC Energy Inc., Hearing Order Number GH-001-2014, July 10, 2014. Subject: Tolling for pipeline extensions.

Before the National Energy Board, Expert Testimony on behalf of Alliance Pipeline, May 22, 2014. Subject: Restructuring services/tolls.

Before the Economic Regulation Authority of Western Australia on behalf of ATCO Gas Australia, March 2014. Subject: Cost accounting for gas pipeline regulation.

Before the 298th Judicial District Court of Dallas County, Texas, Expert Testimony on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, February 2014. Subject: Assessment of causation and valuation of damages from lost crude oil pipeline opportunity.

Before the National Energy Board, Expert Testimony on behalf of Enbridge Gas Distribution Inc. and Union Gas limited, Hearing Order MH-001-2013, November 1, 2013. Subject: Tolling issues involving pipeline abandonment.

Before the National Energy Board, Expert Report and Direct Evidence on behalf of MAS (Market Area Shippers Group), Hearing Order RH-001-2013, July 26, 2013. Subject: Contract renewal provisions.

Before the 298th Judicial District Court of Dallas County, Texas, Supplemental Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, July 24, 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the 298th Judicial District Court of Dallas County, Texas, Rebuttal Expert Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, March 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the 298th Judicial District Court of Dallas County, Texas, Direct Expert Report on behalf of plaintiff in Energy Transfer Partners, L.P., and Energy Transfer Fuel, L.P. v. Enterprise Products Partners, L.P., Enbridge (US) Inc., and Enterprise Products Operating LLC, Cause No. 11-12667, January 2013. Subject: Causation and damages in abandoned joint oil-pipeline venture

Before the Alberta Public Utility Commission, Direct Testimony on behalf of ATCO Electric and ATCO Gas, Proceeding ID #2131, December 2012. Subject: Analysis of ATCO Electric's and ATCO Gas' capital tracker proposals

Before the American Arbitration Association, Expert Report with Dr. Victor P. Goldberg, Case No. AAA No. 16 132 Y 00502 11. December 17, 2012. Subject: Confidential Arbitration.

Before the National Energy Board, Written Evidence on behalf of FortisBC Energy Inc., Hearing Order GH-001-2012, May 29, 2012. Subject: Tariff treatment for pipeline extensions to new Canadian gas production regions.

Before the National Energy Board, Expert Report and Direct Testimony on behalf of Market Area Shippers Group, Hearing Order RH-003-2011, March 2012. Subject: Assessment of TransCanada's omnibus restructuring proposal and commentary on Market Area Shippers Group's alternative solution.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Alberta Public Utility Commission (with Agustin J. Ros). Reply Expert Report. Application No. 1606029, AUC Proceeding 566. February 22, 2012. Subject: Update to TFP analysis and review of PBR plans for the Commission's performance-based regulation initiative.

Before the State Corporation Commission of the State of Kansas, Testimony on Behalf of Coffeyville Resources Refining & Marketing, LLC, Docket No. 12-MDAP-068-RTS. October 25, 2011. Subject: Reasonable ratemaking methodology.

Before the United States Federal Energy Regulatory Commission, Prepared Direct Testimony in Public Utilities Commission of Nevada and Sierra Pacific Power Company v Tuscarora Gas Transmission Company, Docket No. RP11-1823-000. October 17, 2011. Subject: Reasonable interstate gas pipeline tariff levels.

Before the Public Utilities Commission of Nevada, Pre-filed Rebuttal Testimony on behalf of Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy. Docket Nos. 11-03003, 11-03004 & 11-03005. August 3, 2011. Subject: Prudence of hedging practices.

Before the United States Federal Energy Regulatory Commission, Affidavit in Public Utilities Commission of Nevada and Sierra Pacific Power Company v Tuscarora Gas Transmission Company, Docket No. RP11-1823-000. February 28, 2011. Subject: Reasonable interstate gas pipeline tariff levels.

Before the Public Utilities Commission of Nevada, Prepared Direct on behalf of Nevada Power Company d/b/a NV Energy, 2011 Gas and Electric Deferred Energy Proceeding, Docket No. 11-03___. February 24, 2011. Subject: Prudence of hedging practices.

Before the Public Utilities Commission of Nevada, Prepared Direct on behalf of Sierra Pacific Power Company d/b/a NV Energy, 2011 Gas Deferred Energy Proceeding, Docket No. 11-03___. February 24, 2011. Subject: Prudence of gas hedging practices.

Before the Federal Energy Regulatory Commission and the State of Alaska Regulatory Commission, Prepared Direct Testimony on behalf of Trans Alaska Pipeline System. Docket No. IS09-348-004, *et al*. January 21, 2011. Subject: Prudence of capital rehabilitation costs.

Expert report filed before the Alberta Public Utility Commission (with Agustin J. Ros). Application No. 1606029, AUC Proceeding 566. December 30, 2010. Subject: Total factor productivity study for use in the Commission's performance-based regulation initiative.

Before the Commonwealth of Kentucky, Edmonson Circuit Court. Opinion on behalf of plaintiff in Honeycutt vs. Atmos Energy Corporation. Docket No. 09-CI-00198 and 10-CI-00040. September 10, 2010. Subject: Valuation of natural gas for royalty computations.

Before the Régie de l'Energie, Direct Testimony on behalf of Hydro-Québec TransÉnergie. Demande R-3738-2010. August 2, 2010. Subject: Economic analysis of issues related to the regulatory policies for network upgrades.

Before the Public Utilities Commission of Nevada, Pre-Filed Supplemental Direct Testimony on behalf of Nevada Power Company, Sierra Pacific Power Company d/b/a NV Energy (electric and gas departments), Docket No: 10-03003, 10-03004, 10-03005. May 5, 2010. Subject: Gas hedging.

Before the Arkansas Public Service Commission, Rebuttal Testimony on behalf of Entergy Arkansas, Inc., Docket No. 09-084-U. March 24, 2010. Subject: Justification of the operation of a multi-year formula rate plan.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Nevada, Pre-Filed Direct on behalf of Nevada Power Company, Docket No. 10-03003. February 26, 2010. Subject: Prudence of gas purchase costs.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Rochester Gas and Electric Corporation, Case 09-E--07717 Case 09-G-0718 and New York State Electric & Gas Corporation, Case 09-E-0715, Case 09-E-0716. February 12, 2010. Subject: Cost of equity capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company , Docket No. 09-09001. December 15, 2009. Subject: Gas hedging plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Nevada Power Company , Docket No. 09-07003. December 15, 2009. Subject: Gas hedging plan.

Before the New York State Public Service Commission, Direct Testimony on behalf of Rochester Gas and Electric Corporation, Case 09-E--07717 Case 09-G-0718. September 17, 2009. Subject: Cost of capital and capital structure.

Before the New York State Public Service Commission, Direct Testimony on behalf of New York State Electric & Gas Corporation, Case 09-E-0715, Case 09-E-0716. September 17, 2009. Subject: Cost of capital and capital structure.

Before the Arkansas Public Service Commission, Direct Testimony on behalf of Entergy Arkansas, Inc., Docket No. 09-084-U. September 4, 2009. Subject: Justification of the operation of a multi-year formula rate plan.

Submission before the New Zealand Commerce Commission, on behalf of Orion New Zealand Limited, July 31, 2009. Subject: Theory and practice of price cap regulation.

Before the Hawaii Public Utilities Commission, Testimony on behalf of Hawaiian Electric Company Inc., Docket No. 2008-0083. July 2009. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Nevada Power Company , Docket No. 09-02____. February 27, 2009. Subject: Prudence of gas purchase costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 09-02_____. February 27, 2009. Subject: Prudence of gas purchase costs.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Connecticut Natural Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Department of Public Utility Control of Connecticut, Direct Testimony on behalf of Southern Connecticut Gas Corporation. Docket No. 08-12-06. January 11, 2009. Subject: Cost of capital.

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of Lone Star Transmission, LLC. Docket No. 35665. November 14, 2008. Subject: Licensing of new electricity transmission projects.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utilities Commission of Ohio, Direct Testimony on behalf of The Dayton Power and Light Company. Case No. 08-1094-EL-SSO. October 10, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. September 25, 2008. Subject: Cost of capital.

Before the Illinois Commerce Commission, Testimony on behalf of Northern Illinois Gas Company, Case No. 08-0363. April 29, 2008. Subject: Cost of equity.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. April 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the New York State Public Service Commission, Rebuttal Testimony on behalf of Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Green Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, Case No. 07-M-0906. January 31, 2008. Subject: Regulatory philosophy/ merger issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. January 14, 2008. Subject: Stand-alone costs and cost allocation issues.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No. 07-09016. January 11, 2008. Subject: Allocation of pipeline transport costs.

Before the Illinois Commerce Commission, Testimony on behalf of Shelby Coal Holdings, LLC, Christian Coal Holdings, LLC and Marion Coal Holdings, LLC. Docket No. 07-0446. January 7, 2008. Subject: Pipeline certification and competition in pipeline transport market.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Consolidated Edison Company of New York, Docket No. OA08-13-000. January 7, 2008. Subject: Planning and allocation of electric transmission costs.

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-09016. December 14, 2007. Subject: Stand-alone costs and cost allocation issues.

Before the New Hampshire Public Service Commission, Docket No. DE 07-064, invited appearance on an expert panel to present perspectives and answer questions on policies and practices regarding retail gas and electric distribution rate "decoupling," November 7, 2007.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 07-05019. May 15, 2007. Subject: Prudence of gas purchase costs.

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., *et al.*, Debtors, Case No. 03-17949 (PCB) (Jointly Administered), April 20, 2007. Subject: Discount rate for contract rejection damages.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. April 19, 2007. Subject: Stand-alone costs and cost allocation issues.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the United States Bankruptcy Court, Southern District of New York, Supplemental Report on behalf of Solutia, Inc., et al., Debtors, Case No. 03-17949 (PCB) (Jointly Administered), March 23, 2007. Subject: Discount rate for contract rejection damages.

Before the United States District Court, District of Kansas, Expert Report on behalf of J.P. Morgan Trust Company, *et al*. in the matter of J.P. Morgan Trust Company, *et al*. V. Mid-America Pipeline Company, *et.al*., Docket No. 05-CV-2231-CM/JPO. March 21, 2007. Title: "Harm to Farmland's Coffeyville Refinery Expert Report", by Jeff. D. Makholm.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Nevada Power Company, Docket No. 07-01022. January 16, 2007. Subject: Prudence of gas purchase costs.

Before the Public Utilities Commission of the State of Hawaii, Supplemental Testimony on behalf of Hawaii Electric Light Company, Inc., Docket No. 05-0135. December 29, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of the State of Hawaii, Testimony on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386. December 22, 2006. Subject: Energy cost adjustment clause.

Before the Public Utilities Commission of Nevada, Pre-filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-12001. December 1, 2006. Subject: Stand-alone costs and cost allocation issues.

Before the State of New Jersey Board of Public Utilities, Prepared Reply Testimony on behalf of Public Service Electric & Gas, OAL Docket No. PUC1191-06 and BPU Docket No. EO05111005. November 3, 2006. Subject: Unregulated contract prices for telecommunication conduit rental contracts.

Before the State of New Jersey Board of Public Utilities, Rebuttal Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, October 10, 2006. Subject: Cost of Capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 06-05016. October 2, 2006. Subject: Prudence of gas purchase costs.

Before the Federal Energy Regulatory Commission, Reply Testimony on behalf of the State of Alaska, Docket No. OR05-2-001, August 11, 2006. Subject: Relative risk and capital structure for the Trans Alaska Pipeline System (TAPS).

Before the Maine Public Utilities Commission, Response to the Bench Analysis on behalf of Central Maine Power Company, Docket 2005-729. May 19, 2006. Subject: Specification of productivity offset for price cap formula.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No. 05-12001. May 17, 2006. Subject: Prudence of the company's gas hedging strategy.

Before the Public Utilities Commission of Nevada, Prefiled Direct Testimony on behalf of Sierra Pacific Power Company (Gas Division, WestPac Gas), Docket No. 06-0516. May 15, 2006. Subject: Prudence of the company's gas hedging strategy.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of New Jersey Board of Public Utilities, Testimony on behalf of the New Jersey American Water Company, Case No. WR06030257, March 29, 2006. Subject: Cost of Capital.

Before the Public Utilities Commission of Nevada, Direct Testimony on behalf of Nevada Power Company, Docket No.06-01016. January 17, 2006. Subject: Prudence of the company's gas hedging costs.

Before the New Brunswick Board of Commissioners of Public Utilities, Rebuttal Testimony on behalf of the Public Intervenor, Board Reference 2005-002. December 30, 2005 (original filing), January 23, 2006 (updated filing). Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Pre-Filed Direct Testimony on behalf of Sierra Pacific Power Company, Docket No.05-12001. December 1, 2005. Subject: Prudence of the company's gas hedging costs.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Sierra Pacific Power Company, Docket No.05-9016. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Nevada, Pre-Filed Rebuttal Testimony on behalf of Nevada Power Company, Docket No.05-9017. December 2, 2005. Subject: Prudence of the company's energy supply plan.

Before the Public Utilities Commission of Ohio, Supplemental Testimony on behalf of The Dayton Power and Light Company. Case No. 05-276-EL-AIR. September 26, 2005. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. May 12, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Reply Report on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). April 12, 2005. Subject: Pipeline capacity valuation.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Docket No 05-1028. April 12, 2005. Subject: Prudence of gas purchase costs.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Northern Illinois Gas Company d/b/a Nicor Gas Company. Case No. 04-0779. April 5, 2005. Subject: Cost of capital.

Before the United States Bankruptcy Court, Northern District of Texas, Fort Worth Division, Report on behalf of Mirant Corporation, et al, Debtors. Case No. 03-46590 (Jointly Administered). March 22, 2005. Subject: Pipeline capacity valuation.

Before the Public Utilities Commission of the State of Oregon, Direct Testimony and Exhibits on behalf of Portland General Electric. Docket No.UE-88 Remand. February 15, 2005. Subject: The cost consequences of abandoning the regulatory compact in Oregon on prudent invested capital.

Before the Louisiana Public Service Commission, testimony on behalf of Entergy Gulf States, Ind., and Entergy Louisiana, Inc., in Re: Analysis of Competitive Implications, Consolidated Docket No. U-21453, et al, January 13, 2005. Subject: Retail electricity competition.

Before the Public Utilities Commission of Nevada, Testimony and Exhibits on behalf of Sierra Pacific Power Company. Docket No 05-1028. January 5, 2005. Subject: Prudence of gas purchase costs.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utility commission of Oregon, Direct Testimony on behalf of Portland General Electric. Docket No. UE-165. November 17, 2004. Subject: Power supply risk related to PGE's hydroelectric generation sources.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Nevada Power Company. Docket No. 04-11028. November 10, 2004. Subject: Examination of the prudence of gas purchase and hedging decision in the Company's 2004 deferral case.

Before the Illinois Commerce Commission, Testimony on behalf of Nicor Gas Company. Docket No. 04-0779. November 1, 2004. Subject: Cost of Capital.

Rebuttal Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 15, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Before the International Center for the Settlement of Investment Disputes, Testimony on behalf of Azurix Corp., in the case of Azurix Corp v. Government of Argentina in Paris, France, October 11th, 2004. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the Circuit Court of Fairfax, Virginia, Testimony on behalf of Upper Occoquan Sewage Authority in the case against Blake Construction Co., Inc., Poole and Kent, a Joint Venture. Case No. 206595. October 1, 2004. Subject: Valuation of capacity expansion project.

Expert Report for an ad-hoc arbitration on behalf of CITIBANK, N.A. in their case against NEW HAMPSHIRE INSURANCE COMPANY. Policy No. 576/ MF5113500. October 1, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of a toll-road concession's assets in Argentina.

Before the London Courts of International Arbitration, Rebuttal Report on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. September 17, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Before the London Courts of International Arbitration, Expert Report on behalf of CITIBANK, N.A. AND DRESDNER BANK AG in their case against AIG EUROPE (UK) LTD. AND SOVEREIGN RISK INSURANCE. Arbitration No. 3473. August 6, 2004. Subject: Claimants right to collect on a political risk insurance policy as a result of the expropriation of electric utility assets in Argentina.

Before International Center for the Settlement of Investment Disputes, Rebuttal Report on behalf of Azurix Corp., in the case of Azurix Corp v. Government of Argentina, April 15th, 2004. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-12002. March 29, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 03-10001 and 03-10002. February 5, 2004. Subject: Rebutted argument that there was a link between the merger and the cost of electricity in the post-merger period.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the New Zealand Commerce Commission, Testimony on behalf of Orion New Zealand. November 5, 2003. Subject: Productivity measures used in resetting the price path thresholds for electricity distributors in New Zealand.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. September 2, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of FairPoint New England Telephone Companies. July 11, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Testimony on behalf of Sierra Pacific Power Company. Case No: 03-5021. May 14, 2003. Subject: Structure in place for governing and overseeing hedging/risk management process at Westpac Utilities, an operating division of Sierra Pacific Power Company.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Sierra Pacific Power Company. Case No: 03-1014. May 5, 2003. Subject: Prudence of gas procurement and hedging program.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of FairPoint New England Telephone Companies. April 7, 2003. Subject: Cost of capital.

Before the Public Utilities Commission of Nevada, Rebuttal Testimony on behalf of Nevada Power Company. Case No: 02-11021. March 31, 2003. Subject: Prudence of gas procurement and hedging program.

Before Federal Communications Commission, Testimony on behalf of Iowa Telecommunications Services, Inc. Case No. March 25, 2003. Subject: Cost of capital.

Before Federal Energy Regulatory Commission, Testimony on behalf of PPL Wallingford Energy LLC. Case No: ERO3-421-000. January 9, 2003. Subject: Cost of equity.

Before the State of New Hampshire Public Utilities Commission, Rebuttal Testimony on behalf of Kearsarge Telephone Company. Case No. DT 01-221. December 20, 2002. Subject: Rebuttal on cost of equity.

Before the New York State Public Service Commission, Affidavit in support of Rochester Gas and Electric Corporation's Response to Staff's November 8, 2002 filing. Case No. 02-E-0198, 02-G-0199. November 14, 2002. Subject: Respond to staff's filing with respect to the rate-of-return and risk impacts of various regulatory mechanisms.

Before the Public Utility Commission of Texas, Rebuttal Testimony on behalf of American Electric Power Company, Inc., Mutual energy CPL, LP, Mutual Energy WTU, LP and Centrica PLC, Centrica N.S. Holding, Inc., Centrica Holdco, Inc.. Case No. 25957. October 28, 2002. Subject: Impact of the merger on competition in the retail electric market.

Before the International Center for the Settlement of Investment Disputes, Expert Testimony on behalf of Azurix Corp in the case of Azurix Corp v. Government of Argentina, October 15, 2002. Subject: Expropriation of a water utility concession in the province of Buenos Aires.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of New York Public Service Commission, Rebuttal Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. September 30, 2002. Subject: Cost of capital

Before the Connecticut Department of Public Utility Control, Update and Rebuttal Testimony on behalf of The United Illuminating Company, Case No. 01-10-10, April 4, 2002. Subject: Cost of capital.

Before the State of New York Public Service Commission, Direct Testimony on behalf of Rochester Gas and Electric Corporation. Case No. 02-E-0198, Case No. 02-G-0199. February 15, 2002. Subject: Cost of capital.

Before the Alberta Energy and Utilities Board, Update of Evidence on behalf of UtiliCorp Networks Canada, November 30, 2001. Subject: Testimony on the elements of the company's performance based regulation plan.

Before the Connecticut Department of Public Utility Control, Direct Testimony on behalf of The United Illuminating Company, Case No. 01-10-10, November 15, 2001. Subject: Cost of capital.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, October 24, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, September 18, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the State of New York Public Service Commission, Prepared Rebuttal Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. September 12, 2001. Subject: Electric price protection plan

Before the State of Maine Public Utilities Commission, Joint Rebuttal Testimony on behalf of Community Service Telephone Company. September 6, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the Public Service Commission of the State of Missouri, Rebuttal Testimony on behalf of Gateway Pipeline Company. Case GM-2001-595. August 20, 2001. Subject: Acquisition of Capital Stock of Utilicorp Pipeline Systems, and connection.

Before the State of New York Public Service Commission, Prepared Direct Testimony on behalf of New York State Electric & Gas Corporation. Case 01-E-0359. August 3, 2001. Subject: Electric price protection plan.

Before the Federal Energy Regulatory Commission, Prepared Answering Testimony on behalf of the Association of Oil Pipe Lines. Case No: OR96-2-000. June 21. 2001. Subject: Light-handed regulation of oil pipeline tariffs.

Before the Illinois Commerce Commission, Direct Testimony on behalf of Commonwealth Edison Company, Case No. 01-0423, June 1, 2001. Subject: Economic pricing for unbundled retail distribution services.

Before the Federal Energy Regulatory Commission, Affidavit on behalf of Florida Power & Light Co. May 31, 2001. Subject: Pricing of transmission services.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the Public Utility Commission of the State of Oregon, Rebuttal Testimony on behalf of Portland General Electric Company. May 21, 2001. Subject: Cost of capital.

Before the State of Maine Public Utilities Commission, Direct Testimony on behalf of Community Service Telephone Company. April 4, 2001 (with C. Zarkadas). Subject: Cost of equity capital.

Before the State of New Jersey Board of Public Utilities, Cross-Answering Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564, March 26, 2001. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

Before the Indiana Utility Regulatory Commission, Testimony on behalf of Tipton Telephone Company, Inc, February 23, 2001 (with C. Zarkadas). Subject: Cost of capital.

Before the Supreme Court of Victoria at Melbourne, in the matter of an appeal brought by TXU Electricity Limited of the Final Determination of the Office of the Regulator General of the 2001 to 2005 tariffs for the Victorian electricity distributors. Testimony on behalf the Office of the Regulator General, February 11, 2001. Subject: The distinctions between price cap and rate of return regulatory practices.

Before the Australian Competition Tribunal. Statement on behalf of the National Competition Council regarding the application under section 38(1) of the Gas Pipelines Access Law for review of the decision by the Minister for Industry, Science and Resources to Cover (i.e., regulate) the Eastern Gas Pipeline pursuant to the provisions of the National Third Party Access Code for Natural Gas Pipeline Systems and the Gas Pipelines Access Law, January 19, 2001. Subject: Evaluation of the criteria for regulating an interstate gas pipeline.

Before the Public Utility Commission of Texas. Rebuttal Testimony on behalf of American Electric Power Texas Companies (Central Power & Light Company, Southwest Electric Power Company, West Texas Utilities Company), Entergy Gulf States, Inc., Reliant Energy HL&P, Southwestern Public Service Company, Texas-New Mexico Power Company, and TXU Electric Company. October 27, 2000. Subject: Capital structure and allowed return on equity.

Before the Federal Energy Regulatory Commission, "Assessment of PJM Owner's Transmission Enhancement Package," prepared in support of the PJM (Pennsylvania, New Jersey, Maryland) electricity transmission owners as part of their Order No. 2000 compliance filing. Docket No. RT01-2, October 11, 2000. Subject: Analysis of incentive package for transmission efficiency.

Before the Appeal Panel under Section 38(2) of the Office of the Regulator-General Act 1994, Victoria, Australia. In the matter of an appeal pursuant to s.37 of the Act brought by United Energy Ltd., Testimony on behalf of the Office of the Regulator General, October 10, 2000. Subject: The distinctions between price cap and traditional cost-based regulatory practices.

Before the Alberta Energy and Utilities Board, Evidence on behalf of UtiliCorp Networks Canada, September 1, 2000. Subject: Testimony on the elements of the company's performance based regulation plan.

Before the State of Maine Public Utilities Commission, Surrebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, August 10, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the State of New Jersey Board of Public Utilities, Testimony on behalf of Public Service Electric and Gas Company, Case No. GM00080564, July 26, 2000. Subject: Forecasting the net market value for natural gas transportation and storage contracts.

RECENT TESTIMONY (SINCE 2000 CONTINUED)

Before the State of Maine Public Utilities Commission, Rebuttal Testimony on behalf of Central Maine Power Company, Case No. 99-666, June 22, 2000. Subject: Empirical analysis and productivity offset for price cap formula.

Before the Illinois Commerce Commission, Surrebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 12, 2000. Subject: Investigation Concerning the Unbundling of delivery Services under Section 16-108 of the Public Utilities Act.

Before the Illinois Commerce Commission, Rebuttal Testimony on behalf of Commonwealth Edison Company, Case No. 99-0013, Phase III, June 5, 2000. Subject: Investigation Concerning the Unbundling of delivery Services under Section 16-108 of the Public Utilities Act.

PUBLICATIONS

"Electricity Deregulation under Siege," *Natural Gas and Electricity*, Volume 34, No. 5 (August 2017), forthcoming.

"The Mysterious Cost of Capital for Energy Utilities," *Natural Gas and Electricity*, Volume 34, No. 3 (June 2017), pp. 28-32

"Climate Change, "Grid Neutrality," and Electricity Distributors," *Natural Gas and Electricity*, Volume 34, No. 1 (April 2017), pp. 28-32.

"The Interaction of Pipelines and Geography in Support of Fuel Markets," in Warf, B.L., (Ed.) *The Handbook on Geographies of Technology*, Edward Elgar, Cheltenham, UK (2017), pp. 347-361.

"Brexit and Divestiture Provides New Hope for "British" Gas," *Natural Gas and Electricity*, Volume 33, Number 6, February 2017.

"When Worlds Collide: Universal Challenges in Natural Gas and Electricity Markets," *Natural Gas and Electricity*, Volume 33, Number 7, December 2016.

"The REVolution Yields to a More Familiar Path: New York's Reforming the Energy Vision (REV)," *The Electricity Journal* (November 2016). pp. 48-55.

"The Politics of US Oil Pipelines: The First Born Struggles to Learn from the Clever Younger Sibling," *Energy Law Journal*, November 11, 2016, (with Laura T.W. Olive). pp. 409-427.

"Will LNG Rescue World Gas Market? Maybe a Little," *Natural Gas and Electricity*, Volume 33, Number 5, October 2016.

"Distributed Energy and Low Carbon vs. Consumers, Regulators and Tin Men," *Natural Gas and Electricity,* Volume 33, Number 3, August 2016.

Section Editor (Midstream Sector), *Current Sustainable and Renewable Energy Reports*, Springer (ISSN: 2196-3010), 2016.

"There is But One True Hub, and His Name is Henry," *Natural Gas and Electricity*, Volume 32, Number 11 (June 2016). pp. 27-30.

"El Nino's Uneven Disruption of World's Electricity Systems", *Natural Gas and Electricity*, Volume 32, Issue 9 (April 2016), pp. 29–32.

"Choose your path: the future for Australia's gas market." *The Australian Pipeliner*, April 2016.

"Why Does Most Shale Gas Worldwide Remain in the Ground?" *Natural Gas and Electricity*, Volume 32, Issue 7 (February 2016), pp. 29–32

"Utility Regulation Principles Vary Widely Country to Country," *Natural Gas and Electricity*, Volume 32, Issue 5 (December 2015), pp. 31–32

"'Entry/Exit' Pipeline Pricing in Gas "Islands" Enables EU to Resist Competition," *Natural Gas and Electricity*, Volume 32, Issue 3 (October 2015), pp. 27–29

"Regulation of Natural Gas in the United States, Canada, and Europe: Prospects for a Low Carbon Fuel," *Review of Environmental Economics and Policy*, Vol. 9, Issue 1 (Winter 2015), pp. 107-127.

PUBLICATIONS (CONTINUED)

“Congress Can Stop the Boom in Oil Tank Cars,” The London School of Economics daily weblog on American Politics and Policy, 30 March 2015.

“If Europe wants to embrace natural gas as a bridge to a low-carbon future, it should draw from America’s success,” The London School of Economics daily weblog on European Politics and Policy, 21 March 2015.

“Ensuring Natural Gas Availability,” paper included in MIT Energy Initiative 2013 MITEI Symposium publication *Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems*, April 16, 2013.

“Marginal Costs with ~~Wings~~ a Ball and Chain: Pipelines and Institutional Foundations for the U.S. Gas Market,” *Economics of Energy and Environmental Policy*, Vol. 1, Issue 1 (2012).

“North American Performance-Based Regulation for the 21st Century,” *The Electricity Journal*, May 2012, Vol. 25, Issue 4, (with Agustin J. Ros and Stephen C.W. Collins).

The Political Economy of Pipelines: A Century of Comparative Institutional Development, The University of Chicago Press, Chicago and London (2012). Chinese-language edition published by the Petroleum Industry Press, Beijing (2016).

“Real Unbundlings: The Foundation for a Competitive Gas Market in the United States,” *Competition and Regulation in Network Industries*, Vol. 12, No.4 (2011).

“Zone of Reasonableness: Coping with Rising Profitability a Decade after Restructuring,” *Public Utilities Fortnightly*, 1 July 2011 (with Kurt Strunk).

“Fueling the Price of Power (and Gas): The Rising Profitability of Pipelines and the Need for Collective Action,” *The Electricity Journal,* June 2011, Vol. 24 Issue No.5. pp. 7-13 (with Wayne Olson).

“Seeking Competition and Supply Security in Natural Gas: the US Experience and the European Challenge,” in Lévêque, F., Glachant, J-M., Barquín, J., von Hirschhausen, C., Holz, F., and Nuttal, W.J., (eds.), *Security of Energy Supply in Europe*, Edward Elgar, Cheltenham, UK (2010), pp. 21-55.

“Decoupling” for Energy Distributors: Changing 19th Century Tariff Structures To Address 21st Century Energy Markets,” *Energy Law Journal*, Vol. 29, No.1 (2008), pp.157-172.

“Electricity Transmission Cost Allocation: A Throwback to an Earlier Era in Gas Transmission,” *The Electricity Journal*, Vol. 20, Issue 10 (December 2007), pp. 13-25

“Elusive Efficiency and the X-Factor in Incentive Regulation: The Törnqvist v. DEA/Malquist Dispute,” in Voll, S.P., and King, M.K. (Eds.), *The Line in the Sand: The Shifting Boundaries Between Markets and Regulation in Network Industries*, National Economic Research Associates, White Plains, New York (2007), pp. 95-115.

“Theoretische Rechtfertigung des X-Faktors” (“Theoretical Justification for X-Factors”), *Energiewirtschaftliche Tagesfragen*, Vol. 47, No. 3 (March 2007), pp. 50-52.

“Ex Ante or Ex Post? Risk, Hedging and Prudence in the Restructured Power Business,” with Meehan, E.T., and Sullivan, J.E., *The Electricity Journal*, Vol. 19, No 3 (April 2006), pp. 11-29.

“The Thaw: The End of the Ice Age for American Utility Rate Cases,” with Parmesano, H., *The Electricity Journal*, Vol. 17, No. 4 (July 2004), pp.69-74.

PUBLICATIONS (CONTINUED)

"In Defense of the 'Gold Standard," *Public Utilities Fortnightly*, Vol. 141, No. 10 (May, 2003), pp. 12-18.

"Incentive Regulation Meets Electricity Transmission on a Grand Scale: FERC Order No. 2000 and PBR," *The Electricity Journal*, Vol. 13, No. 2 (May 2000), pp.57-64.

"ISO's Not the Answer for Gas," *Natural Gas*, Vol. 14, No. 5 (December 1997), pp. 1-6.

Utility Regulation 1997: Economic Regulation of Utilities and Network Industries Worldwide (Chapter on United States), Center for the Study of Regulated Industries, (ISBN 1-901597-00-8) 1997.

"X Marks the Spot: How to Calculate Price Caps for the Distribution Function," *Public Utilities Fortnightly*, Vol. 135, No. 22 (December 1997), p. 52.

"FERC Takes the Wrong Path in Pricing Policy," *Natural Gas*, Vol. 12, No. 3 (September, 1995), pp. 7-11.

The Distribution and Pricing of Sichuan Natural Gas, Chonxing University Press, Chonxing, China (ISBN 7-5624 -1006-2/F 94), 1995.

"Secondary Market Can Compete," *Natural Gas*, Vol. 11, No. 3 (October 1994), pp. 13-17.

"Gas Pipeline Capacity: Who Owns It? Who Profits? How Much?" *Public Utilities Fortnightly*, Vol. 132, No. 18 (October 1994), pp. 17-20.

"Calculating Fairness," with Sander, D.O., *Public Utilities Fortnightly*, Vol. 131, No. 21 (November 1993), pp. 25-29.

"The Risk Sharing Strawman," *Public Utilities Fortnightly*, Vol. 122, No. 1 (July 1988), pp. 24-29.

"The FERC Discounted Cash Flow: A Compromise in the Wrong Direction," with C. J. Cicchetti, *Public Utilities Fortnightly*, Vol. 120, No.1 (July 1987), pp. 11-15.

UNPUBLISHED WORKING PAPERS

"The Political Economy of "P3" Public-Private Partnerships: Chilean Lessons for Rebuilding US Infrastructure," NERA publication, March 25, 2017.

"A Square Regulatory Peg in a Round Industry Hole: Europe's Gas Industry Problems," NERA publication, 11 January 2017.

"2011 Speech Revisited—Whither the "Fourth Gas Package" for the EU: Dealing with Paralysis in Europe's Gas Industry," NERA publication, 8 December 2016.

"A Half-Century of Computing the Cost of Capital for Utilities at NERA," NERA publication, November 9, 2015.

"Pipeline Capacity Rights to Support a Competitive Gas Market: Theory and Applications", with Nina Hitchins, NERA publication, September 26, 2015.

"A Petroleum Tanker of a Different Color: Obstacles to an LNG-based Global Gas Spot Market," with Laura T.W. Olive, NERA Publication, August 18, 2015.

"Seeking Competition and Supply Security in Natural Gas: The US Experience and European Challenge," Prepared for the 1st CESSA Conference, Berlin University of Technology, Berlin, Germany, May 31, 2007.

"The Theory of Relationship Specific Investments, Long-Term Contracts and Gas Pipeline Development in the United States," paper given at the Conference on Energy Economics and Technology at the Dresden University of Technology, Dresden, Germany, April 21, 2006.

"Benchmarking, Rate Cases and Regulatory Commitment," paper given at the Australian Competition & Consumer Commission's Incentive Regulation and Overseas Developments Conference, Sydney, Australia, November 14, 1999

"Price Cap Plans for Electricity Distribution Companies Using TFP Analysis," with Quinn, M.J., NERA Working Paper, July 23, 1997.

"Rocks on the Road to Effective Regulation: The Necessary Elements of Sound Energy Regulation," paper presented at the Brazil-U.S. Aspen Global Forum, December 5, 1996.

"Profit Sharing and "Sliding Scale" Regimes," NERA Working Paper, Quinn, M.J., and Augustine, C., February 29, 1996.

"Four Common Errors in Applying the DCF Model in Utility Rate Cases," with Sander, D.O., NERA Working Paper, February 1992.

"Pareto Optimality through Non-Collusive Bilateral Monopoly with Cost-Of-Service Regulation," with Cicchetti, C.J., *Energy and Environmental Policy Center*, Harvard University, Working Paper, April 1988.

RECENT SPEECHES

"The New Market Conditions in Latin America's Energy Space," Latin Lawyer 8th Annual Oil and Gas Conference, Mexico City, 18 May 2017.

"The Uncertain Connection between Unbundled Electricity Distributors and Interstate Pipeline Capacity," Law Seminars International Energy in the Northeast Seminar, with Laura T.W. Olive, PhD. Boston, MA, September 23, 2016

"The Difficult Economics of a Worldwide LNG Commodity Market," International Bar Association Annual Conference, Oil and Gas Law Committee Section. Washington DC, September 22, 2016

"How to Make LNG Accessible to All of Europe?" CEER Workshop. Athens, Greece, September 12, 2016.

"Gas Markets, Gas Use and Europe's Gas Supply from the East," Eurasian Natural Gas Infrastructure Conference, Istanbul, Turkey, June 9, 2015

"International Perspective on Pathways for Gas Market Reform in Australia," Australian Domestic Gas Outlook, 2016, Sydney, Australia, March 8, 2016.

"What does a Gas Market Need?" Australian Domestic Gas Outlook 2016 In-Depth Learning Session B. Sydney, Australia, March 7, 2016.

"Gas as the Low-Carbon Bridge Fuel? Not without a Lot of Trouble," International Bar Association, Vienna, Austria, October 8, 2015.

"Gas Market Centers and Balancing in the US: Facilitating the Competitive Entry and Trade in Gas," FSR Specialized Training on the Regulation of Gas Markets, Florence, Italy, March 27, 2015.

"Gas Market in the US: Are there some lessons for Europe?" Gas Infrastructure Europe (GIE) Annual Conference 2014, Berlin, Germany, June 13, 2014.

"Ensuring Natural Gas Availability," MIT Energy Initiative, 2013 MITEI Symposium, Cambridge, Massachusetts, April 16, 2013.

"Regulating Access to Gas in North America," Florence School of Regulation, FSR Specialized Training, Florence, Italy, March 13, 2013.

"The Role of Regulation and the Challenges Going Forward," Speech given at the 10th Annual Tufts Energy Conference, Panel 3: The Natural Gas Boom. Medford, Massachusetts, February 21, 2015.

"Natural Gas in the Transformation Process in Europe," German Institution for Economic Research (DIW Berlin), Schumpeter Hall, Berlin, Germany. May 15, 2012.

"The Trouble with Europe: Infrastructure, Institutions and Investment," Keynote Speech at EPRG Winter Seminar 809. Cambridge, U.K., December 5, 2011.

"Regulating Gas TSO's in Europe: Where are all the Pipelines?" Oil and Gas Pipes Global Conference. London, U.K., November 29, 2011.

"Security of Supply in Europe," Florence School of Regulation, State of the EU Conference at the European University Institute. Florence, Italy, May 10, 2012.

"Regulating Gas Pipelines: United States and Europe," Florence School of Regulation, FSR Summer Course Advanced Training on Gas Markets. Florence, Italy, March 23, 2011.

RECENT SPEECHES (CONTINUED)

"Foundation for Regulating Pipelines, United States and Europe: Two Different Regulatory Worlds," Florence School of Regulation Summer Course on Regulation of Energy Utilities. Florence, Italy, June 30, 2010.

"Governance and the Electricity Sector," Governance and Regulation in the Electricity Sector Conference. Toronto, Ontario, June 4, 2010.

"Public Utility Companies and Regulatory Risk," Saul Ewing's 4th Annual Public Utility Symposium. Philadelphia, PA, May 24, 2010.

"It's All About Inland Transportation," US Gas Pipelines Reflect What's Happening in Europe," Florence School of Regulation Specialized Training on Regulation of Gas Markets. Florence, Italy, March 24, 2010.

"Windmills and Wires: FERC Rate Cases, Transmission Cost Allocation, and Renewable Power Development," Law Seminars International Sixth Annual National Conference on Today's Utility, Las Vegas, Nevada, February 11, 2010.

"The East-West Energy Corridor and Europe's Energy Security," The Brookings Institution conference on Turkey, Russian and Regional Energy Strategies, Washington D.C., July 15, 2009.

"Understanding U.S. Gas Pipelines," Florence School of Regulation, FSR Summer School on Regulation of Energy Utilities. Florence, Italy, June 24, 2009.

"Vertical Relations in Energy Markets: On the Role of Contracts and Other Legal Entitlements in the U.S. Gas Transport Market", Vienna University of Economics and Business, Workshop 2009. Vienna, Austria, May 29, 2009.

"Institutional, Transactional and Political Barriers to Competitive Gas Market in Europe: Europe's Pipelines and Economics," Florence School of Regulation Workshop: Tariffs for European Gas Transmission Networks. Florence, Italy, March 6, 2009.

"Cost recovery mechanisms: Options and where each works best; what approach is most likely to get necessary projects built," Law Seminars International, Utility Rate Case: Issues and Strategies 2009. Las Vegas, Nevada, February 5, 2009.

"Alaska as a Gas Supplier: Where is the North Slope Gas Going, and How?" Law Seminars International, Energy in Alaska conference. Anchorage, Alaska, December 8-9, 2008.

"Maintaining Adequate Infrastructure in the Natural Gas and Electric Industries," Increasing Longer-Term Stability in Energy Markets conference sponsored by the Institute for Regulatory Policy Studies. Springfield, Illinois, May 1, 2008.

"Rate Decoupling and Associated Rate and Cost Issues," New Hampshire Public Utilities Commission, Concord, New Hampshire, November 6, 2007.

"Electricity Transmission Cost Allocation in New England: A Throwback to an Earlier Era in Gas Transmission," Law Seminars International, Energy in the Northeast conference, Boston, Massachusetts, October 18-19, 2007.

"Rate Decoupling and Associated Rate and Cost Issues," American Gas Association (AGA) Legal Forum. Vail, Colorado, July 15- 17, 2007.

RECENT SPEECHES (CONTINUED)

"Seeking Competition and Supply Security in Natural Gas: The US Experience and European Challenge," 1st CESSA Conference, Berlin, Germany, May 31-June 1, 2007.

"Toward a Regulatory Equilibrium in Gas Hedging," Electric Utility Consultants' Conference: Utility Hedging in an Era of Natural Gas Price Volatility, Arlington, Virginia, October 4, 2006.

"The Theory of Relationship Specific Investments: Long-Term Contracts and Gas Pipeline Development in the United States." Dresden University of Technology Workshop on Energy Economics and Technology, April 21, 2006.

"A Gas Network to Meet the Needs of New Electricity Generators," Ontario Energy Association, Ontario, Canada, June 23, 2005.

"Forks in the Road for Electricity Transmission," Electricity Industry Regulation and Restructuring conference by The Salt River Project and The Arizona Republic, October 11, 2002.

"Role of Yardsticks in Cost & Service Quality Regulation," London Regulated Industries Group, November 30, 2000.

"Natural Gas Issues: Retail Competition, LDC Gas Rate Unbundling, and Performance Based Rates," Wisconsin Public Utility Institute, November 17, 2000.

"Performance Based Ratemaking (PBR) in Restructured Markets," Edison Electric Institute Seminar in San Antonio Texas, April 27, 2000.

"Benchmarking versus Rate Cases and the Half Live of Regulatory Commitment," Australian Competition & Consumer Commission's Incentive Regulation and Overseas Development Conference, Sydney, Australia, November 19, 1999.

"Benchmarking, Rate Cases and Regulatory Commitment," Australian Competition & Consumer Commission's Incentive Regulation and Overseas Developments Conference, Sydney, Australia, November 14, 1999.

"Gas and Electricity Sector Convergence: Economic Policy Implications," Energy Week '99, "The Global Shakeout," The World Bank, Washington D.C., April 6-8, 1999.

"Gas and Electricity Sector Convergence: Economic Policy Implications," Economic Development Institute, The World Bank, Washington D.C., December 8-9, 1998.

"Sustainable Regulation for Russian Oil Pipelines," Presentation at Pipeline Transportation: A Linkage Between Petroleum Production and Consumers, Moscow, June 25, 1997.

"Rocks on the Road to Effective Regulation," Brazil/US Aspen Global Forum, Aspen, Colorado, December 5-8, 1996.

"Stranded Cost Case Studies in the Gas Industry: Promoting Competition Quickly," MCLE Seminar: Retail Utility Deregulation, Boston, MA, June 17, 1996.

"Why Regulate Anyway? The Tough Search for Business-As-Usual Regulation,"—Panelist at St. Louis 1996, The Fifth Annual DOE-NARUC Natural Gas Conference, St. Louis, Missouri, April 30, 1996.

"Antitrust for Utilities: Treating Them Just Like Everyone Else"—Panelist at St. Louis 1996, The Fifth Annual DOE-NARUC Natural Gas Conference, St. Louis, Missouri, April 29, 1996.

RECENT SPEECHES (CONTINUED)

"Natural Gas Pricing: The First Step in Transforming Natural Gas Industries"—One-Day Interactive Workshop on Pricing Strategy at The Future of Natural Gas in the Mediterranean Conference, Milan, Italy, March 27, 1996.

"Open Access in Gas Transmission," New England Chapter of the International Association for Energy Economics, Boston, Massachusetts, December 13, 1995.

"Light-Handed Regulation for Interstate Gas Pipelines," Twenty-Seventh Annual Institute of Public Utilities Conference, Williamsburg, Virginia, December 12, 1995.

"Ending Cost of Service Ratemaking," Electric Industry Restructuring Roundtable, Boston, Massachusetts, October 2, 1995.

"Promoting Markets for Transmission: Economic Engineering or Genuine Competition?" The Forty-Ninth Annual Meeting of the Federal Energy Bar Association, Inc., May 17, 1995.

"End-Use Competition Between Gas and Electricity: Problems of Considering Gas and Electric Regulatory Reform Separately," ORLANDO '95, The Fourth Annual DOE-NARUC Natural Gas Conference, Orlando, Florida, February 14, 1995.

"Incremental Pricing: Not a Quantum Leap," Natural Gas Ratemaking Strategies Conference, Houston, Texas, February 3, 1995.

"The Feasibility of Competition in the Interstate Pipeline Market," Institute of Public Utilities Twenty-Sixth Annual Conference, Williamsburg, Virginia, December 13, 1994.

"A Mirror on the Evolution of the Gas Industry: The Views from Within the Business and from Abroad," 1994 LDC Meeting-ANR Pipeline Company, October 4, 1994.

"Creating New Markets Out of Old Utility Services," Fifteenth Annual NERA Santa Fe Antitrust and Trade Regulation Seminar, Santa Fe, New Mexico, July 9, 1994.

"Sources of and Prospects for Privatization in Developed and Underdeveloped Economies," Spring Conference of the International Political Economy Concentration and the National Center for International Studies at Columbia University, New York, March 30, 1994.

"Experiencias en el Desarrollo del Mercado de Gas Natural (Experiences in gas market development)," "Perspectivas y Desarrollo de Mercado de Gas Natural," Centro de Extensión de la Pontificia Universidad Católica de Chile, November 16, 1993.

"The Role of Rate of Return Analysis in a More Progressive Regulatory Environment," Twenty-Fifth Financial Forum held by the National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 27, 1993.

"Privatization of Energy and Natural Resources," International Privatization Conference "Practical Issues and Solutions in the New World Order," New York, New York, November 20, 1992.

RECENT INTERNATIONAL REPORTS

"Serious Problems with CREG Document 070 Facing Colombia's Energy Market.", report generated for the Asociación Nacional de Empresas Generadoras (ANDEG). White paper (with Graham Shuttleworth) assessing the economic and policy implications of a proposal by the Colombian Energy and Gas Regulatory Commission (CREG) to reform the country's Reliability Charge mechanism for the wholesale power market. September 2015.

"Principles and Methodology of a Domgas Commercial Price Threshold" Report generated for North West Shelf Joint Venture (NWSJV) to define a methodology for computing a schedule of minimum *reasonable* prices (the Commercial Price Threshold) for prospective gas production for domestic gas (Domgas) based on the NWSJV's supply costs. August 13, 2014.

Gas Pipeline Transport in China: An Economic, Financial and Institutional Analysis," report prepared for Gazprom Export and BP Russian Investments Limited on gas transmission networks and gas pipeline tariffs in China. August 6, 2008.

"Consultation Paper: Development of Approaches Towards Regulating Tariffs for Petroleum Pipelines, Storage and Loading Facilities in South Africa," Report prepared for the National Energy Regulator of South on the determination of economically feasible approaches towards establishing revenue requirements, regulating the setting/approval of tariffs, and developing rules, guidelines and framework regarding regulatory accounts for the petroleum pipelines, storage, and loading facilities in South Africa. December 14, 2006.

"Regulatory Assessment of the Turkish Electricity Sector." Report prepared for Prisma Energy on the examination of the economic and regulatory risks facing investors in the privatization of the energy infrastructure of Turkey. December 6, 2006.

"Calculation of the X-Factor in the 2nd Reference Report of the Bundesnetzagentur." Report prepared for E. ON Ruhrgas, Germany: Design of a regulatory method based on comparison of average tariffs, consistent with new German legislation on the regulation of gas transmission networks. April 21, 2006. (with Graham Shuttleworth and Michael Kraus).

"Cargo Access Charges for the Jorge Chavez International Airport in Lima, Peru." A report prepared for OSITRAN (Public Transport Infrastructure Regulator) on behalf of Lima Airport Partners S.R.L. February 19, 2004.

A Critique of CEPA's Report on "Productivity Improvements in Distribution Network Operators:" A report for EDF Energy (with Graham Shuttleworth). December 16, 2003.

Advised on Fare Regulation Issues related to the Impending Merger of the MTRC and KCRC Railroad Companies in Hong Kong, Mercer Consulting on behalf of MTRC, 2003-2004.

"Natural Gas Pipeline Access Regulation". Report prepared for BHP Petroleum Pty Ltd., May 31, 2001.

"Manual de Procedimientos para el Sistema Uniforme de Cuentas Regulatorias Eléctricas (SUCRE) de México" (April 2000). The report includes an explanation of each of the accounts needed for regulation, recording procedures and the structure the information should take when reporting to the regulator.

"Investigation into Petronets' Liquid Fuels Pipeline Tariffs: Final Report" (March 9th, 2000). This report presents NERA opinions in the quasi-arbitration of the tariffs disputes in the oil industry in South Africa for their liquids pipelines.

"Seeking Genuine Gas Competition in NSW", prepared for BHP Petroleum Pty. Ltd., February 18, 2000.

"Análisis y Revisión del Recurso de Revocatoria Interpuesto por la Compañía Boliviana de Energía S.A. (COBEE) a la Resolución SSDE Nº 92/99 de la Superintendencia de Electricidad" (September 6, 1999). This report represents NERA's opinion on COBEE's appeal in the electricity tariff review process in Bolivia (report in Spanish).

"Gas Sector Regulation Consultancy Services" report prepared for the Vietnam Oil and Gas Corporation, August 10, 1999.

"Natural Gas Demand Estimation for Guatemala, Honduras and El Salvador" (July 19th, 1999). This report done for an international consortium of companies presents calculations of prices and volumes of natural gas demand for three Central American countries if a pipeline is built from Mexico.

"Comments on East Australian Pipeline Limited Access Arrangements: (July 15, 1999). Report prepared on behalf of Incitec Ltd.

"Supplementary Submission to IPART on AGLGN's Proposed Access Arrangements" on behalf of Incitec Limited (April 27th, 1999). This submission discusses reload practices, customer contributions, operating expenses and recalculates charges for a user of the distribution network in New South Wales, Australia.

"Supplementary Submission to IPART on AGLGN's Proposed Costs and Tariffs" on behalf of BHP (April 15th, 1999). This submission explains how NERA recalculated charges for AGLGN in New South Wales, Australia.

"Initial Comments on AGLGN's Revised Access Arrangement Information" on behalf of BHP (March 20th, 1999). This submission presents NERA's comment to AGLGN submission to IPART in New South Wales, Australia.

"International Restructuring Experience" (February 12th, 1999). This paper surveys a number of countries whose experience of restructuring and competition in the electricity sector is directly relevant to the proposed changes in Mexico – Argentina, Australia, Chile, Guatemala, New Zealand, Norway, Spain, the US and the UK

"Report I: Review of the Regulatory Framework" (January 18th, 1999). This report presents the options for a natural gas framework in Peru.

"Conceptual Framework for the Reform of the Electricity Sector in Mexico: White Paper" (November 24th, 1998). This report represents the White Paper for restructuring of the electricity sector in Mexico which is being used in Congress for debate.

"Precios del Gas Natural para la Generación de Electricidad en el Perú" (November 16th, 1998). This report analyzes different alternatives for the treatment of natural gas prices in the electricity tariff model (report in Spanish).

"Tariffs and Subsidies: Report for the Tariffs Group" (November 10th, 1998). This report presents recommendation on the path for tariffs and subsidies for 1999 to the Electricity Tariffs Group of the Government of Mexico.

"Gasoducto México-Guatemala: Informe Final" (October 22nd, 1998). This report analyzes the legal and regulatory framework in both Mexico and Guatemala and costs and volumes for the building of a natural gas pipeline connecting both countries. A copy of the report was given by President Zedillo (Mexico) to President Arzú (Guatemala) (report in Spanish).

"Checks and Balances in Regulating Power Pools: Seven case Studies. A Report for the Electricity Pool of England and Wales" (September 10th, 1998). This report surveys the regulation of power pools in electricity industries around the world.

"Fuels Policy Group: Recommendations" (September 11th, 1998). This report presents recommendations to the Government of Mexico on their fuels policies for the electricity sector.

"Análisis de Costos e Inversiones. Revisión Tarifaria de Transener" (August 25, 1998). Report given to ENRE (the Argentinean electricity regulator) on behalf of a Consortium of Generators on the analysis of costs and investments to be considered for the revenue requirement of the electricity transmission company (report in Spanish).

"Central America Pipeline: Regulatory Analysis and Proposal" (July 28, 1998). This report presents the regulatory analysis and development of a fiscal, legal and commercial framework proposal for gas import, transportation, distribution and marketing in El Salvador, Honduras and Guatemala regarding the proposed Central American Pipeline.

"Energy Regulation in El Salvador" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in El Salvador.

"Energy Regulation in Guatemala" (July 28, 1998). This report presents a deep analysis of the electricity and natural gas regulatory, legal and tax frameworks in Guatemala.

"The Cost of Capital for Gas Transmission and Distribution Companies in Victoria" (June 22, 1998). Report prepared for BHP Petroleum Pty Ltd.

"Principios Económicos Básicos de Tarificación de Transmisión Eléctrica. Revisión Tarifaria de Transener" (May 26, 1998). The main purpose for this report was to provide an economic and regulatory analysis of laws, decrees, license and documents of the tender to provide advise in the tariff review of Transener (the electricity transmission company in Argentina), to present an economic analysis of transmission tariffs and to provide an opinion on specific topics to be discussed in the public hearing. This report was written for a consortium of generators in Argentina (reports in English and Spanish)

"Asesoría en la Fijación de Tarifas de Transener y Normativa del Transporte, Benchmarking Study" (May 26, 1998). This report compares the costs of Transener (the electricity transmission company in Argentina) with those of other companies elsewhere for a consortium of generators (the electricity transmission company in Argentina).

"International Regulation Tool Kit: Argentina" (March 20, 1998). This document describes the natural gas regulatory framework in Argentina for BG.

"Tarificación de los Servicios Que Prestan las Terminales de Gas LP" (January 9, 1998). The final report given to PEMEX Gas y Petroquímica Básica (México) for the determination of rates for LPG terminals.

"NERA-Pérez Companc Distribution Tariff Model" (January 5, 1998). This report explains the methodology behind NERA's calculations of distribution tariffs for Pérez Companc in Monterrey.

"Monterrey Natural Gas Market Assessment," (January 5, 1998). A series of reports were written to present the results of the market study of the demand for natural gas in the geographic zone of Monterrey to a company interested in bidding for the natural gas distributorship.

"Resolving the Question of Escalation of Phases (bb) and (cc) Under the Maui Gas Sale and Purchase Contract", prepared for the New Zealand Treasury, December 16, 1997.

"Timetable and Regulatory Review for the Monterrey International Public Tender," (December 5, 1997). A description of the necessary steps to bid for a distribution company as well as an explanation and analysis of natural regulations in Mexico for Pérez Companc.

"Economic Issues in the PFR for 18.3.1(I)(bb) & (cc)", prepared for the New Zealand Treasury, November 17, 1997.

"NERA's Distribution Tariff Model" (October 29, 1997). This report explains the methodology behind NERA's calculations of distribution tariffs for MetroGas.

"Evaluation Design Standards for MetroGas," (October 24, 1997). This report dealt with the analytical support resulting from work with MetroGas to create a meticulously-documented security criterion analysis that supported its efforts to obtain due recognition—and appropriate tariff treatment—for its costs.

"Ghana Natural Gas Market Assessment," prepared for the Ministry of Mines and Energy, Ghana (March-July, 1997). A series of four reports assessing prospective gas demand usage and netback prices for a number of proposed pipeline project alternatives.

"Final Report for Russian Oil Transportation & Export Study: Commercial, Contractual & Regulatory Component," prepared for The World Bank, June 25, 1997.

Response to FIEL's criticisms regarding NERA's report "Cálculo del Factor de Eficiencia (X)" (June 2, 1997).

"Impacts on Pemex of Natural Gas Regulations" prepared for Pemex Gas y Petroquímica Básica México, May 21, 1997.

"Market Models for Victoria's Gas Industry: A Review of Options," April 1997, prepared for Broken Hill Proprietary (BHP) Petroleum, to propose an alternative model for gas industry restructuring in Victoria, Australia.

"New Market Arrangements for the Victorian Gas Industry," prepared for Broken Hill Proprietary Petroleum; March 13, 1997.

"CEG Privatization: Comments to the Regulatory Framework," prepared for Capitaltec Consultoria Economica SA describing our comments with respect to the regulatory framework and the license proposed in the privatization of Riogas and CEG in Rio de Janeiro, Brazil; March 7, 1997.

"Determination of the Efficiency Factor (X)," prepared for ENARGAS, Argentina, January 24, 1997.

"Determination of Costs and Prices for Natural Gas Transmission," prepared for Pemex Gas y Petroquímica Básica, México, December 19, 1996.

"Regulating Argentina's Gas Industry," a report prepared for The Ministry of Economy and The World Bank, November 26, 1996.

"Open Access and Regulation," prepared for Gascor, in the State of Victoria, Australia; (October 2, 1996).

"A Review and Critique of Russian Oil Transportation Tariffs (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 13, 1996.

"Tariff Options for Transneft (Russian Oil Transportation & Export Study; Commercial, Contractual & Regulatory Component)," prepared for The World Bank, June 6, 1996.

"Comments on the Proposed Amendments to the Regulation of Airports in New Zealand," prepared for the New Zealand Parliament Select Committee hearings on the regulation of monopolies, March 13, 1996.

"Evaluating the Shell Camisea Project," prepared for Perupetro S.A., Government of Peru, December 8, 1995.

"Towards a Permanent Pricing and Services Regime," prepared for British Gas, London, England, November, 1995.

"Final Report: Gas Competition in Victoria," prepared for Gas Industry Reform Unit, Office of State Owned Enterprises, June 1995.

"Natural Gas Tariff Study," prepared for the World Bank, May 1995, consisting of:

Principles and Tariffs of Open-Access Gas Transportation and Distribution Tariffs
Handbook for Calculating Open-Access Gas Transportation and Distribution Tariffs

"Economic Implications of the Proposed Enerco/Capital Merger," prepared for Natural Gas Corporation of New Zealand, December 1994.

"Contract Terms and Prices for Transportation and Distribution of Gas in the United States," prepared for British Gas TransCo, November 1994.

"Economic Issues in Transport Facing British Gas," prepared for British Gas plc, December 1993.

"Overview of Natural Gas Corporation's Open-Access Gas Tariffs and Contract Proposals," prepared for Natural Gas Corporation of New Zealand, October 1993.

Exhibit JDM-2: NERA Report in Alberta Utilities Commission Proceeding 566

December 30, 2010

Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative

NERA
Economic Consulting

Project Team

Jeff D. Makholm, Ph.D.

Agustin J. Ros, Ph.D.

NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
617+1 617 927 4500
617 +1 617 927 4501

Contents

List of Tables

List of Figures

I. Introduction

In 2010, the Alberta Utilities Commission ("AUC" or "Commission") launched an initiative to reform rate regulation in Alberta. A component of that reform is to investigate the application of performance-based ratemaking ("PBR") to the regulation of the electric and gas utilities. PBR-based rate regulation—widely applied around the world—is designed to streamline traditional regulatory practices and to encourage regulated businesses to seek more efficient methods of operation. Such regulatory methods rely upon an objective formula by which regulated prices move between base rate cases according to inflation, relative industry productivity and other factors determined by regulators to be important in setting reasonable rates. In the design of objective PBR formulae, it has become customary for regulatory commissions to rely upon an index number reflecting industry productivity over time called Total Factor Productivity ("TFP"), which has widespread support in the theoretical and empirical economic literature. On September 8, 2010 the AUC engaged National Economic Research Associates ("NERA") to conduct a TFP study for use in AUC Proceeding 566 – Rate Regulation Initiative.[1]

This report describes the methodology, data sources and conclusions of our TFP Study ("Study"). We present our qualifications in Section II. After the Executive Summary in Section III, we present in Section IV a description of the requirements of the TFP study specified by the AUC. In Section V, we describe the methodology used to measure TFP as well as discuss several special considerations in this Study. Sections VI and VII describe the sources of data used for the TFP analysis and the steps undertaken to construct the output and input indexes. Section VIII presents our results on relative industry TFP compared to the U.S. and Canadian economy-wide productivity. The methods we use to calculate TFP for PBR plans are well known, and we provide extensive references in our Study to the standard economic literature on the subject.

II. Qualifications

Dr. Jeff D. Makholm is a Senior Vice President in NERA's Boston office and has been at the firm since 1986. He concentrates on the issues surrounding the privatization, regulation and deregulation of energy and transportation industries. These issues include the broad categories of efficient pricing, market definition and the components of reasonable regulatory practices. Specific pricing issues include tariff design, incentive ratemaking, and the unbundling of prices and services. Issues of market definition include assessments of mergers and the identification and measurement of market power. Issues of reasonable regulatory practices include the creation of credible and sustainable accounting rules for ratemaking as well as the establishment of administrative procedures for regulatory rulemaking and adjudication.

Dr. Makholm is an international expert in the application of price cap regulatory regimes as a variant of traditional cost of service regulation, a subject that draws on his academic work at the University of Wisconsin-Madison (he performed a comprehensive Total Factor Productivity study for electricity companies, using modern index number theory, as his Doctoral Dissertation). On these issues among others, Dr. Makholm has prepared expert evidence, reports

[1] *See*: AUC letter dated September 8, 2010 on Retention of Consultant to Develop a Basic X Factor.

and statements, and has appeared as an expert witness in many state, federal and U.S. district court proceedings as well as before regulatory bodies, High Courts and Parliamentary panels in other countries.

Dr. Makholm's clients in the United States include privately held utility corporations, public corporations and government agencies. He has represented dozens of gas and electric distribution utilities, as well as both intrastate and interstate gas pipeline companies and gas and electricity producers. Dr. Makholm has also worked with many leading law firms engaged in issues pertaining to the local and interstate regulation of energy utilities. Internationally, Dr. Makholm has directed an extensive number of projects in the utility and transportation businesses in 20 countries on six continents. These projects have involved work for investor-owned and regulated business as well as for governments and the World Bank. These projects have included advance pricing and regulatory work prior to major gas, railroad and toll highway privatizations (Poland, Argentina, Bolivia, Mexico, Chile and Australia), gas industry restructuring and/or pricing studies (Canada, China, Spain, Morocco, Mexico and the United Kingdom), utility mergers and market power analyses (New Zealand), gas development and and/or contract and financing studies (Tanzania, Egypt, Israel and Peru), regulatory studies (Chile, Argentina), and oil pipeline transport financing and regulation (Russia). As part of this work, Dr. Makholm has prepared reports, drafted regulations and conducted training sessions for many government, industry and regulatory personnel.

Dr. Makholm has published a number of articles in Public Utilities Fortnightly, Natural Gas and The Electricity Journal and The Energy Law Journal—many involving emerging issues of wholesale and retail competition in gas and electricity, including the issues of unbundled and competitive transport, secondary markets and stranded costs. He is a frequent speaker in the U.S. and abroad at conferences and seminars addressing market, pricing and regulatory issues for the energy and transportation sectors.

Dr. Agustin J. Ros is a Vice President in NERA's Boston office and has been at the firm since 1996. Dr. Ros has appeared as an expert witness in telecommunications and energy proceedings and has participated in arbitration proceedings before international regulatory authorities and before the International Chamber of Commerce Arbitration Panel. He has filed expert reports before regulators in the Bahamas, Barbados, Canada, Guatemala, Indonesia, Italy, Mexico, New Zealand, Peru, Singapore, Spain, and Trinidad and Tobago and the United States and has consulted for clients in Brazil, the Cayman Islands, China, the Eastern Caribbean Islands, the Dominican Republic, Panama, and the United Kingdom. Dr. Ros has worked on dozens of price-cap proceedings in the U.S. and internationally, some of which required estimation of the appropriate X-factor to apply in PBR plans.

Dr. Ros started his career as an Executive Assistant to the Chairman of the Illinois Commerce Commission, where he provided expert advice on matters before the Commission. While at the Commission, Dr. Ros worked on the first RPI-X price regulation plan for Illinois Bell Telephone Company in 1994. The work included estimating the industry's total factor productivity and developing the appropriate X-factor to include in the price-cap plan. During his career at NERA, Dr. Ros has worked on numerous X-factor studies in the U.S. and abroad. In the U.S., he has worked on dozens of X-factor calculations and price cap plans both at the Federal and state level, some of which involved estimating total factor productivity. Dr. Ros was the main expert in

2000 and 2004 in the RPI-X price regulation plan for Telefonica de Peru. The work in Peru included estimating total factor productivity and developing the appropriate X-factor. The work undertaken in Peru is summarized in an article he co-authored that was published in the *Journal of Regulatory Economics*, "X-factor Updating and Total Factor Productivity Growth: The Case of Peruvian Telecommunications, 1996-2003." Dr. Ros was also an expert in the price-cap proceedings in Mexico in 1999 and 2004 that established the X-factor offset to apply to Telmex in its price cap plan.

In 2008 Dr. Ros took a two-year leave of absence from NERA to work for the Organization for Economic Cooperation and Development on a competition policy project in Mexico. Working with the Mexican Competition Commission, he co-led a team of competition experts assessing competition in a number of key sectors of the Mexican economy including, airlines, airports, banking, inter-city bus transport, energy, pharmaceutical, retail superstores, and telecommunications. The team made a series of policy recommendations to improve competition, some of which were enacted into law.

Dr. Ros was an Adjunct Instructor at Northeastern University, where he taught a course on the Economics of Regulation and Antitrust, and he has taught antitrust and competition policy at the University of Anahuac in Mexico City. His articles have appeared in book chapters, in peer-reviewed journals such as the *Journal of Regulatory Economics*, *Review of Network Economics* and *Telecommunications Policy*, and in numerous industry and trade journals, such as *Public Utilities Fortnightly* and the *Journal of Project Finance*. He is co-author of the World Bank's InfoDev ICT Regulation Toolkit, a resource aimed at providing regulators with advice on the design of effective and enabling regulatory frameworks within the context of liberalized telecommunications markets. In addition, his research on local competition has been cited in *Business Week*, and in 2001 he published a book on the productivity of employee-owned firms in the U.S. and Brazil.

III. Executive Summary

PBR-based rate regulation arose with both the wave of utility privatizations that began in the United Kingdom in the 1980s and the search around the same time for more effective ways of regulating prices for the rapidly-changing telecommunication industry. A principal focus of PBR regulation is to provide an alternative to traditional cost-based regulation. With their longstanding institutional regulatory histories, traditional regulation in Canada and the United States meant that regulated prices could only normally change as the result of time consuming and disruptive base rate cases where all costs and billing quantities were subject to measurement and update. PBR regulation permits regulated prices to change without a base rate case, lengthening what is known as "regulatory lag." That lengthened regulatory lag subjects regulated utilities to the type of incentives experienced by company managements in competitive industries where benchmark prices move according to the productivity of the industry in question rather than the particular costs of one company.

The extent to which PBR regulation transmits incentives to utility managements is critically dependent on the transparency, stability and objectivity of the formula that governs price movements between base rate cases. Creating an index number for relative industry TFP with those attributes requires a high-quality, transparent and uniform source of data that is readily available to the parties of regulatory proceedings. Such data are collected by the Federal Energy Regulatory Commission ("FERC") for electricity and combination electricity/gas utilities in its "Form 1," which we use as the source of industry empirical data for this Study. We hold objective uniformity in source data for a TFP study to be of paramount importance when such a study is part of regulatory proceedings where the interests of consumers and investors traditionally vie with one another. The FERC Form 1 data is the only source of information that satisfies the criteria of transparency and objectivity for a broad population of industry participants.

We find that during the period 1972 to 2009 the weighted average TFP growth for our population of 72 U.S. electricity and combination electricity/gas companies was **0.85 percent**. During this time period Canadian and U.S. TFP growth averaged approximately **-0.04 percent** and **0.97 percent**, respectively.

IV. Requirements of the Study

As specified by the AUC, a TFP study contributing to a PBR plan must meet six requirements, with which we concur. Those requirements are as follows:

- Be applicable to Alberta gas and electric utilities;
- Compare productivity for gas and electric utilities to economy wide productivity;
- Make the comparison in a transparent manner;
- Use publicly available data;
- Be for use and testing in a regulatory proceeding and for adjusting rates for Alberta electric and gas utilities; and
- Be filed in AUC Proceeding 566 – Rate Regulation Initiative prior to December 31, 2010.

The results of the TFP Study can be used as a transparent and objective basis for adjusting rates for Alberta electricity and gas utilities. Our TFP Study uses a population of 72 U.S. electricity and combination electricity/gas companies from 1972 to 2009.[2] We measure TFP of the distribution component of the electricity business. The population includes companies of different sizes and located in different parts of the United States reflecting a wide diversity of geography, development and age.

We have a deep and longstanding familiarity with electricity and gas distribution and transmission businesses from a regulatory perspective and conclude that a robust TFP study using FERC Form 1 data is a useful component of a PBR plan that applies to both

[2] Appendix I contains a list of the companies used in the study.

the electricity and gas companies in Alberta. We do not conclude that specialized TFP studies for electricity and gas distribution or electricity transmission would be a useful part of Alberta's PBR initiative, given the lack of uniform and objective data for a broad array of firms that such studies would require to be a part of transparent and objective PBR plans.

A well-formulated PBR plan measures *relative* long-term industry productivity, *vis-à-vis* the economy as a whole, as a component of approved price movements between base rate cases. In this Study we compare our measure of TFP to the U.S. and Canadian economy-wide TFP.

We conclude that transparency is the *sine qua non* of useful inputs to PBR plans. Thus, we document our methodology and the data used to measure TFP for each step of our analysis. Our calculations and work papers, including any adjustments to the electronic data set (for missing observations or rare but evident data anomalies) are available for inspection and assessment by other parties.

All the data in the Study are both publicly available and of a highly standardized form suitable for a broad-based and objective TFP study. The data used to measure total factor productivity for U.S. standalone electricity as well as combination electricity/gas companies are publicly available from the FERC and other publicly available sources.[3] FERC Form 1 data is filed annually by jurisdictional U.S. standalone electricity and combination electricity/gas companies. The Form 1 provides financial and operational information and can be accessed independently and checked by any interested party.

V. Productivity Methodology and Special Considerations

A. Productivity growth

Productivity growth is specified, by definition, as the *difference* between the *growth rates* of a firm's physical outputs and physical inputs. That is, to the extent that a firm's productivity grows, it will transform its inputs into a greater level of output. Thus, the task of productivity measurement involves comparing a firm's outputs and inputs over time. "Total" factor productivity measures all of a firm's inputs and outputs, employing advanced theoretical techniques to combine disparate inputs and outputs into single input and output indexes suitable for comparison to one another.

Because a company produces different types of outputs and uses different types of inputs, a TFP study needs to combine those disparate measures into well defined output and input indexes. Index number theory provides reliable procedures for doing so.[4] In this Study, output, input and

[3] In addition to using FERC data, we use data from the U.S. Bureau of Economic Analysis, the U.S. Labor Department, Statistics Canada, the Handy-Whitman Index of Public Utility Construction, and data compiled by the following financial service firms: Standard and Poor's, Bloomberg, Moody's, and Barclays.

[4] *See*: e.g., Caves, D.W., L.R. Christensen, and W.E. Diewert (1982), "The Economic Theory of Index Numbers and the Measurement of Input, Output and Productivity," *Econometrica*, 50:6, pp. 1393-1414.

TFP indexes are constructed using the Tornqvist/Theil index methodology for the various components of outputs and inputs.[5] We create individual TFP indexes and growth rates for each company for each year. We then calculate a weighted average TFP index and growth rate for each year, using the company's total mWh for each year as weights.[6]

TFP measures for this Study span the period 1972 to 2009 with certain data series for capital additions and retirements reaching back to 1964—the earliest date for which electronic Form 1 data was available. Since the rate of growth of TFP is defined as the difference between the growth rates of inputs and outputs, the annual TFP growth for any company is affected by annual changes in inputs (changes in capital investment or labor utilization) and outputs (the introduction of new services or changes in service demand growth). For this reason, TFP growth analysis should span a sufficient number of years to mitigate the effects of business cycle or other idiosyncratic swings inherent to these factors.[7] Major capital replacements, for instance, would have the immediate effect of reducing measured TFP because the investment appears as an unusually large annual capital expenditure without a corresponding change in demand. Over time, however, replacement of the old capital is likely to increase productivity growth because it embodies new technology to serve demand more efficiently. The more years of data that are added, the more the effects of year-to-year changes in TFP growth are moderated and a picture of long-term productivity growth emerges.

B. Special considerations

Our TFP Study used the FERC cost data directly assigned to the distribution portion of the companies.[8] Costs related to production (generation) and transmission are not included in this Study, nor are costs related to general overheads (*i.e.*, common costs) or customer accounts (e.g., uncollectible accounts).

The data for this Study are electricity data and pertain to electricity companies, whether standalone electricity companies or combination electricity/gas companies. The data used in this

[5] *See*: Christensen, L.R., D.W. Jorgenson, and L.J. Lau (1971), "Transcedental Logarithmic Production Frontiers," *Review of Economics and Statistics*, 55:1, pp. 28-45. The authors developed a particular flexible functional form called the "translog". This is a second-order function. The superlative index number that is exact to the translog functional form is the Tornqvist/Theil index.

[6] One use of this approach can be found in the doctoral dissertation of Jeff D. Makholm, "Sources of Total Factor Productivity in the Electricity Industry," 1986 University of Wisconsin-Madison ("Makholm Dissertation").

[7] With approximately 20 data series for 72 companies over 38 years, the database for our Study contains over 50,000 "data points". We reviewed the data to identify any anomalies and determined that some data points were sufficiently extreme to consider replacement. Although in each instance the data point could be traced back to the original FERC data, in 110 cases we decided that the data points were too extreme to be correct. For these data points, we extrapolated from nearby data points to estimate new numbers. Appendix II lists these adjustments.

[8] As discussed in more detail below, one exception to this specification concerns the data series for labor. Because the FERC data provide the total number of employees but do not assign these employees into the various components of service, such as generation, transmission, and distribution, we applied an allocation formula to assign the number of employees to distribution. In addition, we use an allocation formula to determine the net distribution plant in service in 1964, as set out below.

Study do not include data for standalone gas utilities. We are not aware of a readily-available data source that would permit a comparably transparent TFP study for standalone gas utilities.

There is evidence that productivity of gas and electricity companies are similar. Both electricity and natural gas distribution are highly capital intensive. In some instances, the electricity and gas distribution facilities share the same support structure. According to data from Statistics Canada, TFP growth during the period 1972 to 2006 for Canadian electric power generation, transmission and distribution companies was 0.28 percent (using gross output as the output measure) while for natural gas distribution, water and other systems TFP growth was 0.21 percent (using gross output as the output measure).[9] Using value added as the measure of output, the numbers are 0.37 percent for electric power generation, transmission and distribution companies and 0.34 percent for natural gas distribution, water and other systems.[10]

VI. Methodology - Output Index

Growth in a firm's productivity is measured by the difference between the growth rate of the firm's outputs and the growth rate of the firm's inputs.[11] To create the output index we obtain data on the outputs that the companies produce. Since standalone electricity and combination electricity/gas companies produce several outputs, we also need to determine the weights (shares) that are applied to each type of output in order to determine one overall output index.

A. Output quantity

The output measure that we use in this Study is sales volume (mWh). We combine sales volume for several different types of customers to create the output index. The different categories of sales volumes used in this Study and the accompanying FERC account information are:

1. Residential Electric Sales Volume;[12]
2. Small (Commercial) Electric Sales Volume;[13]
3. Large (Industrial) Electric Sales Volume;[14] and

---

[9] *See*: Statistics Canada, Table 383-0022, Multiproductivity based on gross output; electric power generation, transmission and distribution; Multiproductivity based on gross output; natural gas distribution, water and other systems. A statistical "t-test" rejected the hypothesis that there was a statistically significant difference in the two series. All data are available for a fee at: http://www.statcan.gc.ca/start-debut-eng.html.

[10] *See*: Statistics Canada, Table 383-0022, Multiproductivity based on value added; electric power generation, transmission and distribution; and Multiproductivity based on value added; natural gas distribution, water and other systems. A statistical "t-test" rejected the hypothesis that there was a statistically significant difference in the two series. All data are available for a fee at: http://www.statcan.gc.ca/start-debut-eng.html.

[11] *See*: Caves, Christensen and Diewert (1982) *op. cit.* footnote 4.

[12] Electric Operating Revenues: Residential Sales: Megawatt Hours Sold. FERC FORM 1: Page 301, Line 2, Column d.

[13] Electric Operating Revenues: Small or Commercial Electric Sales: Megawatt Hours Sold. FERC FORM 1: Page 301, Line 4, Column d.

4. Total Public Street, Other, Railroad Sales Volume.[15]

Based upon these data, we create an index for each of the first four categories (residential, commercial, industrial, and public).[16]

B. Output shares

Because we have separate indexes for each of the sales volume categories (*i.e.*, residential, commercial, industrial, and public) we need weights (shares) in order to determine one overall output index. In this Study, we use electric sales ($) for each of the categories (*i.e.*, residential, commercial, industrial, and public) to construct the shares. Specifically, the different categories of sales used in this Study and the accompanying FERC account information are:

1. Residential Electric Sales;[17]

2. Small (or Commercial) Electric Sales;[18]

3. Large (or Industrial) Electric Sale;[19] and

4. Total Public Street, Other, Railroad Sales.[20]

The weight for the output category residential sales volume is the ratio of residential electric sales to the summation of categories (1) – (4) (residential sales, commercial sales, industrial sales and public sales). The same applies for determining the weights for commercial, industrial, and public sales. The output index is then determined using the Tornqvist/Theil methodology.

VII. Methodology – Input Index

To create the input quantity index, we need to measure the growth of three separate inputs (labor, capital and materials, rents and services[21]) and aggregate the three separate inputs into an overall

---

[14] Electric Operating Revenues: Large or Industrial Sales: Megawatt Hours Sold. FERC FORM 1: Page 301, Line 5, Column d.

[15] Electric Operating Revenues: Public Street and Highway Lighting, Other Sales to Public Authorities, and Sales to Railroad and Railways: Megawatt Hours Sold. FORM 1: Page 301.

[16] The comparison base for this index (and all the indexes and calculations in this study) is Duquesne Light Company (1980). That is, the comparison base in the Tornqvist/Theil indexing methodology is Duquesne Light (1980) and all indexes in this study are normalized by the value of that company in that year. Selection of the comparison base is arbitrary and selecting a different company and/or year would not materially affect the results for TFP growth. *See*: Makholm Dissertation *op. cit* footnote 6.

[17] Electric Operating Revenues: Residential Sales. FERC FORM 1: Page 300, Line 2, Column b.

[18] Electric Operating Revenues: Small or Commercial Electric Sales. FERC FORM 1: Page 300, Line 4, Column b.

[19] Electric Operating Revenues: Large or Industrial Sales. FERC FORM 1: Page 300, Line 5, Column b.

[20] Electric Operating Revenues: Public Street and Highway Lighting, Other Sales to Public Authorities, and Sales to Railroad and Railways. FORM 1: Page 300.

input index using weights (shares). Some of the components to create the input quantity index are also used to create an input price index that measures how input prices have changed during the relevant time period. In this section we discuss the methodology used for each input.

A. Labor

1. Labor quantity

For labor quantity we use number of employees. Specifically, we use the number of full-time employees and add 50 percent of part-time and temporary employees to obtain the number of full-time equivalents ("FTEs"). The FERC Form 1 does not contain employment data separated into the different components, including generation, transmission, and distribution. Therefore, we used the following formula to assign the FTEs to distribution:

$$FTEs\ Distribution = (FTEs) \times \left(\frac{Direct\ Payroll\ to\ Electric\ Distribution}{Total\ Electric\ Salary\ \&\ Wages} \right).$$

The FERC accounts that we use to create the labor quantity index are:

1. Total Regular Full-Time Employees;[22]
2. Total Part-Time and Temporary Employees;[23]
3. Direct Payroll to Electric Distribution;[24] and
4. Total Electric Salaries & Wages.[25]

Beginning in 2002, the FERC Form 1 no longer contains employee data. To account for this change, we estimated the number of employees by using the previous years' electric distribution payroll growth rate for the years 2002 to 2009.[26] Based upon these data, we create a labor quantity index.[27]

[21] In a TFP study, the materials, rents and services category ("MRS") is also known as the "all others" category.

[22] Total Regular Full-Tim Employees: FERC FORM 1: Page 323, Line 2 (1972-2001).

[23] Total Part-Time Employees: FERC FORM 1: Page 323, Line 3 (1972-2001).

[24] Direct Payroll: Electric Distribution Operation and Maintenance. FERC FORM 1: Page 354, Line 23, Column b.

[25] Total Electric Operation and Maintenance Salaries and Wages: FERC FORM 1: Page 354, Line 28, Column d.

[26] For the missing years of employment data, we took the previous year's growth rate in the account direct payroll electric distribution and applied that growth rate to the previous year's employees.

[27] *See*: footnote 16.

2. Labor share

In order to obtain an aggregate input index made up of the labor, capital and materials, rents and services indexes we must use weights (shares). For labor, we use the FERC account Direct Payroll to Electric Distribution.

3. Labor price

The price of labor is calculated by dividing Direct Payroll to Electric Distribution by FTEs Distribution. We construct a labor price index that is then combined with the capital and material rents and services price index to construct an overall input price index.

B. Materials, Rents and Services ("All Others")

1. MRS quantity

Materials, rents and services are an important input into a company's production process. To calculate the MRS quantity, we follow a two-step process. The first step is to obtain MRS expenses. The second step is to deflate the MRS expense by a price index.

With respect to the first step, we calculate the MRS expense as the difference between operating expenses and labor expenses. Specifically, we subtract Direct Payroll to Electric Distribution (used above in determining labor input) from Total Distribution Operation and Maintenance Expenses (Distribution O&M). Salary and wages are a component of Distribution O&M and need to be removed. Depreciation and amortization are not a component in the FERC Distribution O&M account.

With respect to the second step, we divide the MRS expense by the Gross Domestic Product Price Index to obtain a measure of the MRS quantity input.

We use the following data from FERC and the U.S. Bureau of Economic Analysis to create a material, rents and services index:[28]

1. Total Distribution Operations and Maintenance Expenses;[29] and

2. U.S. Gross Domestic Product Price Index.[30]

2. MRS share

We use weights (shares) in order to obtain an aggregate input index made up of labor, capital and materials, rents and services indexes. The MRS expense is used as the weight (share).

---

[28] *See*: footnote 16.

[29] Total Distribution Operation and Maintenance Expenses: FERC FORM 1: Page 322, Line 156, Column b.

[30] Bureau of Economic Analysis, National Income Product Accounts (NIPA) Table 1.1.4 using 1987 as base year.

3. MRS price

For the price of MRS, we use the U.S. GDP-PI.

C. Capital

Unlike labor services, which are rented on an ongoing basis at a relatively easily quantifiable price, capital equipment rental prices must be imputed because capital is purchased in one time period but delivers a flow of service over many subsequent time periods.

In addition, the "stock" of capital at any one point in time must be calculated in a way that permits comparisons across time. This is due to the fact that the "value" of the capital stock is affected by many variables. First, at any point in time there are varying vintages of capital that a company uses, some purchased recently and others that have been in use for much longer periods of time. The existence of heterogeneous types of plant and equipment[31] and the simultaneous use of capital of varying vintages at different stages of depreciation requires a method of comparison. Second, besides the initial purchase price, other variables affect the value of the capital stock, such as tax laws, depreciation, interest rates, and the differences between accounting and economic cost.

To measure the economic value of such assets, we must: (1) account for the loss of economic value represented by depreciation; and (2) adjust for changes in plant construction prices over time. A measure of the capital stock that meets these requirements is the "replacement cost of plant" expressed in constant dollars, as discussed below.

1. Capital quantity

For the capital quantity, we measure the replacement cost of distribution plant expressed in constant dollars. One common method of measuring the replacement cost of distribution plant expressed in constant dollars is the perpetual inventory method which accounts for the presence of different vintages of capital stock at any given point in time.[32]

The first year of our data sample (1972) is the base year. The first year for which capital information is available (1964) is the benchmark year. From the benchmark year forward, we adjust capital stock annually to reflect actual capital stock additions and actual capital stock retirements.[33] In the benchmark year (1964), there is capital of varying vintages in place. Because the vintages of this capital stock are not known to us, we must approximate them.[34] By

---

[31] Plant and equipment is a common term used to denote a firm's capital assets.

[32] L.R. Christensen and D.W. Jorgenson (1969), "The Measurement of Real Capital Input, 1929-1967," *Review of Income and Wealth*, Series 15, No. 4, December, pp. 293-320.

[33] We use a "one-hoss shay" depreciation pattern specification for capital—*i.e.*, where the flow of services received from capital is constant at full productive efficiency up until its retirement.

[34] If we could track the data back to the company's inception, we would have a full set of additions and retirements and not need to estimate the benchmark year. However, since that data is not available we trace the data back as far as we can and work with what is available.

allowing the benchmark year (*i.e.*, the first year for which we have capital data) to predate the base year (*i.e.*, the first year of the data sample to be used for TFP calculations), the effect of this approximation is mitigated.

For the benchmark year, we compute capital quantity from the Handy-Whitman Index of Public Utility Construction ("HW"),[35] which provides asset price indexes and the capital book value in the benchmark year. The Handy-Whitman Index numbers furnish a yardstick for fluctuations in the value of property, reflecting constant dollar reproduction costs. Average prices and cost trends are used to develop the Handy-Whitman Index. The Handy-Whitman Index is commonly used by utilities and regulators in their calculations of rate base for rate cases and in their valuations of property for insurance purposes.

The formula for calculating the value of the distribution capital stock in the benchmark year is:

$$K_{benchmark} = \frac{\textit{book value of utility plant in benchmark year}}{\sum_{1}^{20} i \left[\frac{i}{\sum_{i=1}^{20} i} \right] HW_{1944+i}}.$$

Capital quantities after the benchmark year are given by:

$$K_t = K_{t-1} + \frac{\textit{gross additions to plant}_t}{HW_t} - \frac{\textit{retirements}_t}{HW_{t-s}},$$

where s is the depreciable service life of the asset.

The equation above lists two different indexes—one for additions and one for retirements. In the FERC Uniform System of Accounts, additions are added in current dollars, and retirements are subtracted according to their original dollars.

The FERC accounts that are used to create the capital quantity index are:

1. Total Distribution Plant: Additions;[36]
2. Total Distribution Plant: Retirements;[37]
3. Production Plant in Service;[38]

[35] The Handy-Whitman Index is prepared especially for electric, gas, and water utilities and it is the only known publication of its kind. The electric and gas groups are arranged according to the FERC Uniform System of Accounts.

[36] Total Distribution Plant: Additions. FERC FORM 1: Page 206, Line 75, Column c.

[37] Total Distribution Plant: Retirements. FERC FORM 1: Page 207, Line 75, Column d.

4. Transmission Plant in Service;[39]

5. Distribution Plant in Service;[40]

6. General Plant in Service;[41] and

7. Net Plant in Service.[42]

We also use the Handy-Whitman Index of Public Utility Construction for electric utilities. The Handy-Whitman Index provides an index number for six regions for the U.S. for every year dating back to 1912, including an index number for Total Distribution Plant. The index uses 1973 as its base year.[43]

Data on production, transmission, general and net plant in service is required in order to determine the net distribution plant in service for the benchmark year (1964). The FERC account for distribution plant in service is for the gross (total) book value of distribution plant while for the benchmark year we require net distribution plant in service. The following methodology is used to obtain net distribution plant in service for the benchmark year (1964):

$$Net\ Distribution\ Plant = \frac{(Net\ Plant\ in\ Service) \times (Distribution\ Plant\ in\ Service)}{(Production + Transmission + Distribution + General\ Plant\ in\ Service)}.$$

Using these data, we create a capital quantity index.[44]

2. Capital share

In order to obtain an aggregate input index made up of the labor, capital and materials, rents and services indexes we use weights (shares). For capital, the share used is the capital quantity described above multiplied by the price of capital. Our methodology for determining the price of capital is discussed in the next subsection.

---

[38] Total Production Plant in Service: End Year Balance. FERC FORM 1: Page 205, Line 46, Column g (1964).

[39] Total Transmission Plant in Service: End Year Balance. FERC FORM 1: Page 207, Line 58, Column g (1964).

[40] Total Distribution Plant in Service: End Year Balance. FERC FORM 1: Page 207, Line 75, Column g (1964).

[41] Total General Plant: End Year Balance. FERC FORM 1: Page 207, Line 99, Column g (1964).

[42] Net Electric Utility Plant in Service: FERC FORM 1: Page 200, Line 15, Column c (1964).

[43] For the last ten years, the Handy-Whitman data uses two index numbers for each year, one for January 1st and the other for July 1st, rather than an annual number. To convert these two numbers into one annual number, we examined the formula Handy-Whitman used for years prior to 2001 and found the following calculation to transform the two six-month numbers into an annual figure: $HW_t = (HW_{Jan\ 1,t}$ x $2(HW_{Jul\ 1,\ t})$ x $HW_{Jan\ 1,\ t+1})/4$. We calculated an annual number for 2001-2009 using this formula. In addition, the Handy-Whitman data is divided into six regions: North Atlantic, South Atlantic, North Central, South Central, Plateau, and Pacific. We cross-referenced the states in each of these six regions with the state in which each operating company is located to find the applicable index number.

[44] *See*: footnote 16.

3. Capital price

Capital service prices are based on the relationship between the acquisition price of new capital goods and the present value of all future services from these goods. To calculate the price of capital we use the following formula based upon Christensen and Jorgenson (1969):[45]

$$P_{k,t} = \left(\frac{1-k-uz}{1-u}\right)(r-i)\left[1-\left(\frac{1+i}{1+r}\right)^{s}\right]^{-1} HW_{t-1}\,.$$

where:

1. $k =$ the investment tax credit rate;
2. $u =$ the corporate profits tax rate;
3. $z =$ the present value of the depreciation deduction on new investment;
4. $r =$ the cost of capital;
5. i = the expected inflation rate over the lifetime of the assets;
6. $s =$ asset lifetime; and
7. $HW_{t-1} =$ Handy-Whitman's asset price in the prior year.

For k, there has been no general investment tax credit for over twenty years.[46] For u, the corporate profits tax rate, we obtained information using Form 1120 on the IRS website.[47]

The present value of future depreciation deductions on new investment, z, is a function of the tax depreciation method used, the asset tax lifetime, and the rate of return. The distinction in asset lives is drawn because depreciation for tax purposes is frequently allowed to take place over a much shorter time span (e.g., five years, or the "sum of the years' digits" method[48]) than is allowed for ratemaking purposes. Using the sum of the years' digits method, z then becomes:

$$z = \frac{2}{RT}\left[1-\left[\frac{(1+R)}{R(T+1)}\right]\left[1-\left(\frac{1}{(1+R)}\right)^{T+1}\right]\right],$$

[45] *Op. cit.* footnote 32.

[46] The list of all business tax credits can be found at the IRS website for small businesses: http://www.irs.gov/businesses/small/article/0,,id=99839,00.html, accessed on December 12, 2010.

[47] *See*: IRS publication, "Instructions for Forms 1120 and 1120-A" for each year, available at http://www.irs.gov/app/picklist/list/priorFormPublication.html, accessed on December 30, 2010.

[48] The sum of the years' digits method is one form of accelerated depreciation. We assign a number to each year of the asset's useful life, starting with 1 for the first year, etc. These numbers are added to get their sum, i.e., n(n+1)/2. A separate depreciation rate is then calculated for each year, with the number assignments being reversed. For example, with a 12-year asset life, the sum of the digits is 78. Depreciation in year 1 is then 12/78.

where R is the rate of return for discounting depreciation deductions and T is the tax lifetime of the asset. In this Study we use a value of 0.511.[49]

To calculate r, the cost of capital, we used the bond yields of the company's debt. We obtained monthly long-term bond ratings from Standard & Poor's ("S&P") Ratings Direct for each of the companies.[50] We then downloaded S&P's and Moody's monthly utility bond yields from Bloomberg for Aaa, Aa, A, and Baa ratings.[51]

To find i, the expected inflation rate over the lifetime of the assets, we obtained data on the Daily Treasury Yield Curve Rates for 30-year bonds from the U.S. Treasury website and averaged them to arrive at a Yearly Treasury Yield Rate (Risk-Free Return).[52] To find the Risk-Free Return Net of Inflation, we downloaded the Consumer Price Index from the Bureau of Labor Statistics and subtracted it from the Yearly Treasury Yield Rate for each year from 1972-2009.[53] We then averaged this differenced to arrive at the Risk-Free Return Net of Inflation for the period 1972-2009. To find the Expected Long Term Inflation Rate for each year, we subtracted the Risk-Free Return Net of Inflation from the Yearly Treasury Yield Rate.

For s, the asset lifetime, we use 33 years. HW_{t-1} refers to the same Handy-Whitman Total Distribution Plant asset price index number as that used to calculate the capital index.

---

[49] *See*: Makholm Dissertation *op. cit* footnote 6. Christensen and Jorgenson (1969), *op. cit*. footnote 32, and Gollop and Jorgenson, "U.S. Productivity Growth by Industry, 1947-1973," Discussion Paper 7712, Social Systems Research Institute, University of Wisconsin, Madison, September (1977), use a value of R (the rate of return for discounting depreciation deductions) of 0.10. M. Sing (Doctoral Thesis University of Wisconsin 1984), employs a value of T (the tax lifetime of the asset) of 23 years on electric plants. These values give a value of z of 0.511.

[50] Because S&P did not have a ratings history for Commonwealth Electric, one of the companies that was consolidated into NSTAR, we found the rating history for that company on Bloomberg.

[51] Because Moody's does not provide yields for anything lower than the Baa rating, we downloaded Fair Value daily utility bond yields from Bloomberg for the Ba rating. We also downloaded monthly (non-utility specific) junk bond yields from Barclays for the B and D ratings, both of which are non-investment grade. In some instances, the company's rating was between the ratings provided by Moody's, such as an A1 rating. In these cases we rounded to the nearest available rating and used the yield for that rating.

[52] The Daily Treasury Yield Curve Rates for 30-year bonds were discontinued between February 2002 and February 2006. For this time period, the U.S. Treasury published Daily Treasury Yield Curve Rates for 20-year bonds as well as an "extrapolation factor," which was designed to be added to the 20-year yield curve rates to estimate 30-year yield curve rates. We therefore used the 20-year yield curve rates plus the extrapolation factor as a substitute for the 30-year yield curve rates between February 2002 and February 2006.

[53] Bureau of Labor Statistics, available at: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt, accessed on December 30, 2010.

VIII. Results

In this section we present our results for output, inputs and TFP growth.

A. Output Index

Table 1 summarizes the average output shares and the average output index growth by type of service during the period 1972 to 2009. Residential service comprised the largest component of the firms' output, followed by commercial, industrial and the public category. The fastest growing output measure was commercial, followed by residential, industrial and the public category.

Table 1. Output shares and output index growth, 1972-2009[54]

Service	Share of Output	Output Index Growth Rate
	(percent)	
Residential	41.27	2.54
Commercial	34.95	3.68
Industrial	20.51	1.41
Public	3.26	1.31

Figure 1 in Appendix III depicts the output shares from 1972 to 2009 while Figure 2 through Figure 5 depict the growth rates for the different outputs during the same period. Figure 1 shows that residential and commercial shares increased slightly during the period while the share of industrial output declined, beginning in the mid 1980s. The share for public remained fairly constant at about three percent over the period.

Residential output growth during the period averaged 2.54 percent and was the least volatile (standard deviation of 2.77 percent) of the four output measures during the period (see Figure 2). Most of the growth was positive, with the exception of six years, three of which occurred after 2005. The year with the fastest growth was 1973, at 8.00 percent, and the year with the slowest growth was 1992, when the residential output index fell by 2.92 percent.

Commercial output growth during the period averaged 3.68 percent and was the second least volatile output series with a standard deviation of 2.88 percent (see Figure 3). There were only three years of negative growth for commercial output, two of which occurred in 2008 and 2009. The year with the fastest growth was 1988, at 10.31 percent, and 2009 was the year with the slowest growth, -4.00 percent.

Industrial output growth during the period averaged 1.41 percent and was the most volatile output series with a standard deviation of 3.69 percent (see Figure 4). There were 12 years of

[54] Source: NERA TFP Study, share of output and growth rates are unweighted.

negative growth during the period. The year with the fastest growth was 1976, at 10.73 percent. The year with the slowest growth was 1982, at -7.18 percent.

Finally, public output growth during the period averaged 1.31 percent, the output measure with the slowest growth rate and the second most volatile output series with a standard deviation of 3.20 percent (see Figure 5). There were 10 years of negative growth and the year with the fastest growth rate was 2003, at 14.20 percent. The year of slowest growth was 2005, at -3.76 percent.

B. Input Index

Table 2 summarizes the average input shares and the average input growth rate by the type of input during the period 1972 to 2009. Capital accounted for the largest share of the companies' inputs at a little over 63 percent, followed by labor at 18.6 percent and MRS at 17.8 percent. Labor was the slowest-growing input, followed by capital and MRS.

Table 2. Input shares and input index growth, 1972-2009[55]

Input	Share	Input Index Growth Rate
	------------------------(percent)------------------------	
Labor	18.58	1.16
MRS	17.80	4.17
Capital	63.62	1.32

Figure 6 depicts the input shares during the period 1972 to 2009 while Figure 7 through Figure 9 depict the growth rate of the inputs during the same period. The share of capital increased during the period from 60 percent in 1972 to 73 percent in 2009. Labor decreased from 23 percent in 1972 to 12 percent in 2009 while MRS increased slightly initially and then decreased in the later years.

Labor input growth during the period averaged 1.16 percent with a standard deviation of 4.95 percent, the most volatile input series. MRS input growth during the period averaged 4.17 percent with a standard deviation of 4.49 percent. Capital input growth during the period averaged 1.32 percent with a standard deviation of 0.61 percent, the least volatile input series.

C. TFP Growth

Table 3 summarizes output, input and TFP growth for each year. Figure 10 in Appendix III depicts the yearly TFP growth rates. The weighted average TFP growth for our population of companies is 0.85 percent. Figure 10 depicts a TFP growth that fluctuates considerably year to year and that in more recent years exhibits sharp declines. The fastest TFP growth occurred in 1976 at 4.96 percent while the slowest TFP growth occurred in 2008 at -5.26 percent.

[55] Source: NERA TFP Study, share of input and growth rates are unweighted.

Table 3. Output, input and TFP growth, 1973-2009[56]

Year	Output growth	Input growth	TFP growth
		(percent)	
1973	7.59	2.88	4.72
1974	-0.50	0.05	-0.55
1975	2.32	-2.23	4.55
1976	5.12	0.16	4.96
1977	4.38	1.67	2.71
1978	3.52	2.35	1.17
1979	2.87	1.31	1.56
1980	1.39	2.19	-0.79
1981	1.05	0.60	0.45
1982	-1.03	2.53	-3.57
1983	2.91	1.96	0.95
1984	4.59	1.78	2.80
1985	1.87	2.08	-0.20
1986	2.77	0.37	2.40
1987	4.11	1.81	2.30
1988	5.07	-0.04	5.11
1989	2.18	1.43	0.75
1990	1.70	0.70	1.00
1991	2.33	1.82	0.51
1992	-0.64	-0.81	0.17
1993	4.20	1.21	2.99
1994	2.27	0.37	1.90
1995	2.74	-1.20	3.95
1996	2.01	0.39	1.62
1997	1.12	0.52	0.60
1998	3.15	2.62	0.53
1999	1.72	1.82	-0.10
2000	3.13	1.02	2.12
2001	-1.02	2.39	-3.41
2002	3.09	2.66	0.43
2003	0.66	3.53	-2.87
2004	2.00	-0.29	2.29
2005	2.94	1.28	1.66
2006	-0.24	2.69	-2.92
2007	2.33	2.28	0.05
2008	-1.84	3.43	-5.26
2009	-3.92	-1.01	-2.91
Average	2.11	1.25	0.85

[56] Note: Output, input and TFP growth in each year are weighted by total mWh. Source: NERA TFP Study.

D. Economy-wide TFP

We have been asked to compare our Study TFP growth to economy-wide productivity. Canadian TFP growth during the 1972 to 2009 period has averaged -0.04 percent. During the same time period U.S. TFP growth has averaged 0.91 percent. Table 4 summarizes the yearly TFP growth rates for the U.S. and Canadian economy *vis-à-vis* the TFP growth rates in our Study. Figure 11 and Figure 12 compare our Study TFP growth to the TFP growth for the Canadian and U.S. economies, respectively.

Table 4. Study TFP growth and U.S. and Canadian economy TFP growth, 1973-2009[57]

Year	Study TFP Growth	U.S. TFP Growth	Canadian TFP Growth
	(percent)		
1973	4.72	2.80	0.73
1974	-0.55	-3.40	-1.56
1975	4.55	1.20	-1.37
1976	4.96	3.60	3.97
1977	2.71	1.60	1.55
1978	1.17	1.30	-0.10
1979	1.56	-0.30	-1.63
1980	-0.79	-2.20	-2.38
1981	0.45	0.30	-0.32
1982	-3.57	-3.20	-1.91
1983	0.95	2.90	1.41
1984	2.80	3.00	3.31
1985	-0.20	1.30	1.24
1986	2.40	1.70	-1.53
1987	2.30	0.40	-0.10
1988	5.11	0.80	0.10
1989	0.75	0.30	-1.24
1990	1.00	0.70	-1.78
1991	0.51	-0.90	-2.78
1992	0.17	2.50	0.55
1993	2.99	0.20	0.98
1994	1.90	0.70	2.38
1995	3.95	-0.30	0.21
1996	1.62	1.70	-0.95
1997	0.60	0.80	1.17
1998	0.53	1.50	0.74
1999	-0.10	1.80	1.99
2000	2.12	1.70	2.25
2001	-3.41	0.80	-0.30
2002	0.43	2.40	0.50
2003	-2.87	2.60	-0.50
2004	2.29	2.60	-0.70
2005	1.66	1.00	0.20
2006	-2.92	0.50	-0.71
2007	0.05	0.50	-0.61
2008	-5.26	0.10	-2.25
2009	-2.91	0.80	-2.20
Average	0.85	0.91	-0.04

[57] Source: TFP growth: NERA TFP Study, Table 3 above; U.S. TFP growth: U.S. Bureau of Labor Statistics, Historical Multifactor Productivity Measure, Table PG 4c available at: http://www.bls.gov/mfp/mprdload.htm, accessed on December 30, 2010, data for 2009 is preliminary; Canadian TFP growth: Statistics Canada, Table 383-0021, Multifactor productivity in the aggregate business sector and major sub-sectors; Canada; Multifactor productivity; Business sector (index, 2002=100) available for a fee at: http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 17, 2010.

E. Input price growth

We also measured the input price growth during the period 1972 to 2009 and compared it to the input price growth of the Canadian and U.S. economy, respectively. Table 5 summarizes the results.

Input prices in our TFP Study grew at an annual rate of 5.61 percent compared to input price growth for the Canadian and U.S. economy of 4.46 percent and 4.84 percent, respectively. Figure 13 compares our Study input price growth to the input price growth for the Canadian economy during the same period while Figure 14 compares our Study input price growth to the input price growth for the U.S. economy during the same period.

We conducted a statistical test to test the hypothesis that there was a statistically significant difference in the input price growth series for our Study and the input price growth series for the Canadian and U.S. economy. Specifically, we estimated the probability associated with a Student's t-test and rejected the hypothesis that there was a statistically significant difference in the input price growth series for our Study and the input price growth series for the Canadian and U.S. economy.

Table 5. Study input price growth and U.S. and Canadian economy input price growth, 1973-2009[58]

Year	Input price growth(1)	U.S. input price growth	Canadian input price growth
	(percent)		
1973	3.03	8.35	10.40
1974	8.19	5.68	13.76
1975	19.55	10.65	9.26
1976	12.51	9.34	13.58
1977	-0.35	7.97	8.12
1978	6.52	8.32	6.58
1979	11.20	8.02	8.49
1980	13.82	6.92	7.69
1981	11.90	9.67	10.42
1982	4.08	2.90	6.53
1983	1.49	6.85	6.87
1984	5.29	6.76	6.61
1985	1.13	4.33	4.28
1986	9.75	3.91	1.57
1987	3.73	3.30	4.47
1988	-2.77	4.23	4.62
1989	5.94	4.08	3.21
1990	3.53	4.56	1.47
1991	2.38	2.64	0.13
1992	2.45	4.87	1.85
1993	5.84	2.41	2.50
1994	-0.68	2.81	3.53
1995	5.02	1.78	2.48
1996	0.16	3.60	0.60
1997	2.00	2.57	2.48
1998	5.22	2.63	0.20
1999	5.36	3.27	3.72
2000	0.31	3.87	6.41
2001	11.96	3.06	0.82
2002	11.96	4.02	1.61
2003	-6.16	4.75	2.80
2004	-4.41	5.44	2.49
2005	4.46	4.34	3.49
2006	6.10	3.76	1.93
2007	8.36	3.44	2.58
2008	20.60	2.29	1.86
2009	8.12	1.72	-4.34
Average	5.61	4.84	4.46

[58] Note: (1) Input price growth is weighted by total mWh. Input price growth for U.S. and Canadian economy are derived from: Economy-wide input price growth = GDP-PI growth + economy-wide TFP growth. Source: Input price growth: NERA; U.S. GDP-PI: Bureau of Economic Analysis, Table 1.1.9, *Implicit Price Deflators for Gross Domestic Product*, available at: http://www.bea.gov/national/nipaweb/SelectTable.asp?Selected=N, accessed on December 30, 2010; Canadian GDP-PI: Statistics Canada, Table 380-0056, *Implicit Chain Price Index Gross Domestic Product*, available for a fee at http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 17, 2010.

IX. APPENDIX I. List of companies used in the Study

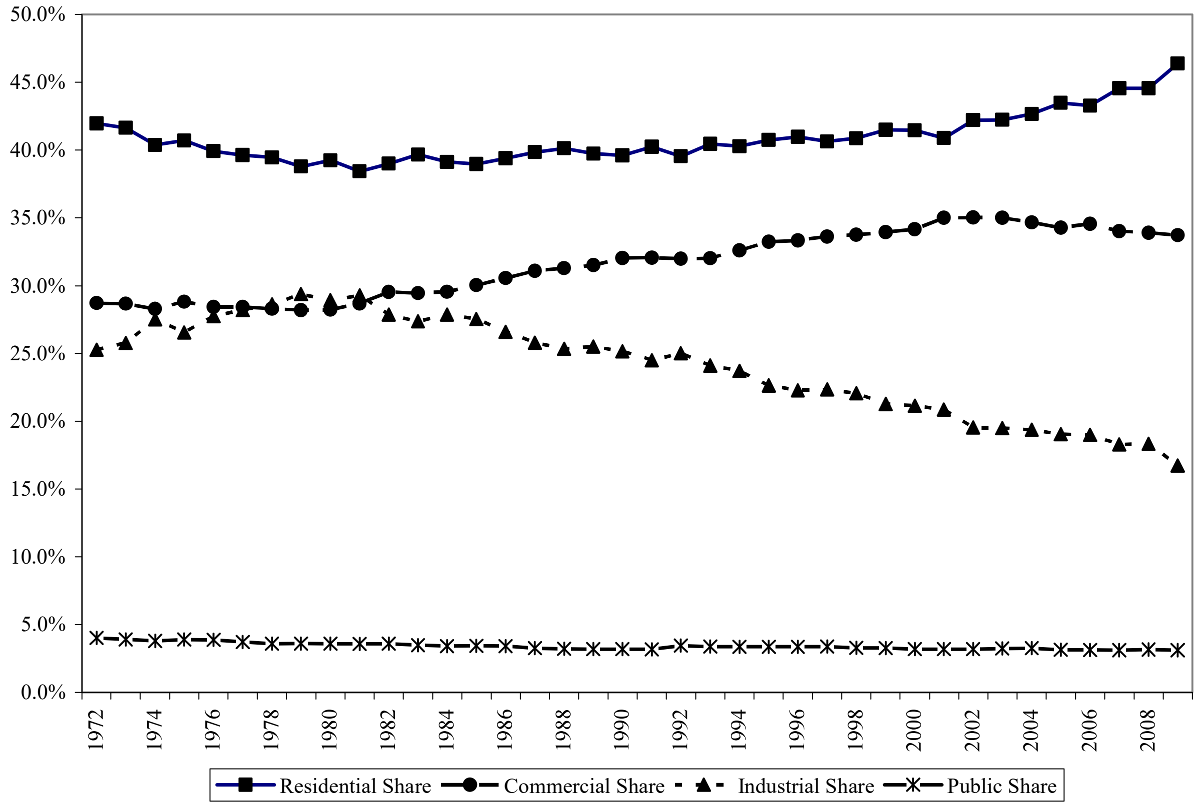
Alabama Power Company
Appalachian Power Company
Arizona Public Service Company
Baltimore Gas and Electric Company
Carolina Power & Light Company
Central Hudson Gas & Electric Corp
Central Illinois Light Company
Central Vermont Public Service Corporation
Cleveland Electric Illuminating Company
Columbus Southern Power Company
Commonwealth Edison Company
Connecticut Light and Power Company
Consolidated Edison Company of New York, Inc.
Consumers Energy Company
Dayton Power and Light Company
Delmarva Power & Light Company
Detroit Edison Company
Duke Energy Indiana, Inc.
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
El Paso Electric Company
Empire District Electric Company
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, L.L.C.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Florida Power & Light Company
Florida Power Corporation
Green Mountain Power Corporation
Gulf Power Company
Idaho Power Company
Illinois Power Company
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas and Electric Company
Kentucky Utilities Company
Madison Gas and Electric Company
Massachusetts Electric Company
MDU Resources Group, Inc.
Metropolitan Edison Company
Mississippi Power Company
Monongahela Power Company
Narragansett Electric Company
Nevada Power Company
New York State Electric & Gas Corp
Niagara Mohawk Power Corporation
Northern Indiana Public Service Co.
NSTAR
Ohio Edison Company
Oklahoma Gas and Electric Company
Orange and Rockland Utilities, Inc.
Otter Tail Corporation
Pacific Gas and Electric Company
PECO Energy Company
Pennsylvania Electric Company
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Electric and Gas Company
Puget Sound Power and Light Company
South Carolina Electric & Gas Co.
Southern California Edison Co.
Southern Indiana Gas and Elec. Company, Inc.
Southwestern Electric Power Company
Southwestern Public Service Company
Tucson Electric Power Company
Virginia Electric and Power Company
Western Massachusetts Electric Company
Wisconsin Electric Power Company
Wisconsin Public Service Corp

X. APPENDIX II. List of changes made to original FERC data

Company Name	Year(s)	Variable(s) Changed	Methodology
Appalachian Power Company	1972	TWGSAL	Extrapolated backwards using DWGSAL growth rate.
Central Illinois Light Company	2002	DWGSAL, TWGSAL, ADD, & RET	Averaged respective 2001 & 2003 values.
Cleveland Electric Illuminating Company	1975	TWGSAL	Averaged 1974 & 1976 values.
Consolidated Edison Company of New York, Inc.	2002-2009	DWGSAL	Extrapolated forwards using TWGSAL growth rates.
Consolidated Edison Company of New York, Inc.	1983	DWGSAL	Averaged 1982 & 1984 values.
Consumers Energy Company	2002-2005	DWGSAL, TWGSAL, ADD, RET, & O&M	Averaged respective 2001 & 2006 values.
Consumers Energy Company	1993	DWGSAL & TWGSAL	Averaged respective 1992 & 1994 values.
Delmarva Power & Light Company	1979-1986	TWGSAL	Extrapolated forwards using DWGSAL growth rates.
Detroit Edison Company	2005	DWGSAL	Averaged 2004 & 2006 values.
Duke Energy Kentucky, Inc.	1996	DWGSAL & TWGSAL	Averaged respective 1995 & 1997 values.
Illinois Power Company	2007-2009	OPREVI	Extrapolated forwards using MWHIND growth rates.
Illinois Power	1977	MWHCOM & MWHIND	Averaged respective 1976 & 1978 values.
Jersey Central Power & Light Company	2002	OPREVP	Averaged 2001 & 2003 values.
Jersey Central Power & Light Company	1999-2002	FTEMPLOY, PTEMPLOY, DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values.
Kentucky Utilities Company	2005	RET	Averaged 2004 & 2006 values.
MDU Resources Group	1987	TWGSAL	Extrapolated forwards using DWGSAL growth rate.
Metropolitan Edison Company	1999-2002	FTEMPLOY, PTEMPLOY, DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values.
Monongahela Power Company	1997-2001	FTEMPLOY & PTEMPLOY	Extrapolated forwards using TWGSAL growth rates.
Pennsylvania Electric Company	1999-2002	DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values.
Public Service Company of New Hampshire	1991-1992	O&M	Averaged 1990 & 1993 values.
Virginia Electric and Power Company	2002	DWGSAL	Averaged 2001 & 2003 values.
Wisconsin Electric Power Company	1982	TWGSAL	Averaged 1981 & 1983 values.
Wisconsin Public Service Corp	1972	TWGSAL	Extrapolated backwards using DWGSAL growth rate.

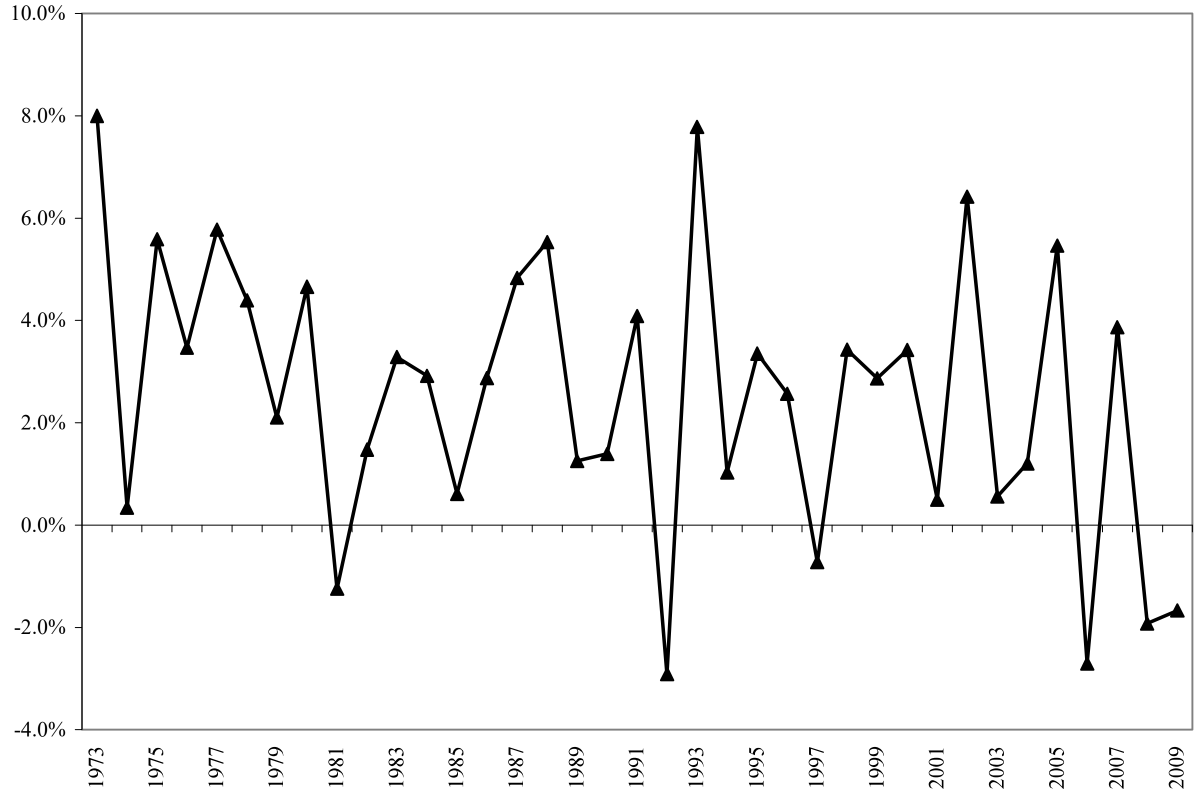
XI. APPENDIX III. Figures

Figure 1. Output shares, 1972-2009



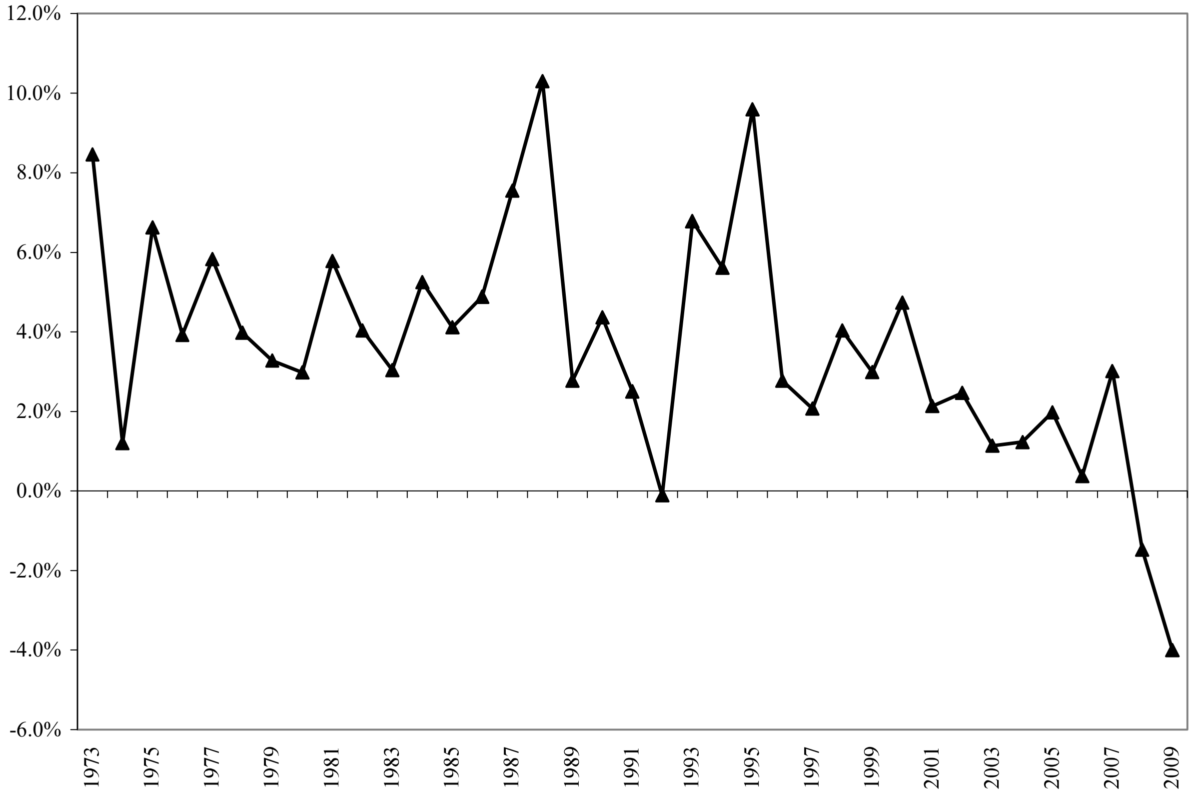
Source: NERA TFP Study

Figure 2. Residential output index growth, 1973-2009



Source: NERA TFP Study

Figure 3. Commercial output index growth, 1973-2009

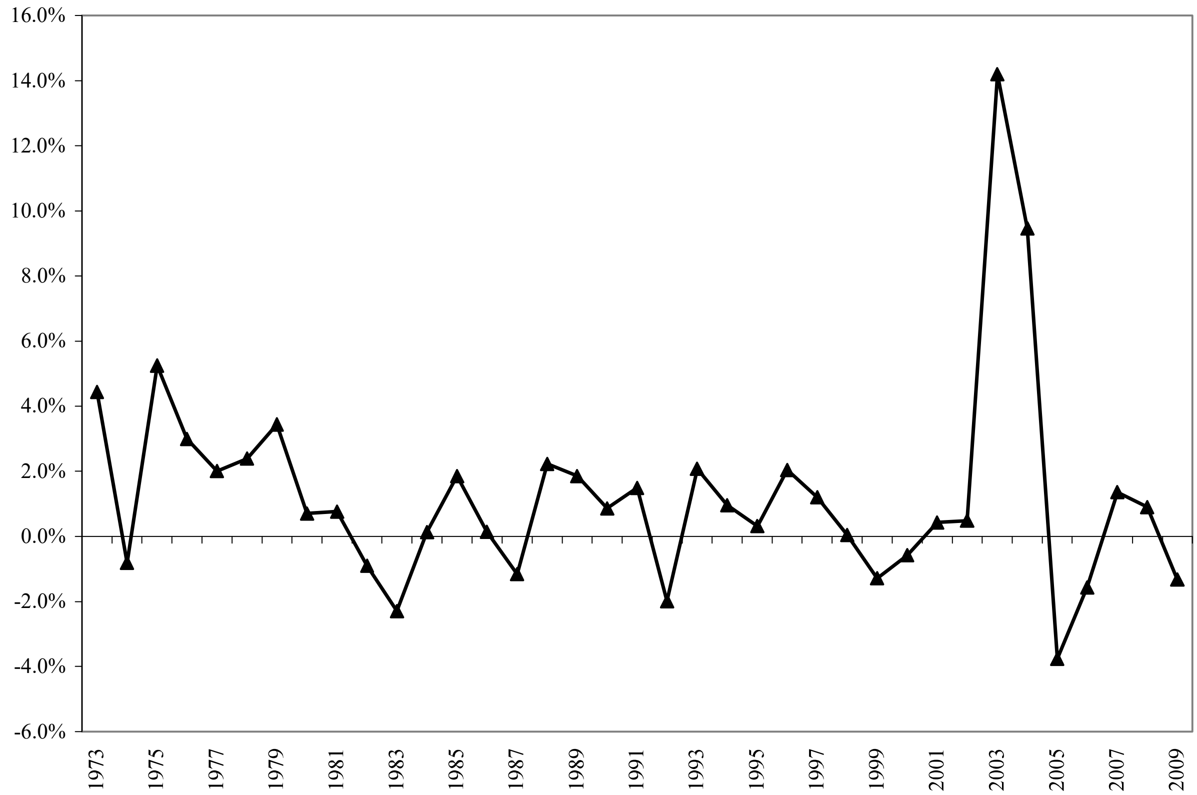


Source: NERA TFP Study

Figure 4. Industrial output index growth, 1973-2009

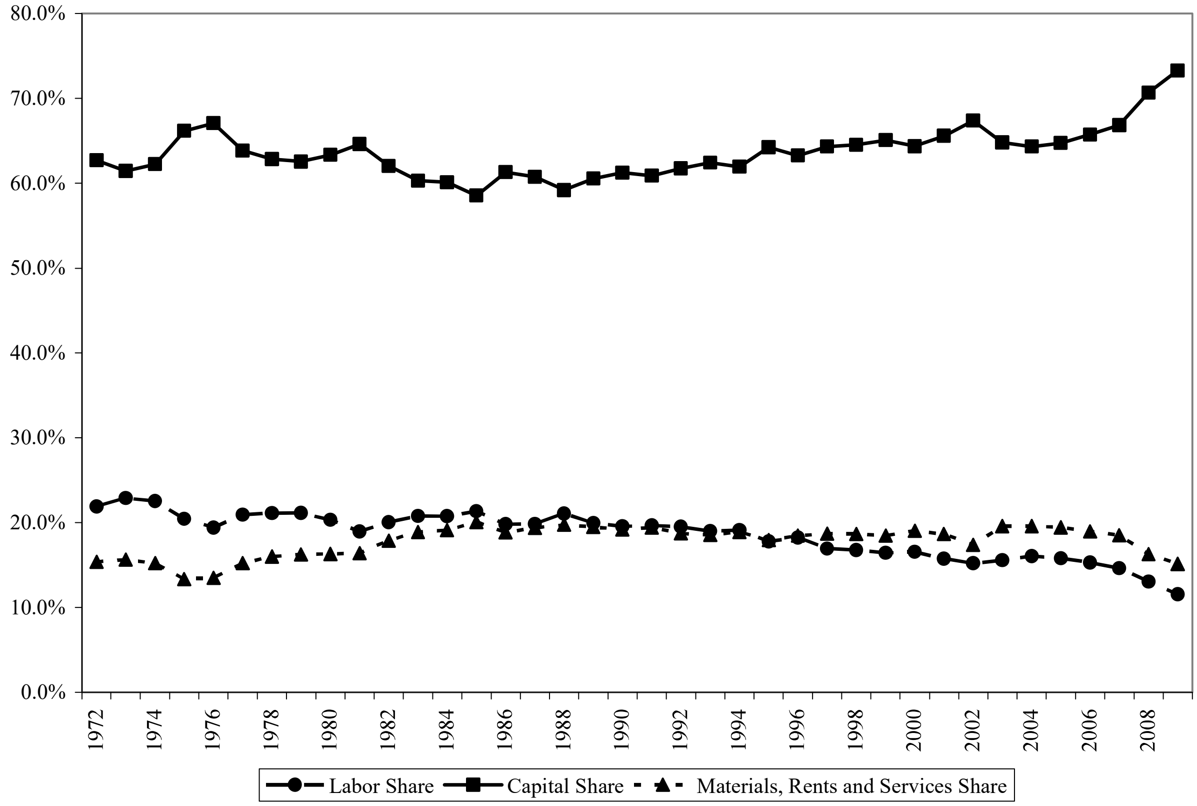
Source: NERA TFP Study

Figure 5. Public output index growth, 1973-2009



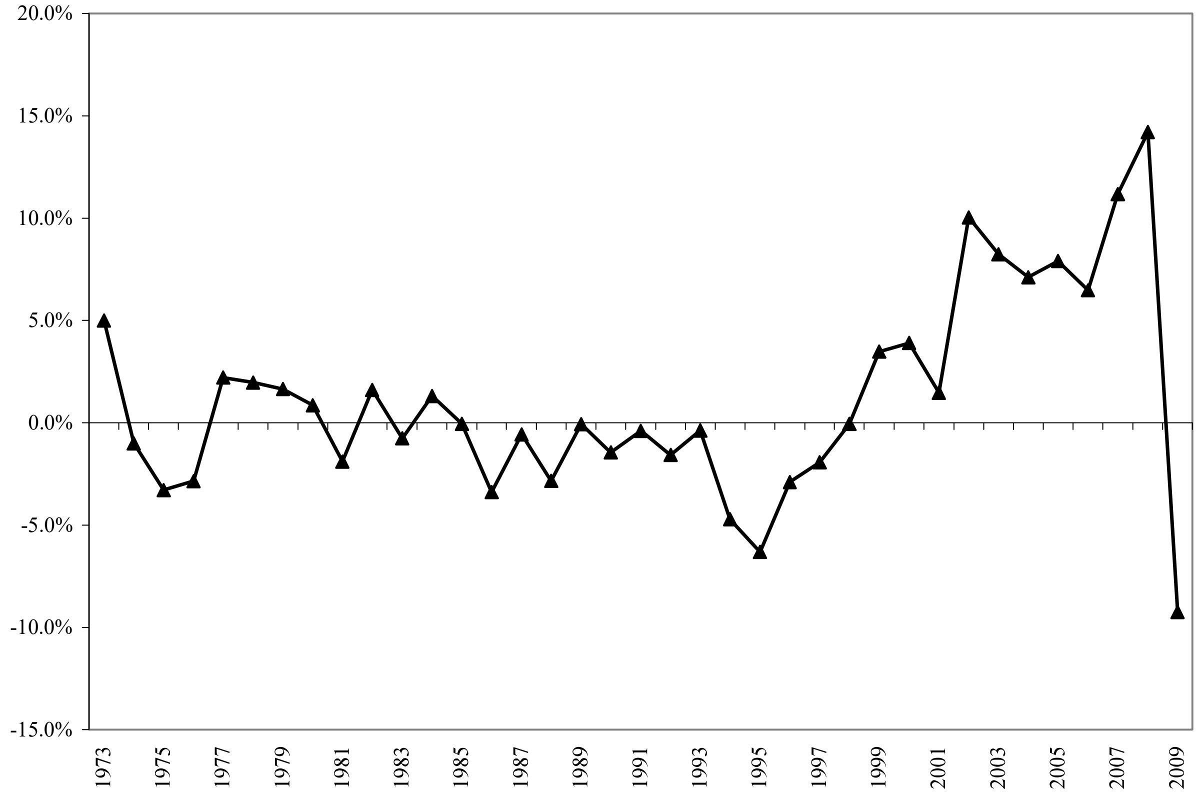
Source: NERA TFP Study

Figure 6. Input shares, 1972-2009



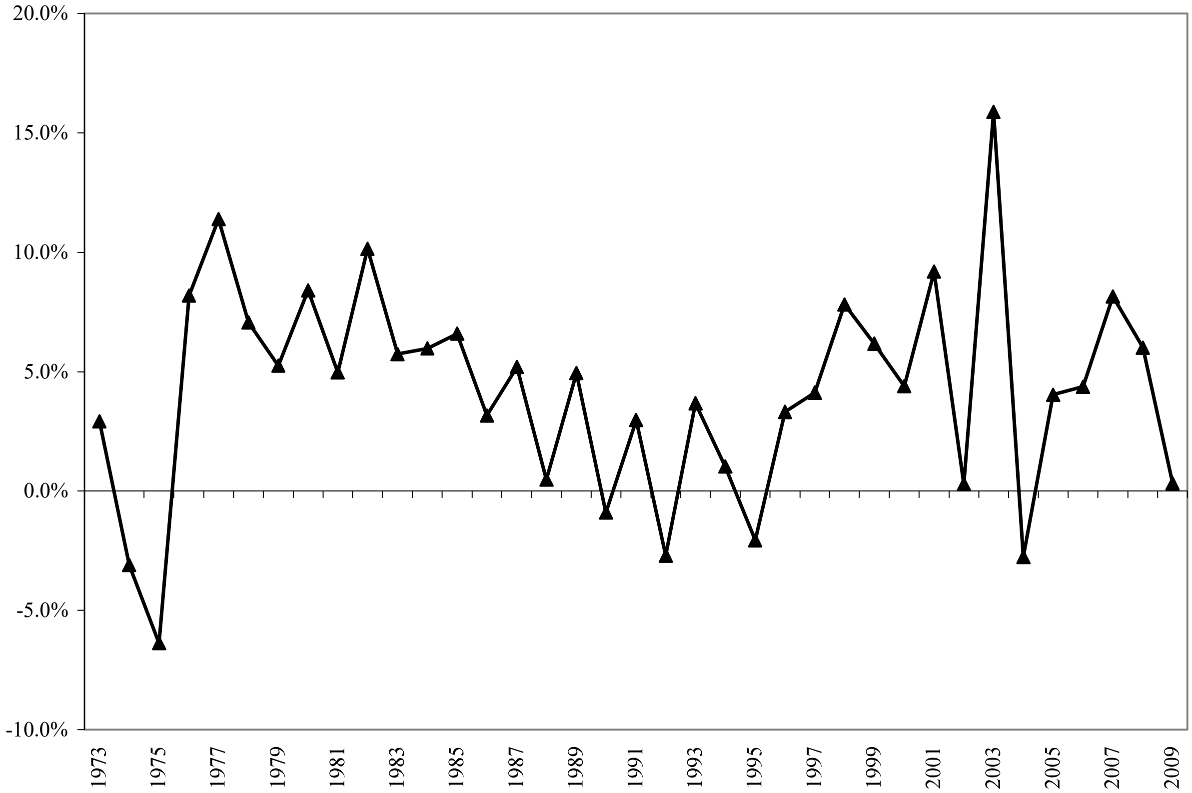
Source: NERA TFP Study

Figure 7. Labor input index growth, 1973-2009



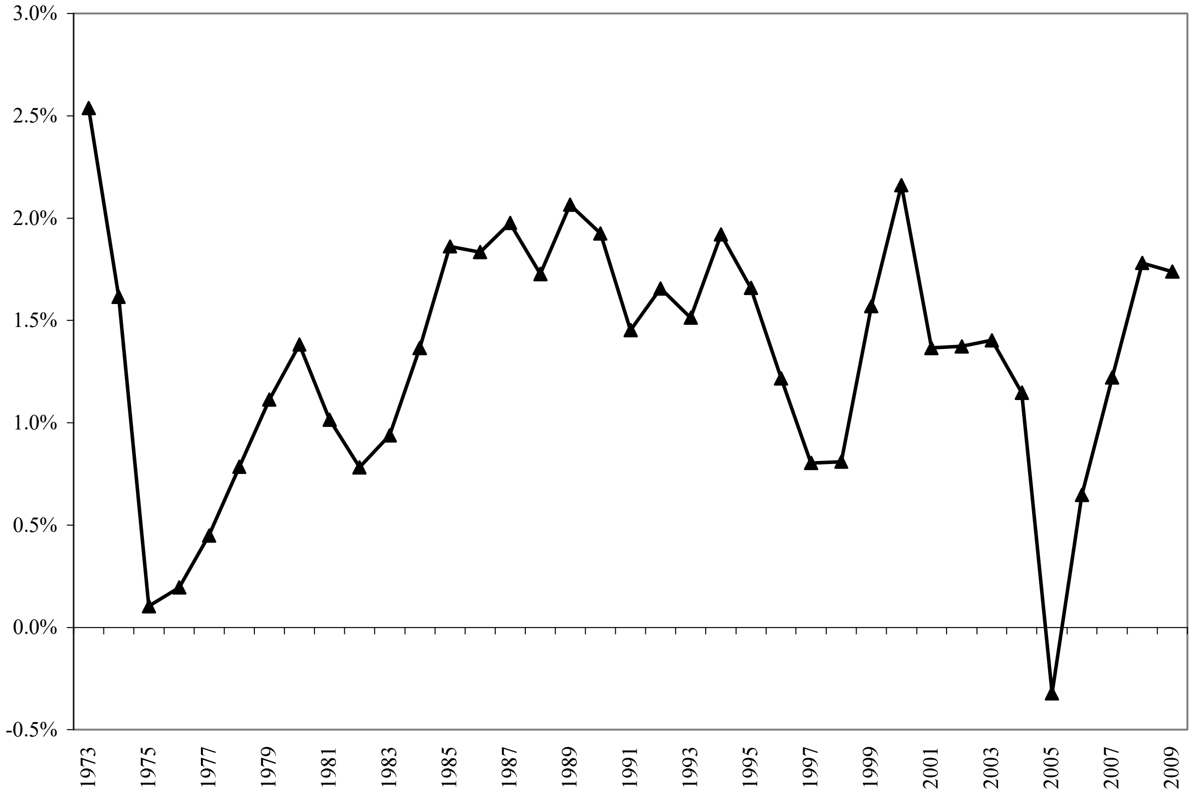
Source: NERA TFP Study

Figure 8. MRS input index growth, 1973-2009



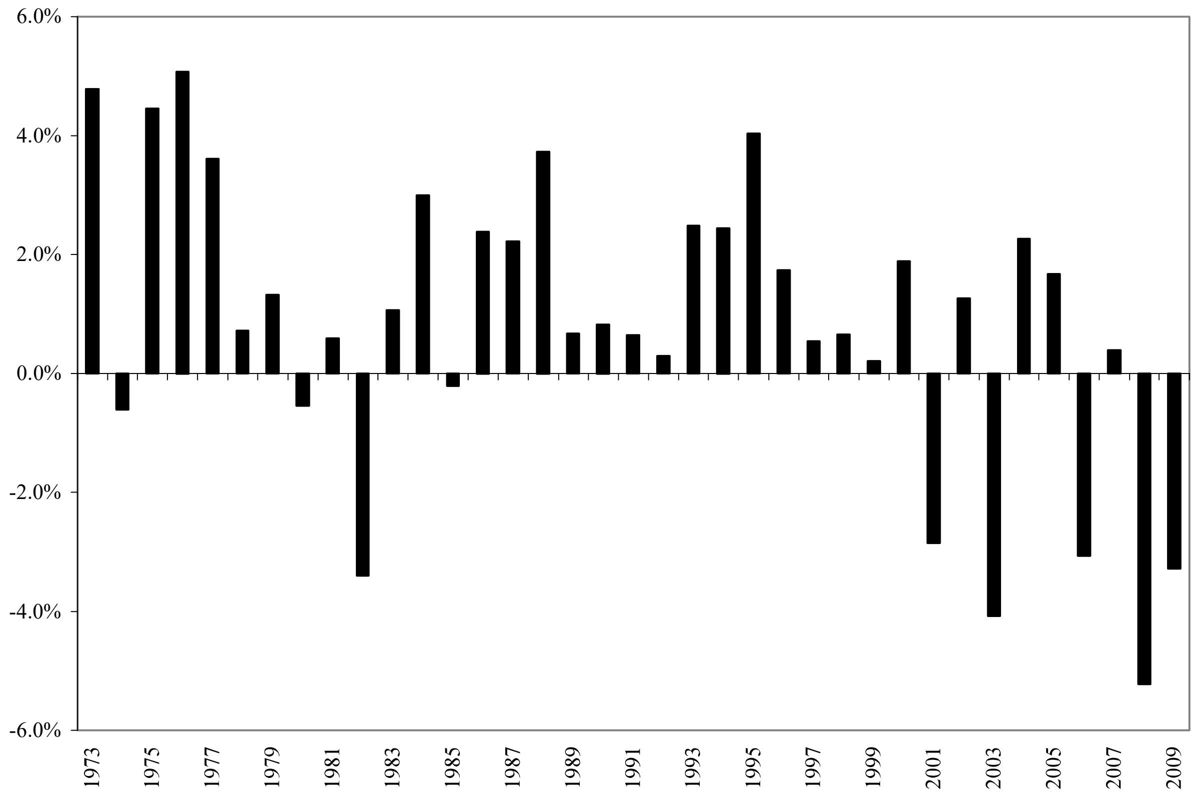
Source: NERA TFP Study

Figure 9. Capital input index growth, 1973-2009



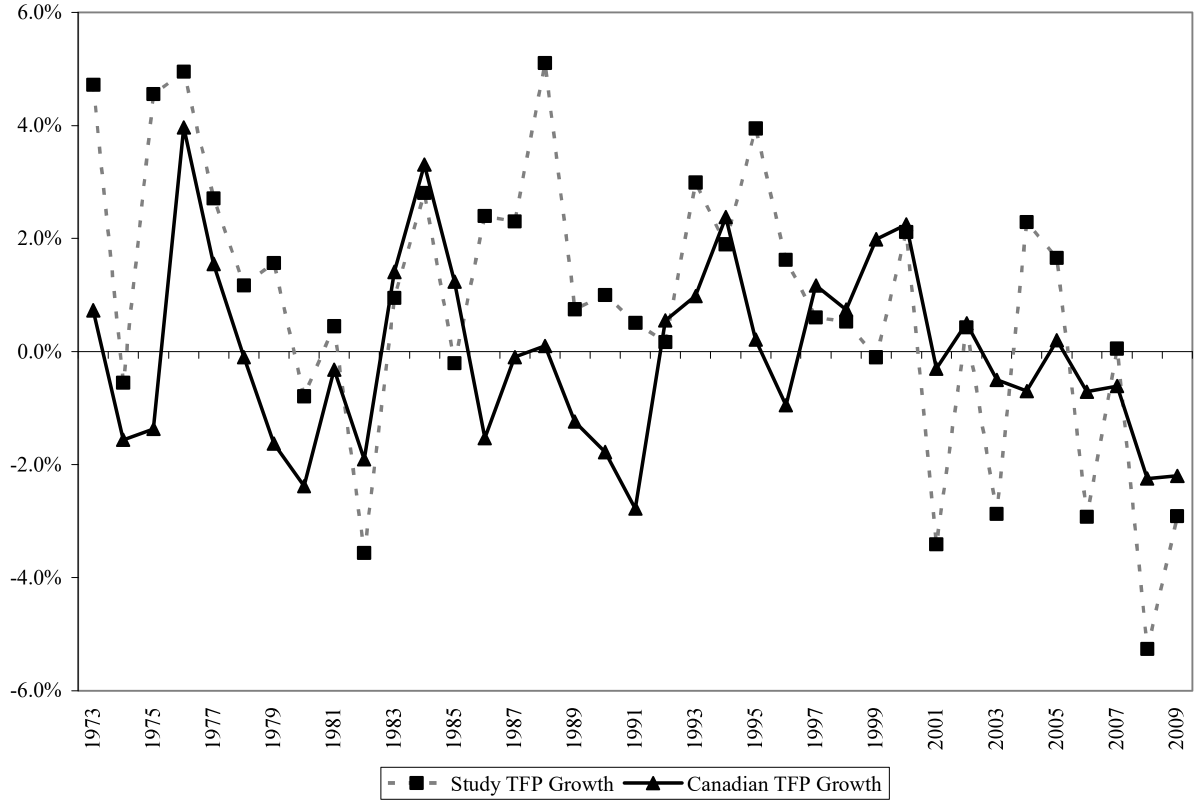
Source: NERA TFP Study

Figure 10. TFP growth, 1973-2009



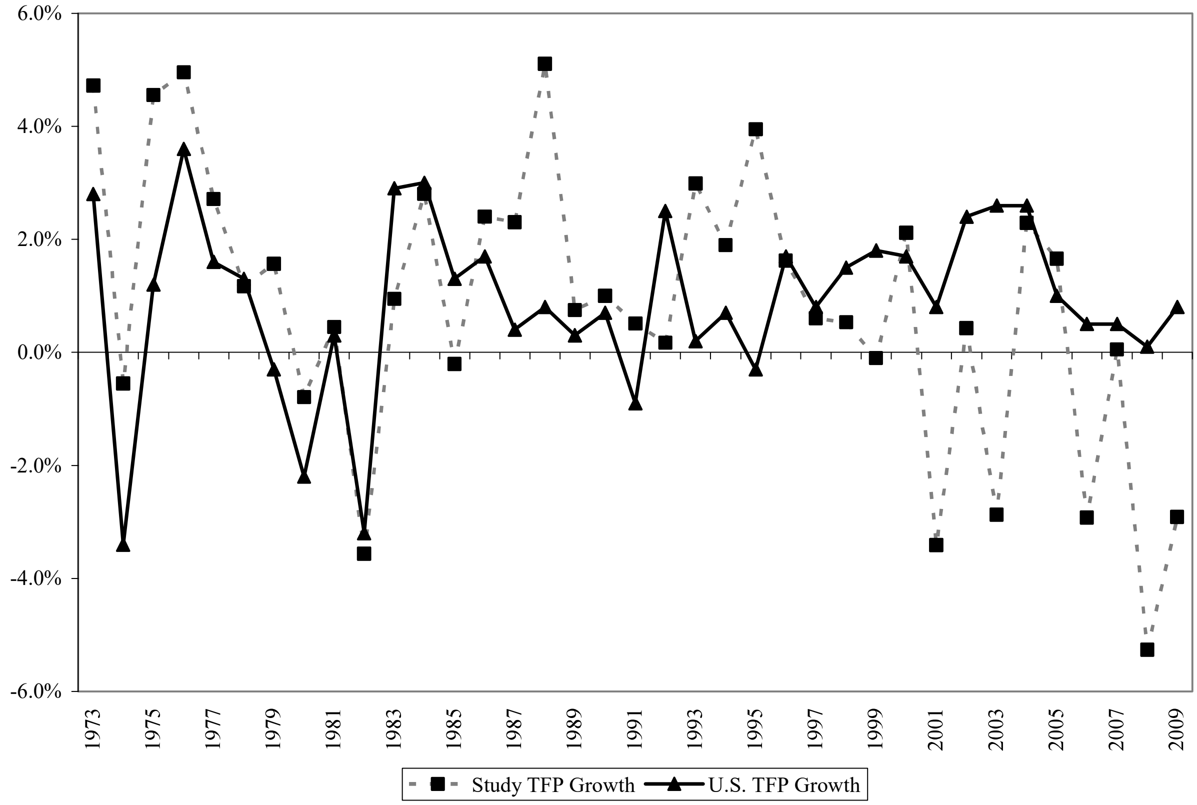
Source: NERA TFP Study

Figure 11. Study TFP growth and Canadian economy TFP growth, 1973-2009



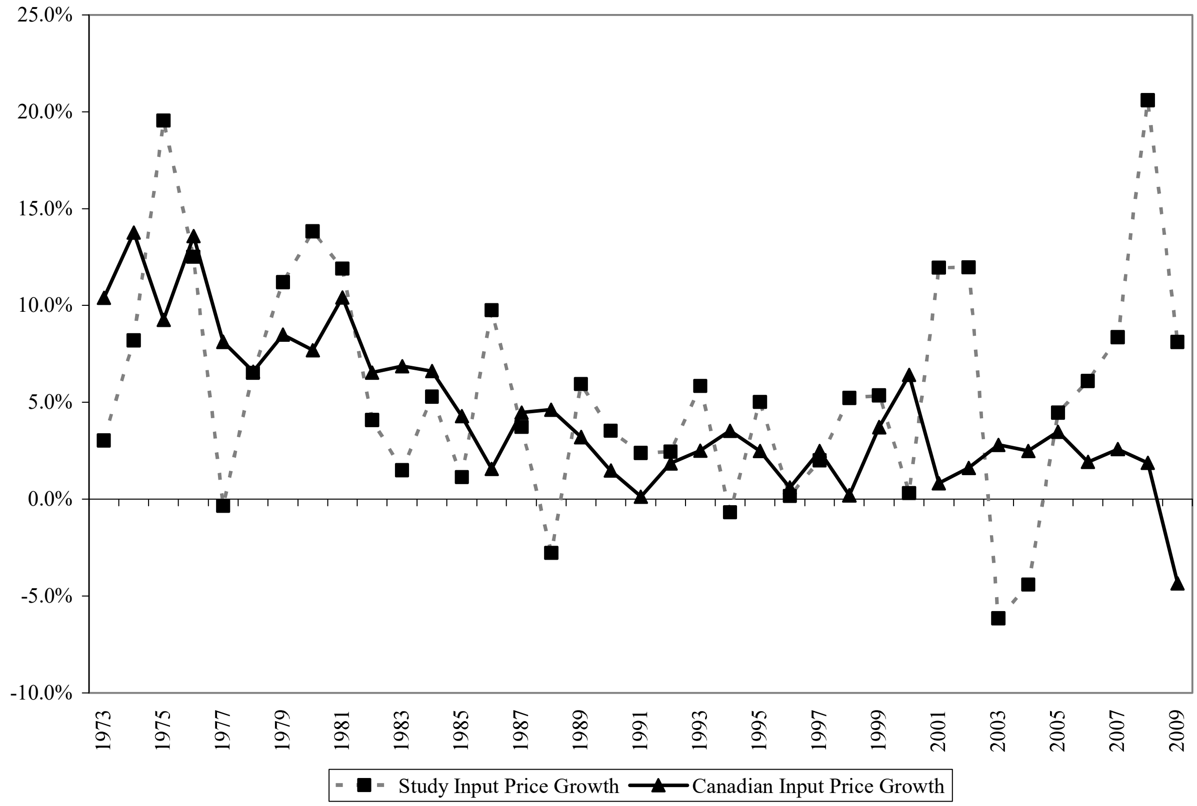
Source: NERA TFP Study and Statistics Canada

Figure 12. Study TFP growth and U.S. economy TFP growth, 1973-2009



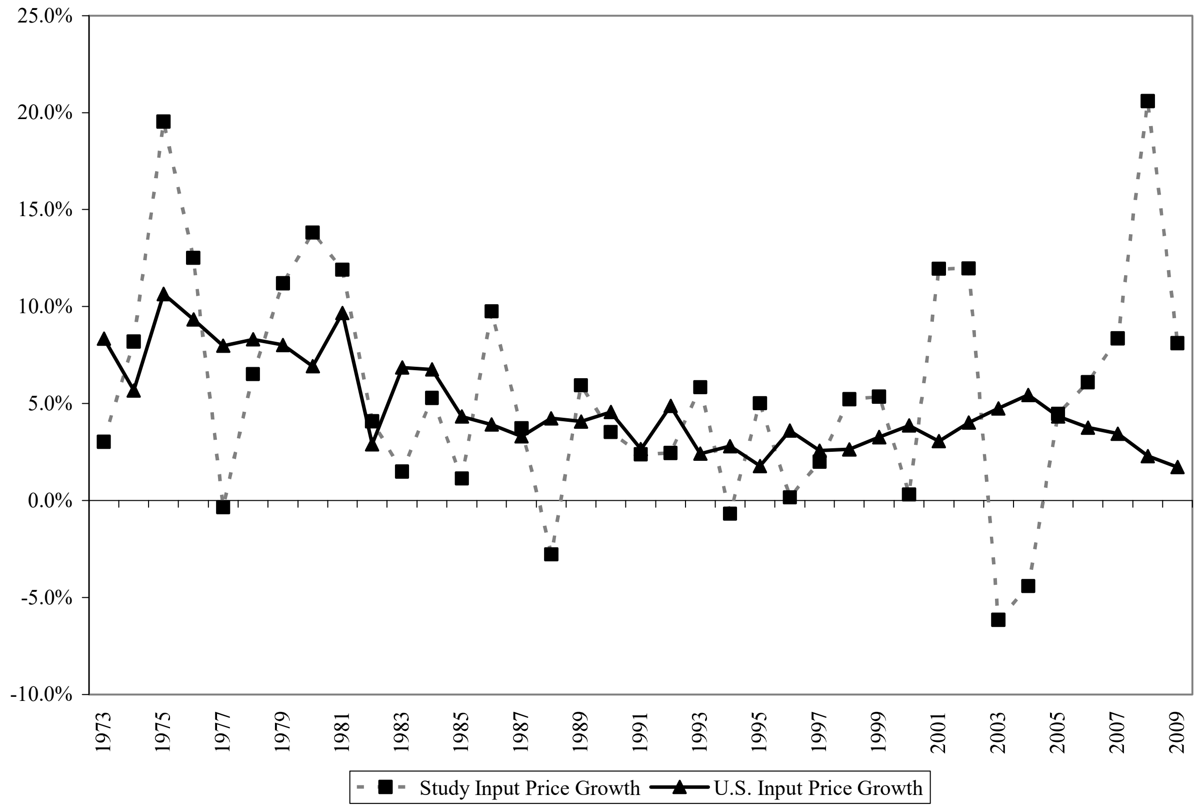
Source: NERA TFP Study and U.S. Bureau of Labor Statistics

Figure 13. Study input price growth and Canadian economy input price growth, 1973-2009



Source: NERA TFP Study and Statistics Canada

Figure 14. Study input price growth and U.S. economy input price growth, 1973-2009



Source: NERA TFP Study, U.S. Bureau of Labor Statistics and U.S. Bureau of Economic Analysis

NERA
Economic Consulting

200 Clarendon Street, 11th Floor
Boston, Massachusetts 02116
617+1 617 927 4500
617 +1 617 927 4501

Exhibit JDM-3, Tab 1: NERA Industry Study Summary Tables and Figures

I. List of companies used in the Industry Study

Alabama Power Company
Appalachian Power Company
Arizona Public Service Company
Baltimore Gas and Electric Company
Central Hudson Gas & Electric Corporation
Cleveland Electric Illuminating Company
Commonwealth Edison Company
Connecticut Light and Power Company
Consolidated Edison Company of New York, Inc.
Consumers Energy Company
Dayton Power and Light Company
Delmarva Power & Light Company
DTE Electric Company
Duke Energy Indiana, LLC
Duke Energy Kentucky, Inc.
Duke Energy Ohio, Inc.
Duquesne Light Company
El Paso Electric Company
Empire District Electric Company
Entergy Arkansas, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Florida Power & Light Company
Green Mountain Power Corporation
Gulf Power Company
Idaho Power Co.
Indiana Michigan Power Company
Jersey Central Power & Light Company
Kansas City Power & Light Company
Kansas Gas and Electric Company
Kentucky Utilities Company
Madison Gas and Electric Company
Massachusetts Electric Company
MDU Resources Group, Inc.
Metropolitan Edison Company
Mississippi Power Company
Monongahela Power Company
Narragansett Electric Company
Nevada Power Company
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Northern Indiana Public Service Company
NSTAR Electric Company
Ohio Edison Company
Oklahoma Gas and Electric Company
Orange and Rockland Utilities, Inc.
Otter Tail Power Company
Pacific Gas and Electric Company
PECO Energy Company
Pennsylvania Electric Company
Portland General Electric Company
Public Service Company of Colorado
Public Service Company of New Hampshire
Public Service Electric and Gas Company
Puget Sound Energy, Inc.
South Carolina Electric & Gas Co.
Southern California Edison Company
Southern Indiana Gas and Electric Company, Inc.
Southwestern Electric Power Company
Southwestern Public Service Company
Tucson Electric Power Company
Virginia Electric and Power Company
Western Massachusetts Electric Company
Wisconsin Electric Power Company
Wisconsin Public Service Corporation

II. List of changes made to original FERC data[1]

Company Name	Year (s)	Variable(s) Changed	Methodology
Appalachian Power Company	1972	TWGSAL	Extrapolated forward using DWGSAL growth rate
Cleveland Electric Illuminating Company	1975	TWGSAL	Averaged respective 1974 & 1975 values
Consolidated Edison Company of New York, Inc.	2002-2016	DWGSAL	Extrapolated forward using TWGSAL growth rate
Consolidated Edison Company of New York, Inc.	2008-2011	OPREVI, OPREVC, MWHCO, MWHIN	Extrapolated forward using OPREVR and MWHRES growth rates, repectively
Consolidated Edison Company of New York, Inc.	1983	DWGSAL	Averaged respective 1982 & 1984 values
Consumers Energy Company	1993	DWGSAL & TWGSAL	Averaged respective 1992 and 1994 values
Duke Energy Indiana, LLC	1995	DWGSAL & TWGSAL	Values from Alberta Study were taken as given
Duke Energy Kentucky, Inc.	1996	DWGSAL & TWGSAL	Averaged respective 1995 & 1997 values
Jersey Central Power & Light Company	1999-2002	DWGSAL, TWGSAL, FTEMPLOY, PTEMPLOY	Averaged respective 1998 & 2003 values
Jersey Central Power & Light Company	2002-2009	OPREVP	Values from Alberta Study were taken as given
Jersey Central Power & Light Company	2010-2016	OPREVP	Extrapolated forwards using OPREVR growth rate
Kentucky Utilities Company	2005	RET	Averaged respective 2004 and 2006 values
MDU Resources Group, Inc.	1987	TWGSAL	Extrapolated forwards using DWGSAL growth rate
Metropolitan Edison Company	1999-2002	DWGSAL, TWGSAL, FTEMPLOY, PTEMPLOY	Averaged respective 1998 & 2003 values
Monongahela Power Company	1999-2002	DWGSAL, TWGSAL, FTEMPLOY, PTEMPLOY	Averaged respective 1998 & 2003 values
Narrangsett Electric Company	1993	FTEMPLOY & PTEMPLOY	Values from Alberta Study were taken as given
PECO Energy Company	1993	FTEMPLOY & PTEMPLOY	Used value for Total Employees from SNL instead of deriving value from FTEMPLOY & PTEMPLOY
PECO Energy Company	1988	FTEMPLOY & PTEMPLOY	Used PTEMPLOY value reported by SNL for FTEMPLOY
Pennsylvania Electric Company	1999-2002	DWGSAL & TWGSAL	Averaged respective 1998 & 2003 values
Public Service Company of Colorado	1993	FTEMPLOY & PTEMPLOY	Values from Alberta Study were taken as given
Virginia Electric and Power Company	2002	DWGSAL	Averaged respective 2001 and 2003 values
Wisconsin Public Service Corporation	1972	TWGSAL	Extrapolated backwards using DWGSAL growth rate
Wisonsin Electric Power Company	1982	TWGSAL	Averaged respective 1981 & 1983 values

[1] For these FERC Form 1 data points, it was necessary to estimate values because I determined that the values were too extreme to be correct or they were missing altogether. In some cases, I took the values used in my previous report in Alberta Proceeding 566 as given (this report is denoted as "the Alberta Study" in the table above).

III. Industry Study Tables

Table 1. Industry TFP Study, output shares and output index growth, 1972-2016[2]

Service	Share of Output	Output Index Growth Rate
	(percent)	
Residential	42.04%	2.19%
Commercial	32.30%	2.96%
Industrial	22.44%	1.24%
Public	3.22%	0.95%

Table 2. Industry TFP Study, input shares and input index growth, 1972-2016[3]

Input	Share	Input Index Growth Rate
	(percent)	
Labor	17.86%	0.71%
MRS	17.54%	4.49%
Capital	64.60%	1.44%

[2] Source: NERA Industry TFP Study, share of output and growth rates are unweighted.

[3] Source: NERA Industry TFP Study, share of input and growth rates are unweighted.

Table 3. Industry TFP Study, output, input and TFP growth, 1973-2016[4]

Year	Output growth	Input growth	TFP growth
	(percent)		
1973	7.38	2.66	4.71
1974	-0.59	0.21	-0.80
1975	2.24	-2.31	4.55
1976	4.99	0.25	4.74
1977	4.00	1.60	2.40
1978	3.34	2.27	1.07
1979	2.91	1.06	1.85
1980	1.11	1.97	-0.86
1981	1.03	0.12	0.91
1982	-0.93	2.69	-3.62
1983	2.86	2.06	0.80
1984	4.46	1.67	2.79
1985	1.97	2.17	-0.20
1986	2.73	0.40	2.33
1987	4.16	1.77	2.39
1988	4.80	-0.35	5.15
1989	2.02	1.57	0.45
1990	1.59	0.92	0.67
1991	2.40	2.08	0.33
1992	-0.54	-0.67	0.13
1993	3.79	2.04	1.75
1994	2.20	0.39	1.81
1995	2.77	-1.32	4.09
1996	1.89	0.36	1.53
1997	1.03	0.75	0.28
1998	3.01	2.77	0.24
1999	1.76	0.17	1.58
2000	3.06	1.14	1.92
2001	-0.94	1.91	-2.85
2002	3.09	0.93	2.16
2003	0.49	3.29	-2.80
2004	2.15	-1.10	3.25
2005	3.12	0.74	2.38
2006	-0.34	2.63	-2.97
2007	2.80	1.95	0.84
2008	-1.26	3.65	-4.92
2009	-4.37	-1.51	-2.86
2010	3.45	1.40	2.05
2011	-1.43	2.95	-4.38
2012	-1.20	0.94	-2.13
2013	0.01	0.37	-0.36
2014	0.16	2.03	-1.88
2015	-0.23	1.13	-1.36
2016	-0.20	3.32	-3.52
Average	1.74	1.21	0.54

[4] Note: Output, input and TFP growth in each year are weighted by total mWh. Source: NERA Industry TFP Study.

Table 4. Industry Study TFP growth, Canadian economy TFP growth and X-factor calculation, 1973-2016[5]

Year	Study TFP Growth	Canadian TFP Growth
	(percent)	
1973	4.71	1.04
1974	-0.80	-1.30
1975	4.55	-0.34
1976	4.74	3.93
1977	2.40	1.92
1978	1.07	0.26
1979	1.85	-1.45
1980	-0.86	-2.11
1981	0.91	0.34
1982	-3.62	-1.15
1983	0.80	1.65
1984	2.79	3.43
1985	-0.20	1.10
1986	2.33	-1.50
1987	2.39	0.31
1988	5.15	0.21
1989	0.45	-0.95
1990	0.67	-1.81
1991	0.33	-2.64
1992	0.13	0.70
1993	1.75	1.11
1994	1.81	2.43
1995	4.09	0.37
1996	1.53	-0.92
1997	0.28	1.06
1998	0.24	0.63
1999	1.58	2.38
2000	1.92	2.12
2001	-2.85	0.06
2002	2.16	1.29
2003	-2.80	-0.73
2004	3.25	-0.32
2005	2.38	0.04
2006	-2.97	-0.82
2007	0.84	-1.14
2008	-4.92	-2.30
2009	-2.86	-2.57
2010	2.05	1.78
2011	-4.38	1.49
2012	-2.13	-0.61
2013	-0.36	0.91
2014	-1.88	1.33
2015	-1.36	-1.00
2016	-3.52	*0.19*
Average	0.54	0.19
X-Factor	0.35	

[5] Source: Industry TFP growth: NERA Industry TFP Study, Industry TFP growth is weighted by total mWh; Canadian TFP growth: Canadian Multifactor Productivity (MFP) for the Business Sector was used for this comparison. These data were taken from Statistics Canada, Table 383-0021, www5.statcan.gc.ca/cansim/a47. For 2016, I assume that Canadian TFP is equal to the average TFP over the time period 1973-2015, since Statistics Canada has not yet published a TFP figure for this year.

Table 5. Industry Study input price growth and US economy input price growth, 1973-2016[6]

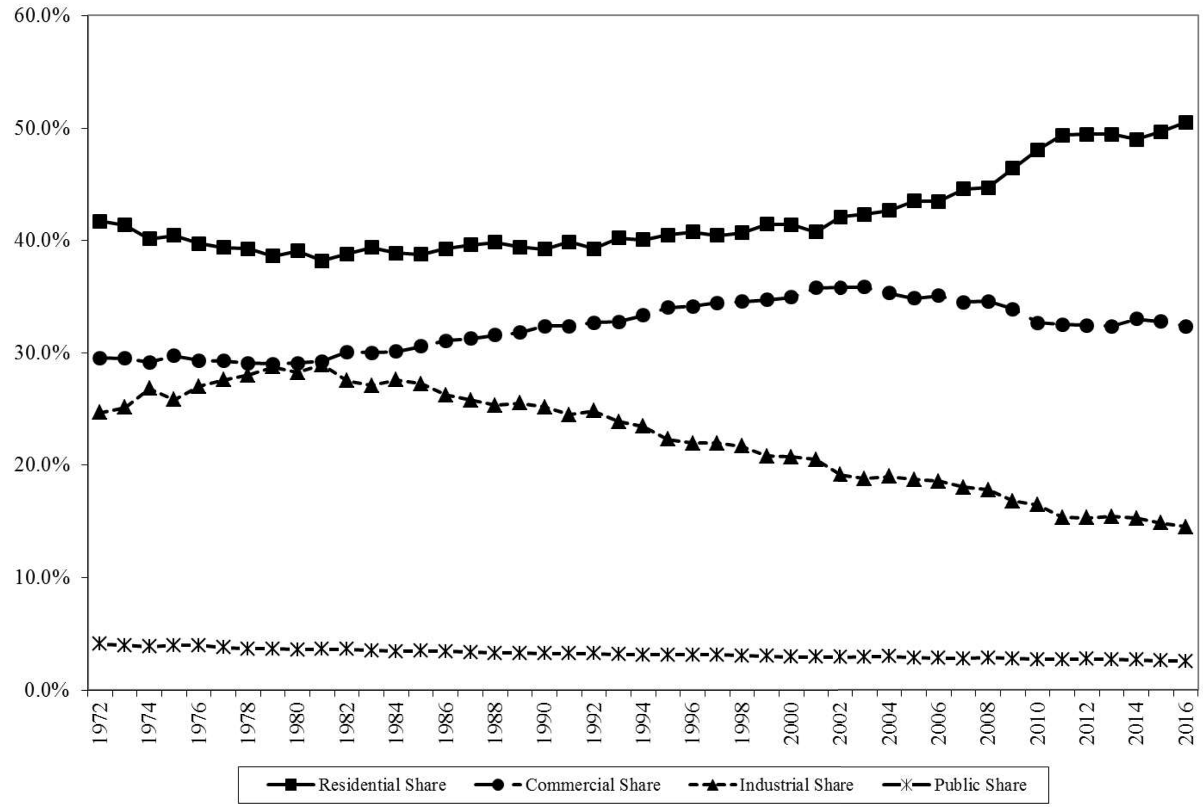
Year	Input price growth	US Input Price Growth
	(percent)	
1973	3.22	8.50
1974	8.14	5.40
1975	19.12	10.40
1976	11.96	9.20
1977	0.03	8.10
1978	6.62	8.60
1979	11.00	7.50
1980	13.80	6.60
1981	12.01	9.40
1982	3.78	4.10
1983	1.91	4.20
1984	5.25	7.30
1985	1.30	3.40
1986	9.41	2.10
1987	3.63	4.20
1988	-2.71	4.10
1989	6.01	4.20
1990	3.37	3.90
1991	2.41	1.40
1992	2.54	4.90
1993	5.87	2.10
1994	-0.47	2.00
1995	4.97	1.40
1996	0.41	3.40
1997	1.91	2.60
1998	5.42	1.90
1999	5.35	2.90
2000	5.57	3.60
2001	35.65	2.30
2002	-2.40	2.50
2003	-5.92	4.20
2004	-3.54	5.50
2005	5.11	4.70
2006	6.29	3.30
2007	8.56	3.50
2008	19.60	1.60
2009	8.21	-1.60
2010	-8.03	4.00
2011	1.59	2.30
2012	5.65	1.80
2013	0.28	2.30
2014	1.87	1.80
2015	8.67	1.20
2016	1.31	*4.11*
Average	5.34	4.11

t-statistic	Critical value (two-tail)	Degrees of freedom
1.1504	2.021	42

[6] Source: Industry Input Price Growth: NERA Industry TFP Study, Industry input price growth is weighted by total mWh; US Input Price Growth: U.S. Bureau of Labor Statistics (BLS), Net Multifactor Productivity and Cost (Private Business Sector), Table PG 4.3 available at: https://www.bls.gov/mfp/mprdload.htm. I estimate input price growth for the US economy in 2016, using the average input price growth for 1973-2015, since I did not have data for 2016 at the time of my analysis. The difference in means test encompasses the years 1973-2015.

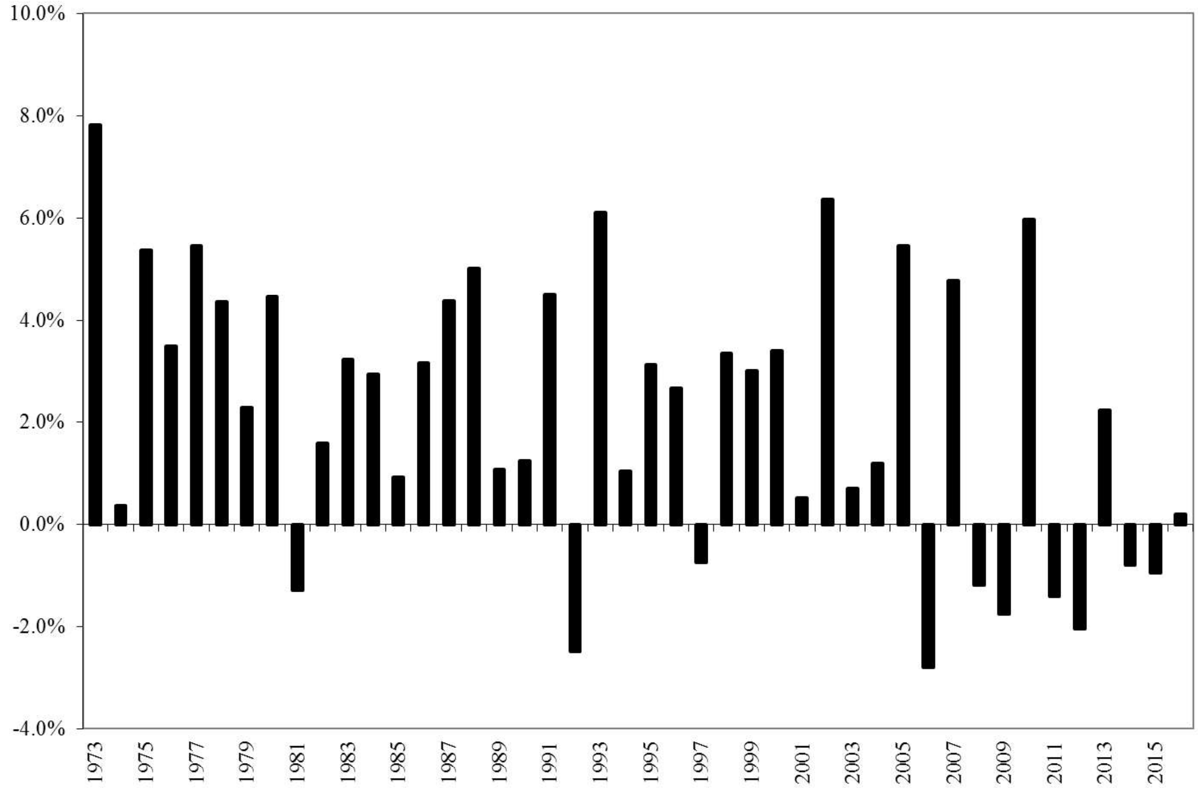
IV. Industry Study Figures

Figure 1. Output shares, 1972-2016



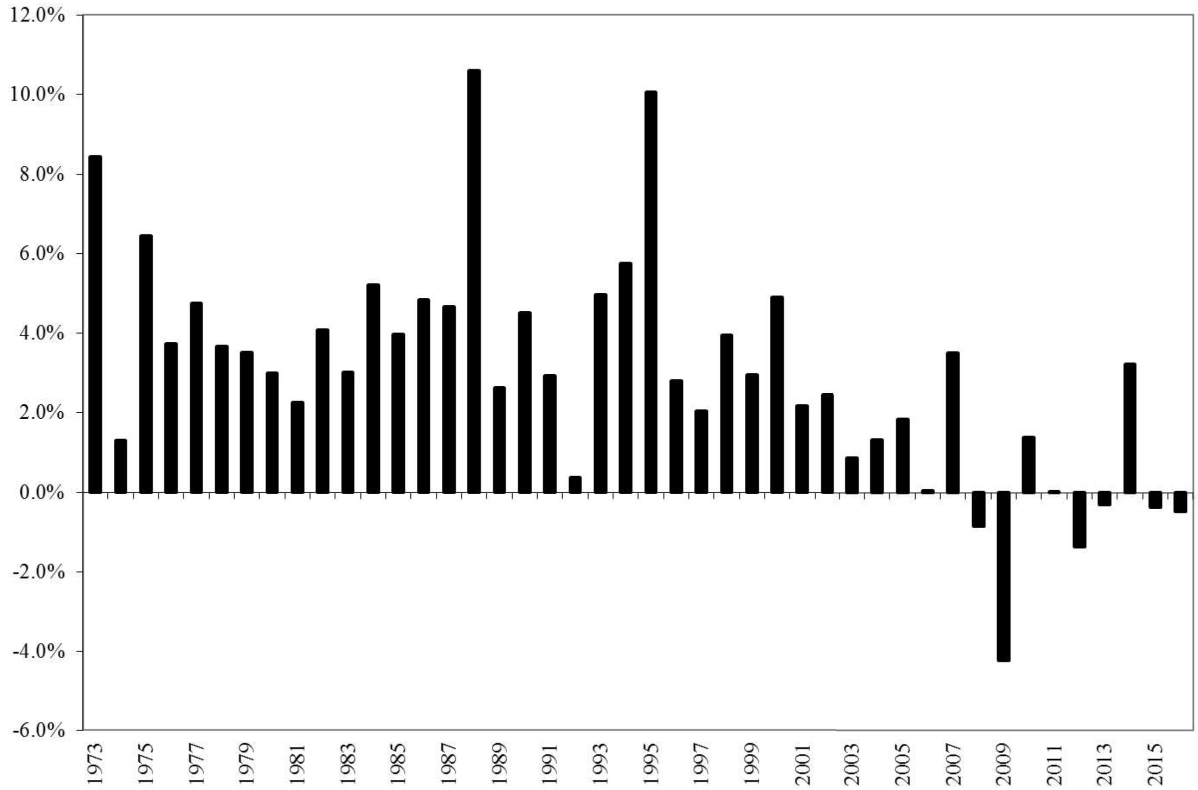
Source: NERA Industry TFP Study

Figure 2. Residential output index growth, 1973-2016



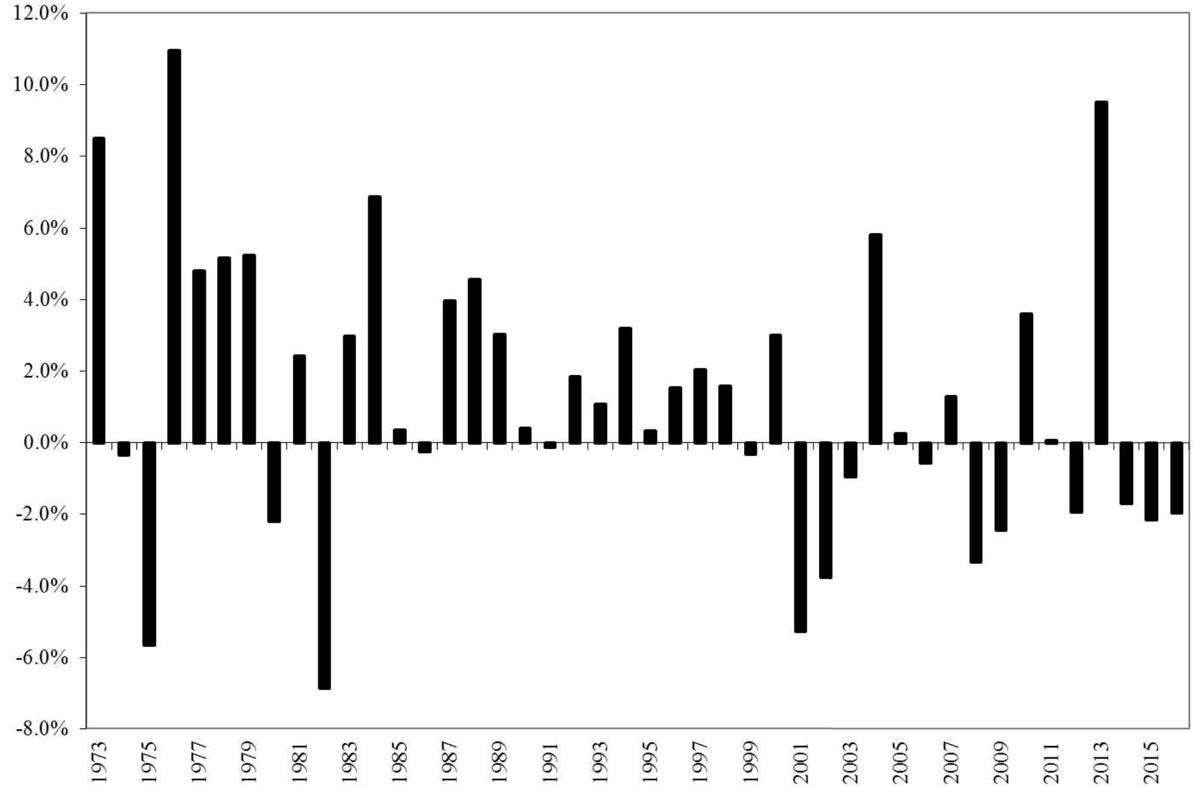
Source: NERA Industry TFP Study

Figure 3. Commercial output index growth, 1973-2016



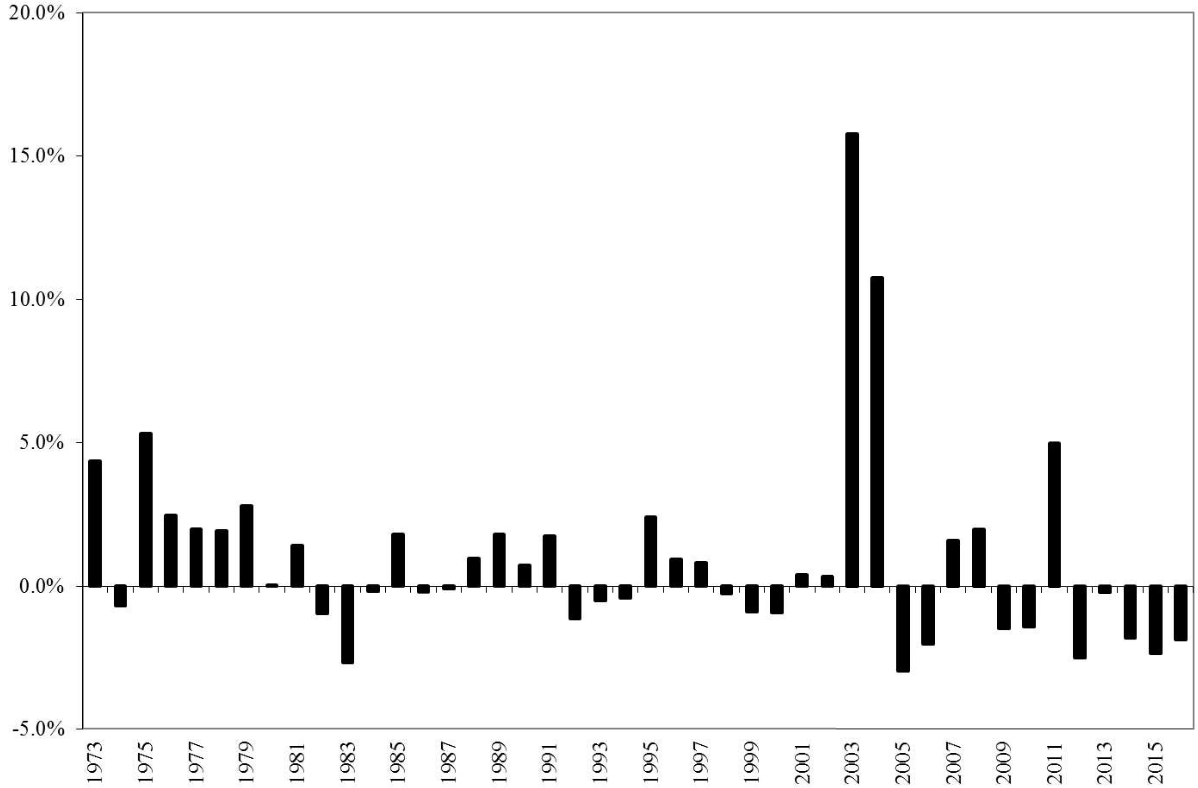
Source: NERA Industry TFP Study

Figure 4. Industrial output index growth, 1973-2016



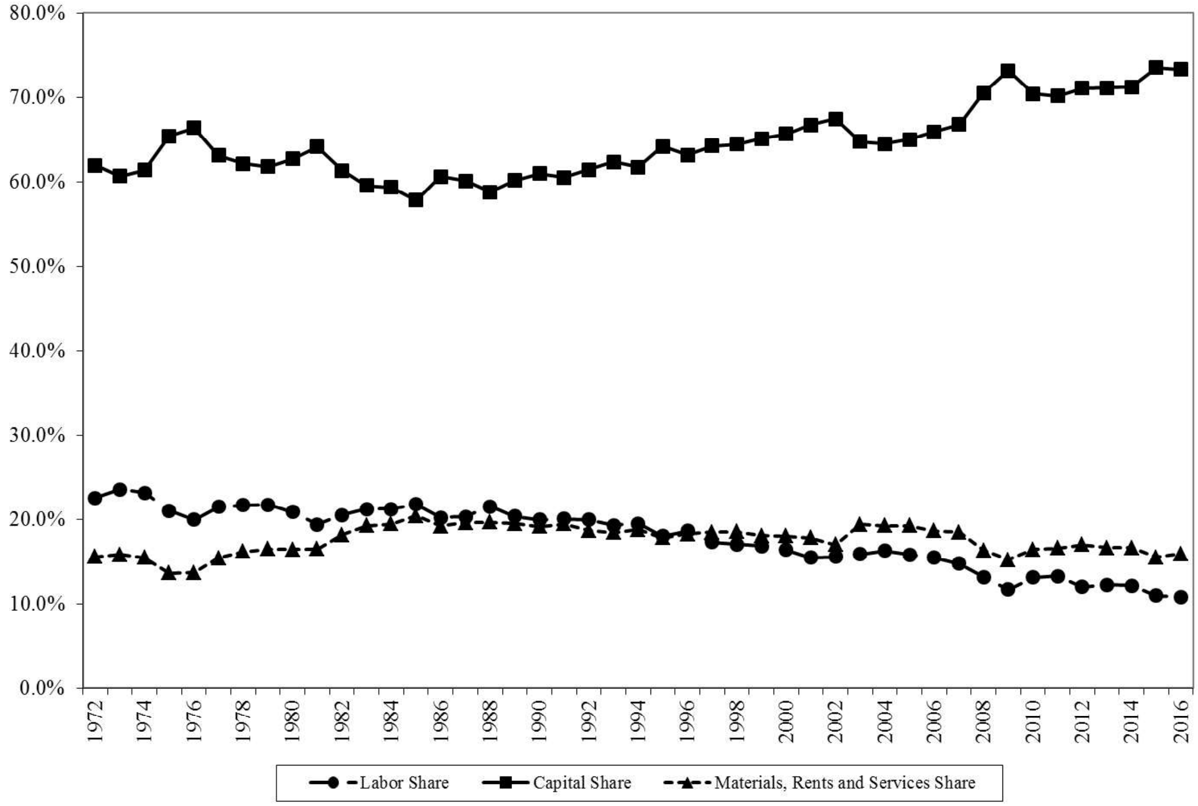
Source: NERA Industry TFP Study

Figure 5. Public output index growth, 1973-2016



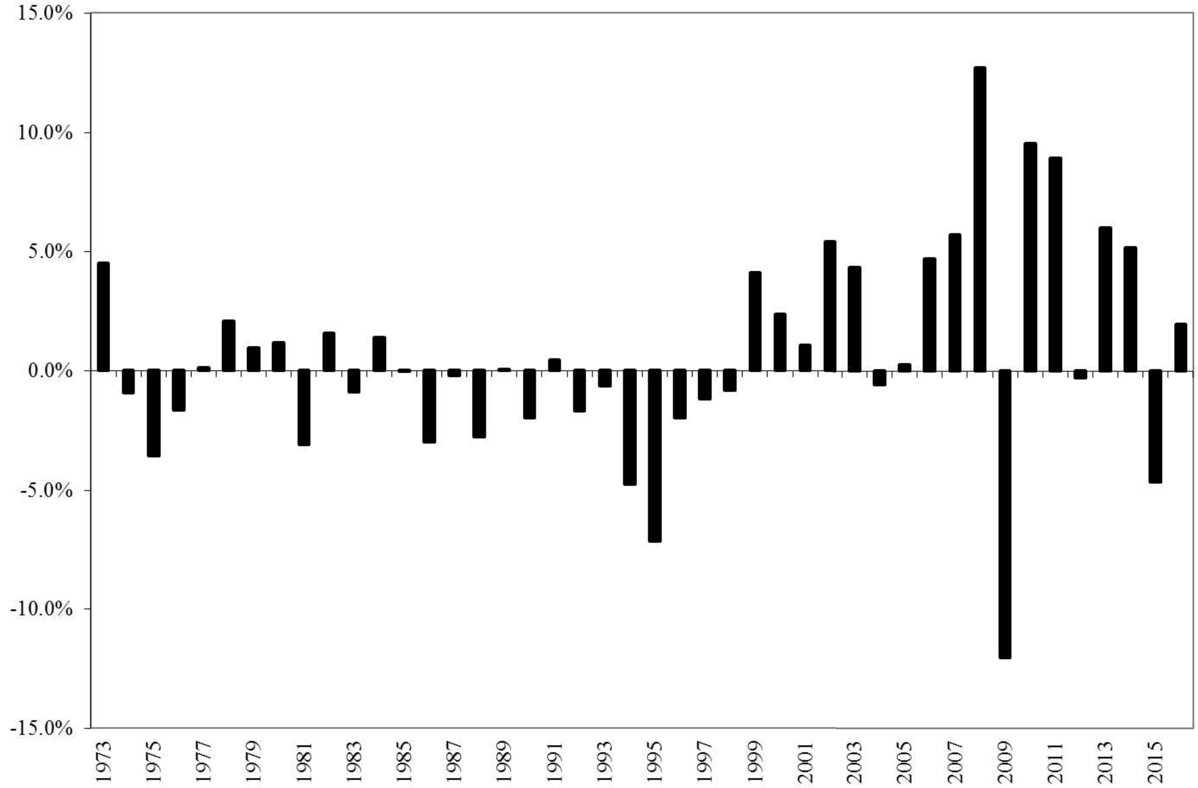
Source: NERA Industry TFP Study

Figure 6. Input shares, 1972-2016



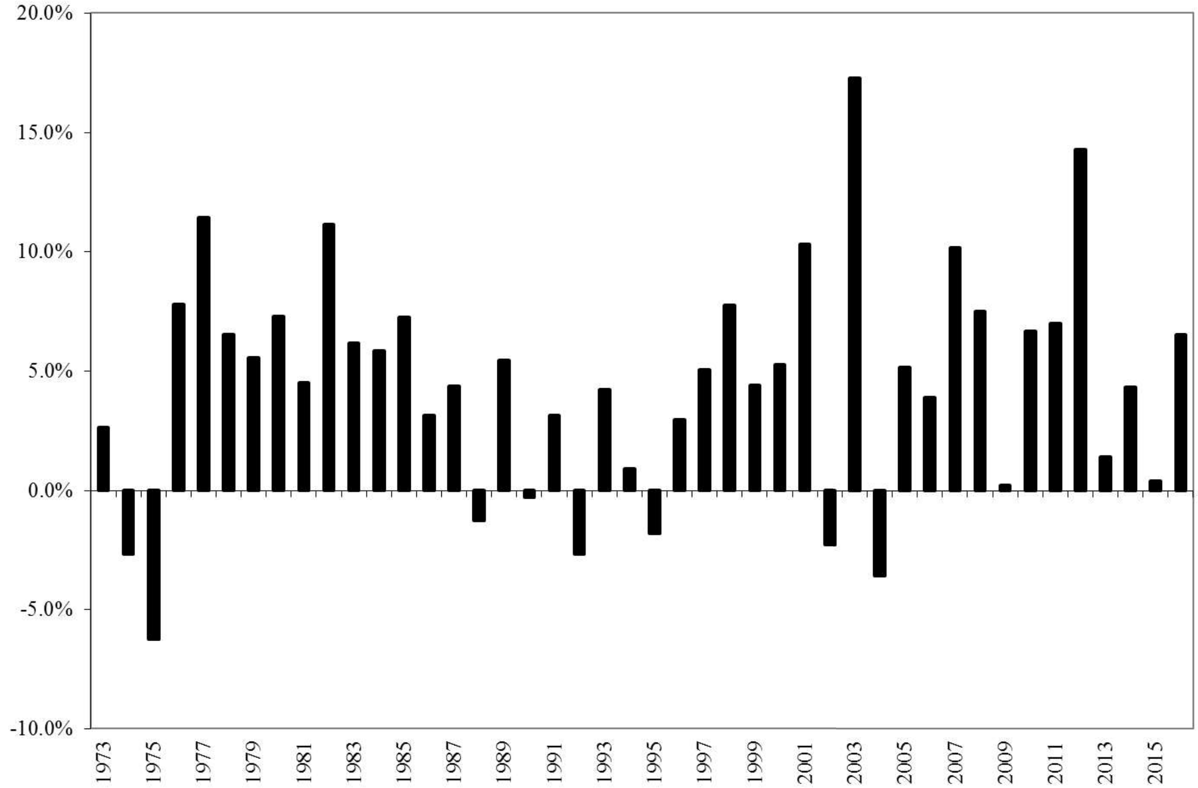
Source: NERA Industry TFP Study

Figure 7. Labor input index growth, 1973-2016



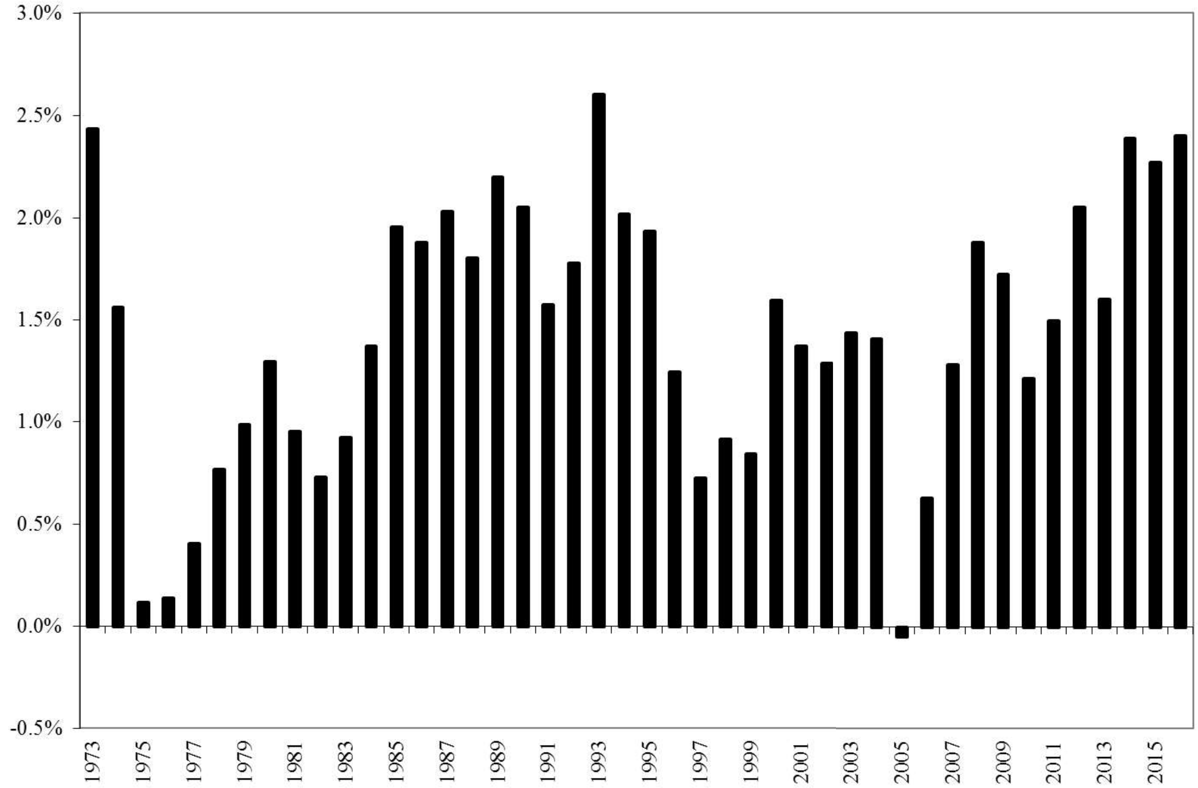
Source: NERA Industry TFP Study

Figure 8. MRS input index growth, 1973-2016



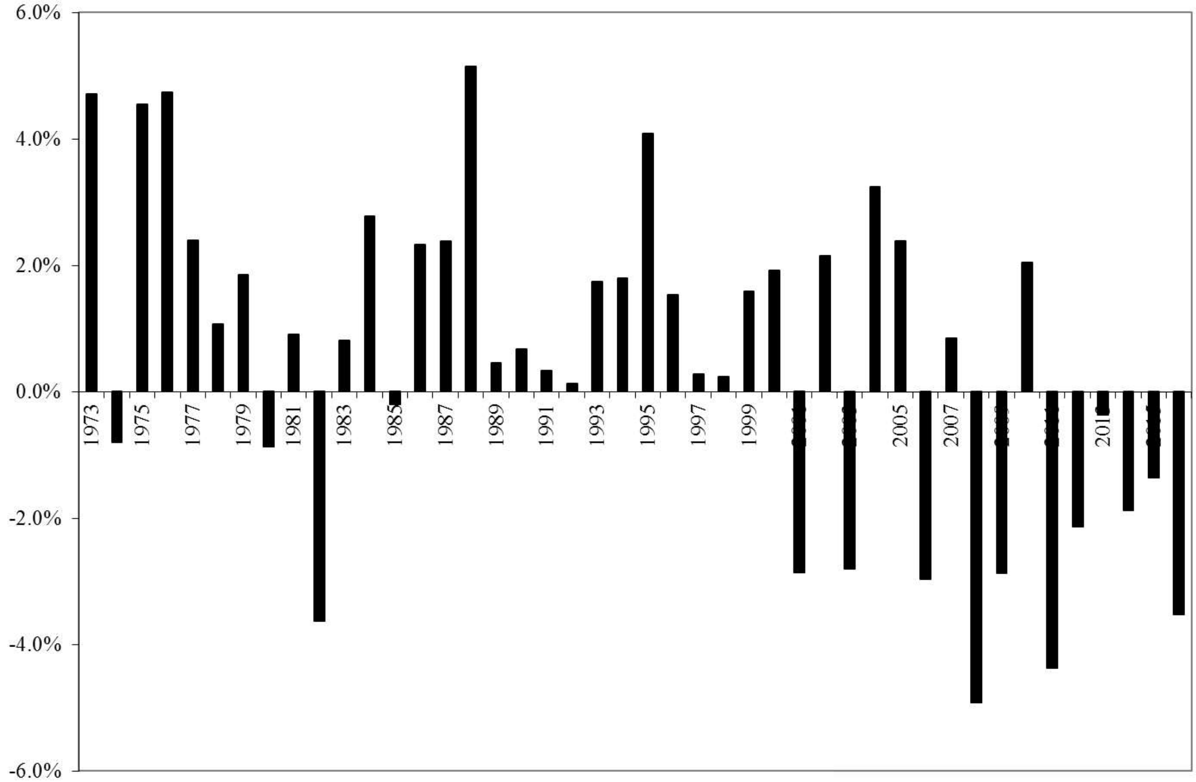
Source: NERA Industry TFP Study

Figure 9. Capital input index growth, 1973-2016



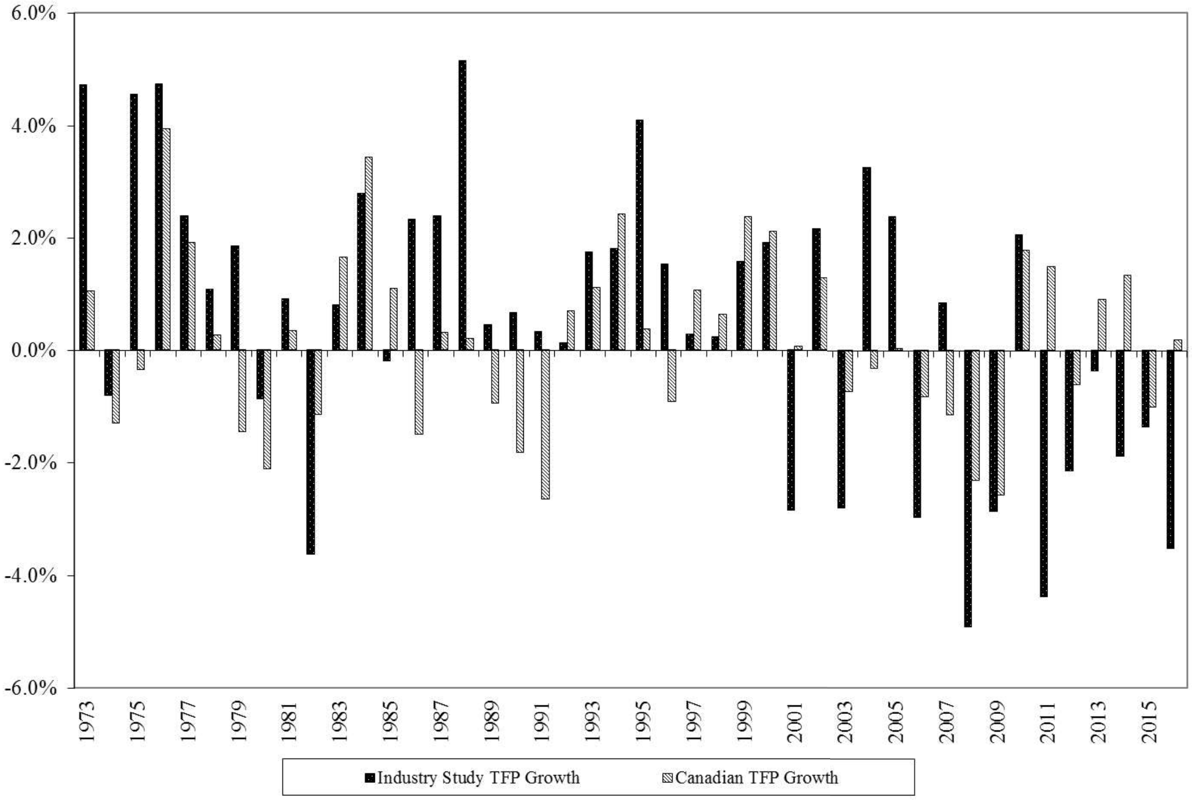
Source: NERA Industry TFP Study

Figure 10. Industry TFP growth, 1973-2016



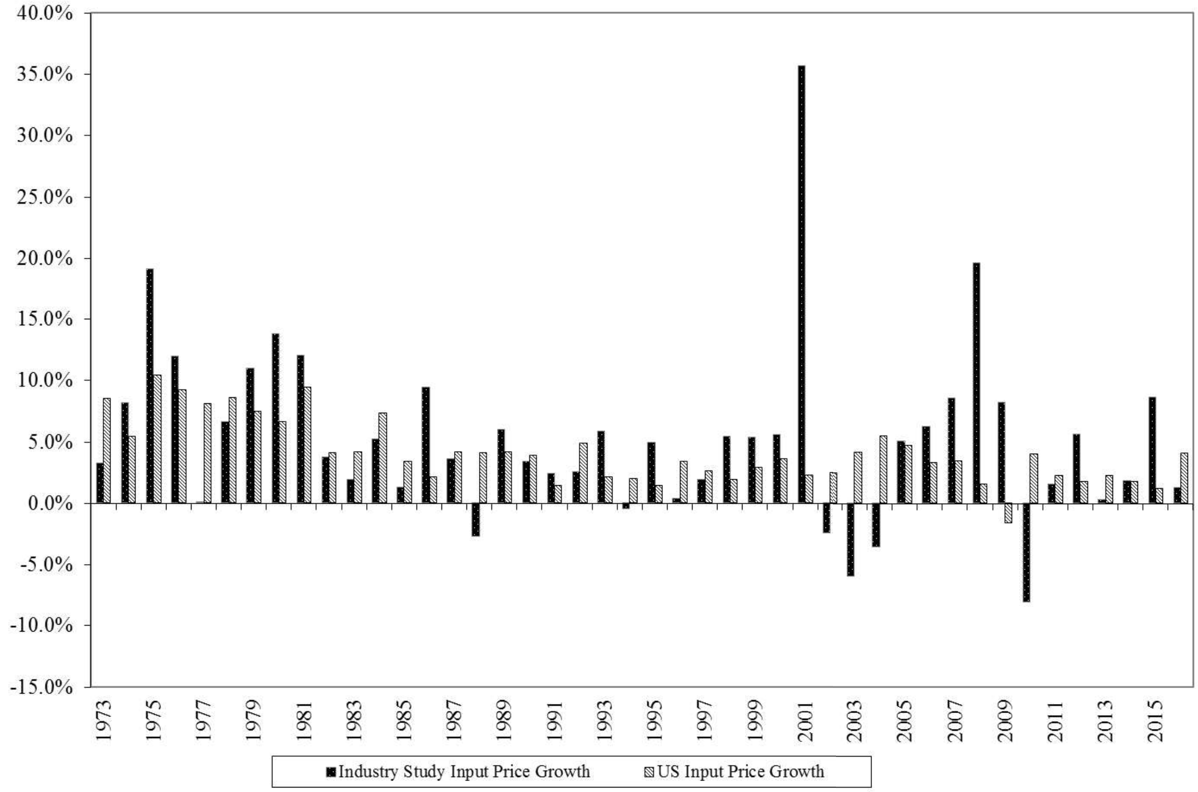
Source: NERA Industry TFP Study

Figure 11. Industry TFP growth and Canadian economy TFP growth, 1973-2016



Source: NERA Industry TFP Study and Statistics Canada

Figure 12. Industry input price growth and US economy input price growth, 1973-2016



Source: NERA Industry TFP Study and US Bureau of Labor Statistics

Exhibit JDM-3, Tab 2: NERA EGD Study Summary Tables and Figures

I. Sources for EGD Data Set

Year	Output Quantity: Sales Volume				Output Shares: Operating Revenues			
	Residential	Commercial	Industrial	Other (Wholesale)	Residential	Commerical	Industrial	Other (Wholesale)
1992	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 485, Exhibit C5, Tab 1, Schedule 1, p.4
1993	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 487, Exhibit C5, Tab 1, Schedule 1, p. 4
1994	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4	EBRO 490, Exhibit C5, Tab 1, Schedule 1, p. 4
1995	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 492, Exhibit C5, Tab 1, Schedule 1, p.4
1996	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4	EBRO 495, Exhibit C5, Tab 1, Schedule 1, p.4
1997	Company provided data	Company provided data	Company provided data	Company provided data	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3	EBRO 497, Exhibit C5, Tab 1, Schedule 1, p. 3
1998	Company provided data	Company provided data	Company provided data	Company provided data	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3	RP-1999-0001, Exhibit C5, Tab 1, Schedule 1, p.3
1999	Company provided data	Company provided data	Company provided data	Company provided data	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3	RP-2000-0040, Exhibit C5, Tab 1, Schedule 1, p.3
2000	Company provided data	Company provided data	Company provided data	Company provided data	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2001-0032, Exhibit C3, Tab 1, Schedule 1, p. 3
2001	Company provided data	Company provided data	Company provided data	Company provided data	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2002-0133, Exhibit C3, Tab 1, Schedule 1, p. 3
2002	Company provided data	Company provided data	Company provided data	Company provided data	Average of 2001 and 2003 values	Average of 2001 and 2003 values	Average of 2001 and 2003 values	Average of 2001 and 2003 values
2003	Company provided data	Company provided data	Company provided data	Company provided data	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3	RP-2003-0203, Exhibit C3, Tab 1, Schedule 1, p. 3
2004	Company provided data	Company provided data	Company provided data	Company provided data	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3	EB-2005-0001, Exhibit C3, Tab 1, Schedule 1, p. 3
2005	Company provided data	Company provided data	Company provided data	Company provided data	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2006-0034, Exhibit C5, Tab 1, Schedule 1, p. 3
2006	Company provided data	Company provided data	Company provided data	Company provided data	Average of 2005 and 2007 values	Average of 2005 and 2007 values	Average of 2005 and 2007 values	Average of 2005 and 2007 values
2007	Company provided data	Company provided data	Company provided data	Company provided data	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3	EB-2008-0219, Exhibit D, Tab 2, Schedule 1, p. 3
2008	Company provided data	Company provided data	Company provided data	Company provided data	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2009-0055, Exhibit B, Tab 3, Schedule 1, p. 3
2009	Company provided data	Company provided data	Company provided data	Company provided data	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2010-0042, Exhibit B, Tab 3, Schedule 1, p. 3
2010	Company provided data	Company provided data	Company provided data	Company provided data	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2011-0008, Exhibit B, Tab 3, Schedule 1, p. 3
2011	Company provided data	Company provided data	Company provided data	Company provided data	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3	EB-2011-0354, Exhibit C5, Tab 1, Schedule 1, p. 3
2012	Company provided data	Company provided data	Company provided data	Company provided data	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2013-0046, Exhibit B, Tab 3, Schedule 1, p. 3
2013	Company provided data	Company provided data	Company provided data	Company provided data	Average of 2012 and 2014 values	Average of 2012 and 2014 values	Average of 2012 and 2014 values	Average of 2012 and 2014 values
2014	Company provided data	Company provided data	Company provided data	Company provided data	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2015-0122, Exhibit B, Tab 3, Schedule 1, p. 3
2015	Company provided data	Company provided data	Company provided data	Company provided data	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2016-0142, Exhibit B, Tab 3, Schedule 1, p. 3
2016	Company provided data	Company provided data	Company provided data	Company provided data	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3	EB-2017-0102, Exhibit B, Tab 3, Schedule 1, p. 3

	Labor		Materials	Capital					
Year	**FTEs**	**Wages & Salaries**	**Operations & Mainenance Expense**	**Additions to Distribution Plant**	**Retirements to Distribution Plant**	**Distribution Plant in Service**	**Storage Plant in Service**	**General Plant in Service**	**Total Net Plant in Service**
1992	EBRO 485, Exhibit D5, Tab 9, Schedule 2, p. 1	EBRO 485, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 485, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1993	EBRO 487, Exhibit D5, Tab 9, Schedule 2, p. 1	EBRO 487, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 487, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1994	EBRO 490, Exhibit D5, Tab 10, Schedule 2, p. 1	EBRO 490, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 490, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1995	EBRO 492, Exhibit D5, Tab 10, Schedule 2, p. 1	EBRO 492, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 492, Exhibit D5, Tab 3, Schedule 2, p. 3	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1996	EBRO 495, Exhibit D5, Tab 10, Schedule 2, p. 1	EBRO 495, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 495, Exhibit D5, Tab 3, Schedule 2, p. 3	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1997	EBRO 497, EBO 170-14, Exhibit D5, Tab 9, Schedule 2, p. 1	EBRO 497, EBO 170-14, Exhibit D5, Tab 4, Schedule 2, p. 1	EBRO 497, EBO 179-14, Exhibit D5, Tab 3, Schedule 2, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1998	Average of 1997 and 2000 values	Average of 1997 and 2000 values	RP-1999-0001, Exhibit D5, Tab 1, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
1999	Average of 1997 and 2000 values	Average of 1997 and 2000 values	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2000	Company provided data	Company provided data	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2001	Company provided data	Company provided data	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2002	Company provided data	Company provided data	RP-2002-0133, Exhibit A6, Tab 1, Schedule 1, p. 4	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2003	Company provided data	Company provided data	RP-2003-0203, Exhibit D3, Tab 4, Schedule 1, p. 2	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2004	Company provided data	Company provided data	EB-2005-0001, Exhibit A6, Tab 1, Schedule 1, p. 12	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2005	Company provided data	Company provided data	EB-2006-0034, Exhibit D1, Tab 1, Schedule 1, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2006	Company provided data	Company provided data	Average of 2005 and 2007 values	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2007	Company provided data	Company provided data	EB-2008-0219, Exhibit D, Tab 3, Schedule 1, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2008	Company provided data	Company provided data	EB-2009-0055, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2009	Company provided data	Company provided data	EB-2010-0042, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2010	Company provided data	Company provided data	EB-2011-0008, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2011	Company provided data	Company provided data	EB-2011-0354, Exhibit D1, Tab 3, Schedule 1, p. 11	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2012	Company provided data	Company provided data	EB-2013-0046, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2013	Company provided data	Company provided data	EB-2012-0459, Exhibit D1, Tab 3, Schedule 1, p. 27	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2014	Company provided data	Company provided data	EB-2015-05-0122, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2015	Company provided data	Company provided data	EB-2016-0142, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data
2016	Company provided data	Company provided data	EB-2017-0102, Exhibit B, Tab 4, Schedule 2, p. 1	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data	Company provided data

II. EGD Study Tables

Table 1. EGD TFP Study, output shares and output index growth, 1992-2016[7]

Service	Share of Output	Output Index Growth Rate
	(percent)	
Residential	59.28%	1.45%
Commercial	32.33%	0.49%
Industrial	6.84%	0.18%
Other	1.55%	-0.05%

Table 2. EGD TFP Study, input shares and input index growth, 1992-2016[8]

Input	Share	Input Index Growth Rate
	(percent)	
Labor	6.80%	1.69%
MRS	16.60%	0.62%
Capital	76.59%	1.11%

[7] Source: NERA EGD TFP Study, share of output and growth rates are unweighted.

[8] Source: NERA EGD TFP Study, share of input and growth rates are unweighted.

Table 3. EGD TFP Study, output, input and TFP growth, 1993-2016[9]

Year	Output growth	Input growth	TFP growth
	(percent)		
1993	4.33	3.10	1.22
1994	3.19	1.32	1.87
1995	-3.00	1.21	-4.21
1996	8.98	1.94	7.04
1997	-2.76	0.90	-3.65
1998	-6.04	-1.36	-4.68
1999	3.76	0.40	3.35
2000	5.37	-2.72	8.10
2001	1.43	1.62	-0.18
2002	0.01	0.94	-0.93
2003	9.57	2.79	6.78
2004	-2.60	0.25	-2.85
2005	0.79	0.71	0.08
2006	-8.34	0.96	-9.30
2007	9.22	0.84	8.39
2008	0.08	0.06	0.03
2009	-2.97	-0.19	-2.78
2010	-2.88	0.20	-3.08
2011	4.18	0.63	3.56
2012	-8.50	1.83	-10.33
2013	11.26	1.93	9.33
2014	6.58	0.43	6.16
2015	-6.32	1.61	-7.94
2016	-6.49	4.58	-11.07
Average	0.79	1.00	-0.21

[9] Source: NERA EGD TFP Study.

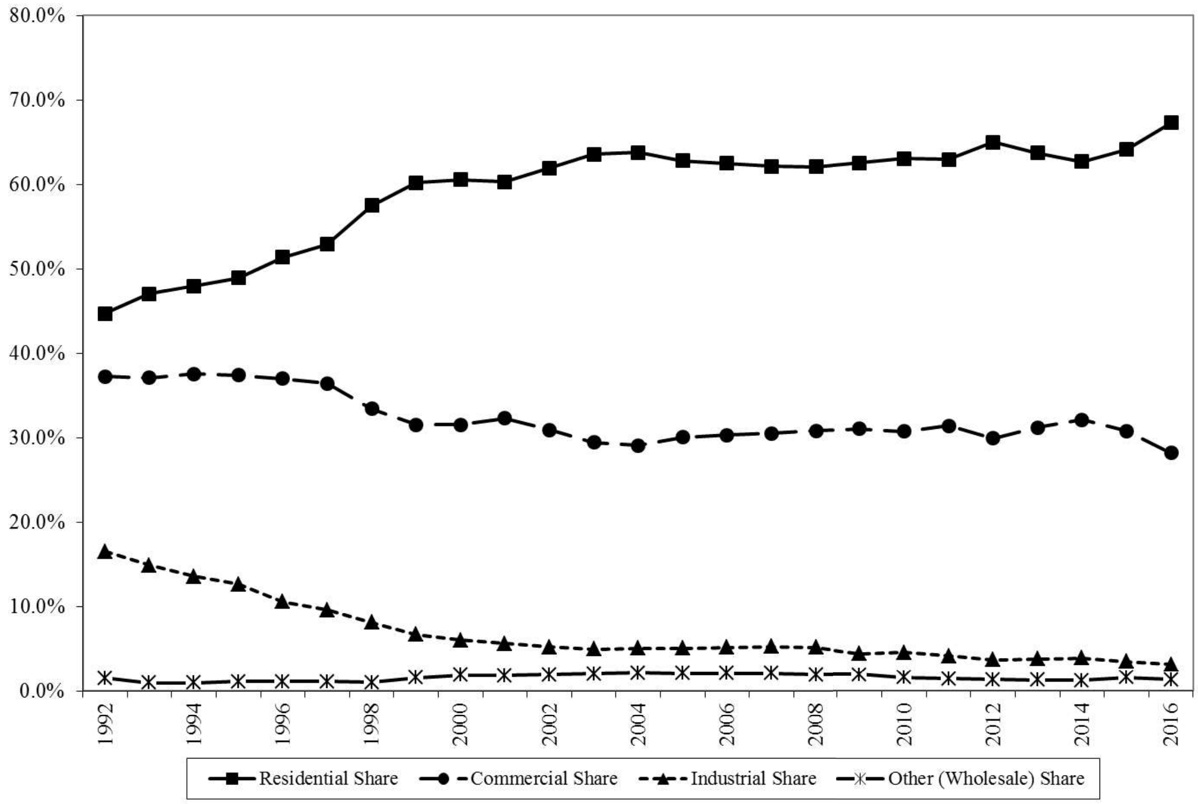
Table 4. EGD Study TFP growth, Canadian economy TFP growth and X-factor calculation 1993-2016[10]

Year	EGD TFP Growth	Canadian TFP Growth
	(percent)	
1993	1.22	1.11
1994	1.87	2.43
1995	-4.21	0.37
1996	7.04	-0.92
1997	-3.65	1.06
1998	-4.68	0.63
1999	3.35	2.38
2000	8.10	2.12
2001	-0.18	0.06
2002	-0.93	1.29
2003	6.78	-0.73
2004	-2.85	-0.32
2005	0.08	0.04
2006	-9.30	-0.82
2007	8.39	-1.14
2008	0.03	-2.30
2009	-2.78	-2.57
2010	-3.08	1.78
2011	3.56	1.49
2012	-10.33	-0.61
2013	9.33	0.91
2014	6.16	1.33
2015	-7.94	-1.00
2016	-11.07	*0.29*
Average	-0.21	0.29
X-Factor	-0.50	

[10] Source: EGD TFP growth: NERA EGD TFP Study, Canadian TFP growth: Canadian Multifactor Productivity (MFP) for the Business Sector was used for this comparison. These data were taken from Statistics Canada, Table 383-0021, www5.statcan.gc.ca/cansim/a47. I estimated Canadian TFP growth in 2016 using the average TFP growth for the time period 1993-2015 since Statistics Canada has not yet published a TFP number for this year.

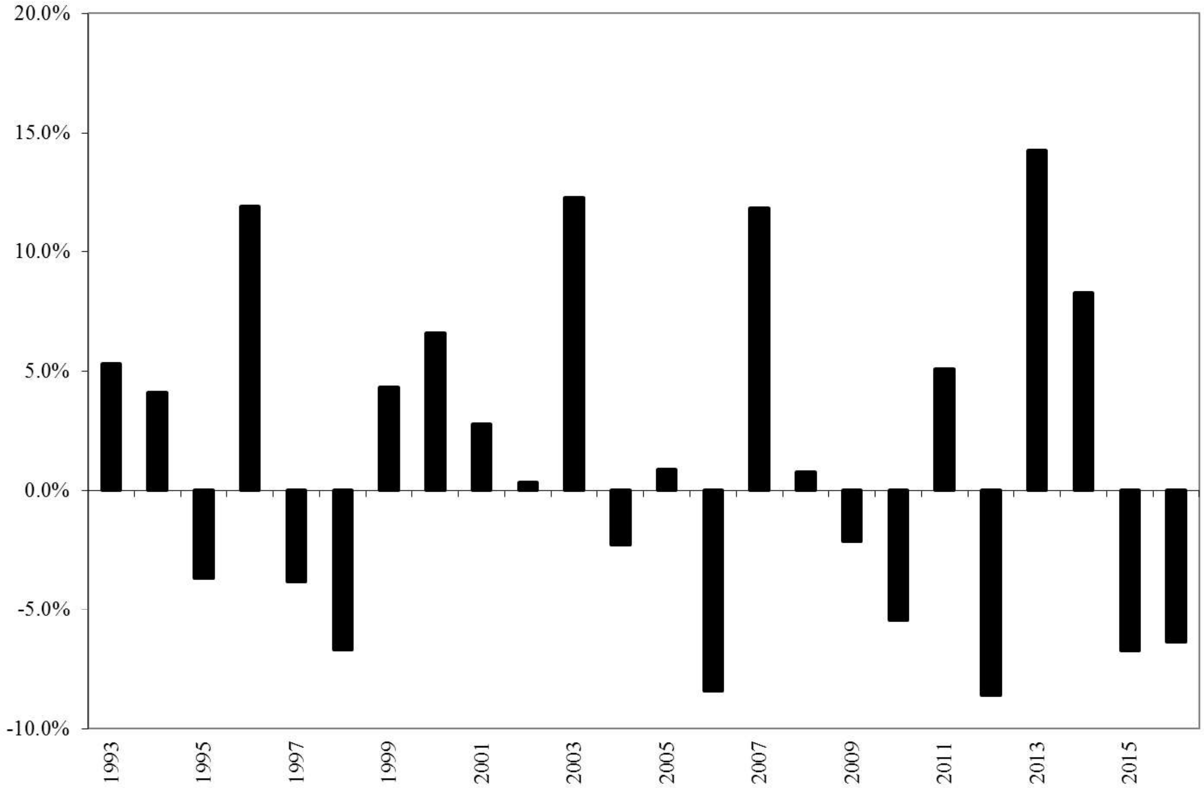
III. EGD Study Figures

Figure 1. EGD output shares, 1992-2016



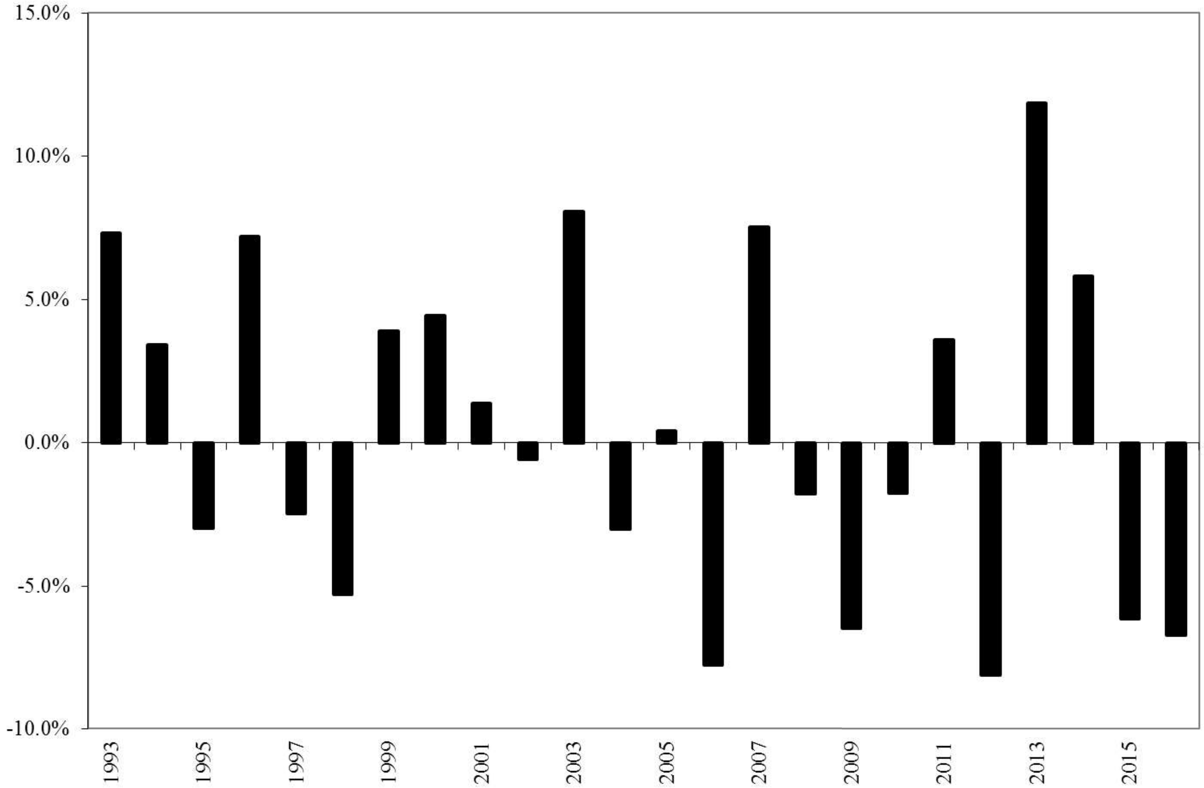
Source: NERA EGD TFP Study

Figure 2. EGD residential output index growth, 1993-2016



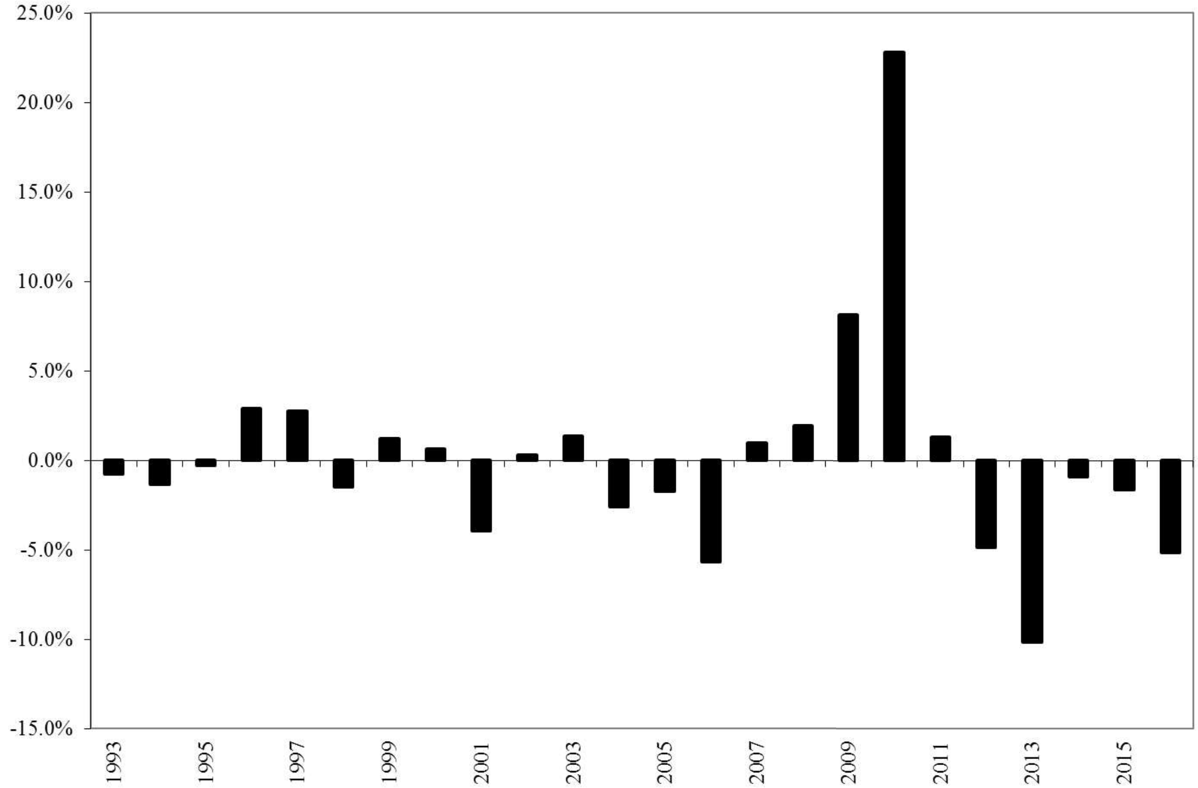
Source: NERA EGD TFP Study

Figure 3. EGD commercial output index growth, 1993-2016



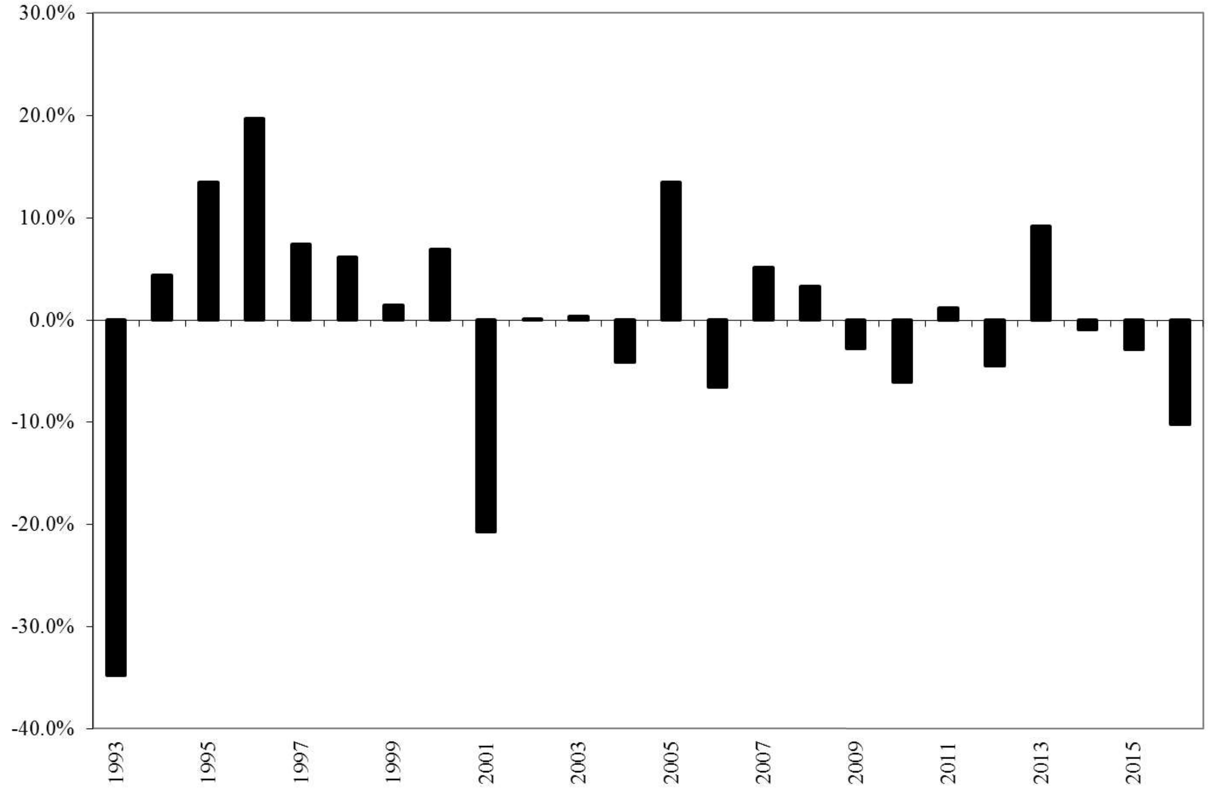
Source: NERA EGD TFP Study

Figure 4. EGD industrial output index growth, 1993-2016



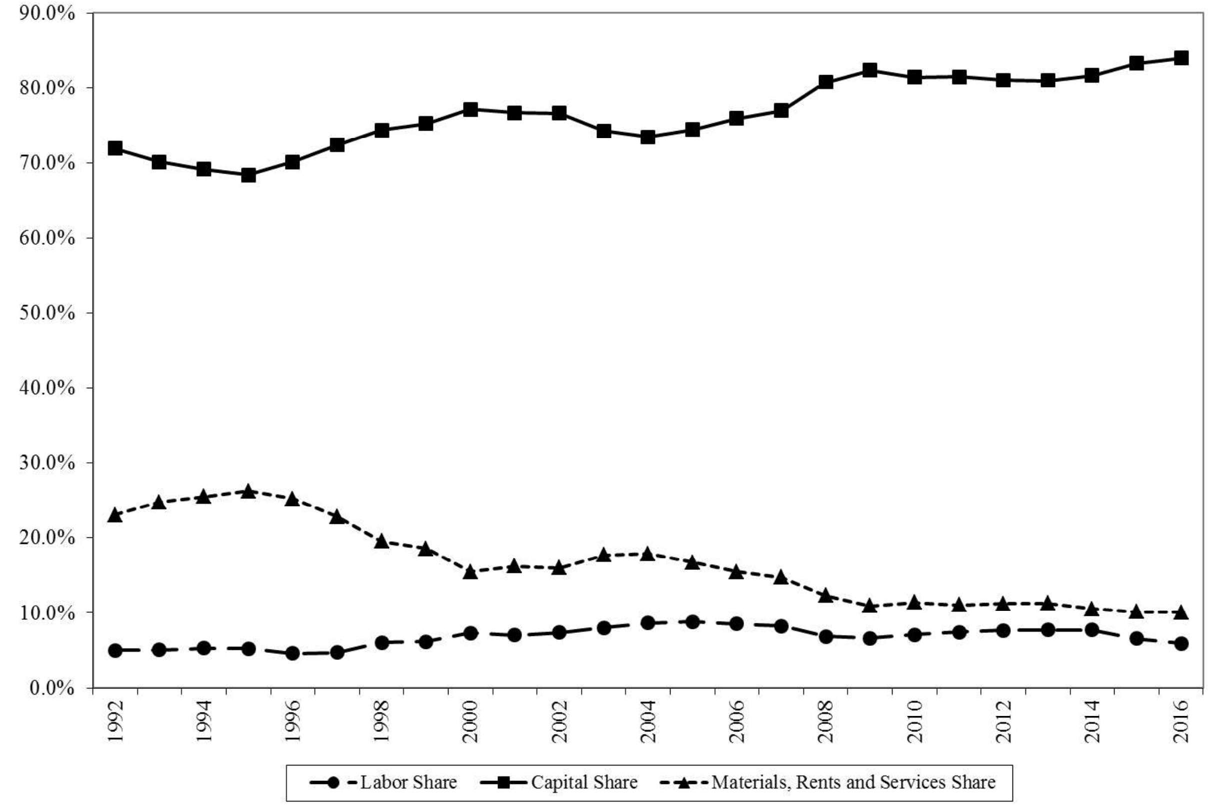
Source: NERA EGD TFP Study

Figure 5. EGD other (wholesale) output index growth, 1993-2016



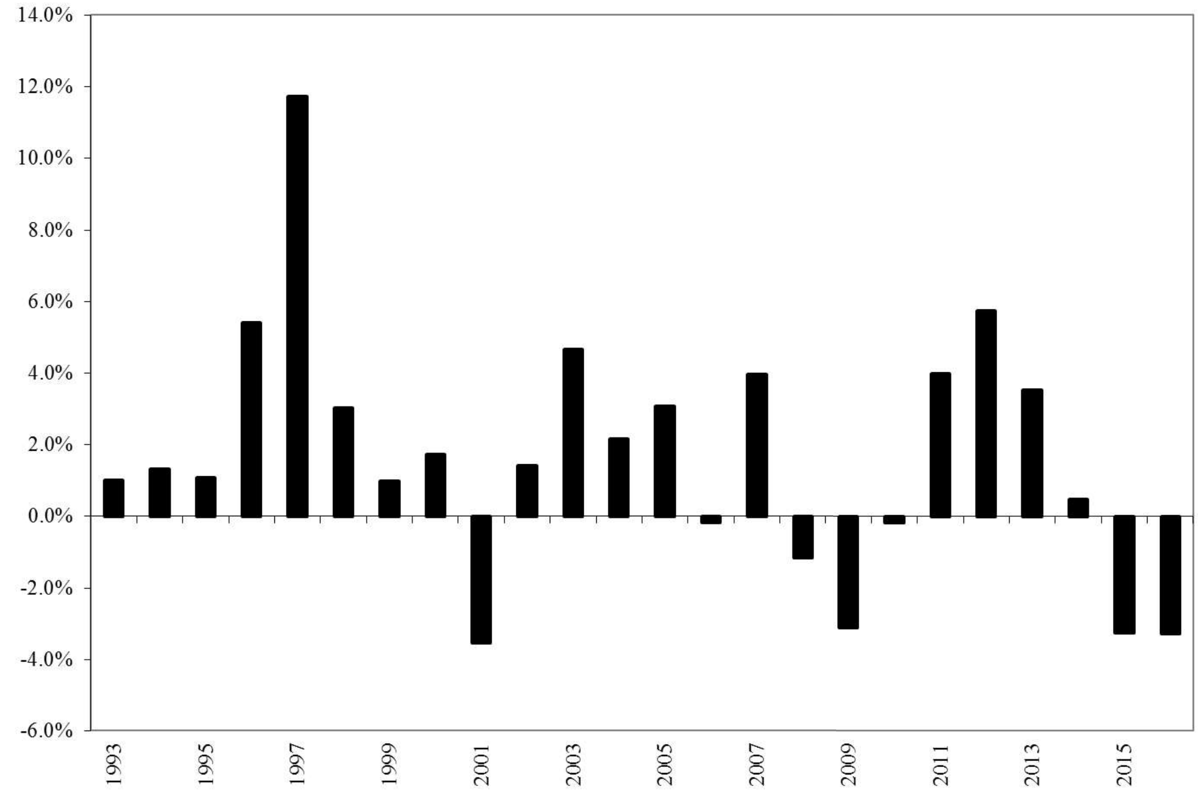
Source: NERA EGD TFP Study

Figure 6. EGD input Shares, 1992-2016



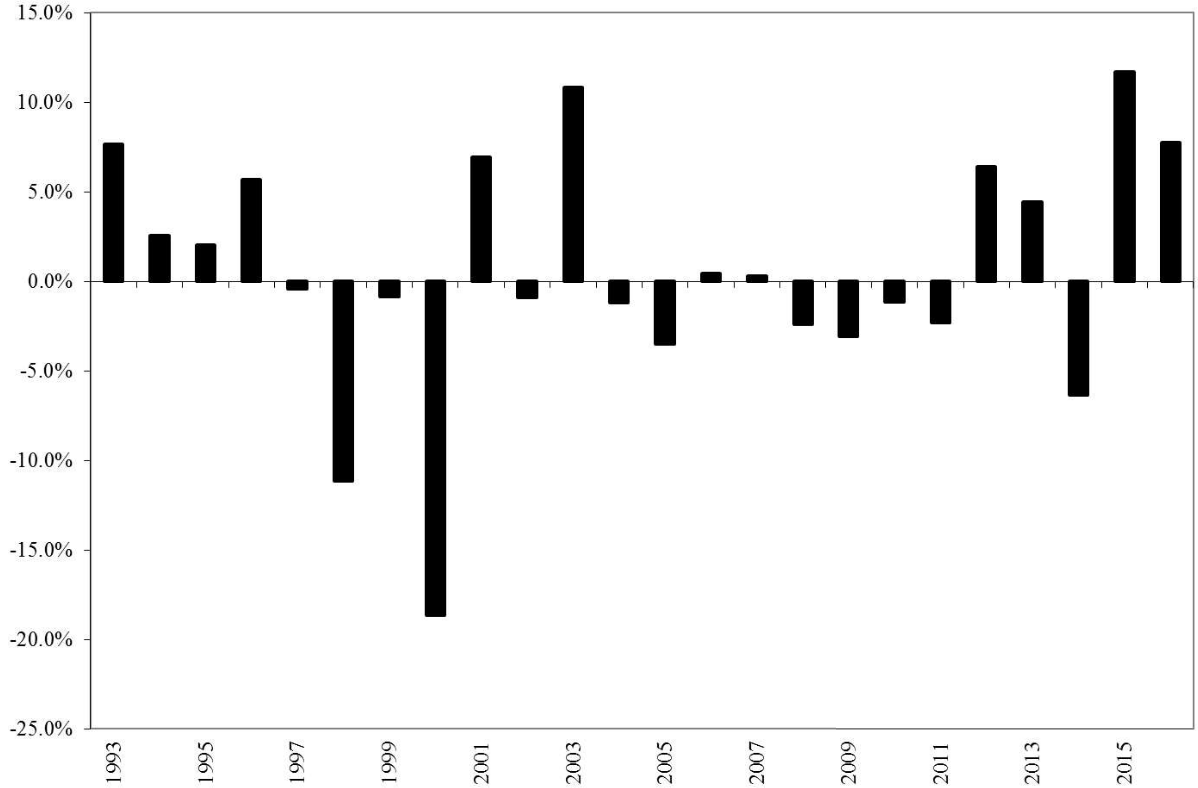
Source: NERA EGD TFP Study

Figure 7. EGD labor input index growth, 1993-2016



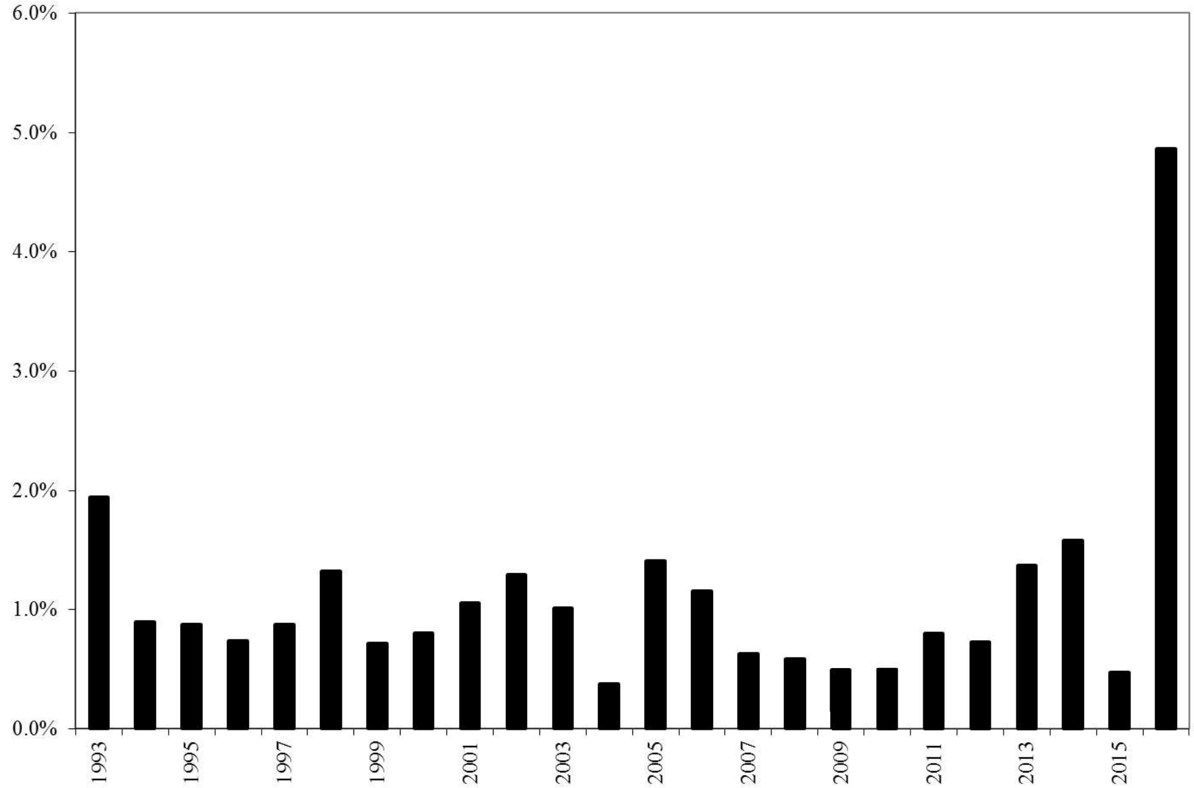
Source: NERA EGD TFP Study

Figure 8. EGD MRS input index growth, 1993-2016



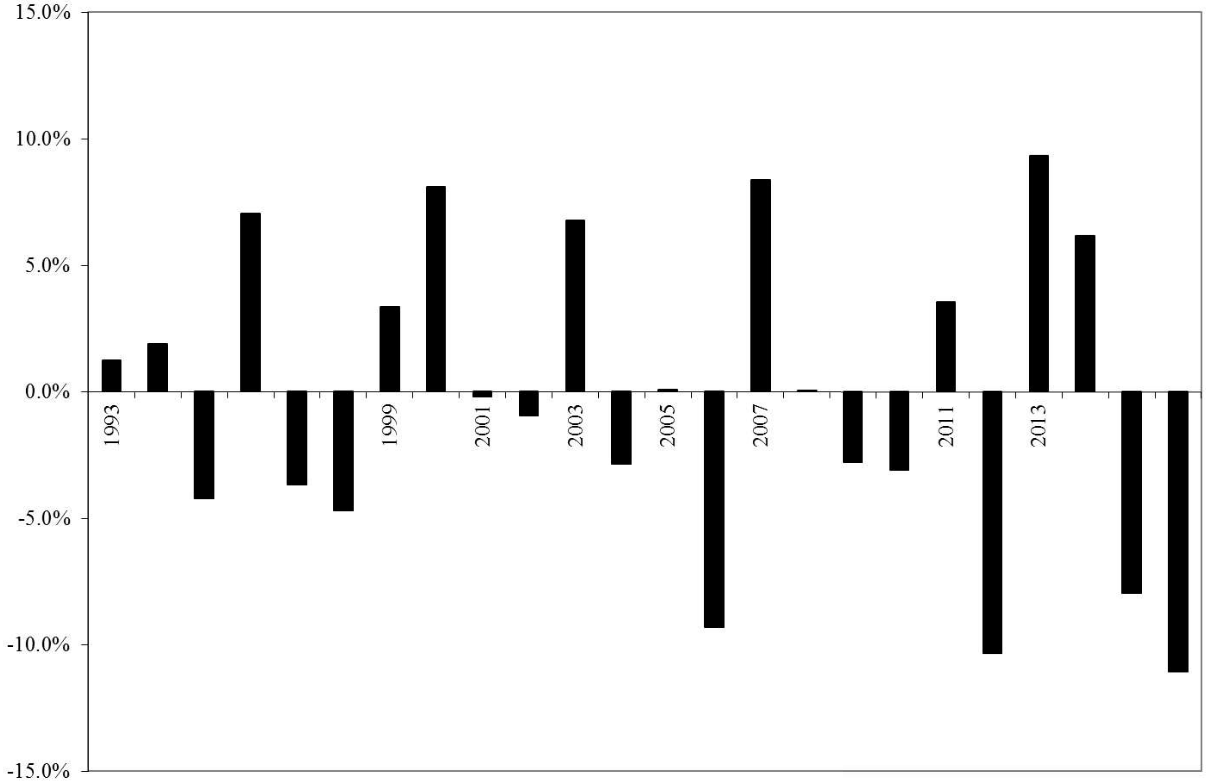
Source: NERA EGD TFP Study

Figure 9. EGD capital input index growth, 1993-2016



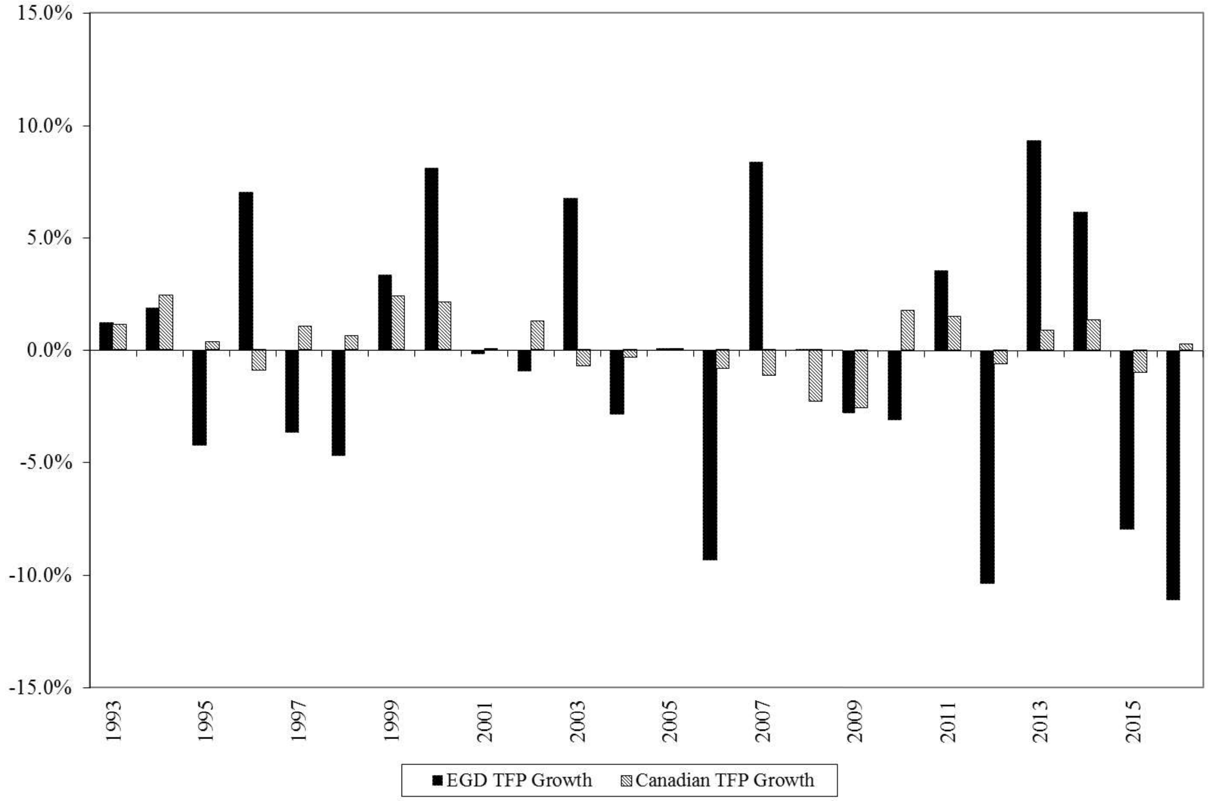
Source: NERA EGD TFP Study

Figure 10. EGD TFP growth, 1993-2016



Source: NERA EGD TFP Study

Figure 11. EGD TFP growth and Canadian economy TFP growth, 1993-2016



Source: NERA EGD TFP Study and Statistics Canada

Exhibit JDM-3, Tab 3: NERA Union Study Summary Tables and Figures

I. Union Study Tables

Table 1. Union TFP Study, output shares and output index growth, 2000-2016[11]

Service	Share of Output	Output Index Growth Rate
	(percent)	
General Service	81.97%	0.27%
Contract	18.03%	-0.88%

Table 2. Union TFP Study, input shares and input index growth, 2000-2016[12]

Input	Share	Input Index Growth Rate
	(percent)	
Labor	8.58%	-0.42%
MRS	8.58%	1.40%
Capital	82.84%	-0.03%

[11] Source: NERA Union TFP Study, share of output and growth rates are unweighted.

[12] Source: NERA Union TFP Study, share of input and growth rates are unweighted.

Table 3. Union TFP Study, output, input and TFP growth, 2001-2016[13]

Year	Output growth	Input growth	TFP growth
	(percent)		
2001	-6.92	0.04	-6.89
2002	6.74	0.33	7.08
2003	3.82	1.61	5.43
2004	-4.24	-0.67	-4.91
2005	0.22	0.61	0.83
2006	-8.19	-0.04	-8.23
2007	6.96	0.00	6.96
2008	2.50	-0.17	2.33
2009	-4.10	0.11	-4.00
2010	-3.47	-0.60	-4.06
2011	6.42	-0.09	6.34
2012	-8.20	-0.09	-8.29
2013	12.29	0.23	12.52
2014	6.44	0.18	6.62
2015	-7.73	-0.57	-8.30
2016	-5.82	-1.32	-7.13
Average	-0.21	-0.03	-0.23

[13] Source: NERA Union TFP Study.

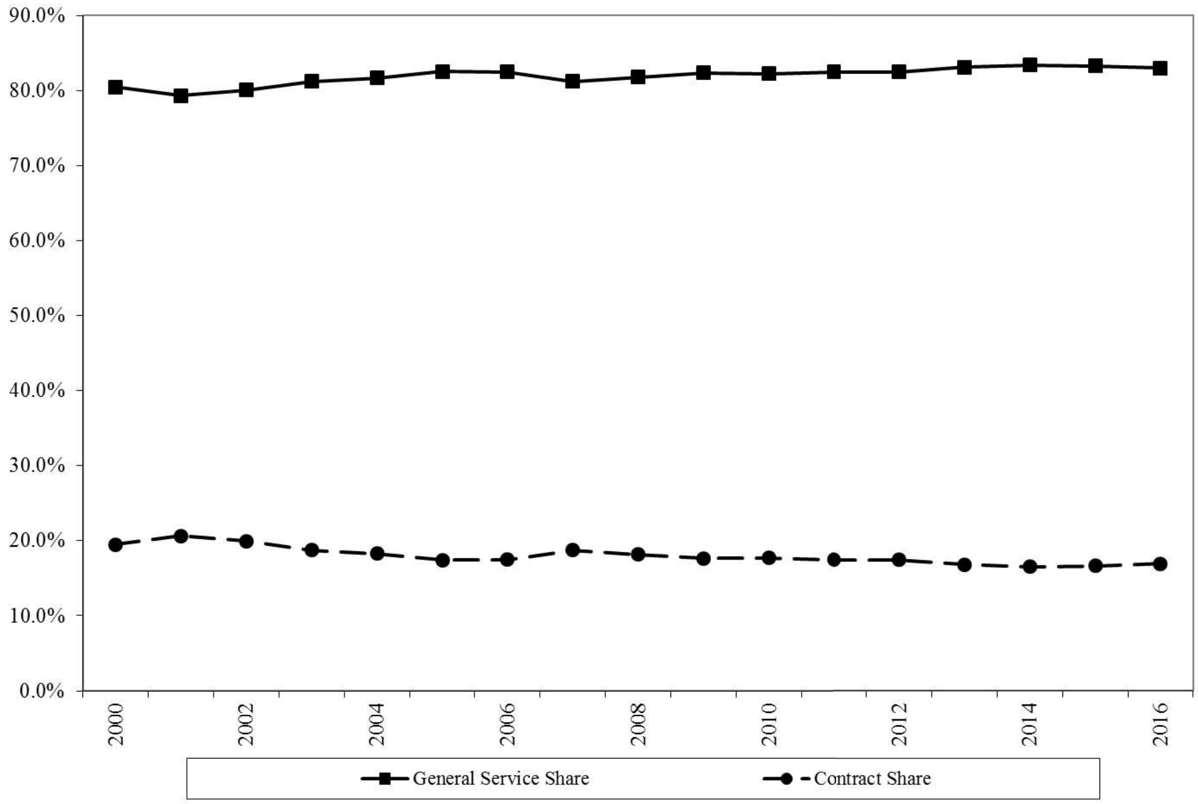
Table 4. Union Study TFP growth, Canadian economy TFP growth and X-factor calculation 2001-2016[14]

Year	Union TFP Growth	Canadian TFP Growth
	--------(percent)--------	
2001	-6.89	0.06
2002	7.08	1.29
2003	5.43	-0.73
2004	-4.91	-0.32
2005	0.83	0.04
2006	-8.23	-0.82
2007	6.96	-1.14
2008	2.33	-2.30
2009	-4.00	-2.57
2010	-4.06	1.78
2011	6.34	1.49
2012	-8.29	-0.61
2013	12.52	0.91
2014	6.62	1.33
2015	-8.30	-1.00
2016	-7.13	*-0.17*
Average	-0.23	-0.17
X-Factor	-0.06	

[14] Source: Union TFP growth: NERA Union TFP Study, Canadian TFP growth: Canadian Multifactor Productivity (MFP) for the Business Sector was used for this comparison. These data were taken from Statistics Canada, Table 383-0021, www5.statcan.gc.ca/cansim/a47. I estimated Canadian TFP growth in 2016 using the average TFP growth for the time period 1993-2015 since Statistics Canada has not yet published a TFP number for this year.

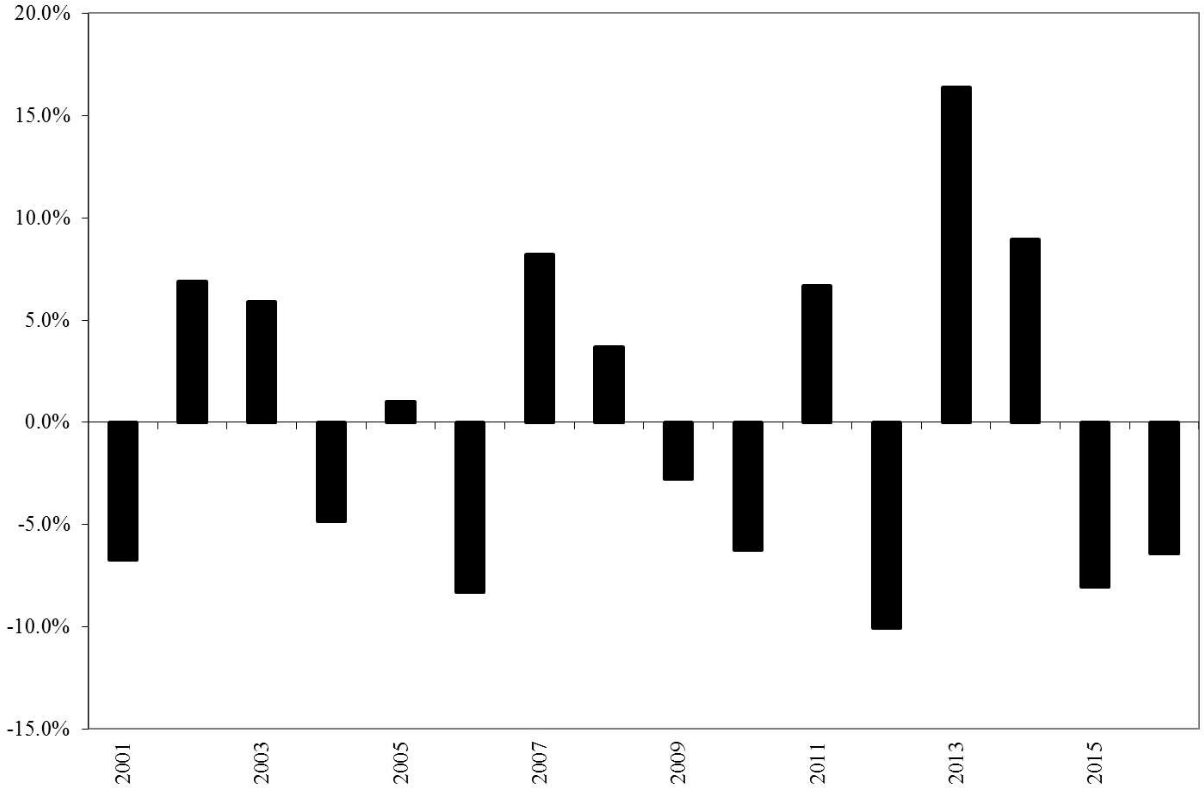
II. Union Study Figures

Figure 1. Union output shares, 2000-2016



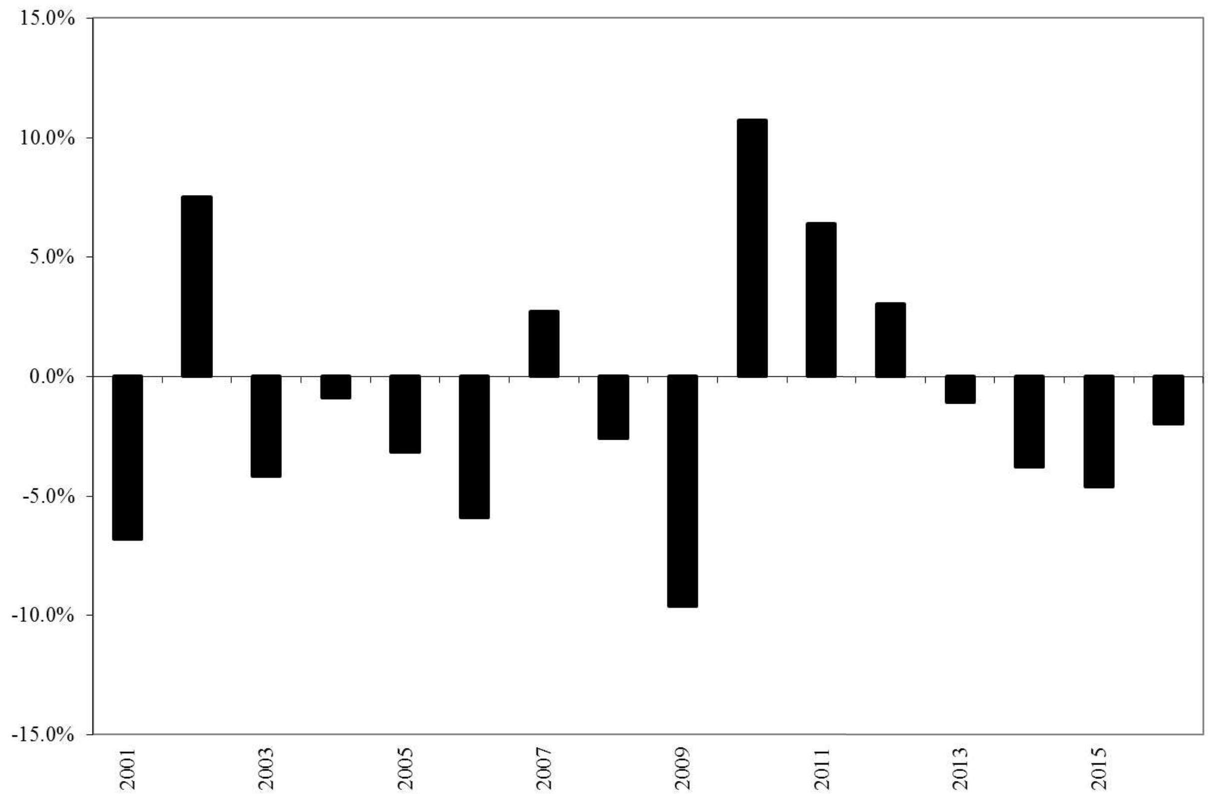
Source: NERA Union TFP Study

Figure 2. Union general service output index growth, 2001-2016



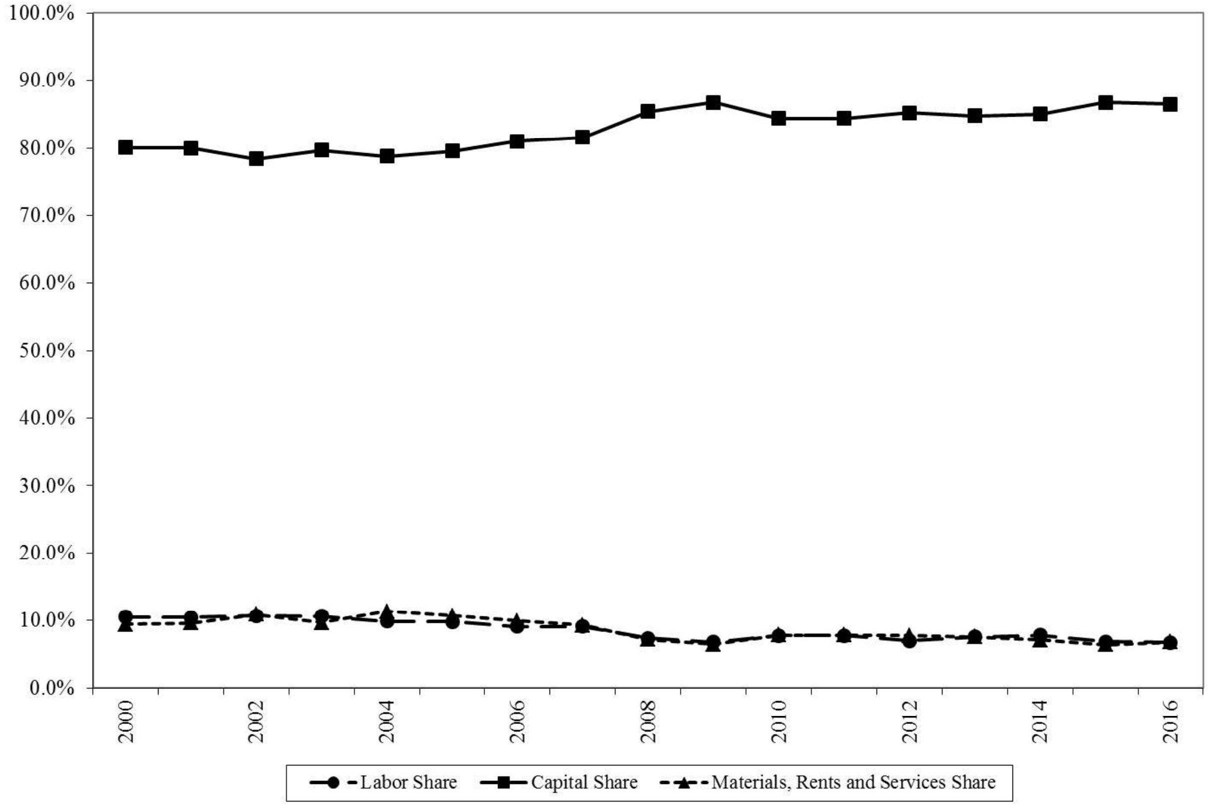
Source: NERA Union TFP Study

Figure 3. Union contract output index growth, 2001-2016



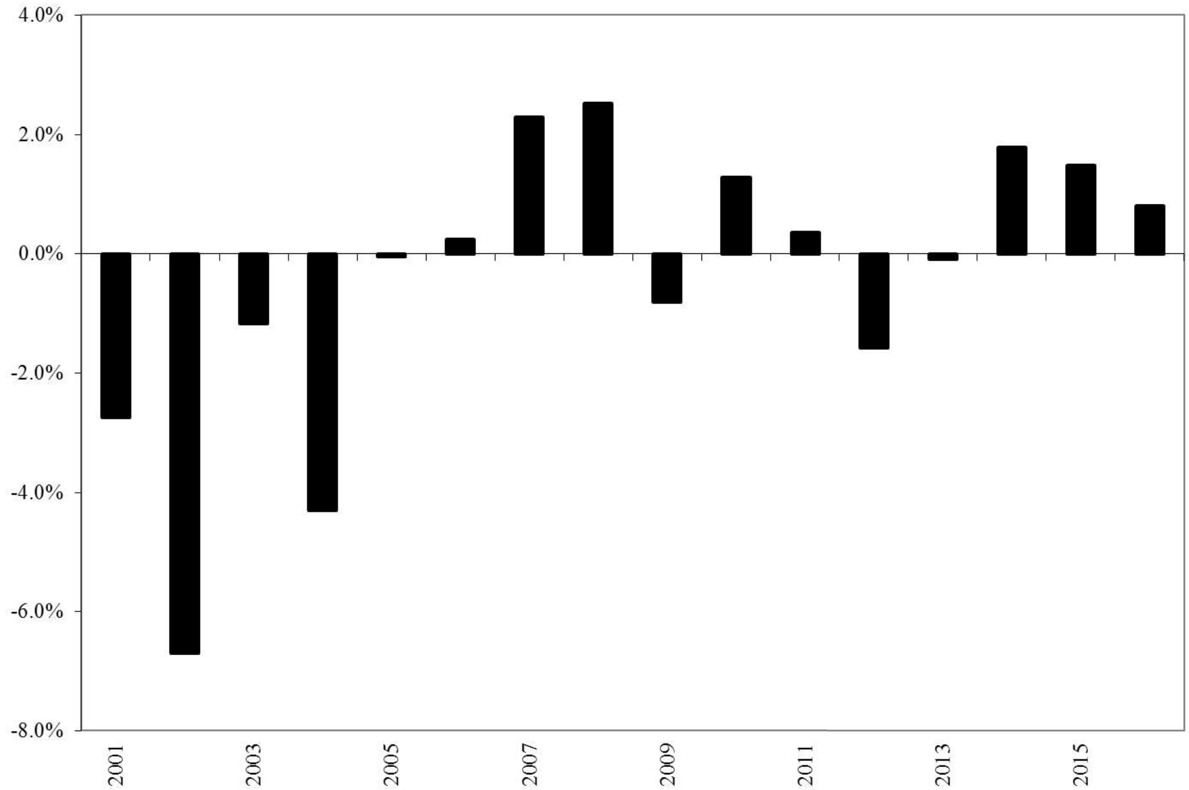
Source: NERA Union TFP Study

Figure 4. Union input shares, 2000-2016



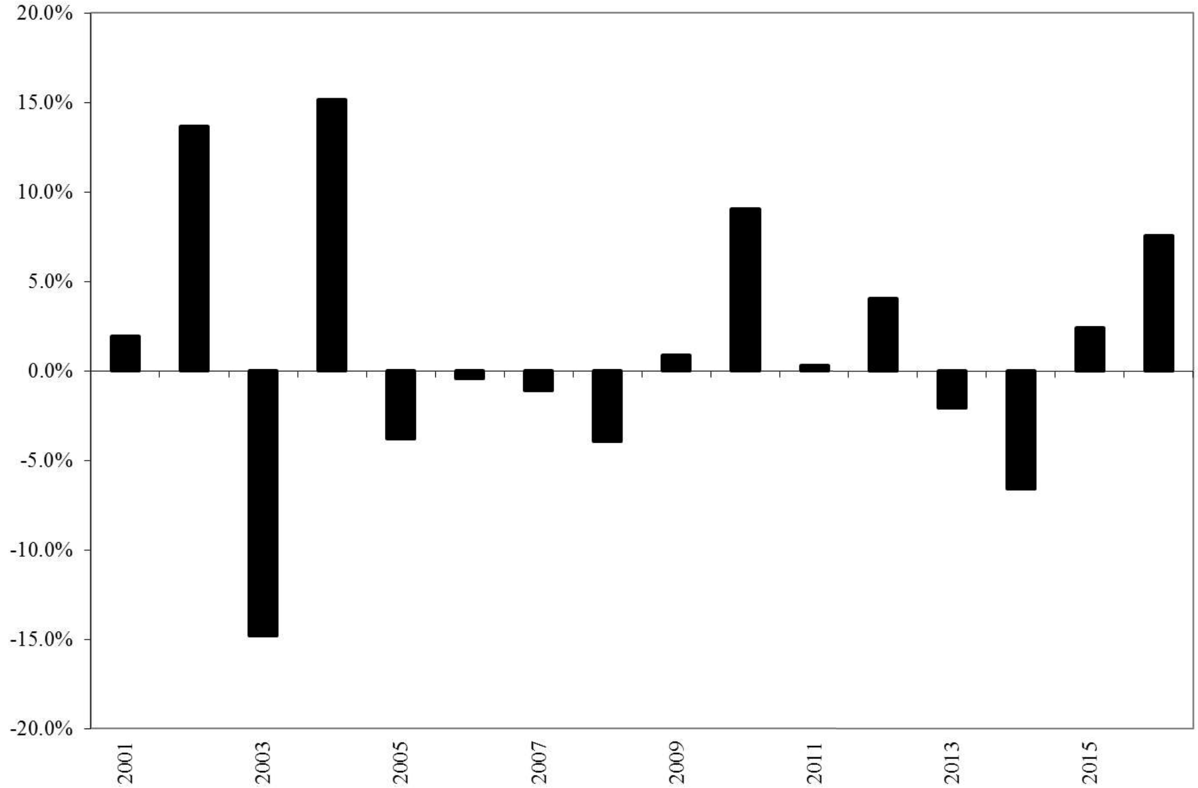
Source: NERA Union TFP Study

Figure 5. Union labor input index growth, 2001-2016



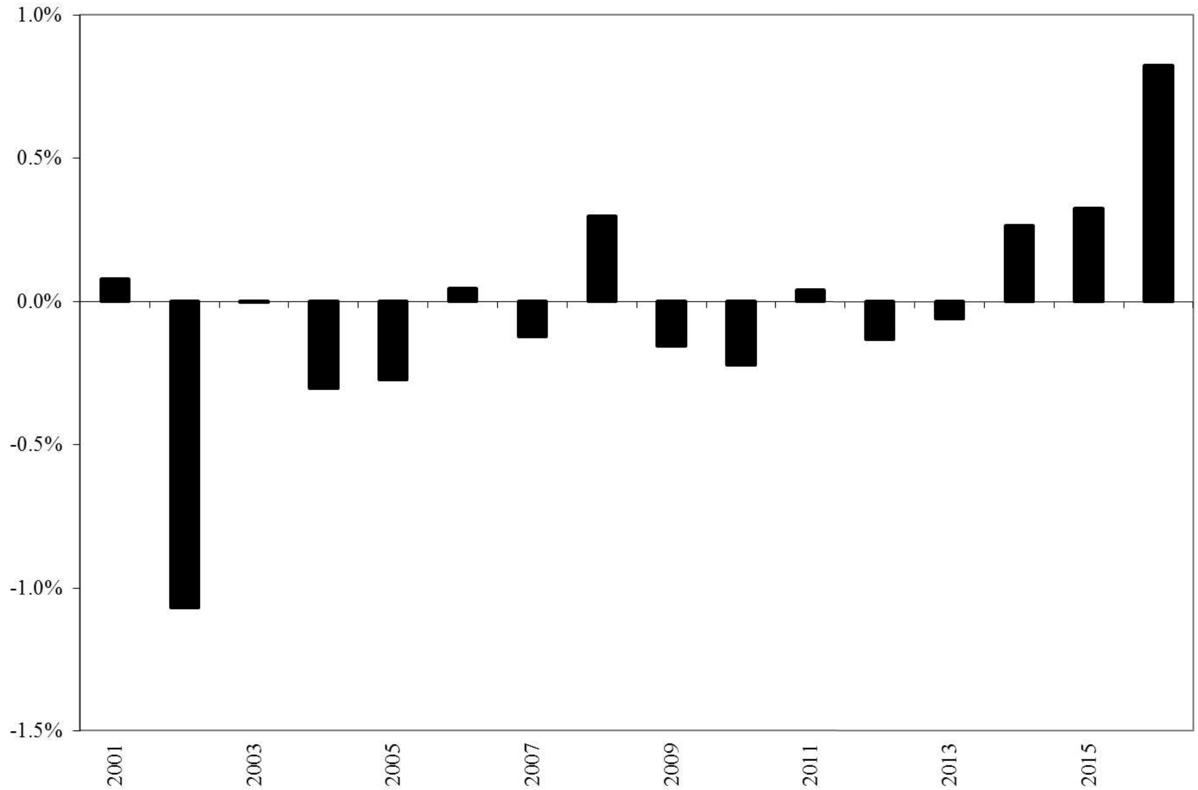
Source: NERA Union TFP Study

Figure 6. Union MRS input index growth, 2001-2016



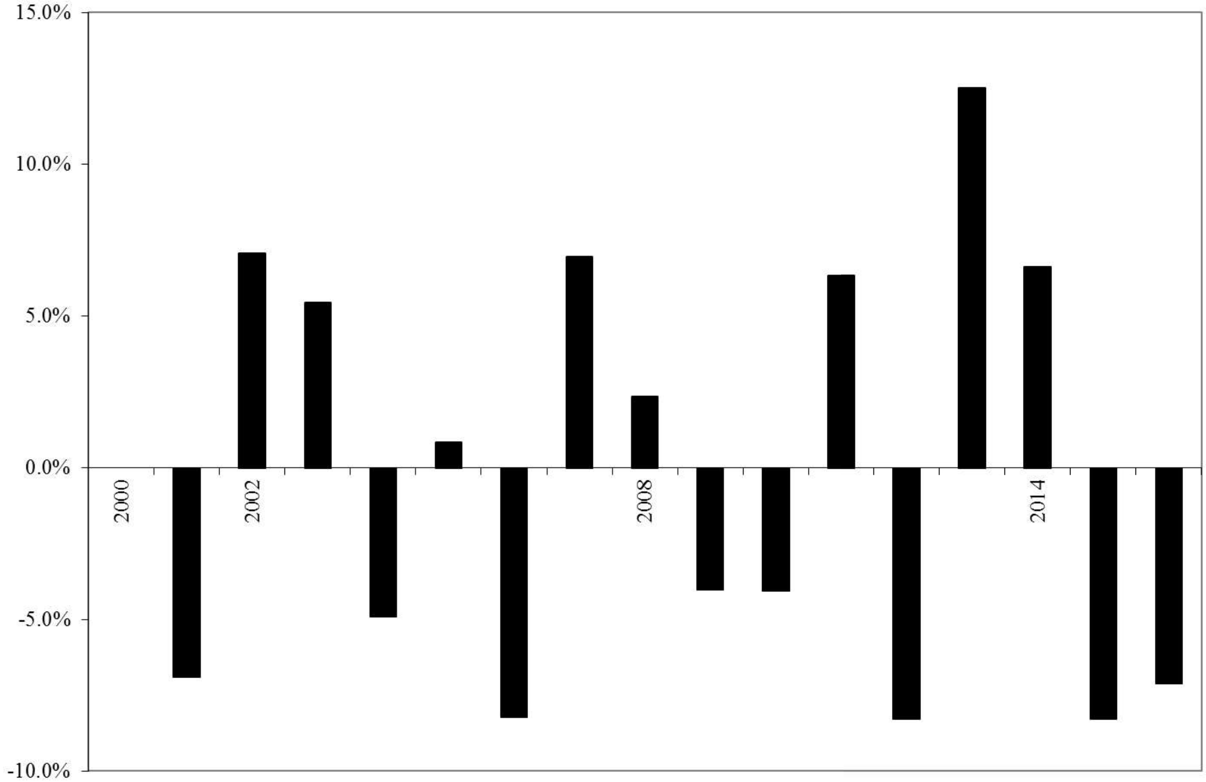
Source: NERA Union TFP Study

Figure 7. Union capital input index growth, 2001-2016



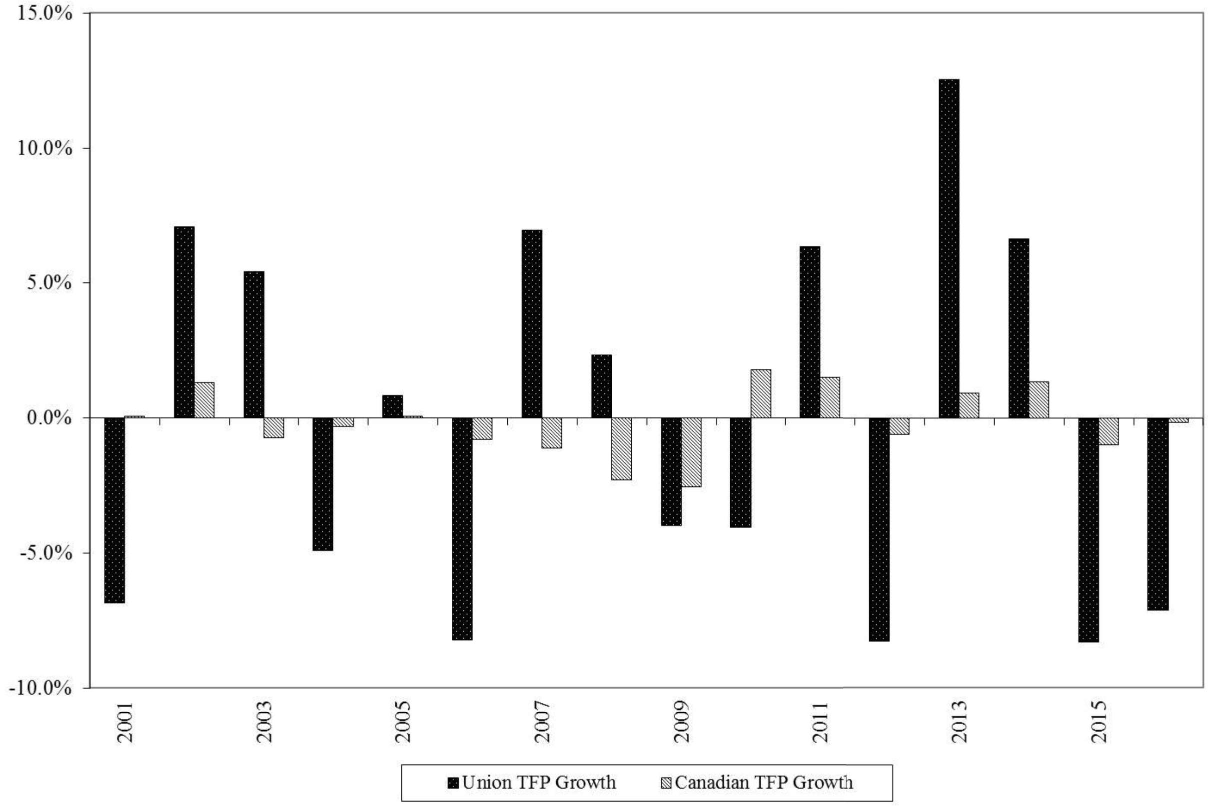
Source: NERA Union TFP Study

Figure 8. Union TFP growth, 2001-2016



Source: NERA Union TFP Study

Figure 9. Union TFP growth and Canadian economy TFP growth, 2001-2016



Source: NERA Union TFP Study and Statistics Canada

Exhibit JDM-4: Summary of Calculation of Input Price Differentials in Past Proceedings

I. Current Industry Study[1]

Year	Input price growth	US Input Price Growth
	(percent)	
1973	3.22	8.50
1974	8.14	5.40
1975	19.12	10.40
1976	11.96	9.20
1977	0.03	8.10
1978	6.62	8.60
1979	11.00	7.50
1980	13.80	6.60
1981	12.01	9.40
1982	3.78	4.10
1983	1.91	4.20
1984	5.25	7.30
1985	1.30	3.40
1986	9.41	2.10
1987	3.63	4.20
1988	-2.71	4.10
1989	6.01	4.20
1990	3.37	3.90
1991	2.41	1.40
1992	2.54	4.90
1993	5.87	2.10
1994	-0.47	2.00
1995	4.97	1.40
1996	0.41	3.40
1997	1.91	2.60
1998	5.42	1.90
1999	5.35	2.90
2000	5.57	3.60
2001	35.65	2.30
2002	-2.40	2.50
2003	-5.92	4.20
2004	-3.54	5.50
2005	5.11	4.70
2006	6.29	3.30
2007	8.56	3.50
2008	19.60	1.60
2009	8.21	-1.60
2010	-8.03	4.00
2011	1.59	2.30
2012	5.65	1.80
2013	0.28	2.30
2014	1.87	1.80
2015	8.67	1.20
2016	1.31	*4.11*
Average	5.34	4.11

t-statistic	Critical value (two-tail)	Degrees of freedom
1.1504	2.021	42

[1] Source: Industry Input Price Growth: NERA Industry TFP Study, Industry input price growth is weighted by total mWh; US Input Price Growth: U.S. Bureau of Labor Statistics (BLS), Net Multifactor Productivity and Cost (Private Business Sector), Table PG 4.3 available at: https://www.bls.gov/mfp/mprdload.htm. I estimate input price growth for the US economy in 2016, using the average input price growth for 1973-2015, since I did not have data for 2016 at the time of my analysis. The difference in means test encompasses the years 1973-2015.

II. Alberta Study[2]

Table 5. Study input price growth and U.S. and Canadian economy input price growth, 1973-2009[58]

Year	Input price growth[(1)]	U.S. input price growth	Canadian input price growth
	(percent)		
1973	3.03	8.35	10.40
1974	8.19	5.68	13.76
1975	19.55	10.65	9.26
1976	12.51	9.34	13.58
1977	-0.35	7.97	8.12
1978	6.52	8.32	6.58
1979	11.20	8.02	8.49
1980	13.82	6.92	7.69
1981	11.90	9.67	10.42
1982	4.08	2.90	6.53
1983	1.49	6.85	6.87
1984	5.29	6.76	6.61
1985	1.13	4.33	4.28
1986	9.75	3.91	1.57
1987	3.73	3.30	4.47
1988	-2.77	4.23	4.62
1989	5.94	4.08	3.21
1990	3.53	4.56	1.47
1991	2.38	2.64	0.13
1992	2.45	4.87	1.85
1993	5.84	2.41	2.50
1994	-0.68	2.81	3.53
1995	5.02	1.78	2.48
1996	0.16	3.60	0.60
1997	2.00	2.57	2.48
1998	5.22	2.63	0.20
1999	5.36	3.27	3.72
2000	0.31	3.87	6.41
2001	11.96	3.06	0.82
2002	11.96	4.02	1.61
2003	-6.16	4.75	2.80
2004	-4.41	5.44	2.49
2005	4.46	4.34	3.49
2006	6.10	3.76	1.93
2007	8.36	3.44	2.58
2008	20.60	2.29	1.86
2009	8.12	1.72	-4.34
Average	5.61	4.84	4.46

[58] Note: [(1)] Input price growth is weighted by total mWh. Input price growth for U.S. and Canadian economy are derived from: Economy-wide input price growth = GDP-PI growth + economy-wide TFP growth. Source: Input price growth: NERA; U.S. GDP-PI: Bureau of Economic Analysis, Table 1.1.9, *Implicit Price Deflators for Gross Domestic Product*, available at: http://www.bea.gov/national/nipaweb/SelectTable.asp?Selected=N, accessed on December 30, 2010; Canadian GDP-PI: Statistics Canada, Table 380-0056, *Implicit Chain Price Index Gross Domestic Product*, available for a fee at http://www.statcan.gc.ca/start-debut-eng.html, accessed on December 17, 2010.

[2] Taken from: "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," AUC Proceeding 566 – Rate Regulation Initiative, December 30, 2010, p. 22.

III. Central Maine Power Study[3]

APPENDIX 5

Comparison of U.S. Economy Input Price Growth
with Northeast Power Distribution Input Price Growth

	U.S. Economy* (%)	Northeast Power Distribution** (%)
1973	8.3%	7.4%
1974	4.2%	20.2%
1975	9.4%	3.4%
1976	9.1%	1.9%
1977	8.6%	10.7%
1978	7.8%	10.6%
1979	8.2%	10.7%
1980	6.6%	12.5%
1981	9.9%	8.5%
1982	3.7%	5.2%
1983	5.6%	0.1%
1984	7.4%	7.0%
1985	4.0%	1.3%
1986	3.8%	1.9%
1987	3.1%	3.1%
1988	4.4%	5.7%
1989	4.1%	2.7%
1990	4.2%	3.3%
1991	2.9%	-0.3%
1992	5.1%	0.7%
Average 1972-1992:	6.0%	5.8%
t Statistic:	-0.168	
t Critical Value (two-tail)	2.093	

Note: The t-Statistic tests the assumption that the means of both time series are equal.

Sources: * Affidavit of Dr. Laurits R. Christensen on Behalf of the United States Telephone Association, CC Docket No. 94-1, February 1, 1995, Appendix A.
** Bureau of Labor Statistics, Average Hourly Earnings of Production Workers, Electric Services, Series ID: EEU42491006.
Standard & Poor's DRI, Operation and Maintenance Cost Model, Total Electric Distribution O&M Cost Index.
Standard & Poor's DRI, Operation and Maintenance Cost Model, Rental Price of Capital - Non Residential Structures - Public Utilities.
Ferc Form 1 Filings, 1972-1992.

[3] Taken from: Direct Testimony of Jeff D. Makholm, on behalf of Central Maine Power, in Docket No. 99-666 regarding Central Maine Power Company's Alternative Rate Plan (ARP2000), September 30, 1999, Appendix 5. Note that economy wide input price growth is measured for the US economy.

IV. UtilitCorp Networks Canada Study[4]

APPENDIX 6: COMPARISON OF INDUSTRY AND ECONOMY WIDE INPUT PRICE INDEXES

	Input Price Growth		
	Electricity Sector[1]	Total Economy[2]	Input Price Differential[3]
1973	8.07%	13.16%	-5.10%
1974	8.98%	13.97%	-4.99%
1975	5.51%	11.84%	-6.33%
1976	11.80%	11.16%	0.64%
1977	22.43%	7.54%	14.89%
1978	9.64%	8.00%	1.64%
1979	11.39%	10.47%	0.91%
1980	13.09%	9.94%	3.16%
1981	7.69%	5.83%	1.86%
1982	10.96%	4.56%	6.40%
1983	8.83%	8.82%	0.01%
1984	9.91%	7.09%	2.82%
1985	6.40%	5.48%	0.93%
1986	6.21%	1.59%	4.62%
1987	5.14%	5.79%	-0.65%
1988	6.20%	4.42%	1.77%
1989	-0.94%	3.13%	-4.08%
1990	-1.19%	0.74%	-1.92%
1991	8.95%	0.42%	8.53%
1992	3.44%	1.57%	1.87%
1993	-0.79%	1.97%	-2.76%
1994	1.54%	4.49%	-2.96%
1995	4.19%	3.80%	0.39%
average (72-95)	7.28%	6.34%	0.94%
standard deviation	5.26%	4.04%	4.76%

			95% confidence interval	
t-statistic	t critical value (two-tail)	degrees of freedom	high	low
0.950169131	2.07	22	10.80%	-8.92%

[1]Calculated by summing the growth rates of GDP-PI and MFP for the electric power systems industry. GDP-PI is calculated by dividing GDP in current dollars by GDP in constant dollars. For GDP Current Dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of Current Dollars, Business Sector, Electric Power Systems Industry, I193829 4763 8.35.129 (DOLLARS x 1M). For GDP Constant Dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of 1992 Constant Dollars, Business Sector, Electric Power Systems Industry, I196829 4767 8.35.129 (K DOLLARS x 1M). For MFP: Fisher Ideal Indices (1992=100) of Multifactor Productivity Based on Gross Output for Business Sector Industries, Annual, Electric Power Systems Industries, ID I710309 9456 4.109 (INDEX)

[2]Calculated by summing MFP and GDP-PI growth indices for the Canadian Economy. For MFP: Fisher Ideal Indices (1992=100) of Multifactor Productivity Based on Real Value Added and Related Data for Business Sector and Selected Aggregates, Annual. Multifactor Productivity Business Sector, I720328 9458 1.1 (Index). GDP-PI is calculated by dividing GDP in current dollars by GDP in constant dollars.For GDP current dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of Current Dollars, Special Aggregations, Business Sector Industries, I195902 4766 2 (Dollars x 1M). For GDP current dollars: Gross Domestic Product at Factor Cost - System of National Accounts Benchmark Values by Industry - Annual Data in Millions of 1992 Constant Dollars, Special Aggregations, Business Sector Industries, I198902 4770 2 (K Dollars x 1M).

[3]The difference between the electicity sector and total economy input price growths.

Note: All growth rates calculated using ln method: growth rate = ln(x/(x-1)).

[4] Taken from: Evidence of Jeff D. Makholm, on behalf of Utilicorp Networks Canada, on a Productivity Offset for a Proposed PBR Plan, September 1, 2000, Appendix 6. Note that economy wide input price growth is measured for the Canadian economy.

GRID MODERNIZATION LABORATORY CONSORTIUM
U.S. Department of Energy

State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities

July 2017

MN Lowry
M Makos
J Deason
L Schwartz, Project Manager and Technical Editor

State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities

MN Lowry[1]
M Makos[1]
J Deason[2]
L Schwartz,[2] Project Manager and Technical Editor

July 2017

1 Pacific Economics Group Research LLC
2 Lawrence Berkeley National Laboratory

Executive Summary

Berkeley Lab published a report in 2016 that discussed two approaches to performance-based regulation (PBR) of electric utilities: multiyear rate plans (MRPs) and performance incentive mechanisms (PIMs).[1] The authors described these approaches at a high level and in the context of growing levels of demand-side management (DSM), distributed generation and other distributed energy resources (DERs).

This report presents a more in-depth analysis of the multiyear rate plan approach to PBR for electric utilities, applicable to both vertically integrated and restructured states. The report is aimed primarily at state utility regulators and stakeholders in the state regulatory process. The approach also provides ideas on how to streamline oversight of public power utilities and rural electric cooperatives by their governing boards.

We discuss the rationale for MRPs and their usefulness under modern business conditions. We then explain critical plan design issues and challenges and present results from numerical research that considers the extra incentive power achieved by MRPs with different plan provisions. Next, the report presents several case studies of utilities that have operated under formal MRPs or, for various reasons, have stayed out of rate cases for more than a decade. In these studies we consider the effect of MRPs and rate case frequency on utility cost, reliability and other performance dimensions. Appendices present further information on MRP plan design and some details of the technical work.

What Are MRPs?

MRPs are a comprehensive approach to PBR designed to strengthen general incentives for good utility performance. Two key provisions of MRPs strengthen cost containment incentives and streamline regulation:

1. A rate case moratorium reduces the frequency of rate cases, typically to once every four or five years.

2. An attrition relief mechanism (ARM) escalates rates or revenue between rate cases to address cost pressures such as inflation and growth in number of customers independently of the utility's own cost.

Loosening the link between its own cost and revenue gives a utility an operating environment more like that which competitive markets experience.

Most MRPs feature a performance metric system that includes some PIMs. These PIMs provide awards or penalties, or both, for performance in targeted areas. PIMs are most commonly used in MRPs to strengthen incentives for utilities to maintain or improve reliability and customer service quality. Some plans also include earnings sharing mechanisms, efficiency carryover mechanisms and marketing flexibility.

Provisions are often added to plans to strengthen utility incentives for DSM. For example, utility expenditures on DSM programs are usually tracked, and PIMs can be added to reward utilities for successful DSM programs. Revenue decoupling can mitigate a utility's incentive to boost retail sales and reduce risks of revenue losses from rate designs that encourage DSM.

[1] Lowry and Woolf (2016).

How Prevalent Is This Approach?

MRPs were first widely used in the United States in the 1980s to regulate railroads and telecommunications carriers, industries beset by rising competition. Early adopters of MRPs in the U.S. electric utility industry included California and several northeastern states. Use of MRPs has recently grown among vertically integrated electric utilities in diverse states that include Arizona, Georgia and Washington. Greater use of MRPs for power distributors has been slowed by their requests for accelerated system modernization, which complicate plan design. MRPs are much more common for electric utilities in Canada and countries overseas. The impetus for adopting MRPs in these countries has often come from policymakers rather than utilities.

What Is the Rationale for These Plans?

America's investor-owned electric utility industry was largely built under cost of service regulation (COSR). This regulatory system traditionally adjusted rates that compensate utilities for costs of capital, labor and materials only in general rate cases. The scope of costs eligible for tracker treatment, which expedites cost recovery, has gradually enlarged and sometimes includes capital costs as well as energy expenditures.

The efficacy of COSR varies with external business conditions. When conditions favor utilities (e.g., are conducive to realizing at least the target rate of return), rate cases are infrequent. Performance incentives are then strong and the cost of regulation is quite reasonable. When conditions are less favorable, rate cases are more frequent and more costs are tracked. Performance incentives can then be weak and regulatory cost can be high. These attributes of COSR are worrisome because business conditions today are often less favorable to utilities than in the past.

MRPs are a different approach to regulation that is especially appealing when the alternative is frequent rate cases or expansive cost trackers. The regulatory process is streamlined and better utility performance can be encouraged due to stronger performance incentives and increased operating flexibility. Benefits of better performance can be shared with customers. Recent advances in MRPs such as efficiency carryover mechanisms and statistical benchmarking can "turbocharge" their incentive power and ensure benefits for customers.

What Are Some Disadvantages of MRPs?

MRPs are complex, and their adoption can involve extensive change to the regulatory system. It can be challenging to design plans that strengthen incentives without undue risk and share benefits fairly between utilities and their customers. Some kinds of business conditions (e.g., brisk inflation and declining average use) have proven easier to address using MRPs than others (e.g., capital spending surges). MRPs can invite strategic behavior and controversies over plan design.

Case Studies

This report discusses six case studies of utilities operating under MRPs:

1. Central Maine Power operated under a sequence of MRPs from 1996 to 2013. The plans afforded the company unusual marketing flexibility which it used to develop special contracts with large-volume customers. These contracts helped the company retain their contributions to fixed costs of the system, for the benefit of all customers.

2. California has the nation's longest history with MRPs for retail services of electric utilities. The Public Utilities Commission has limited rate case frequency and staggered plan terms to avoid simultaneous rate cases. Plan provisions have provided strong incentives for utilities to embrace DSM.
3. New York has regulated electric utilities using MRPs since the 1990s. The state's Reforming the Energy Vision proceeding has considered how rate plans should evolve to regulate the "utility of the future."
4. MidAmerican Energy operated under a rate freeze in Iowa from 1997 to 2013. This freeze extended to charges for energy procured as well as for capital, labor and materials.
5. Ontario, Canada, has used MRPs to regulate the dozens of power distributors since the late 1990s. Capital spending surges have posed special plan design challenges. Innovations in Ontario regulation also include incentive-compatible menus and extensive use of benchmarking.
6. Great Britain also has a long history with MRP regulation. The current "RIIO" approach to regulation of energy utilities there has attracted the attention of many North American regulators.

Impact on Cost Performance

This report also addresses the impact of MRPs (and, more generally, rate case frequency) on utility cost performance using two analytical tools: incentive power analysis and empirical research on utility productivity trends. An Incentive Power Model uses numerical analysis to assess the incentive impact of alternative stylized regulatory systems. For North American case studies, we compared productivity trends of utilities operating under MRPs to U.S. norms. We also considered productivity trends of utilities that operated under unusually frequent and infrequent rate cases.

Both lines of research suggest that the frequency of rate cases can materially affect utility cost performance. For example, the multifactor productivity (MFP) growth of the electric, gas and sanitary sector of the U.S. economy was materially slower than that of the economy as a whole from 1974 to 1985, when rate cases were frequent due in part to adverse business conditions, than in the early postwar period, when favorable business conditions encouraged less frequent rate cases. We also found that the MFP growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs.

Conclusions

The case studies and incentive power and productivity research presented in this report have important implications. First, utility performance and regulatory cost should be on the radar screen of U.S. regulators, consumer groups and utility managers. Our research shows that key business conditions facing utilities today are less favorable than in the decades before 1973 when COSR worked well and was becoming a tradition. Today's conditions encourage more frequent rate cases and more expansive cost trackers. MRPs can produce material improvements in utility performance which can slow growth in customer bills and bolster utility earnings.

Notwithstanding the potential benefits of MRPs, they are still not used in most American states. COSR is well established and there are many accomplished practitioners. It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design. Continuing innovation of COSR will occur, and this will slow diffusion of MRPs.

However, MRPs are also evolving and remedies to problems encountered in early plans have been developed. MRPs are well suited for addressing conditions expected in coming years, such as rising input price inflation and DER penetration and increased need for marketing flexibility. For these and other reasons, we foresee expanded use of MRPs in U.S. electric utility regulation in coming years.

Acknowledgments

The work described in this study was funded by the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, Transmission Permitting and Technical Assistance Division, and the Office of Energy Efficiency and Renewable Energy, Solar Energy Technologies Office, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231, DOE Grid Modernization Initiative Task 1.4.29 – Future Electric Utility Regulation.

We thank Larry Mansueti, Guohui Yuan and Elaine Ulrich (DOE) for their support of this work. For reviewing drafts of this report and providing comments, we thank Sonia Aggarwal (Energy Innovation), Peter Cappers (Berkeley Lab), Steven Corneli, Asa Hopkins (Synapse Energy Economics), Ronald Lehr, Larry Mansueti (DOE), Andy Satchwell (Berkeley Lab) and Jay Shepherd (Energy Law).

About the Authors

Mark Newton Lowry is President of Pacific Economics Group (PEG) Research LLC. He has been active in the field of performance-based regulation since the 1990s, doing research, consultation and expert witness testimony on multiyear rate plans, productivity, benchmarking and revenue decoupling. A former Pennsylvania State University energy economics professor, he holds a Ph.D. in applied economics from the University of Wisconsin.

Matt Makos is a Consultant II at PEG Research LLC. Over the past 10 years he has played a leading role in the gathering, appraisal and documentation of precedents for performance-based regulation and other alternatives to traditional utility regulation. He holds a bachelor's degree in business administration from the University of Wisconsin.

Jeff Deason is a Program Manager in the Electricity Markets and Policy Group at Lawrence Berkeley National Laboratory (Berkeley Lab). He focuses on energy efficiency research and technical assistance projects in the areas of policy, program design, implementation and evaluation. He is in the final stages of a Ph.D. program in public policy at University of California, Berkeley, where he completed degrees in resource economics and behavioral economics.

Glossary of Terms

Attrition Relief Mechanism (ARM): An essential provision of multiyear rate plans that automatically adjusts allowed rates or revenues to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable business conditions such as inflation and growth in the number of customers served.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs such as labor, materials and capital. Base rates sometimes also include charges for costs of energy inputs like fuel and purchased power, but trackers usually adjust rates so these costs are recovered more exactly.

Capex: Capital expenditures

Cost Tracker: A mechanism providing expedited recovery of targeted costs. An account typically tracks costs that are eligible for recovery. These costs are then typically recovered via rate riders. Tracker treatment was traditionally limited to costs that are large, volatile and largely beyond the control of the utility. The scope of costs eligible for tracking has widened over time. In multiyear rate plans, trackers have been used for costs that are difficult for the ARM to address.

Earnings Sharing Mechanism (ESM): An ESM shares surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity deviates from its commission-approved target. ESMs often have dead bands in which earnings variances are not shared.

Efficiency Carryover Mechanism: A mechanism that allows for a share of lasting performance gains (or losses) to be kept by the utility for a set period of time when a multiyear rate plan expires.

Formula Rate Plan: An approach to ratemaking that uses cost of service formulas to cause a utility's revenue to track its own cost of service closely. This is sometimes accomplished with an earnings true-up mechanism that adjusts rates automatically to eliminate variances between a company's actual and target rate of return on equity. Review of the cost of service may be streamlined.

Lost Revenue Adjustment Mechanism (LRAM): A ratemaking mechanism that compensates utilities for base rate revenue lost from specific causes such as demand-side management programs and distributed generation. Requires estimates of load impacts.

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Marketing flexibility is typically accomplished via light-handed regulation of rates and services with certain attributes. Services often eligible for flexibility include optional tariffs for standard services, optional value-added (discretionary) services, and services to competitive markets. Price floors are often established to discourage predation and cross-subsidization.

Multiyear Rate Plan (MRP): A common approach to performance-based regulation that typically features a rate case moratorium for several years, an ARM, and performance incentive mechanisms for service quality.

Off-ramp Mechanism: An MRP option that permits reconsideration of a multiyear rate plan under prespecified conditions such as an extremely high or low rate of return on equity.

Performance-Based Regulation (PBR): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism (PIM): A popular form of performance-based regulation that links utility revenue or earnings to performance in targeted areas. Most PIMs involve metrics, targets (sometimes called *outcomes*) and financial incentives (rewards and penalties). Service quality and demand-side management are common focuses.

Productivity: The efficiency with which a utility converts inputs to outputs, commonly measured by productivity indexes. Labor, operation and maintenance, capital and multifactor productivity are commonly measured. Industry productivity trends are often used in the design of ARMs.

Rate Base: A utility's total "used and useful" plant in service, at original cost, minus accumulated depreciation and deferred income taxes. Rate base includes "working capital" — cash the utility must have available to meet the current cost of operations given the lag between customers receiving electric service and when they pay their electric bills. Regulators may allow other adjustments.

Rate Rider: An explicit mechanism outlined on tariff sheets to allow a utility to receive supplemental revenue adjustments.

Revenue Decoupling Mechanism: A mechanism that periodically adjusts rates to ensure that actual revenue closely tracks allowed revenue. Decoupling can reduce or eliminate the "throughput incentive" that can cause utilities to resist demand-side management.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MRPs that include relatively long rate case moratoria (e.g., eight years), a forecast-based ARM, and an extensive set of performance incentive mechanisms.

Statistical Benchmarking: The use of statistics on the operations of utilities to appraise utility performance. Methods commonly used in statistical cost benchmarking include unit cost and productivity indexes and econometric models.

X Factor (Productivity Factor): A term in a rate or revenue cap index that reflects the impact of productivity growth on cost growth. It may also incorporate stretch factors and adjustments for other considerations such as the inaccuracy of the inflation measure.

Z Factor: A term in a rate or revenue cap index that permits rate adjustments for the financial impact of miscellaneous events (e.g., severe storms) that are beyond the utility's control.

Contents

Figures

Tables

1.0 Introduction

The electric utility industry has made significant contributions to the success of the U.S. economy over the years. Rates and service quality of electric utilities affect both household welfare and the competitiveness of business and industry. The large role played by many U.S. utilities in power generation magnifies their importance.

Utilities today must contain cost growth at a time when many need to modernize aging systems. Major changes are occurring in technologies, customer preferences, load growth, competitive challenges, and federal and state policies and regulations. Most electric utility facilities in the United States are investor-owned and subject to rate and service regulation by state public utility commissions. Regulatory systems under which these utilities operate affect their performance and ability to meet challenges.

Multiyear rate plans have some advantages over traditional rate regulation in today's business environment. This is a form of performance-based regulation (PBR) that suspends general rate cases for several years. Revenue growth between rate cases is to some degree predetermined and independent of a utility's own cost. Better utility performance can sometimes be achieved under MRPs while achieving lower regulatory costs.[2] Benefits can be shared between utilities and their customers. However, plans are complex and their adoption can involve sizable changes in the regulatory system. Designing plans that stimulate performance without undue risk and share benefits fairly can be challenging.

Berkeley Lab prepared a report on PBR in 1995, when it was just beginning.[3] The study appraised some approved PBR plans using an "incentive power index." Thoughtful commentary on PBR included prescient discussion of revenue decoupling, which is now widely used in utility regulation. In 2016, Berkeley Lab published a report comparing MRPs to another popular approach to PBR — targeted performance incentive mechanisms — in the context of growing levels of distributed energy resources.[4] The report focused on advantages and disadvantages from utility shareholders' and customers' perspectives.[5]

This report takes a closer look at MRPs for electric utilities:

- how and where they have been applied to electric utilities in the United States and other countries;
- key plan design and implementation issues;
- metrics used to evaluate and incentivize utility performance; and
- successes, failures and lessons learned.

The focus is on retail services, such as power supply, distribution and customer care, which are regulated by states.

[2] The impact of PBR on the performance of cooperative and publicly owned utilities is not well understood. However, PBR provides ideas on how to streamline regulation of these utilities. Numerous publicly owned utilities in other countries have operated under PBR.
[3] Comnes et al. (1995).
[4] The report explained that energy efficiency, demand response, and distributed generation and storage can help contain costs of meeting America's energy needs, but can reduce utility earnings.
[5] Lowry and Woolf (2016).

While the authors of the 1995 Berkeley Lab study anticipated restructuring of retail U.S. power markets, vertically integrated electric utilities (VIEUs) still serve retail customers in many states. This report thus considers the situations of VIEUs as well as those of the utility distribution companies (UDCs) that serve regions with restructured retail power markets. The report also provides results from an incentive power model and research on trends in the productivity with which utilities provide their services.

Section 2 of this report provides an introduction to MRPs. Section 3 considers rationales for MRPs and their suitability for electric utilities today. Section 4 drills down into important issues in MRP design. Section 5 discusses results of our research on the incentive power of alternative regulatory systems. Section 6 presents several case studies, and Section 7 discusses lessons learned. Two appendices discuss some topics in greater detail.

2.0 Multiyear Rate Plans

2.1 The Basic Idea

PBR is an approach to utility regulation designed to encourage good performance using strong performance incentives. Multiyear rate plans are a common form of PBR around the world. Berkeley Lab's 2016 report discussed basic features of these plans.[6] General rate cases are typically held every four or five years. Between rate cases, an attrition relief mechanism (ARM) permits revenue (or rates) to grow in the face of cost pressures, without linking relief to a utility's *specific* costs.[7] Some costs may be addressed separately using cost trackers and associated rate riders.

Following is a generic formula for revenue escalation in a multiyear rate plan:

$$\textit{growth Revenue} = \textit{growth ARM} + Y + Z. \qquad [1]$$

The "Y factor" indicates the revenue adjustment for costs, such as fuel and purchased power expenses, which are chosen in advance for tracking treatment. The "Z factor" indicates the revenue adjustment for miscellaneous changes in cost which may occasionally be accorded tracker treatment. The Z factor may address cost changes due to miscellaneous factors outside utility control, such as government mandates (e.g., facility undergrounding requirements) and force majeure events such as severe storms.[8]

MRPs also typically feature performance metric systems. Some metrics provide the basis for targeted performance incentive mechanisms (PIMs) that aid measurement of performance in areas of special concern to customers and the public. Most commonly, PIMs are used to strengthen incentives for utilities to maintain or improve reliability and customer service quality. A broader range of metrics has recently been considered by regulators in several jurisdictions, including Great Britain and New York.[9]

Demand-side management (DSM) can lower the cost of meeting customer energy needs. MRPs often contain provisions that strengthen utility incentives to facilitate DSM. Utility expenditures on DSM programs are usually tracked.[10] Performance incentive mechanisms can reward utilities for successful DSM programs. Revenue decoupling is often added to sever short-term links between a utility's revenue and electricity sales.[11] This shifts the risk of fluctuations in system use to customers but reduces utility incentives to boost throughput between rate cases. Decoupling also reduces the risks of rate designs that encourage DSM and efficient customer-side distributed generation and storage.

Some MRPs feature earnings sharing mechanisms (ESMs) that share surplus or deficit earnings, or both, between utilities and their customers, which result when the rate of return on equity (ROE) deviates from its public utility commission-approved target.[12] Off-ramp mechanisms may permit review of a plan under prespecified outcomes such as extreme ROEs.

Some MRPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. Utilities also may be permitted (or required) to gradually redesign rates for

---

[6] Lowry and Woolf (2016).
[7] To simplify the discussion, this report will provide illustrations only for revenue cap escalators.
[8] Z factors are discussed further in Appendix A2.
[9] Ofgem (2014) and New York Public Service Commission (2016a).
[10] Institute for Electric Innovation (2014).
[11] Lazar et al. (2016).
[12] Earnings sharing mechanisms are discussed further in Appendix A1.

standard services in fulfillment of commission-approved goals. Marketing flexibility is discussed further in Appendix A.

Plan review and termination provisions are also important in MRPs. Some plans provide for a midterm review of the MRP toward the end of the plan period. These reviews sometimes result in a plan extension without a general rate case. To bolster incentives to achieve lasting efficiency gains, the true-up of a utility's revenue requirement to its cost is sometimes limited if the plan ends with a rate case. For example, the utility may be permitted to keep a share of the difference between its cost and a cost benchmark. Provisions of the latter kind are sometimes called *efficiency carryover mechanisms.*

2.2 MRP Precedents

MRPs have been used in U.S. rate regulation since the 1980s. They were first used on a large scale for railroads and telecommunication carriers.[13] These companies faced significant competitive challenges that complicated regulation. MRPs streamlined regulation and afforded utilities more marketing flexibility and a chance to earn a superior return for superior performance. Some states still use MRPs to regulate services of telecommunication carriers in less competitive markets.[14] The Federal Energy Regulation Commission (FERC) uses MRPs to regulate oil pipelines.[15]

MRPs have been used in several states to regulate retail services of natural gas and electric utilities.[16] In addition to formal rate plans, several states established extended rate freezes for electric utilities during the transition to retail competition. Rate freezes also have been part of the ratemaking treatment for many mergers and acquisitions. Utilities have occasionally and for various other reasons managed to stay out of rate cases for periods exceeding a decade.

Figure 1 shows states that currently use MRPs to regulate retail services of U.S. electric and gas utilities. The figure shows that MRPs are more common for U.S. electric utilities than for gas distributors. Growth in the use of MRPs to regulate electric power distributors has been slowed by grid modernization challenges that complicate plan design. On the other hand, use of MRPs has recently spread to vertically integrated electric utilities in diverse states that include Arizona, Colorado, Georgia, Virginia and Washington. This reflects in part the slowdown and increased predictability of VIEU cost growth in an era when there is less need for large generation plant additions. Many states also have recently experimented with "mini" MRPs involving only two plan years.

Figure 2 shows that MRPs are widely used to regulate retail energy services of Canadian utilities. Overseas, MRPs are the norm in Australia, Ireland, New Zealand and the United Kingdom. Countries that use MRPs in continental Europe include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania and Sweden. MRPs are also common in Latin America.

The impetus for adopting MRPs outside the United States has often come from policymakers rather than utilities. For example, provincial law in Quebec requires the Régie de l'Energie to use an approach to regulation which streamlines regulation, encourages continual performance gains and shares benefits

[13] A discussion of early railroad and telecommunication MRPs can be found in Lowry and Kaufmann (2002).
[14] See, for example, California Public Utilities Commission (2015a), and Vermont Public Service Board (2016).
[15] Federal Energy Regulatory Commission (2015).
[16] MRP precedents for gas and electric utilities have been monitored by the Edison Electric Institute in a series of surveys. The latest is Lowry et al. (2015).

fairly with customers.[17] The Régie recently ordered Hydro-Quebec to operate its power distributor services prospectively under an MRP that the company had opposed.[18]

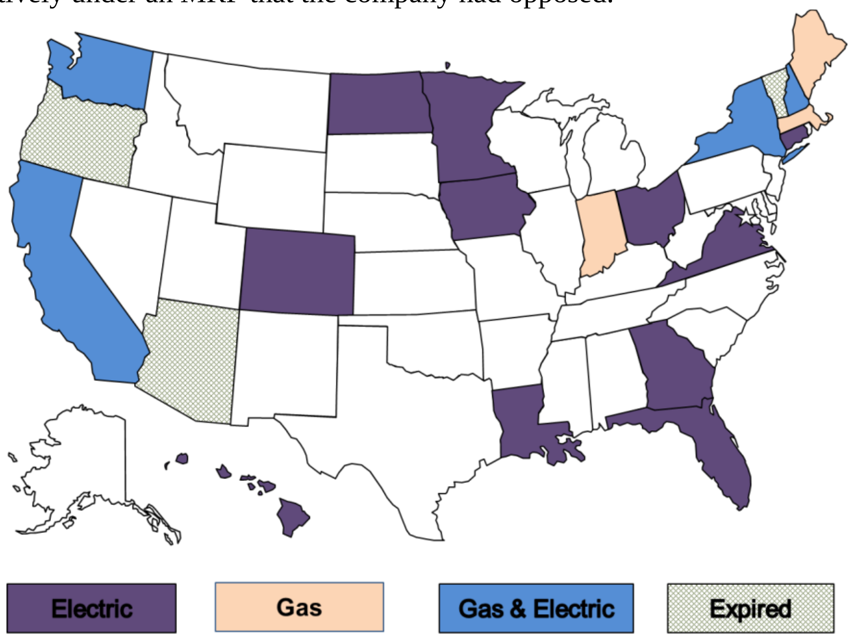


Figure 1. Multiyear Rate Plans in the United States. MRPs are used in many states today to regulate utilities.

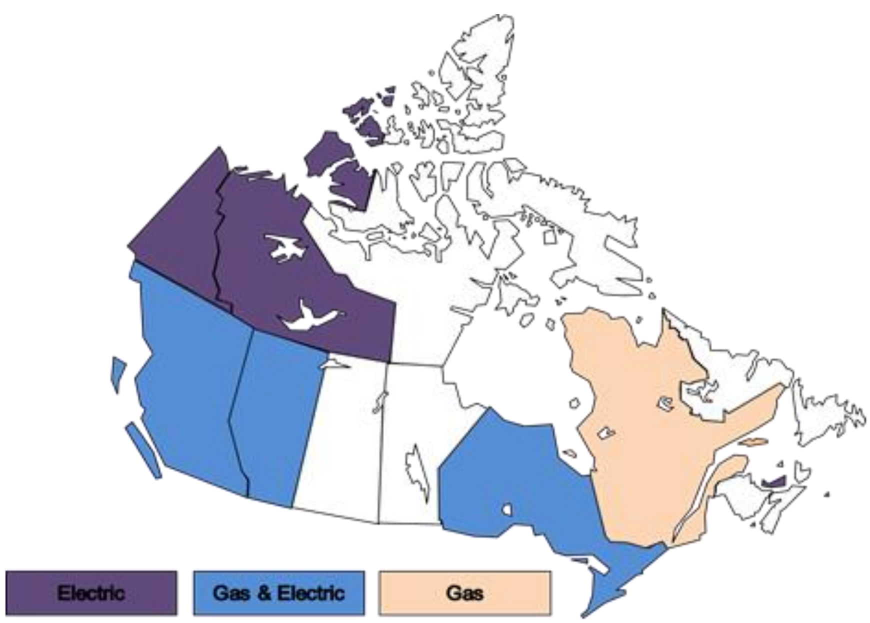


Figure 2. Multiyear Rate Plans in Canada. MRPs have in recent years been used to regulate energy utilities in the most populous Canadian provinces.

[17] Quebec National Assembly (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed 14 June, 2013.
[18] Régie de l'Energie, D-2017-043, R-3897-2014 Phase 1, April 7, 2017.

3.0 Rationale for Considering MRPs

To explain rationales for considering MRPs we first consider basic features of traditional cost of service regulation (COSR) approaches which are widely used in the United States and then discuss reasons that some jurisdictions have adopted MRPs. We conclude with a discussion of circumstances under which PBR may make sense for some electric utilities under today's business conditions.

3.1 Traditional Cost of Service Regulation

Under COSR,[19] base rates that address costs of capital, labor and materials are reset periodically in rate cases to more effectively recover the utility's cost of service. Rate cases usually occur at irregular intervals and are typically initiated by utilities when the cost of their base rate inputs is growing faster than the corresponding revenue. Between rate cases, growth in base rate revenue depends chiefly on growth in billing determinants such as delivery volumes and numbers of customers served. Most base rate revenue is drawn from usage charges — e.g., charges per kilowatt-hour (kWh) or kilowatts (kW) of system use. The need for rate cases thus depends on a "horse race" between costs and system use.

In the short and medium terms, costs of base rate inputs are driven more by growth in system capacity (e.g., the capacity to serve peak load and to deliver to multiple locations) than by growth in system use. The number of customers served is highly correlated with peak load and an important cost driver in its own right.[20,21] A convenient proxy for the gap between the growth rates of system use and capacity is thus the growth in volume per customer (average use). Earnings are especially sensitive to trends in average use by residential and commercial customers.

Under legacy rate designs, growth in average use bolsters earnings and reduces the need for rate cases, while a decline has the reverse effect. Rate case frequency also depends on input price inflation and the balance between the declining value of older assets due to depreciation and capital expenditures to replace aging infrastructure.

The regulatory cost of COSR is high (for utilities, public utility commissions and stakeholders) when rate cases are frequent or unusually difficult. Rate cases are frequent to the extent that the jurisdiction regulates numerous utilities or the operating conditions facing utilities are continuously unfavorable. Individual rate cases are more difficult to the extent that utilities are large and rate cases involve complex issues.

Regulators understandably take measures to contain regulation's costs. Some of these measures may have adverse consequences. For example, expanded use of cost trackers and a reduced scope for prudence reviews weaken utility incentives to cut costs.[22] Because frequent rate cases and expansive cost trackers are more likely when business conditions are unfavorable, utility performance under traditional regulation tends to deteriorate just when better performance is most needed to keep customer bills reasonable.

[19] Bonbright et al. (1988) is an authoritative treatise on COSR. Lowry and Woolf (2016) provides a more extensive discussion of COSR than provided here, emphasizing incentive problems.
[20] This is because the total number of customers is dominated by the number of residential and small commercial customers, and these customers tend to have more peaked loads.
[21] DSM programs can alter this relationship but to date have had more effect on delivery volumes than they have on the peak demand that drives capacity growth.
[22] Cost trackers have the merit of reducing the need for general rate cases.

Regulatory Lag

Regulatory economists acknowledge the incentive problems with traditional regulation that arise when rate cases are frequent or cost trackers are expansive. In the literature, "regulatory lag" is commonly defined as the time period between the moment when a utility's cost changes and the moment when there is a commensurate change in its rates.[23] James Bonbright, for example, states in a classic treatise that:

> There is the so-called "regulatory lag" — the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or rate increase may be put into effect by commission order or otherwise.[24]

The ability of regulatory lag to strengthen a utility's incentive to contain costs has been discussed in the literature. For example, Bonbright states that:

> Quite aside from the recognized undesirability of too frequent rate revisions, commissions recognize the regulatory lag as a practical means of reducing the tendency of a fixed-profit standard to discourage efficient management.[25]

Another noted regulatory economist, Alfred Kahn, suggested that:

> Public utility commissions ought not to even *try* continuously and instantaneously to adjust rate levels in such a way as to hold companies continually to some fixed rate of return; and they probably ought not to try either to hold the rate of return down to the bare cost of capital. The *regulatory lag* — the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upward adjustments ordinarily called for if profits are too low — is thus to be regarded not as a deplorable imperfection of regulation but as a positive advantage. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.[26] [emphasis in original]

Under traditional regulation, regulatory lag also delays when rates are changed in response to increasing *external* cost pressures such as input price inflation. For this reason, utility executives and consumer advocates have both emphasized regulatory lag in their rate case evidence despite goals that are often in opposition.

[23]Alternative definitions of "regulatory lag" have been used. One is the period of time between the filing of a request for a rate increase and the increase in rates.
[24] Bonbright et al. (1988).
[25] Ibid., p. 198.
[26] Kahn (1988), p. 48 II.

The Utility Productivity Slowdown of 1973–1986

The productivity growth of a utility is the difference between growth in its operating scale and growth in quantities of inputs that it uses. It is typically measured using an index. Productivity growth reflects changes in diverse business conditions that affect cost, including technological change and realization of scale economies. A multifactor productivity (MFP) index typically considers productivity in use of capital, labor and materials. Appendix B.2 discusses productivity more extensively.

One way to gauge the importance of regulatory lag is to compare utility productivity growth in years when business conditions for utilities were favorable to the growth in years when conditions were unfavorable. Since rate cases tend to be more frequent and cost trackers more expansive when business conditions are unfavorable, productivity growth should be slower. The federal government calculated an index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50-year period from 1948 to 1998.[27] We can consider the growth rate of this index during periods of favorable and unfavorable business conditions.

Table 1 presents evidence on two of the most important sources of potential financial attrition for electric and natural gas utilities:

- Trends in the average use of energy by residential and commercial customers
- Price inflation, measured here by the gross domestic product price index (GDPPI)[28]

Average use directly affected MFP growth as measured by the government, but inflation did not.

We constructed summary indicators of potential attrition facing gas and electric utilities. The indicator in each case is the difference between inflation and the average of the growth in average use of energy (gas or electricity) by residential and commercial customers. We report trends over several subperiods between 1927 and 2014.

Results for electric utilities, where data are available for more years, show that these business conditions were quite favorable on balance from the late 1920s until the early 1970s. Except in the 1940s, inflation was generally slow until the late 1960s.[29] Average use of electricity grew rapidly.

These business conditions grew dramatically more adverse for electric utilities in the 1970s and remained so well into the 1980s. Spurred by two oil price shocks, general price inflation was much higher in these years. Inflation in prices of energy commodities such as coal and gas was especially rapid. Combined with slower economic growth, this caused growth in the average use of power by residential and commercial electric customers to slow markedly.

Rate cases were much more frequent.[30] Table 2 reproduces some results of a survey of electric utility rate cases from 1948 through 1977.[31] The table shows that the number of rate cases increased markedly after the mid-1960s and rarely featured a request for rate decreases.

[27] Computation of this index ended in 1998. For a discussion of this research, see Glaser (1993), pp. 34–49.
[28] The GDPPI is the federal government's featured index of inflation in the prices of the economy's final goods and services. It is calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce.
[29] Rapid inflation during the Korean War was offset by slower inflation in later years of the 1950s.
[30] See Joskow and MacAvoy (1975).
[31] Braeutigam and Quirk (1984), p. 47.

Table 1. Indicators of Energy Utility Financial Attrition in the United States (1927–2014)

	Average Annual Electricity Use					Average Annual Natural Gas Use					GDPPI Inflation[4]		Summary Attrition Indicators	
	Residential[1]		Commercial[1]		Average	Residential[2]		Commercial[3]		Average				
	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Level	Growth Rate	Growth Rate	Level	Growth Rate	Electric	Natural Gas
Multiyear Averages					[A]					[B]		[C]	[C]-[A]	[C]-[B]
1927-1930	478	7.06%	3,659	6.67%	6.86%	NA	NA	NA	NA	NA	9.71	-3.92% [5]	-10.79%	NA
1931-1940	723	5.45%	4,048	2.00%	3.73%	NA	NA	NA	NA	NA	7.99	-1.59%	-5.31%	NA
1941-1950	1,304	6.48%	6,485	5.08%	5.78%	NA	NA	NA	NA	NA	11.37	5.26%	-0.52%	NA
1951-1960	2,836	7.53%	12,062	6.29%	6.91%	NA	NA	NA	NA	NA	16.04	2.42%	-4.49%	NA
1961-1972	5,603	5.79%	31,230	8.79%	7.29%	125	1.78% [6]	726	3.97% [6]	2.88% [6]	20.35	2.98%	-4.32%	0.10% [7]
1973-1980[8]	8,394	2.03%	50,576	2.53%	2.28%	117	-2.22%	764	-0.63%	-1.42%	34.74	7.18%	4.90%	8.61%
1981-1986[8]	8,820	0.12%	54,144	0.81%	0.46%	98	-2.67%	651	-3.84%	-3.26%	54.22	4.57%	4.11%	7.82%
1987-1990	9,424	1.39%	60,211	2.29%	1.84%	93	-1.25%	631	1.33%	0.04%	63.32	3.33%	1.49%	3.29%
1991-2000	10,061	1.15%	67,006	1.68%	1.41%	88	-0.37%	639	0.30%	-0.04%	75.70	2.03%	0.62%	2.07%
2001-2007	10,941	0.73%	74,224	0.64%	0.68%	77	-2.12%	594	-1.55%	-1.83%	89.83	2.47%	1.79%	4.30%
2008-2014	11,059	-0.38%	75,311	-0.22%	-0.30%	72	0.58%	597	1.75%	1.17%	103.53	1.60%	1.90%	0.43%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

[2] Energy Information Administration, Historical Natural Gas Annual 1930 Through 1999 (Table 38. Average Consumption and Annual Cost of Natural Gas per Consumer by State, 1967-1989) (1967-1986); Energy Information Administration series N3010US2, "U.S. Natural Gas Residential Consumption (MMcf)" and Energy Information Administration series NA1501_NUS_8, "U.S. Natural Gas Number of Residential Consumers (Count)" (1987-2014).

[3] Includes vehicle fuel. Sources: Energy Information Administration series NA1531_NUS_10, "U.S. Natural Gas Average Annual Consumption per Commercial Consumer (Mcf)" (1967-1986); Energy Information Administration series N3020US2, "Natural Gas Deliveries to Commercial Consumers (Including Vehicle Fuel through 1996) in the U.S. (MMcf)" (1987-2014), Energy Information Administration series N3025US2, "U.S. Natural Gas Vehicle Fuel Consumption (MMcf)" (1997-2014), Energy Information Administration series NA1531_NUS_8, "U.S. Natural Gas Number of Commercial Consumers (Count)" (1987-2014).

[4] Bureau of Economic Analysis, Table 1.4.4. Price Indexes for Gross Domestic Product, Gross Domestic Purchases, and Final Sales to Domestic Purchasers, Revised October 28, 2016.

[5] Growth rate is for 1930 only. Levels are for 1929 and 1930. Data are not available before 1929.

[6] Levels are for 1967-1972 and growth rates are for 1968-1972. Data are not available before 1967.

[7] Note that the growth rates used to compute this value cover different periods.

[8] Shaded years had unusually unfavorable business conditions.

Table 2. U.S. Electric Utility Rate Cases: 1948–1977[32]

Period	Number of Rate Cases	Company Initiated Rate Cases			PUC Initiated Rate Cases
		Number	Rate Increases	Rate Decreases	
1948-1952	46	45	42	3	1
1953-1957	34	31	28	3	3
1958-1962	43	39	38	1	4
1963-1967	17	16	12	4	1
1968-1972	104	100	96	4	4
1973-1977	119	119	119	0	0

After 1986, inflation slowed to a pace more typical of the 1950s and 1960s. However, sluggish growth in average use continued. Thus, business conditions improved on balance, but were less favorable than those in the decades preceding the first oil price shock.[33]

Table 3 and Figure 3 show the trend in the federal government's index of the MFP of the electric, gas and sanitary sector of the U.S. economy over the 50 years from 1948 to 1998. The MFP growth of the sector was remarkably brisk until the early 1970s, averaging 3.9 percent annually compared to the 2.1 percent trend in the MFP of the entire private business sector of the economy.

[32] Most rate cases are initiated by utilities. However, state regulatory commissions may initiate general rate cases to investigate potential excessive utility earnings.

[33] Average use data for a comparably long period were not found for natural gas distributors. However, average use of natural gas fell briskly during the 1973 to 1986 period, whereas it had risen briskly from 1968 to 1972. Inflation and average use trends were thus extremely unfavorable for gas distributors from 1973 to 1986. While inflation slowed after 1986, declining average use continued so that, on balance, business conditions improved for gas distributors but were less favorable than in the 1960s.

Table 3. Multifactor Productivity Growth of Electric, Gas, and Sanitary Utilities and the U.S. Private Business Sector: 1949–1998

	Electric, Gas, and Sanitary Utilities[1]		U.S. Private Business Sector[2]		MFP Growth Differential
	Level	Growth Rate	Level	Growth Rate	
Year		[A]		[B]	[A - B]
1948	34.67		50.34		
1949	35.23	1.60%	50.93	1.16%	0.45%
1950	37.85	7.16%	54.63	7.03%	0.14%
1951	41.50	9.19%	55.90	2.29%	6.90%
1952	43.27	4.19%	56.39	0.87%	3.32%
1953	44.95	3.81%	57.66	2.22%	1.59%
1954	46.73	3.87%	57.76	0.17%	3.71%
1955	50.37	7.51%	60.49	4.62%	2.89%
1956	52.90	4.89%	60.20	-0.49%	5.37%
1957	54.86	3.64%	61.07	1.45%	2.19%
1958	56.36	2.69%	61.37	0.48%	2.21%
1959	59.91	6.11%	63.51	3.44%	2.67%
1960	61.68	2.92%	63.90	0.61%	2.31%
1961	63.18	2.40%	65.27	2.11%	0.28%
1962	66.26	4.77%	67.61	3.52%	1.24%
1963	67.57	1.96%	69.66	2.99%	-1.03%
1964	71.12	5.12%	72.39	3.85%	1.28%
1965	74.02	3.99%	74.73	3.18%	0.81%
1966	77.01	3.96%	76.98	2.96%	1.00%
1967	79.44	3.11%	77.07	0.13%	2.98%
1968	82.99	4.37%	79.12	2.62%	1.75%
1969	85.23	2.67%	78.63	-0.62%	3.29%
1970	86.64	1.63%	78.54	-0.12%	1.76%
1971	87.66	1.18%	80.98	3.06%	-1.88%
1972	89.16	1.69%	83.41	2.97%	-1.28%
1973	90.84	1.87%	85.66	2.65%	-0.79%
1974	87.85	-3.35%	82.54	-3.71%	0.37%
1975	88.04	0.21%	83.32	0.94%	-0.73%
1976	89.16	1.27%	86.44	3.68%	-2.41%
1977	88.97	-0.21%	87.80	1.57%	-1.78%
1978	88.88	-0.11%	88.98	1.32%	-1.43%
1979	87.85	-1.16%	88.59	-0.44%	-0.72%
1980	87.38	-0.53%	86.63	-2.23%	1.69%
1981	87.38	0.00%	86.73	0.11%	-0.11%
1982	86.54	-0.97%	84.10	-3.08%	2.12%
1983	85.42	-1.30%	86.44	2.75%	-4.05%
1984	88.32	3.34%	89.27	3.22%	0.11%
1985	88.22	-0.11%	90.15	0.98%	-1.08%
1986	88.50	0.32%	91.61	1.61%	-1.29%
1987	88.60	0.11%	91.90	0.32%	-0.21%
1988	92.06	3.83%	92.49	0.63%	3.19%
1989	92.43	0.41%	92.98	0.53%	-0.12%
1990	93.83	1.51%	93.17	0.21%	1.30%
1991	93.64	-0.20%	92.20	-1.05%	0.85%
1992	93.46	-0.20%	94.34	2.30%	-2.50%
1993	95.89	2.57%	94.73	0.41%	2.15%
1994	96.45	0.58%	95.80	1.13%	-0.54%
1995	98.69	2.30%	96.00	0.20%	2.10%
1996	99.91	1.22%	97.56	1.61%	-0.39%
1997	99.91	0.00%	98.73	1.19%	-1.19%
1998	100.00	0.09%	100.00	1.28%	-1.18%
Annual Averages					
1949-1972		3.94%		2.10%	1.83%
1973-1986		-0.05%		0.67%	-0.72%
1987-1998		1.02%		0.73%	0.29%

[1] Bureau of Labor Statistics, Multifactor Productivity, Electric, Gas and Sanitary Utilities (SIC 49).

[2] Bureau of Labor Statistics, Multifactor Productivity, Private Business Sector.

Note: Shaded years had unusually unfavorable business conditions.

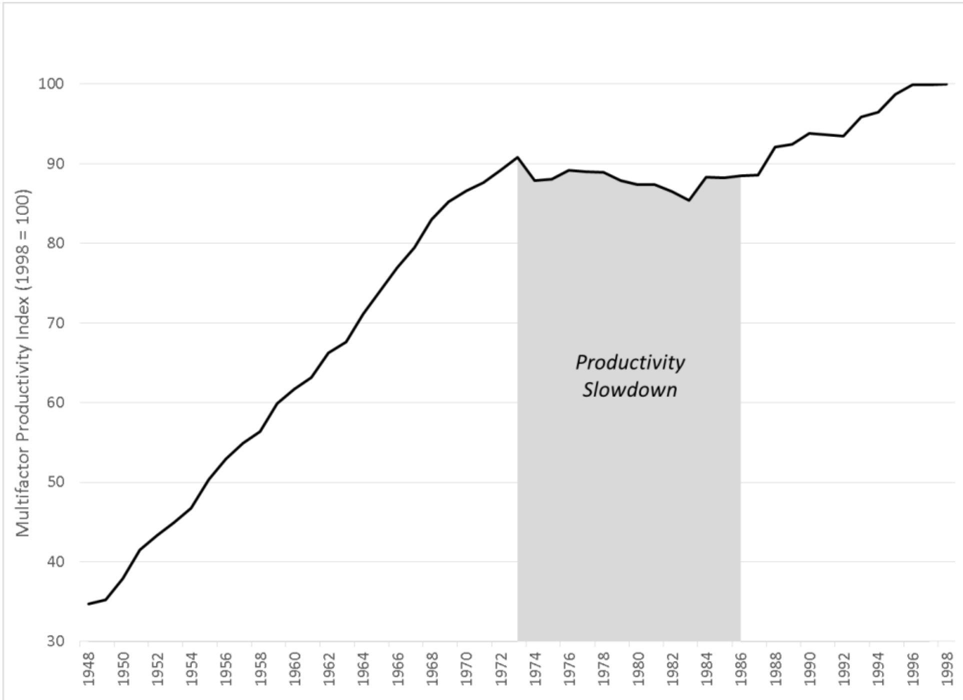


Figure 3. Multifactor Productivity Trend of U.S. Electric, Gas and Sanitary Utilities (1948–1998). MFP growth of U.S. utilities slowed during the period 1973 to 1986 under unfavorable business conditions.

The MFP growth of electric, gas and sanitary utilities fell to zero on average during the following years of markedly unfavorable business conditions, when rate cases were much more frequent. Both capital and labor productivity growth of this utility sector slowed markedly. MFP

growth of the U.S. private business sector exceeded that of electric, gas and sanitary utilities by around 72 basis points annually on average during these years.[34]

The generation sector of the utility industry was a notable problem area during this period. Overbuilding generation capacity and cost overruns and delays on generation plant additions were widespread. Resultant overcapacity boosted sales in wholesale markets and widened the gap between wholesale and retail power prices. This gap was one of the factors that ultimately led to restructuring of retail power markets in many states.

MFP growth of utilities resumed at a slower 1.02 percent average annual pace from 1987 to 1998, a period during which the frequency of rate cases slowed. Utility MFP trends exceeded private business sector MFP trends by a modest 29 basis points on average.

The MRP Alternative

Advantages

A core advantage of MRPs is their potential to strengthen cost containment incentives.[35] The attrition relief mechanism can provide timely, predictable rate escalation that permits an extension of the period

[34] A basis point is one-hundredth of 1 percent.
[35] For further discussions of the rationale for MRPs see Lowry and Kaufmann (2002), Lowry and Woolf (2016), Comnes et al. (1995), and Kaufmann and Lowry (1995).

between rate cases. Escalation is based on cost forecasts, industry cost trends or both, rather than the utility's *specific* costs. Regulatory lag is thus achieved without sacrificing the timeliness of rate relief, increasing opportunities for a utility to bolster earnings from efforts to contain costs addressed by the ARM (i.e., costs that are not tracked). A well-designed efficiency carryover mechanism can magnify the incentive "power" of the MRP.[36] Loosening the link between a utility's cost and its revenue gives it an operating environment more like that which producers in competitive markets experience.

MRPs can also encourage more operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency means that the prudence of management strategies must be considered less frequently. Utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., low capex). This potential advantage of MRPs in facilitating operating flexibility has been most thoroughly developed in the area of marketing flexibility (see Appendix A for further discussion).

PIMs play a special role in multiyear rate plans. The plans can strengthen incentives to contain costs.[37] These include costs incurred to maintain or improve service quality and worker safety. In competitive markets, a producer's revenue can fall abruptly if the quality of its offerings falls. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.[38]

Advantages of MRPs in encouraging utilities to consider cost-effective DSM and other distributed energy resources (DERs) are not widely recognized. MRPs can strengthen incentives to use DERs to contain load-related costs that are reflected in retail rates. The combination of an MRP, revenue decoupling, PIMs to encourage efficient DSM, and the tracking of DER-related costs can provide four "legs" for the DER "stool."[39] MRPs can reduce the need for complicated measurement of load and cost savings from DERs.

With stronger performance incentives and greater operating flexibility, MRPs can encourage better utility performance. Benefits of better performance can be shared with customers via earnings sharing mechanisms, plan termination provisions and careful ARM design. Customers can also benefit from more market-responsive rates and services. The strengthened performance incentives and reduced preoccupation with rate cases which MRPs provide can create a more performance-oriented corporate culture at utilities. This may increase the likelihood of success in mergers, acquisitions and unregulated market ventures in which utility companies engage.

MRPs also can increase the efficiency of regulation. Rate cases can be less frequent and better planned and executed. MRPs also facilitate scheduling rate cases so that proceedings overlap less. Streamlining ratemaking processes can reduce cost burdens on ratepayers and free up resources in the regulatory community to more effectively address other important issues, such as rules of prospective application. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively. Streamlined regulation has special appeal in situations where costs of regulation are especially high due to numerous utilities, large utilities or especially difficult regulatory issues. It is not surprising, then, that several commissions with unusually large regulatory burdens (e.g., Ontario and Germany) have been MRP leaders.

[36] See Sections 4 and 5 and Appendix A1 for further discussion of efficiency carryover mechanisms.
[37] See, for example, Comnes et al. (1995).
[38] Alberta Utilities Commission (2012), p. 186.
[39] A three-legged stool for DSM consisting of revenue decoupling, performance incentive mechanisms, and DSM cost trackers is discussed in York and Kushler (2011).

Disadvantages

MRPs are complex regulatory systems. The transition to these plans can be challenging in some jurisdictions. As we discuss at some length in Section 4, it can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers. Controversies can arise in plan design, as they do in COSR. Poorly designed plans can create opportunities for strategic behavior that reduces plan benefits for customers. For these and other reasons, most American jurisdictions have not yet adopted MRPs for gas and electric utilities. The concluding section of this report provides a more extensive discussion of reasons for the continued popularity of COSR.

3.2 How MRPs Can Help Address Contemporary Challenges

Benefits of MRPs tend to be greatest where traditional regulation is especially disadvantageous. These include situations where rate cases are especially frequent, a large number of utilities are regulated, marketing flexibility is especially desirable, and regulators have numerous other issues to attend to. We discuss here the extent to which these conditions are present today.

Need for Rate Cases and Expansive Cost Trackers

Table 1 shows that key business conditions that cause utility attrition are considerably less favorable today on balance than they were in the decades before 1973. Since the start of the Great Recession, sluggish economic growth and energy efficiency gains have caused unusually slow growth in average use of electricity by residential and commercial customers.[40] The financial stress on utilities of this development has been partly offset to date by unusually slow input price inflation.[41] However, inflation may be higher in the future due, for example, to rising bond yields. Increased penetration of DERs could further slow growth in average use.

The need for frequent rate cases varies among electric utilities. Variation in capex requirements is a major reason. In a period of sustained high capex, utilities need brisk escalation in rates, especially when the capex does not automatically produce new revenue. Some utilities need high capex today to replace aging distribution assets. This kind of capex does not, like distribution system extensions, typically produce new revenue without a rate case or cost tracker. Technological change has created opportunities for “smart grid” capex that improves utility performance but may not trigger much new revenue.[42]

Distribution capex induces less growth in the total cost of a VIEU than it does in the cost of a UDC. Furthermore, slow demand growth and interest by some state regulatory commissions for VIEUs to rely on power purchase agreements rather than build and own more power plants is reducing the need for new VIEU generation capacity. On the other hand, some VIEUs are refurbishing or replacing old power plants.

[40] Demand growth in some states has also been affected by distributed generation and deindustrialization.
[41] Reduction in utility revenue due to declines in average electricity use can, in any event, be addressed by targeted remedies such as revenue decoupling.
[42] Some of these expenditures do, however, produce offsetting operation and maintenance cost savings.

Technological Change

Technological change is creating new ways to meet the energy needs of customers. Well-designed MRPs can, by strengthening performance incentives and increasing operating flexibility, drive utilities to embrace these technologies where they are cost effective. However, when new technologies involve sizable up-front capex with little automatic revenue growth they can complicate MRP design.

Number of Utilities

The number of utilities that a state public utility commission regulates rarely grows, but sometimes falls due to mergers and acquisitions. Several states (e.g., California, New York, Pennsylvania and Texas) still regulate five or more electric utilities, and states must typically also regulate natural gas, telecommunications and water utilities.[43] Mergers and acquisitions have caused the number of utilities owned by some companies to rise over the years. Multi-utility companies have more incentive to adopt MRPs and other economical approaches to regulation.[44]

Marketing Flexibility

Marketing flexibility is increasingly useful to utilities in order to fashion time-sensitive rates, green power services, and miscellaneous new services enabled by new technologies. VIEUs may have greater need for marketing flexibility than UDCs. One reason is that the large-load customers whose demand has traditionally been most sensitive to the terms of service make a much larger contribution to a VIEU's base rate revenue. Another reason is that VIEUs may benefit more from renewable energy and electric vehicle options than UDCs since VIEUs may provide the power from company-owned generation. In addition, time-sensitive pricing can contain generation costs as well as transmission and distribution capacity needs.

Instability Concerns

We noted above that traditional regulation provides weaker incentives for cost management when business conditions are especially adverse. This idiosyncrasy of traditional regulation raises questions about its ability to cope with increased penetration of customer-side distributed generation and storage. Penetration slows growth in average electricity use. To the extent that this leads to more frequent rate cases and more expansive cost trackers, utility performance deteriorates. Utilities may, for example, choose such a time for high replacement capex. The end result can be higher rates that further discourage use of grid services.[45] This is a source of potential instability in the utility industry. The contrast to competitive markets is striking. In a period of weak demand, prices fall in competitive markets and firms scramble to cut their costs.

[43] In contrast, regulation outside the United States is often conducted at the national level.

[44] Minneapolis-based Xcel Energy is an example of a multi-utility company that has publicly embraced MRPs. See Xcel Energy's "Strategic Plan for Growth," May 2015, http://investors.xcelenergy.com/Cache/1500071832.PDF?O=PDF&T=&Y=&D=&FID=1500071832&iid=4025308, and Xcel Energy's SEC Schedule 14A filed April 2015, http://investors.xcelenergy.com/Cache/28758163.PDF?O=PDF&T=&Y=&D=&FID=28758163&iid=4025308.

[45] For further discussion of the potential for a utility "death spiral," see Graffy and Kihm (2014).

Competing Needs for Regulatory Resources

Regulatory resources that are currently devoted to rate cases have many alternative uses in this era of rapid change. Among the areas where thoughtful review is currently needed are rate design, distribution system planning, and the terms of compensation for customer-side DER services.

Difficulty of MRP Implementation

The difficulty of implementing MRPs changes over time and varies considerably among utilities. One key challenge is the identification of a reasonable ARM. Implementation of index-based ARMs has traditionally been easier for UDCs than for vertically integrated utilities. The cost of UDC base rate inputs tends to grow gradually and predictably as the economies UDCs serve gradually expand. In contrast, VIEUs have in the past had "stair step" cost trajectories with large rate increases when large power plants came into service alternating with periods of slow cost growth as new units depreciated. Another complication for VIEUs was that the exact timing of major plant additions was often uncertain, due in part to construction delays.

However, many UDCs have in recent years proposed accelerated grid modernization programs involving several years of high capex. The need for these programs is often difficult for regulators to judge in an era of rapid technological change and shifting demand. VIEUs, meanwhile, are experiencing *more gradual* cost growth because fewer generation capacity additions are needed and capacity that is built tends to be more modular natural gas-fired or wind-powered units. Depreciation of older generation plant meanwhile slows rate base growth.[46] Figures 4 and 5 illustrate the changing needs for rate escalation for UDCs and VIEUs.

Consider also that jurisdictions vary in their regulatory traditions and human capital (the experience and the expertise of regulatory practitioners). Generally speaking, adoption of MRPs is easier for jurisdictions that have experience with the use of forward test years in rate cases. Accumulation of experience with MRPs in the United States and improvements in MRP design will facilitate broader implementation.

Conclusions

Our analysis suggests that unusually slow inflation since the Great Recession of 2008 has thus far offset declining residential and commercial average use to contain the need for electric utilities to file frequent rate cases. However, these business conditions are still less favorable on balance than they were before 1972 when COSR worked well and became a tradition. Resumption of normal inflation and accelerated penetration of customer-side DERs may well occur and would spark more interest in MRPs. MRPs can also address the need for marketing flexibility.

Whereas the need for multiyear rate plans may be greater for UDCs with high capex, the ease of implementing these plans is often greater for VIEUs today. VIEUs also may have stronger interest in marketing flexibility. This helps to explain why use of MRPs is growing most rapidly in the United States for VIEUs.

[46] However, some utilities are building new, cleaner generating facilities (including emissions control equipment) or modernizing older generation plants. Aging generating capacity (especially nuclear capacity) can have rising operating costs.

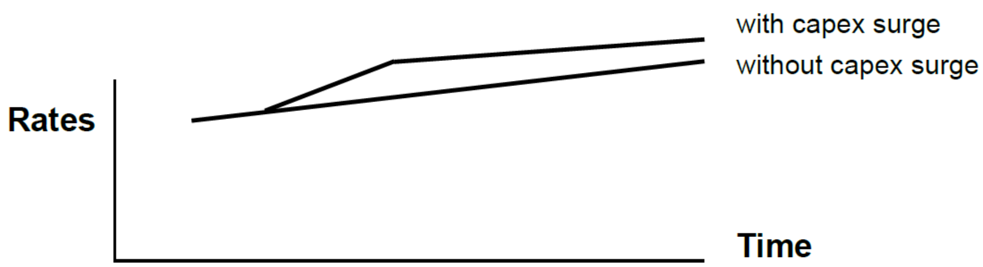


Figure 4. Rate Escalation Requirements for UDCs. Capex surges can accelerate the normally gradual escalation of UDC rates.

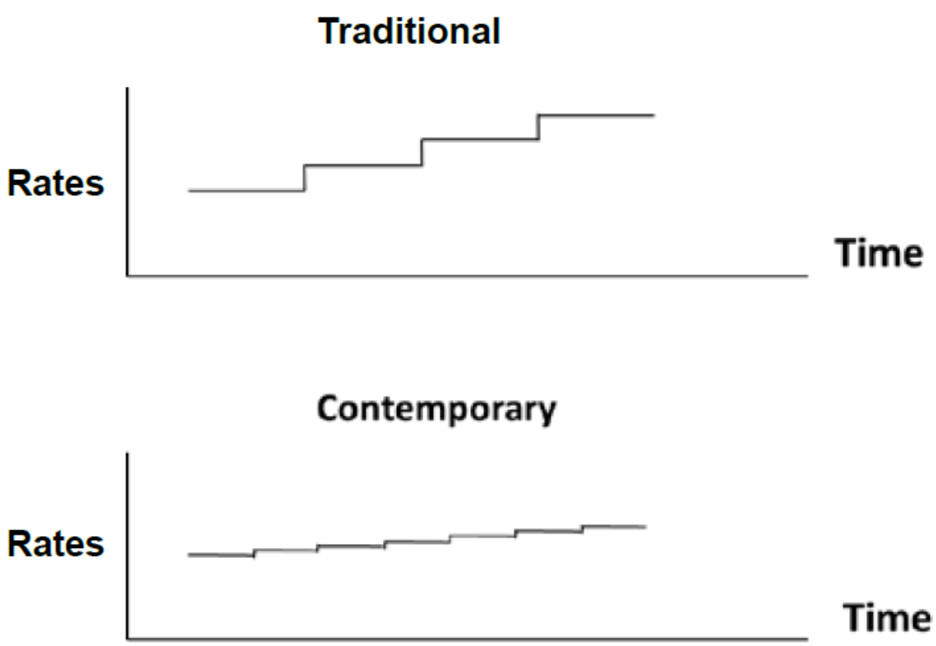


Figure 5. Rate Escalation Requirements for VIEUs. Rate escalation requirements of VIEUs are becoming more gradual.

Growing familiarity with best practices in the design of plans for UDCs may encourage greater use in this utility sector. Use of MRPs for UDCs may also increase as they complete accelerated grid modernization programs that complicate plan design and return to gradual cost growth. Companies and commissions with unusually large regulatory burdens gain special advantages from streamlined regulation. Some of these companies and commissions are likely to be MRP leaders.

4.0 MRP Design Issues

This section takes a deeper look at important issues in MRP design. We first consider how attrition relief mechanisms (ARMs) can cap rate and revenue growth and then discuss major approaches to ARM design. Following are discussions of cost trackers, decoupling, performance metric systems and efficiency carryover mechanisms.

4.1 Attrition Relief Mechanisms

Rate Caps vs. Revenue Caps

ARMs can escalate allowed rates or revenue. Limits on rate growth are sometimes called *price caps.*[47] In price cap plans, allowed rate escalation is often applied separately to multiple service "baskets." For example, there might be separate baskets for small-load (e.g., residential and general service) and large-load customers. The utility can typically raise rates for services in each basket by a common percentage that is determined by the ARM, cost trackers and any earnings sharing adjustments.[48] Customers in each basket are insulated from the discounts and demand shifts going on with services in other baskets, except as these developments influence shared earnings or cost trackers.

Price caps have been widely used to regulate utilities, such as telecommunications carriers, which are encouraged to promote use of their systems. In the electric utility industry, legacy rate designs feature usage charges that are well above the utility's short-run marginal cost of service provision.[49] With less frequent rate cases, price caps can therefore make utility earnings more sensitive to the kWh and kW of system use, strengthening utility incentives to encourage greater use.

Under revenue caps, the focus is on limiting growth in allowed revenue (the revenue requirement).[50] Services may still be grouped in baskets. Revenue caps are often paired with a revenue decoupling mechanism that relaxes the link between revenue and system use.

Methods for ARM Escalation

Several well-established approaches to ARM design can, with sensible modifications, be used to escalate rate or revenue caps. We use revenue cap examples in the following discussion.

<u>Indexing</u>

An indexed ARM is developed using index and other statistical research on utility cost trends. For example, a revenue cap index for a power distributor might take the following form:

$$\textit{growth Revenue} = \textit{Inflation} - X + \textit{growth Customers} + Y + Z \qquad [2]$$

The inflation measure in such a formula is often a macroeconomic price index such as the Gross Domestic Product Price Index. However, custom indexes of utility input price inflation are sometimes

[47] A notable early discussion of price caps for electric utilities is Lowry and Kaufmann (1994).
[48] In some plans, slower growth in rates for some services in a basket can, within limits, permit more rapid rate growth for other services in the same basket.
[49] Marginal cost is the additional cost incurred to provide a small increment of service.
[50] The allowed revenue yielded by a revenue cap escalator must be converted into rates, requiring assumptions for billing determinants.

used in ARM design. X, the productivity or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of peer distributors. A stretch factor (sometimes called *consumer dividend*) is often added to X to guarantee customers a share of the benefit of the stronger performance incentives that are expected under the plan.

Index-based ARMs compensate utilities automatically for important external cost drivers such as inflation and customer growth. This provides timely rate relief that reduces attrition and operating risk without weakening performance incentives. Between rate cases, customers can be guaranteed benefits of productivity growth which equals (or, with a stretch factor exceeds) industry norms. Controversies over cost forecasts can be avoided.

On the other hand, index-based ARMs are typically based on long-run cost trends. They may therefore undercompensate utilities when capex is surging and overcompensate them on other occasions, such as the years following a surge. Capex surges can be addressed by cost trackers, but trackers involve their own complications, as we discuss further below. Design of indexed ARMs applicable to capital cost sometimes involve statistical cost research that is complex and sometimes controversial.[51] Consultants will seek entry to the field by advocating unusual values for X which serve the interests of their clients. However, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range to date (e.g., zero to 1 percent).

Forecasts

A forecasted ARM is based on multiyear cost forecasts. An ARM based solely on forecasts increases revenue by predetermined percentages in each plan year (e.g., 4 percent in 2018, 5 percent in 2019 and 3 percent in 2020). The outcome is much like that of a rate case with multiple forward test years.

Familiar accounting methods can be used to forecast growth in capital cost. The trend in the cost of older capital is relatively straightforward to forecast since it depends chiefly on mechanistic depreciation.[52] The more controversial issue is the value of plant additions during the plan.

Shortcuts are sometimes taken in preparing forecasts for ARM design. For example, forecasted plant additions may be set for each plan year at the utility's average value in recent years [53] or at its value for the test year of the most recent rate case. Operation and maintenance (O&M) expenses are sometimes forecasted using index-based formulas similar to equation [2].

One important advantage of forecasted ARMs is their ability to be tailored to unusual cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capex surge. Some forecasted ARMs make no adjustment to rates during the plan if the actual cost incurred differs from the forecast. This approach to ARM design can generate fairly strong cost containment incentives despite the use of company-specific forecasts.

On the downside, forecasted ARMs do not protect utilities from unforeseen changes in inflation and operating scale.[54] The biggest problem with forecasted ARMs, however, is that it can be difficult to establish just and reasonable multiyear cost forecasts. It is often difficult to ascertain the value to

[51] For example, productivity studies filed in proceedings to establish an MRP often use mathematically stylized representations of capital costs which differ from those used in traditional ratemaking. Witnesses have disagreed on the appropriate capital cost treatment and sample period for a productivity study.
[52] Note, however, that salvage value and decommissioning costs are sometimes controversial.
[53] The practice of basing a utility's plant addition budgets on its historical plant additions may weaken its capex containment incentives if used repeatedly.
[54] Operating scale risk can be reduced by forecasting unit costs (e.g., cost per customer) and then truing up for actual scale growth.

customers in a given cost forecast. Resources that the regulatory community may expend on benchmarking and engineering studies to develop competent independent views of needed utility cost growth can be sizable.

Hybrids

"Hybrid" approaches to ARM design use a mix of indexing and other escalation methodologies.[55] The most popular hybrid approach in the United States involves separate treatment of revenues (or rates) that compensate utilities for their O&M expenses and capital costs. Indexes address O&M expenses while forecasts address capital costs.

Indexation of O&M revenue provides protection from hyperinflationary episodes and limits the scope of forecasting evidence. Good data on O&M input price trends of electric (and gas) utilities are available in the United States. The forecast approach to capital costs, meanwhile, accommodates diverse capital cost trajectories. The complicated issue of designing index-based ARMs for capital revenue is sidestepped. On the other hand, capex forecasts are required and can be controversial.

Rate Freezes

Some MRPs feature a rate freeze in which the ARM provides no rate escalation during the plan. Revenue growth then depends entirely on growth in billing determinants and tracked costs. Freezes usually apply only to base rates but have occasionally applied to rates for energy procurement. An analogous concept for a plan with revenue decoupling is the revenue/
customer freeze, which permits revenue to grow at the (typically gradual) pace of customer growth.

4.2 Cost Trackers

Basic Idea

A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered costs that regulators deem prudent. Costs are then recovered by tariff sheet provisions called *riders.*

A cost tracker helps a utility's revenue track its own costs more closely. While this is contrary to the spirit of PBR — which focuses on strengthening incentives — it can make it easier for a utility to operate under an MRP, which has an ARM for other costs of base rate inputs. Where cost containment incentives generated by trackers are a concern, methods are available to address them. For example, tracked costs can be subject to especially intensive prudence review.[56] Tracker mechanisms can be incentivized, as we discuss further below.

Capital Cost Trackers

Capital cost trackers compensate utilities for annual costs (e.g., depreciation, return on asset value, and taxes) that capex (or plant additions) give rise to. Such trackers are sometimes used in MRPs to address capex surges that are difficult to address with an ARM. Capex surges are sometimes needed — for

[55] A "hybrid" designation can in principle be applied to a number of ARM design methods, including the design used in Great Britain. However, it would not apply to regulatory systems, such as those used in Vermont, which index O&M revenue but use cost of service regulation for capital cost.
[56] The reduction in rate cases that MRPs make possible frees up resources to review these costs.

example, when VIEUs make large additions to generating capacity, replace large components of existing generating plants, or add extensive emission control systems. VIEUs and UDCs alike may need high capex for rapid build-out of AMI or other smart grid technologies, to meet increased safety and reliability standards, and to replace facilities built in earlier periods of rapid system growth.

Forecasted and hybrid ARMs can address expected capex surges better than index-based ARMs. Thus, capital cost trackers are more commonly combined with index-based ARMs. However, MRPs with forecasted or hybrid ARMs sometimes permit utilities to request supplemental revenue for unforeseen capex, or for capex with uncertain completion dates.[57]

Ratemaking Treatments of Tracked Costs

Supplemental revenue that capital cost trackers produce is often based on capex forecasts. Treatment of variances from approved budgets then becomes an issue. Some capital cost trackers return all capex underspends to ratepayers promptly. As for overspends, some trackers permit conventional prudence review treatment. In other cases, no adjustments are subsequently made between rate cases if capex exceeds budgets. Mechanisms also have been approved in which deviations from budgeted amounts that are in prescribed ranges are shared formulaically (e.g., 50-50) between the utility and its customers.

Appraising the Need for Trackers

A key question in approvals of capital cost trackers is the need for tracking. This question involves two issues: the need for high capex and the need for tracking the capex. It can be challenging to ascertain the need for high capex. For example, trackers for energy distributors sometimes address costs of accelerated system modernization. The need for a particular plan of modernization can be more challenging to appraise than the need for other kinds of capex surges, such as those for new generation capacity or emissions control facilities.[58] Accelerated distribution modernization plans involve many decisions about emerging technology and consumer expectations, as well as timing and scale issues, and regulators in some jurisdictions may not have much expertise in evaluating them.

Determining the need for a capital cost tracker is complicated for a utility operating under an ARM that provides some compensation for capex. An indexed ARM, for example, escalates revenue associated with an older plant between rate cases even though the cost of that plant tends to decline due to depreciation. Furthermore, the X factor in the escalator reflects productivity growth by peer group utilities which has been slowed by capex.[59] If the utility is given dollar-for-dollar compensation for substandard productivity growth when normal kinds of capex surge, but the X factor in the revenue cap formula reflects only the industry productivity trend when capex does not surge, customers are not ensured the benefit of the industry productivity trend in the long run, even if it is achievable.

Ratemaking Treatment of Other Costs

Another issue that arises when considering a capital cost tracker is the ratemaking treatment of costs not included in the tracker. Separate recovery of certain capex costs means that the cost of residual capital —

[57] For example, trackers have been used in conjunction with hybrid or forecasted ARMs to address costs of new generating facilities, major generator refurbishments and AMI.
[58] Generation plant additions also require discretion, but regulators of VIEUs have years of experience considering both the need for new capacity and the types of generation technology. Many states require integrated resource planning or a certificate of public convenience and necessity, or both, before additions to generation capacity can proceed. In addition, there are often competitive alternatives to a utility's proposal to increase capacity. Proponents of these alternatives press their cases in these hearings.
[59] Capex often slows growth in multifactor productivity, even while accelerating O&M productivity.

consisting mainly of gradually depreciating older plant — tends to rise more slowly and predictably. If *all* capex cost flows through trackers, the residual capital cost is that of older plants and may *decline* due to depreciation. Additionally, productivity growth of electric O&M inputs may be brisk. For these reasons, expansive capex trackers often coincide with freezes on rates addressing costs of other inputs.[60] This "tracker/freeze" approach to MRP design has recently been used by VIEUs in Arizona, Colorado, Florida, Louisiana and Virginia.[61]

Capital Cost Tracker Precedents

There are numerous precedents for capital cost trackers in the regulation of retail rates for U.S. gas, electric and water utilities.[62] The popularity of such trackers reflects in part the generally traditional approach to regulation in U.S. jurisdictions. Most capital cost trackers in the United States are not embedded in MRPs with ARMs that provide automatic rate escalation for cost pressures. The alternative to these trackers for regulators is thus more frequent rate cases that require review of costs of *all* base rate inputs and weaken utilities' incentives to contain them. Note also that many trackers are approved in jurisdictions that do not have fully forecasted test years.

Capital cost trackers have been components of a number of MRPs. Plans in California and Maine, for example, have had trackers for costs of AMI.[63] Plans in Alberta and Ontario have permitted cost trackers for a broader range of distributor capex.[64]

Capital cost trackers are occasionally incentivized. In California, for example, the AMI cost trackers of Southern California Edison and San Diego Gas & Electric have involved preapproved multiyear cost forecasts. Each company has been permitted to recover 100 percent of its forecasted cost up to a cap without further prudence review. Above the cap, each company can recover 90 percent of incremental overspends in a certain range without a prudence review. Beyond this range, recovery of incremental overspends requires a prudence review. San Diego Gas & Electric was permitted to keep 10 percent of its underspends.

---

[60] In an MRP with a revenue cap, the analogous ratemaking treatment is a revenue per customer freeze.
[61] See, for example, Arizona Corporation Commission (2012), Colorado Public Utilities Commission (2015), Florida Public Service Commission (2013), Louisiana Public Service Commission (2014), and Virginia Acts of Assembly (2015).
[62] Lowry et al. (2015).
[63] California Public Utilities Commission (2007a), California Public Utilities Commission (2008b), and Maine Public Utilities Commission (2008).
[64] See Alberta Utilities Commission (2012), for a discussion of capital cost trackers in Alberta distribution regulation and Section 6.7 of this report for a discussion of capital cost trackers in Ontario power distribution regulation.

Decoupling Under an MRP

Revenue decoupling can improve utility incentives to adopt a wide array of initiatives to encourage cost-effective DSM and other DERs.[65] In addition to eliminating the utility's short-term incentive to increase retail sales, decoupling can reduce the utility's risk in using retail rate designs that encourage efficient DERs. For example, decoupling reduces risks of revenue loss when customers are offered time-sensitive usage charges that shift loads away from peak demand periods.

When average use is declining for any reason, decoupling reduces the needed frequency of rate cases. Decoupling also reduces controversy over billing determinants in rate cases with future test years because prices will adjust — up or down — based on actual utility sales.

A recent power industry survey found revenue decoupling in use in 14 jurisdictions.[66] DSM is aggressively encouraged by policymakers in many of these jurisdictions. Decoupling is used in tandem with MRPs in California, Minnesota and New York.

Decoupling is much more widely used by gas distributors. This reflects the fact that gas distributors have often experienced declining average use, due chiefly to external forces such as the improved efficiency of furnace technologies. Some utilities have decoupling for some services and lost revenue adjustment mechanisms (LRAMs) for others.[67]

4.3 Performance Metric Systems

Metrics (sometimes called *outputs*) quantify utility activities that matter to customers and the public.[68] These metrics can alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and reduce costs of oversight. Target ("benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. A performance incentive mechanism links utility revenue to the outcome of one or more performance appraisals. "Scorecards" summarizing performance metric results are sometimes tabulated. These may be posted on a publicly available website or included in customer mailings.

Service Quality PIMs

Service quality PIMs are used in multiyear rate plans to improve the incentive balance between cost and quality. This can simulate connections between revenue and product quality that firms in competitive markets experience. Service quality PIMs for electric utilities have addressed both reliability and customer service.[69]

Reliability metrics have addressed systemwide reliability, reliability in subregions, and the success of restoration efforts after major storms. System reliability metrics are most likely to provide the basis for PIMs. The most common system reliability metrics are the system average interruption duration index

[65] For further discussion of revenue decoupling, see Lazar et al. (2016).
[66] Lowry, Makos and Waschbusch (2015).
[67] Electric utilities with decoupling for most customers and LRAMs for some large-volume customers include Portland General Electric, Duke Energy Ohio and AEP Ohio.
[68] Whited et al. (2015).
[69] For a survey of reliability PIMs, see Kaufmann et al. (2010). For a survey of customer service PIMs, see Kaufmann (2007).

(SAIDI) and system average interruption frequency index (SAIFI).[70] Customer service PIMs have addressed customer satisfaction, customer complaints to the regulator, telephone response times, billing accuracy, timeliness of bill adjustments, and the ability of the utility to keep its appointments.

Performance on service quality metrics is usually assessed through a comparison of a company's current year performance to its recent historical performance. Because of limited availability and lack of standardization of service quality data, benchmarking a company's performance on service quality using data from other utilities is difficult.

Demand-Side Management PIMs

Demand-side management PIMs link utility revenue to reward (or penalize) utilities for their performance on DSM initiatives. Metrics on load savings are often used in these PIMs. Compensation for load savings can take several forms:

- *Shared savings.* This approach grants the utility a share of the estimated net benefits that result from DSM. It can therefore encourage utilities to choose more cost-effective programs and manage them more efficiently. However, estimation of net benefits can be complex and controversial. *Ex post* and *ex ante* appraisals of net benefits (or a mix of the two) may be used in net benefit calculations.

- *Management fees.* This alternative grants the utility an incentive equal to a share of program expenditures. The incentive calculation depends on costs incurred (specifically, expenditures by the utility) but not on benefits achieved. Thus, the utility is rewarded for spending money, which is not necessarily well correlated to desired policy outcomes. However, the simplicity of management fees makes them an attractive option in some contexts. This approach is commonly used when net benefits are difficult to measure but are believed to be positive (e.g., public education programs), and its ease of administration has encouraged its use for other DSM programs as well.

- *Amortization.* DSM expenditures can be amortized so that the utility earns a return on them like capital expenditures. Premiums are sometimes added to the rate of return on equity (ROE) for these expenditures, and these premiums may be contingent on achieving certain DSM performance goals.

Most DSM PIMs require estimates of load savings. These savings can be estimated using engineering models, typical savings documented in technical reference manuals (deemed savings), or statistical analyses of customer billing data. Even with high-quality data, reliably estimating savings can be challenging. The complications include free riders (customers who would have implemented the efficiency measure without the program, or would have taken alternative measures), spillovers (additional savings due to the program that are not measured), and rebound effects (behavioral changes that counteract the direct effects of the program, such as using more lighting in the home because light bulbs are more efficient and thus less costly to operate).

DSM initiatives vary with respect to the difficulty of measuring load savings and the scale of expenditures that can produce material management fees and amortization. Some DSM PIMs encourage utilities to design programs with more measurable impacts or larger expenditure requirements. Other DSM initiatives that are equally or more cost-effective may be neglected. Such initiatives may include changes

[70] Other reliability metrics include the customer average interruption duration index (CAIDI) and the momentary average interruption duration index (MAIFI).

in default retail rate designs, cooperation with third-party vendors of energy services and products, support for upgraded state appliance efficiency standards and building codes, and other efforts to transform energy service markets.

Pros and Cons of Demand-Side Management PIMs

Demand-side management PIMs can be a useful addition to multiyear rate plans. Under these plans, utilities may still lack sufficiently strong incentives to encourage DSM. For example, most MRPs accord tracker treatment to fuel and purchased power expenses. Transmission costs may also be tracked. MRPs may provide some incentive to contain load-related capex, but not to levels found in unregulated markets.

Performance incentive mechanisms for DSM can strengthen utility incentives to use DSM as a cost management tool. Such PIMs also can address the utility's short-term throughput incentive in an MRP that does not include revenue decoupling or an LRAM. Well-designed demand-side management PIMs can encourage more cost-effective DSM programs.

Still, demand-side management PIMs have drawbacks. For example, they can involve complex calculations that may complicate regulatory proceedings. Shared savings PIMs are particularly complex. By motivating utilities to improve their performance in relation to specific programs, PIMs may lead to a deterioration in other aspects of DSM performance that are not measured.[71] In addition, utility rewards for load savings can sometimes become sizable over the years.

Precedents for Demand-Side Management PIMs

A 2014 survey by the Edison Foundation Institute for Electric Innovation found that DSM PIMs are quite common in the United States.[72] In all, 29 states had some form of DSM PIM. Among them, all but five had also adopted decoupling or LRAMs. Demand-side management PIMs were included in more than half of the U.S. electric MRPs identified. Among DSM PIMs, those focused on conservation and energy efficiency programs were the most common, and some states have decades of experience with them. PIMs also may address peak load management.

Despite their relative complexity, shared savings mechanisms have been the most popular PIM compensation approach for many years. However, management fees are also widely used. In some cases, regulators have approved more than one compensation approach (e.g., shared savings for programs with quantifiable benefits; management fees for education and marketing programs).

Most DSM PIMs approved to date have pertained to programs serving customers across broad areas of a utility's service territory. However, PIMs can also be targeted to specific geographic areas, such as those where substantial transmission and distribution capex will be needed in the near future to replace aging assets or accommodate growing load. We discuss some examples of these programs in Section 6.

4.4 Efficiency Carryover Mechanisms

Efficiency carryover mechanisms limit true-ups of a utility's revenue to its cost when an MRP concludes. These mechanisms encourage utilities to achieve long-term performance gains that can benefit customers after a plan's conclusion. They can also counteract some adverse incentives that can result under MRPs from periodic rate cases that set a utility's revenue requirement equal to its cost. Due to compression of

[71] New York and other jurisdictions are for this reason considering less program-specific DSM performance metrics like normalized volume per customer.
[72] Institute for Electric Innovation (2014).

the period during which benefits of long-term performance gains improve their bottom line, utilities may have less incentive in later years of a plan to limit upfront costs needed to achieve such gains. In addition, rate cases provide disincentives to contain costs that influence the revenue requirement in the first year of the next plan. For example, there may be less incentive to strike hard bargains with vendors. Given the different incentives to contain cost in early and later plan years, utilities may also be incentivized to defer certain expenditures in the early years of the plan so that these expenses show higher totals in the MRP test year. Customers may then "pay twice" for some costs that are funded by the ARM.

To counteract such incentives, efficiency carryover mechanisms can be designed that reward utilities for offering customers good value in later plans. Such mechanisms can also penalize utilities for offering customers poor value. One kind of efficiency carryover mechanism involves a comparison of revenue requirements in the test year of the next rate case to a benchmark. The mechanism may take the form of a targeted PIM. The revenue requirement in a forward test year could, for example, correspond to the following formula:

$$RR_{t+1} = Cost_{t+1} + \alpha \cdot (Benchmark_{j,t+1} - Cost_{j,t+1})$$

where α is a share of the value implied by benchmarking and takes a value between 0 and 1.[73] Variance between benchmark and actual costs can, alternatively, be used to adjust the X factor in the next plan if it has an index-based ARM.

Choice of a benchmark is an important consideration in design of this kind of efficiency carryover mechanism. One approach is to use as the benchmark the revenue requirement established by the expiring MRP (extended by one year in the case of a forward test year). Cost (or the proposed revenue requirement) may, alternatively, be compared to a benchmark based on statistical cost research which is completely independent of the utility's cost.

[73] Note that the formula allows for the possibility that only a subset (j) of the total cost is benchmarked. This could be the subset that is easier to benchmark.

Efficiency Carryover Mechanisms: An Example From New England

National Grid, a company with utilities that have long operated under MRPs in Britain, incorporated efficiency carryover mechanisms in plans for several power distributors in the northeast United States. For example, in Massachusetts, New England Electric System and Eastern Utilities Associates were in the process of merging when they were acquired by National Grid. In 2000 the Massachusetts Department of Telecommunications and Energy approved a settlement which, among other things, detailed an MRP under which the surviving power distributors of the merging companies (Massachusetts Electric and Nantucket Electric) would operate for 10 years.[74]

The settlement did not require rates to be reset in a rate case at the conclusion of the rate plan. However, the settlement limited over a 10-year "Earned Savings Period" the extent to which rates established in future rate cases could reflect the benefits of cost savings achieved during the plan. These "earned savings" were to conform to the following formula:

Earned Savings = Distribution revenue under rates applicable in March 2009

- *pro forma cost of service (COS)*

The focus on 2009 reflects the fact that Massachusetts has historical test years, so this was expected to be the first year in which cost could provide the basis for post-plan rates. During the Earned Savings Period, Massachusetts Electric was permitted to add to its cost of service during any rate case the lesser of $66 million and 100 percent of earned savings achieved in 2009 up to $43 million, plus 50 percent of any earned savings above $43 million. Thus, if there were no earned savings there would be no revenue requirement adjustment. Any earned savings would be capped at $66 million.

At the end of the plan period, National Grid requested a large revenue requirement increase. This was explained in part by the need to replace aging infrastructure. The utility did not include an allowance for earned savings in its 2009 rate request.

Regulators in Australia, Britain and Ontario routinely take an approach to cost benchmarking which uses econometric methods in rate setting. In the United States, econometric benchmarking studies have occasionally been filed by U.S. utilities. Public Service of Colorado, for example, has filed econometric benchmarking studies of its forward test year revenue requirement proposals for the cost of its gas and electric operations.[75] We discuss econometric benchmarking further in Appendix B.3.

Experience around the world with efficiency carryover mechanisms has been less extensive than experience with some other MRP provisions. Australia has been a leader, using these mechanisms in both power transmission and distribution regulation. The Alberta Utilities Commission uses efficiency carryover mechanisms in MRPs for provincial energy distributors.

[74] See Settling Parties in Massachusetts (1999).
[75] Lowry, Hovde, Kalfayan, Fourakis, and Makos (2014).
Lowry, Hovde, Getachew, and Makos (2010).
Lowry, Hovde, Getachew, and Makos (2009).

4.5 Menus of MRP Provisions

Some MRPs contain menus of provisions from which utilities can choose. Menus typically include a key ARM provision and another plan provision affecting utility finances. In a plan with an indexed ARM, a utility might, for example, have a choice between (1) a low X factor and an earnings sharing mechanism and (2) a higher X factor and no earnings sharing.

An "incentive compatible" menu incentivizes a utility to reveal, by its choice between menu options, its potential for containing cost growth. This approach to MRP design has been discussed in the academic regulatory economics literature since the 1980s. Major theoretical contributions have been made by Michael Crew, Paul Kleindorfer and Nobel prize-winning economist Jean Tirole.[76]

The Federal Communications Commission used a menu approach to MRP design in a 1990 price cap plan for interstate access services of large local telecommunications exchange carriers.[77] The menu embedded in the Information Quality Incentive of British regulators is explained in Appendix A.4.

[76] Laffont and Tirole (1993), Crew and Kleindorfer (1987), Crew and Kleindorfer (1992), and Crew and Kleindorfer (1996).
[77] Federal Communications Commission (1990).

5.0 Incentive Power Research

Pacific Economics Group has developed an Incentive Power model to explore the incentive impact of alternative regulatory systems such as multiyear rate plans. The model addresses the situation of a hypothetical energy distributor that has several kinds of initiatives available to improve its cost performance. Using numerical analysis, the model can predict the cost savings that will occur under various regulatory systems. The regulatory systems considered are stylized but resemble real-world options in use today. Appendix B.1 provides details of the research.

Key results of our incentive power research include the following:

- *Cost containment incentives depend on the frequency of rate cases.* Today, utilities in the United States typically hold rate cases every three years.[78] For a utility with normal operating efficiency, our model finds that long-run cost performance on average improves 0.51 percent more rapidly each year in an MRP with a five-year term and no earnings sharing than it does under traditional regulation when rate cases occur every three years. This means that cost will be about 5 percent lower after 10 years under the MRP. For a utility with an annual revenue requirement of $1 billion, this would be an annual cost saving of $50 million in real terms.

- *If rate cases under traditional regulation occur more frequently, the incremental incentive impact of an MRP is higher.* For example, the long-run impact of MRPs with five-year terms is 0.75 percent additional annual cost containment if rate cases would otherwise be held every two (rather than three) years. This kind of comparison is more relevant to regulators when the alternative to an MRP is frequent rate cases or extensive use of cost trackers.

- *Earnings sharing mechanisms weaken incentives produced by an MRP.* For example, MRPs with a five-year term and 75/25 sharing of all earnings variances between utilities and their customers produce only 0.27 (rather than 0.51) percent annual performance gains compared to a three-year rate case cycle.

- *Performance gains from more incentivized regulatory systems are greater (smaller) for companies with a low (high) initial level of operating efficiency.*

- *Incentives generated by an MRP can be materially strengthened by a well-designed efficiency carryover mechanism or system of menu options.* Suppose, for example, that when rates are rebased the utility absorbs 10 percent of the variance between its own cost and a statistical benchmark of cost. Our model finds that annual performance gains increase by 90 basis points in a plan with a five-year term relative to those from traditional regulation with a three-year rate case cycle. This means a 9 percent lower cost after 10 years.

Our incentive power research has a number of implications. It shows that a utility's performance incentives and performance can be materially affected by the regulatory system under which it operates. This means that more incentivized regulatory systems such as well-designed MRPs can provide material cost savings that can be shared between utilities and their customers. New MRP design provisions such as efficiency carryover mechanisms and menu options can materially increase incentive power.

[78] Lowry and Hovde (2016), p. 44.

Utility performance is materially affected by the frequency of rate cases, and the frequency of rate cases is affected by the adversity of business conditions. Our incentive power research thus supports the notion that performance of utilities under COSR tends to decline under adverse business conditions. When business conditions are adverse, regulators should be especially vigilant about utility operating prudence and consider how to strengthen performance incentives. That can be particularly important given that utilities typically advocate for expedited recovery of their costs when business conditions are adverse, and often are successful.

6.0 Case Studies

This section presents case studies of multiyear rate plans. Each case study discusses the nature of MRPs enacted, identifying important provisions and controversies and rationales for utility regulators to choose PBR. We also consider effects of PBR on cost performance using power distributor productivity indexes. These indexes consider productivity in the provision of customer services such as billing and distribution services. We compare productivity trends of utilities operating under rate plans, or less formal rate case stayouts, to contemporaneous utility norms. Appendix B.2 provides details of our utility productivity research.

6.1 Central Maine Power

The Maine Public Utilities Commission was for many years a leader in energy utility PBR.[79] Central Maine Power (CMP) is Maine's largest electric utility. From 1995 to 2013, it operated under a succession of three MRPs called *alternative rate plans.* Full rate cases did not occur between plans. The first plan took place while the company was still vertically integrated, while later plans applied to CMP's distributor services after restructuring. All three plans were outcomes of settlements between CMP and other parties.

In a 1993 rate case decision, the Commission encouraged CMP to operate under an alternative rate plan. This decision took into consideration CMP's recent history of rapid rate escalation and losses of margins from large-volume customers. The Commission expressed concern that CMP's management had spent "greater attention on a reactive strategy of deflecting blame than on proactively cutting costs."[80] The Commission also noted in its decision general problems with continued use of traditional regulation for CMP. These problems included:

> 1) the weak incentive provided to CMP for efficient operation and investments; 2) the high administrative costs for the Commission and intervening parties from the continuous filing of requests for rate changes; 3) CMP's ability to pass through to its customers the risks associated with a weak economy and questionable management decisions and actions; 4) limited pricing flexibility on a case-by-case basis, making it difficult for CMP to prevent sales losses to competing electricity and energy suppliers; and 5) the general incompatibility of traditional [COSR] with growing competition in the electric power industry.[81]

The Commission outlined its views of potential costs and benefits of MRPs (presumed to feature price caps) in its decision:

> Based on the evidence presented in this proceeding, the Commission finds that multi-year price-cap plans is [sic] likely to provide a number of potential benefits: (1) electricity prices continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) Risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial

[79] Thomas Welch, a former telecommunications lawyer, chaired the Commission during these years.
[80] Maine Public Utilities Commission (1993), pp. 14–15.
[81] Maine Public Utilities Commission (1993), p. 126.

> perspective); and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.[82]

The decision discussed the marketing flexibility benefits of MRPs at some length:

> Price caps coupled with pricing flexibility allow a regulated firm to compete on a more equal basis with other suppliers that threaten its markets: a firm is given wide pricing discretion and the opportunity to offer new services in the absence of case-by-case regulatory approval.
>
> An important benefit of price caps lies with protecting the so-called "core customers" from competition encountered in other markets. For example, if separate price caps are placed on each class of customer, whatever revenues the utility earns in the more competitive industrial markets would not directly affect the price it can charge (say) residential customers… In contrast, under [COSR] a firm is generally given the opportunity to receive revenues corresponding to its revenue requirement. This implies that whenever the firm receives fewer revenues from one group of customers, it would have the right to petition for increased revenues from others by proposing to raise their prices….[83]

Plan Designs

<u>Attrition Relief Mechanism</u>

All three of CMP's plans featured price caps with index-based escalators. The caps applied to both base and energy rates for vertically integrated service in the first plan, and to base rates for distributor services in later plans. Evidence on input price and productivity trends of Northeastern U.S. electric utilities was presented and debated in each proceeding to inform the choice of an X factor.[84] Macroeconomic price indexes were used as inflation measures. The accuracy of such measures as proxies for utility input price inflation was a prominent issue in one proceeding.

<u>Marketing Flexibility</u>

When CMP was vertically integrated, it had a special need for flexibility in its marketing to pulp and paper customers, some of whom had cogeneration options or were economically marginal, or both. Maine's legislature passed a law allowing the Commission to authorize pricing flexibility plans which permit utilities to discount their rates with limited or no Commission approval. The Commission also encouraged utilities to develop special contracts with customers.

The Commission noted the following in approving the first alternative rate plan for CMP:

Because CMP will have substantial exposure to revenue losses due to discounting, the Company will have a strong incentive to avoid giving unnecessary discounts, and it will have a strong incentive to find cost savings to offset any such losses. Pricing flexibility gives CMP the opportunity to use price to compete to retain customers.[85]

---

[82] Maine Public Utilities Commission (1993), p. 130.
[83] Maine Public Utilities Commission (1993), p. 130.
[84] X factors in Maine were commonly referred to as "productivity offsets."
[85] Maine Public Utilities Commission (1995), p. 19.

Marketing flexibility provisions in this plan included these features:

- For core customers, CMP was free to set rates between the rate cap and a rate floor based on an estimate of long-term marginal cost.
- CMP could receive expedited approval of new targeted services.
- CMP could also receive expedited approval of special rate contracts with individual customers. Different provisions applied for short-term and long-term contracts.
- Revenue lost during a plan as a result of discounts was recoverable from other customers only through the earnings sharing mechanism (ESM). In the first plan, a cap of 15 percent was placed on overall lost revenues that could be recovered through the ESM.

Subsequent plans did not make substantial changes to these pricing flexibility provisions.

Other Plan Provisions

Earnings sharing mechanisms and penalty-only service quality PIMs were included in all three plans. Service quality benchmarks for these PIMs became more demanding over time.

The first-generation plan also featured a tracker for DSM costs and a DSM PIM. These latter features were subsequently removed with restructuring and establishment of a third-party DSM program administrator in Maine.

Outcomes

Cost Performance

Table 4 and Figure 6 compare the trends in O&M, capital and multifactor productivity of the company's power distributor services to the average for U.S. electric utilities in our sample from 1980 to 2014. The table shows that from 1980 to 1995, before MRP regulation, the company's MFP growth was a little slower than that of the full sample on average. Over the 1996 to 2013 period during which CMP operated under alternative rate plans, it averaged 0.92 percent annual MFP growth, while the full sample of U.S. electric utilities averaged 0.42 percent annual MFP growth. The MFP growth differential thus averaged 50 basis points. Table 4 also shows that CMP accomplished this through much more rapid *capital* productivity growth. This is notable given the interest of many regulators today with capex containment. O&M productivity trends of CMP and the sample were more similar.

Nuclear Problems

At the start of PBR, when CMP was still vertically integrated, it owned 38 percent of Maine Yankee Atomic Power Co., owner and operator of a nuclear generating station. CMP relied on this station for a sizable share of its power supply. The station experienced an extended outage during the plan. The plan did not fully compensate CMP for the increased costs for repairs, decommissioning and purchased power expenses that resulted from the Maine Yankee outage. This resulted in lower earnings for CMP, which in 1998 triggered the lower bound of the ESM.

Table 4. How Productivity Growth of Central Maine Power Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	CMP			U.S. Average		
	MFP	PFP O&M	PFP Capital	MFP	PFP O&M	PFP Capital
1980	-0.17%	-2.17%	1.08%	-0.49%	-4.19%	1.24%
1981	0.45%	-3.00%	1.47%	0.17%	-2.42%	1.25%
1982	0.08%	-1.43%	1.84%	0.87%	-1.20%	1.53%
1983	0.42%	-2.22%	1.82%	0.51%	-0.38%	0.98%
1984	1.63%	1.28%	1.80%	1.27%	-0.22%	1.79%
1985	0.75%	-1.94%	1.94%	0.95%	-0.21%	1.37%
1986	2.08%	0.89%	2.57%	0.91%	0.88%	0.97%
1987	0.59%	-1.10%	1.28%	0.44%	-0.12%	0.68%
1988	-0.49%	-1.43%	-0.03%	0.57%	1.55%	0.24%
1989	-0.83%	-0.12%	-1.25%	0.26%	0.00%	0.23%
1990	-0.97%	0.24%	-1.79%	0.18%	0.64%	-0.05%
1991	-0.43%	1.04%	-1.39%	-0.03%	0.58%	-0.32%
1992	1.32%	2.51%	0.64%	0.48%	1.61%	0.10%
1993	-0.24%	-2.55%	1.04%	0.45%	1.19%	0.12%
1994	2.10%	2.87%	1.66%	0.94%	2.44%	0.29%
1995	1.80%	0.98%	2.30%	0.94%	3.58%	-0.04%
1996	1.67%	1.75%	1.62%	0.11%	0.67%	-0.13%
1997	1.08%	-0.40%	2.00%	1.53%	4.68%	0.39%
1998	0.17%	-2.94%	2.14%	0.67%	0.73%	0.71%
1999	2.03%	1.98%	2.05%	1.08%	2.24%	0.52%
2000	0.97%	-2.17%	2.18%	0.89%	0.86%	0.73%
2001	0.83%	-0.69%	1.80%	1.20%	2.73%	0.61%
2002	1.23%	1.28%	1.19%	0.79%	2.73%	0.33%
2003	1.35%	-0.49%	2.83%	-0.03%	-1.50%	0.43%
2004	-0.35%	-3.96%	2.56%	0.41%	0.76%	0.22%
2005	1.85%	1.27%	2.32%	-0.07%	-0.25%	0.09%
2006	1.02%	-0.48%	2.62%	-0.52%	-1.07%	-0.21%
2007	1.16%	-0.21%	3.12%	-0.12%	0.00%	-0.02%
2008	-1.51%	-2.67%	1.27%	-0.99%	-2.06%	-0.09%
2009	2.23%	2.57%	1.34%	1.01%	2.73%	-0.46%
2010	-0.51%	-1.65%	1.00%	-0.27%	-0.47%	0.05%
2011	3.54%	6.17%	0.85%	0.50%	0.05%	0.50%
2012	0.56%	1.86%	-0.63%	1.29%	2.90%	0.58%
2013	-0.73%	-2.31%	0.76%	0.03%	0.40%	-0.05%
2014	-1.61%	-4.74%	1.47%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.66%**	**-0.34%**	**1.36%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**0.51%**	**-0.39%**	**0.94%**	**0.53%**	**0.23%**	**0.65%**
1996-2013	**0.92%**	**-0.06%**	**1.72%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**0.28%**	**-0.11%**	**0.86%**	**0.22%**	**0.30%**	**0.15%**

*CMP operated under multiyear rate plans in the years for which results are shaded.

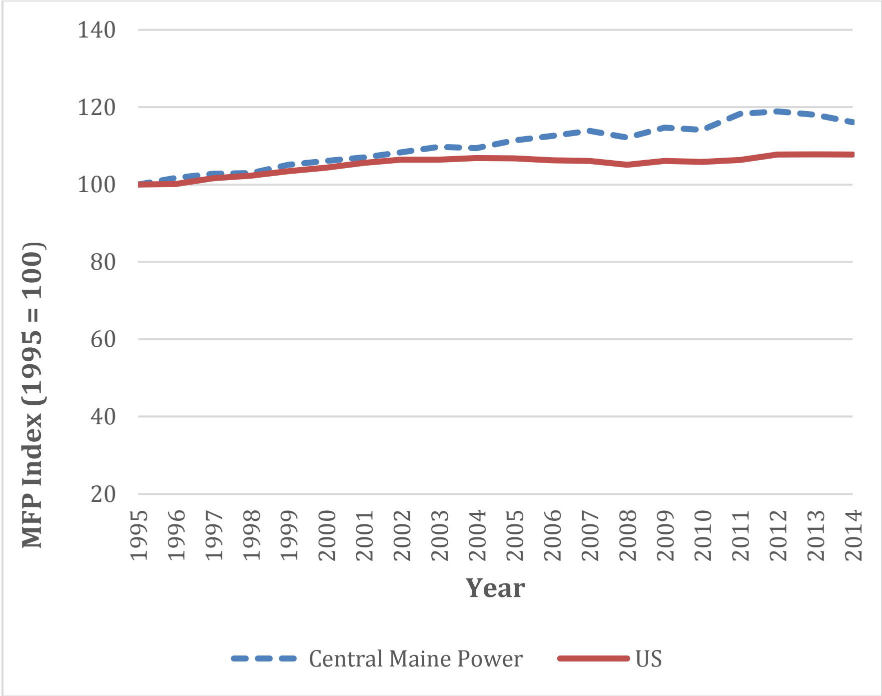


Figure 6. Comparison of Multifactor Productivity Trends of Central Maine Power and the U.S. Sample During Multiyear Rate Plan Periods. The MFP growth of CMP exceeded the industry norm during MRPs.

Marketing Flexibility

During its first rate plan, CMP entered into special contracts with 18 large customers. These contracts featured discounts from tariffed rates in exchange for a guarantee that customers would not attempt to shift their loads to competitors or self-generate during the contract term. In its 1999 10-K filing with the Securities Exchange Commission, CMP described the importance of pricing flexibility and its impacts on the company:

Central Maine believes that without offering the competitive pricing provided in the agreements, a number of these customers would be likely to install additional self-generation or take other steps to decrease their electricity purchases from Central Maine. The revenue loss from such a usage shift could have been substantial.[86]

Service Quality

During the second of CMP's three plans, the Energy and Utilities Committee of Maine's Legislature asked the Public Utilities Commission to investigate effects of the rate plans on service quality performance. This review ultimately resulted in a third-party report.[87] Results of this review were mixed. CMP generally met or exceeded service quality targets. However, performance was uneven. Feeders serving densely populated areas like Portland received greater attention, and these feeders had a greater effect on measured performance systemwide than feeders in rural areas. These performance differences may reflect the fact that reliability PIMs measured only systemwide performance and did not measure performance at a more granular level.

[86] Central Maine Power (1998), p. 81.
[87] Williams Consulting (2007).

Current Status

In 2013, near the conclusion of its third plan, CMP proposed a fourth-generation plan that would have significantly accelerated its revenue growth to help fund a forecasted capex surge.[88] Table 4 shows that CMP's capital productivity trend slowed after 2007. The case ended in a settlement that returned the company to a more traditional regulatory system.[89] A capital tracker for a new customer information system was approved, as was revenue decoupling. While service quality PIMs and the ESM no longer apply, pricing flexibility has continued. No rate case has subsequently been filed.

6.2 California

The California Public Utilities Commission (CPUC) has extensive experience with PBR. This includes the longest experience in North America with MRPs for retail energy utility services. The CPUC has jurisdiction over an energy utility industry that in North America is second in size only to that under the jurisdiction of the Federal Energy Regulatory Commission. Six investor-owned electric utilities (two of which are very large) are regulated, along with natural gas, telecommunications, water, railroad, rail transit and passenger transportation companies. This gives the CPUC strong incentives to contain regulatory costs. MRPs were also facilitated by the CPUC's routine use of forward test years. California's power market was restructured in the 1990s, but two of three large, jurisdictional electric utilities have continued to have sizable generation operations.

The CPUC has limited the frequency of general rate cases using rate case plans for decades. Rate cases were staggered to reduce the chance that the CPUC had to consider cases for multiple large utilities simultaneously. A two-year plan for Southern California Edison was approved in 1980. The standard lag between rate cases was increased to three years in 1984. Longer (e.g., four- or five-year) rate case cycles have since been approved on several occasions.

The CPUC has not always characterized its plans as PBR but did acknowledge the merits of PBR in a 1994 order:

We intend to replace cost-of-service regulation with performance-based regulation. Doing so neither changes the [regulatory] compact's tenets, nor threatens fulfillment of those tenets. We make this change for several reasons.

> First, prices for electric services in California are simply too high. The shift to performance-based regulation can provide considerably stronger incentives for efficient utility operations and investment, lower rates, and result in more reasonable, competitive prices for California's consumers. Performance-based regulation also promises to simplify regulation and reduce administrative burdens in the long term. Second, since the utilities' performance-based proposals currently before us leave both industry structure and the utility franchise fundamentally intact, consumers can expect service, safety and reliability to remain at their historically high levels. Third, the utilities' reform proposals are likely to provide an opportunity to earn that is at a minimum comparable to opportunities present in cost-of-service regulation. Finally, performance-based regulation can assist the utilities in developing the tools necessary to make the successful transition from an operating environment directed by government and focused on regulatory proceedings, to one in which consumers, the rules of competition, and market forces dictate. This is of critical importance in our view.[90]

[88] The Commission stated its opposition to a new plan with a hybrid ARM based on a capital cost forecast.
[89] Maine Public Utilities Commission (2014).
[90] California PUC (1994), pp. 34–35.

The CPUC also has been a national leader in revenue decoupling and PIMs for DSM. This makes California a good case study of the impact performance-based regulation can have on utility DSM as well as cost management. The evolution of MRP design in the state is of further interest given its long history and the diverse situations to which plans have applied.

Plan Design

Attrition Relief Mechanisms

Establishment of multiyear rate case cycles for California energy utilities raised issues of whether and how rates could be adjusted between rate cases. Utilities in the early 1980s were subject to cost pressures from inflation and capacity growth. The three largest utilities invested in nuclear power plants but were denied permission to fund their (often delayed) construction by charging for a return on construction work in progress. The CPUC encouraged large-scale purchases of power from non-utility generators. Revenue decoupling insulated utilities from risks of demand fluctuations but denied them extra revenue from growth in sales volumes, numbers of customers served, and other billing determinants.

Under these circumstances, the CPUC acknowledged that escalation of revenue is typically needed between rate cases.[91] ARMs were thus permitted,[92] and energy costs were addressed by trackers. The out-years of the rate case cycle came to be called *attrition years.* Various approaches to ARM design have been used over the years in California. Predetermined "stepped rate" increases were approved in 1980.[93] However, high inflation encouraged use of inflation measures in ARMs, and many subsequent California ARMs have provided some automatic inflation relief. A hybrid approach to ARM design has been used on many occasions. The broad outline of the first ARMs for Pacific Gas and Electric (PG&E), which started in 1981, is remarkably similar to that of hybrid ARMs that are still occasionally used today.[94]

- O&M expenses were escalated only for inflation. The CPUC implicitly acknowledged that growth in productivity and operating scale also drive cost escalation but assumed that their impact was offsetting.[95]

- Capex per customer was fixed in constant dollars at a five-year average of recent net plant additions, then escalated for inflation.

- Other components of capital cost, like depreciation and return on rate base, were forecasted using cost of service methods. Subsequent hybrid ARMs used in California have involved variations on this basic theme. For example, capex budgets have occasionally been fixed in real terms for several years at forward test year value, then escalated for construction cost inflation. Detailed indexes of utility O&M input price inflation have replaced indexes of

---

[91] The CPUC has nevertheless persistently maintained that attrition adjustments are not an entitlement even under revenue decoupling and has occasionally rejected their implementation. See, for example, the rejection of PG&E's 2002 attrition adjustment in D.03-03-034.
[92] The ARM was sometimes called an Attrition Relief Adjustment and has in recent years been called a post-test-year mechanism.
[93] California PUC D. 92497 (1980a) for Southern California Gas and California PUC D. 92549 (1980b) for Southern California Edison.
[94] Hybrid ARMs are frequently featured by utilities in their post-test year proposals.
[95] "Our labor and nonlabor costs adopted for test year 1982 will be escalated by appropriate inflation factors for labor and nonlabor expenses…. We will not adopt a growth factor but assume that any growth or increase in activity levels will be offset by increased productivity and efficiency." California PUC (1981) Cal. PUC LEXIS 1279; 7CPUC 2d 349.

macroeconomic price inflation in escalation of revenue requirements for O&M expenses. Some plans have permitted utilities to escalate their labor revenue to reflect wage growth in their union contracts.

Several utilities experimented with fully indexed ARMs between 1998 and 2007. For example, PG&E, Southern California Edison, and San Diego Gas & Electric all operated under indexed ARMs.[96] Southern California Gas, America's largest gas distributor, operated under a revenue-per-customer index with inflation and X factor terms. Larger utilities have in recent years most commonly operated under revenue caps with comprehensive stair step escalators. Cost trackers have provided supplemental revenue for advanced metering infrastructure and some reliability-related capex.

Revenue Decoupling

Revenue decoupling has often been used in conjunction with California multiyear rate plans to reduce utilities' incentives to boost retail sales. Revenue decoupling mechanisms called *supply adjustment mechanisms* were first instituted for gas distributors in the late 1970s at the conclusion of a generic proceeding.[97] By 1982, the CPUC approved revenue decoupling mechanisms (called *Electric Revenue Adjustment Mechanisms*) for the three largest California electric utilities. The appeal of decoupling for electric utilities came from several sources:

- Power conservation became a priority in the state in the 1970s, spurred by generation capacity concerns and high fuel prices.[98] The CPUC declared in 1976 that "Conservation is to rank at least equally with supply as a primary commitment and obligation of a public utility."[99] Utilities played a large role in administering DSM programs (and still do).

- Electric utilities had experimental rate designs such as inverted block rates that were intended to promote conservation but increased sensitivity of utility earnings to demand shifts.

- Utilities experienced substantial risk from other sources, including multiyear rate plans and the CPUC's unwillingness to grant funding for nuclear plant construction work in progress.

Despite a generally positive experience, use of decoupling for California electric utilities fell off in the mid 1990s due, in part, to rules governing the transition to retail competition. There was also some thought that DSM might be provided in the future by independent marketers. A return to decoupling was mandated in 2001 by state legislation motivated in part by the need to promote conservation and contain utility risk during the California power crisis.[100] The three largest electric utilities recommenced decoupling, which continues today.

---

[96] Indexed ARMs are still used for California energy utilities serving smaller state loads. For example, a 2007 decision in a PacifiCorp rate case approved a settlement that outlined an MRP featuring a price cap index and a three-year term. The index has escalated base rates to reflect growth in an annual forecast of CPI less a productivity adjustment of 0.5 percent. Supplemental revenue is permitted for the California portion of major plant addition costs exceeding $50 million. Parties later agreed to defer PacifiCorp's scheduled 2010 rate case for one year and adopted an identical MRP in the 2011 general rate case. The CPUC agreed to extend PacifiCorp's renewed MRP for several additional years, and the utility will not file a new rate case until 2019 at the earliest.
[97] CPUC Decision 88835, Case No. 10261, May 1978.
[98] Fossil fueled generators in California burned oil, gas or both.
[99] CPUC Decision 85559, March 1976, p. 489.
[100] See California Public Utilities Code (2001).

Demand-Side Management PIMs

California was also an early innovator in the area of DSM PIMs. The first experimental DSM PIMs were implemented in 1990. These measures did not survive deregulation of California's electricity market later in the decade.

In 2007, California reintroduced DSM PIMs for larger utilities through the Risk-Reward Incentive Mechanism. This mechanism featured a relatively complex shared savings approach to compensation. Each utility had targets for three metrics (if applicable): electricity savings, gas savings and peak demand reductions. Under the original incentive design, utilities could receive a reward of up to 12 percent of the dollar value of evaluated net benefits of eligible DSM programs if they performed strongly on all three metrics. Conversely, they would be penalized if they fell below 65 percent of the target for any one of the three metrics. Critically, utility financial outcomes would be based on evaluated (*ex post*), not predicted (*ex ante*), net benefits. That meant that utility outcomes were not known until program evaluations were completed. This choice extended the process and added complexity. However, the CPUC felt it important to reward or penalize how programs actually performed in order to properly align utility incentives and protect ratepayers from adverse outcomes.[101]

The Risk-Reward Incentive Mechanism was implemented for the first time at the end of the 2006–2008 utility program cycle. Disputes over net benefits soon developed, as the CPUC's evaluation consultants estimated program results that substantially differed from the utilities' estimates and implied very different financial outcomes, in part due to the sharp earnings cutoffs in the mechanism's reward structure.[102] Disputes stretched over several years and proved intractable enough that the CPUC modified the mechanism. It based net benefit calculations on parameters (for example, net-to-gross ratios) estimated before programs were implemented, as well as on actual program delivery outcomes.[103] It also lowered the incentive to a flat 7 percent of net benefits and eliminated the possibility of penalties. Savings used to calculate rewards were in between the utilities' and the CPUC's estimates. For programs from 2010 to 2012, the CPUC simplified these PIMs, establishing rewards conditioned primarily on utility spending (management fees) rather than evaluated program performance.

In 2013, the CPUC adopted the Energy Savings Performance Incentive.[104] Under this mechanism, performance awards for many programs were based on energy savings delivered, not net benefits. Energy savings were not discounted, unlike energy benefits in the earlier net benefits calculation. Thus, the revised mechanism provided greater relative rewards for deeper, longer-lived savings. The revised mechanism did not include a potential penalty and avoided sharp earnings cutoffs of the Risk-Reward Incentive Mechanism. Rewards under the Energy Savings Performance Incentive were expected to be lower, and the incentive also capped the maximum achievable reward at a lower level, compared to the Risk-Reward Incentive Mechanism, largely due to the absence of an earnings penalty.

---

[101] See CPUC, 2007b, Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs, http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf.

[102] The reward/penalty function consisted of four tiers: a penalty if evaluated energy/capacity savings were less than 65 percent of a target; a dead band of no reward or penalty if savings were between 65 percent and 85 percent of a target; a 9 percent shared savings reward if savings were between 85 percent and 100 percent of a target; and a 12 percent shared savings reward if savings exceeded a target. Each transition between tiers created a sharp reward discontinuity. A small change in the evaluated savings could produce a big change in the reward. Further exacerbating these issues, a utility was paid based on the worst of the three outcomes. For example, if a utility fell below 65 percent of any of the three targets, it earned a penalty even if it performed strongly on the other two. In one case, a utility's estimated savings implied a $180 million reward; the evaluation consultants' estimates implied a $75 million penalty. See Chandrashekeran et al. (2015).

[103] This CPUC decision was controversial, with one commissioner objecting that the revised mechanism largely eliminated the actual performance incentives and ratepayer protections provided by the prior, *ex post*-based mechanism. See http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128882.pdf.

[104] CPUC (2013).

The Energy Savings Performance Incentive calculates savings *ex post*, reintroducing one of the challenges under the previous incentive mechanism. Some parameters that are considered relatively certain were locked in *ex ante*; those deemed "sufficiently uncertain" by the CPUC required *ex post* measurement. In reintroducing *ex post* calculations, the CPUC emphasized the need to protect ratepayers from paying out rewards based on overly optimistic *ex ante* projections, arguing that this objective outweighed the utilities' desire for revenue certainty and justified potential disputes over *ex post* savings calculations. The Energy Savings Performance Incentive rewarded both codes and standards support programs and "non-resource" programs (those that cannot support an energy savings calculation — largely market transformation programs) using a management fee based on utility dollars spent. The Risk-Reward Incentive Mechanism had not rewarded these programs. Incentives distributed for 2013 and 2014, as well as some rewards for 2015, have prompted far fewer disputes over process and savings estimates.

The CPUC recently developed a pilot PIM program for DERs such as distributed generation and storage. The CPUC approved a management fee mechanism that would offer investor-owned electric utilities 4 percent of annual payments made to DER providers pretax as an incentive to use third-party DERs to cost-effectively displace or defer the need for capex for traditional distribution system investments that were previously planned and authorized.[105] Utilities are required to pursue at least one project and have the option to pursue three more.

The CPUC also authorized the utilities to keep any savings from capex underspends due to DER that had been previously approved until the next general rate case.[106] Estimated costs of the DER and administration of the solicitation are recoverable with interest up to a preapproved cap when rates are reset in the next rate case. Administrative costs above the cap will be reviewed for reasonableness in the next rate case.

In their procurement decisions, utilities are required to consider the net market value of potential DER pilot projects. The net market value calculation includes a broad range of factors, including capacity, energy, ancillary grid services, costs of grid integration, deferred distribution and transmission system costs, and the cost of the DER procurement contract. During the pilot, each of the three major electric utilities are allowed to use different methods for ensuring that DERs rewarded by the incentive are incremental to the utility's existing plans and efforts as governed by other Commission proceedings, in order to test the performance of each method.

Other MRP Provisions

Other characteristics of California electric utility regulation also merit note:

- The CPUC decided in Decision 89-01-040 to address target rates of return on capital of all energy utilities in a separate annual proceeding. This meant that revenue requirements generated by ARMs often have been subject to supplemental rate of return adjustments. Some of these adjustments have been formulaic.[107]

[105] California PUC (2016).
[106] This is not a change from current California regulatory practices, but was explicitly stated nonetheless.
[107] For example, San Diego Gas & Electric's Market Indexed Capital Adjustment Mechanism, approved in 1996, featured a trigger mechanism that updated the cost of capital if bond yields deviated from the benchmark by a specific amount. A similar mechanism was established in 2008 for all large California utilities.

- Cost allocation and rate design issues are commonly addressed in a second phase of a general rate case. In attrition years, utilities have additional opportunities to adjust cost allocations and rate designs in rate design "windows."[108]

- Use of capital cost trackers has been limited in California, due in part to the fact that hybrid and forecasted ARMs have been prevalent. Several plans have permitted separate treatment of discrete major plant additions such as those for power plants and AMI.

- The CPUC has experimented with incentivized trackers for generation fuel and purchased power expenses. For example, San Diego Gas and Electric had a PIM that assessed the effectiveness of its generation and dispatch costs through simulations of annual production costs using expected and actual data. PIMs also have been used for nuclear generation plant capacity factors where sharing of energy cost variances would occur if the capacity factor of a facility was above or below the dead band.

- The CPUC has approved MRPs for generating facilities, independent of other utility assets. For example, in the late 1980s, the CPUC approved an MRP for PG&E's Diablo Canyon nuclear plant where it was permitted to charge an escalating price per MWh for power produced. This charge initially compensated PG&E for capital costs as well as O&M expenses,[109] strengthening the company's incentive to keep the plan running. The Diablo Canyon rate plan expired in 2001.

- Earnings sharing mechanisms and PIMs for service quality have not been routinely featured in California MRPs. During the experimentation with index-based ARMs, earnings sharing mechanisms and service quality PIMs were more common. The CPUC has monitored service quality performance since at least the 1990s.

Outcomes

Cost Control

Table 5 and Figure 7 compare the distributor productivity trends of California's three largest electric utilities to the norm for our full U.S. electric utility sample. Over the full 1986–2014 period during which MRPs have been extensively used in California, the MFP growth of these utilities averaged a 0.14 percent annual *decline*, whereas the MFP of our full U.S. sample averaged 0.43 percent annual *growth*.[110] Thus, the MFP growth of the California utilities was 57 basis points *slower* on average. All three utilities had subpar trends. The capital productivity growth of California utilities has been especially slow. In the 1980–1985 period, before MRPs were widely used, MFP trends of these utilities and the full sample were similar.

[108] Any attrition relief adjustment that the ARM puts in motion is pooled with certain other revenue requirement adjustments and recovered in advice letter filings using the Phase II cost allocations, as amended by changes effected in the rate design windows.
[109] In 1997, however, the plan was revised so that the mechanism recovered only the incremental costs of the plant (costs of O&M and new plant additions). The ongoing recovery of sunk costs was achieved through a separate transition charge.
[110] The MFP growth trends of California utilities were fairly similar to those for the full sample during the six-year 1980 to 1985 period before MRPs became common.

These unflattering results may reflect special California operating challenges. However, the results may also reflect ineffective plan design. We have noted that California ARMs have often based a utility's budget for plant additions on its own historical additions, and passed through the escalation of a utility's union wages.

Table 5. How the Power Distributor Productivity Growth of Larger California Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	California Average			U.S. Sample Average		
	MFP	O&M PFP	Capital PFP	MFP	O&M PFP	Capital PFP
1980	-0.10%	-2.39%	0.96%	-0.49%	-4.19%	1.24%
1981	0.65%	-0.85%	1.22%	0.17%	-2.42%	1.25%
1982	-0.54%	-3.92%	0.78%	0.87%	-1.20%	1.53%
1983	-0.20%	-3.46%	0.99%	0.51%	-0.38%	0.98%
1984	1.43%	-0.20%	2.00%	1.27%	-0.22%	1.79%
1985	1.27%	-1.44%	1.78%	0.95%	-0.21%	1.37%
1986	0.96%	2.23%	0.61%	0.91%	0.88%	0.97%
1987	0.58%	2.56%	0.02%	0.44%	-0.12%	0.68%
1988	1.86%	10.04%	-0.35%	0.57%	1.55%	0.24%
1989	0.80%	3.51%	-0.04%	0.26%	0.00%	0.23%
1990	0.35%	3.49%	-0.71%	0.18%	0.64%	-0.05%
1991	-1.13%	-0.85%	-1.18%	-0.03%	0.58%	-0.32%
1992	-0.71%	0.98%	-1.26%	0.48%	1.61%	0.10%
1993	-1.45%	-1.66%	-1.38%	0.45%	1.19%	0.12%
1994	0.01%	3.17%	-0.93%	0.94%	2.44%	0.29%
1995	0.27%	0.02%	0.32%	0.94%	3.58%	-0.04%
1996	1.43%	3.26%	0.89%	0.11%	0.67%	-0.13%
1997	0.41%	-1.07%	0.87%	1.53%	4.68%	0.39%
1998	-0.24%	-1.81%	0.32%	0.67%	0.73%	0.71%
1999	-0.53%	1.21%	-1.08%	1.08%	2.24%	0.52%
2000	-0.32%	1.19%	-0.92%	0.89%	0.86%	0.73%
2001	1.63%	1.41%	1.76%	1.20%	2.73%	0.61%
2002	-1.21%	-3.73%	-0.45%	0.79%	2.73%	0.33%
2003	-1.21%	-3.63%	-0.29%	-0.03%	-1.50%	0.43%
2004	-0.14%	0.34%	-0.31%	0.41%	0.76%	0.22%
2005	-0.90%	-2.64%	-0.12%	-0.07%	-0.25%	0.09%
2006	-1.36%	-3.95%	-0.06%	-0.52%	-1.07%	-0.21%
2007	-0.57%	-0.56%	-0.58%	-0.12%	0.00%	-0.02%
2008	-1.44%	-2.17%	-0.80%	-0.99%	-2.06%	-0.09%
2009	0.83%	2.22%	-0.56%	1.01%	2.73%	-0.46%
2010	-1.15%	-0.58%	-1.47%	-0.27%	-0.47%	0.05%
2011	-1.94%	-1.12%	-2.29%	0.50%	0.05%	0.50%
2012	-0.39%	0.82%	-0.91%	1.29%	2.90%	0.58%
2013	1.33%	3.94%	0.23%	0.03%	0.40%	-0.05%
2014	0.04%	3.81%	-1.28%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**-0.05%**	**0.23%**	**-0.12%**	**0.45%**	**0.53%**	**0.43%**
1980-1985	**0.42%**	**-2.04%**	**1.29%**	**0.55%**	**-1.44%**	**1.36%**
1986-2014	**-0.14%**	**0.70%**	**-0.41%**	**0.43%**	**0.93%**	**0.24%**
2008-2014	**-0.39%**	**0.99%**	**-1.01%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

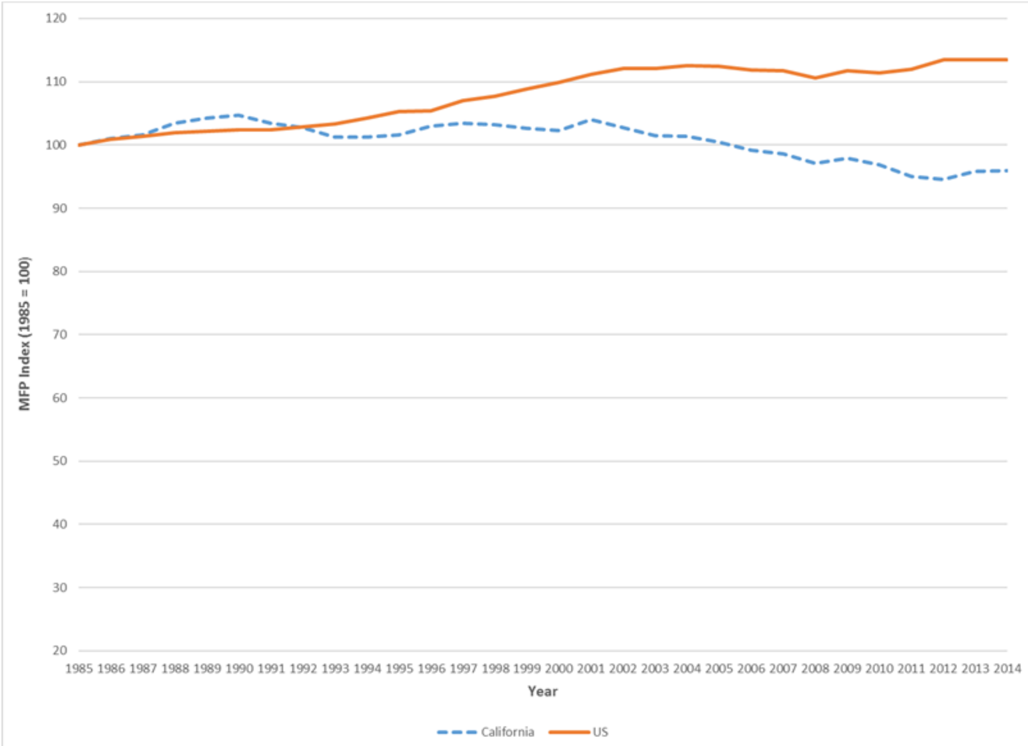


Figure 7. Comparison of Multifactor Productivity Trends of California Distributors and the U.S. Sample during Multiyear Rate Plan Periods. MFP growth of California utilities has fallen short of industry norms under MRPs.

DSM Programs

California electric utilities have typically operated large DSM programs, traditionally ranked near the top of most surveys. Since 1996, the American Council for an Energy-Efficient Economy (ACEEE) has issued annual scorecards evaluating state efforts and achievements in energy efficiency.[111] These surveys include estimates of DSM spending (or budgets) as a percentage of utility revenue. In the eight years for which data were available since 2006, California has averaged a 5.5 ranking out of 51 U.S. jurisdictions (with 1 the highest possible ranking).

Rate Designs

California has also been a national leader in use of rate designs that encourage DSM. For example, inclining block rate designs intended to encourage conservation have been mandated for residential customers since 1976.[112] Until recently, California investor-owned utilities (IOUs) had a very steep inclining block rate structure for these customers, consisting of four tiers ranging from $0.13/kWh for the lowest tier of usage to $0.42/kWh for the highest tier.[113] In a 2015 decision,[114] the CPUC reduced the number of tiers to two (plus a third tier for very high energy users) and specified that the second tier's price should be 25 percent higher than the first. The result is that the lowest tiers now face a higher price

[111] Berg et al. (2016).
[112] California Public Utilities Code, section 739.
[113] St. John (2015).
[114] CPUC (2015b).

than before, while the higher tiers face a lower one — in other words, a flatter rate structure. This reduces what was formerly a very significant incentive for efficiency and distributed generation deployment for customers using large amounts of electricity. On the other hand, it raises this incentive for customers with lower usage.

Time of use rates are currently optional for residential customers. The CPUC has ordered the IOUs to transition most residential customers to default time of use pricing in 2019.[115] Most commercial and industrial IOU customers in California already face seasonally differentiated default time of use prices, which were introduced in 2014. While these customers can opt into non-time-differentiated rates, few have done so.

Service Quality

California's regulatory system for service quality is more reactive than proactive and has featured several investigations to assess utilities' service quality performance. An early investigation focused on whether PG&E had adequately responded to severe storms in 1995. In its decision, the CPUC ordered standardized service quality and reliability reporting requirements to be developed. Southern California Edison and Sempra had service quality PIMs in rate plans with index-based ARMs during the late 1990s and early 2000s.

Edison's service quality PIMs included one for customer satisfaction, as measured by a survey. In 2003 a whistleblower brought to the utility's attention that fraud had occurred in the customer satisfaction surveys. The company investigated the claims, confirmed that there had been misconduct, expanded the investigation to include the other PIMs, and notified the CPUC.

The Commission opened its own investigation on the matter. It found that Southern California Edison had provided false and misleading data in support of its performance claims on the customer satisfaction survey and health and safety PIMs. The Commission's decision required a refund of rewards that Edison had obtained through false reporting, made the utility forego recovery of additional rewards through these PIMs, and fined the utility an additional sum. The Commission was particularly concerned that the utility had gamed an incentive mechanism, stating that:

> Incentive mechanisms, such as the [PIMs], require a great deal of trust between the Commission and the utility's entire management. In turn, the utility's management must communicate through its practices, rules, and corporate culture that the data submitted to the Commission that impacts the incentive mechanisms must be completely accurate and timely. Increasingly, this Commission is turning to incentive mechanisms in order to align the interests of ratepayers and shareholders and to achieve desirable policy outcomes in the most cost effective and least burdensome manner. If the Commission is to continue to rely on and potentially create new incentive mechanisms, we must be able to trust the utilities to be accurate, timely, and completely honest about their reporting, and further, we must be vigilant against abuse and appropriately penalize violations in order to safeguard the integrity of incentive mechanisms going forward for all utilities.[116]

[115] Ibid.
[116] CPUC (2008), p. 102–103.

6.3 New York

New York has also had a long history with MRPs for energy utilities. Plans have been widely used there since the mid-1990s. Experience with MRPs has spanned some years when electric utilities were still vertically integrated, and more than 15 years after industry restructuring was completed. DSM programs are provided primarily by a state agency, the New York State Energy Research and Development Authority, but utilities also have some programs. MRPs are usually outcomes of negotiated settlements in regulatory proceedings.

The inclination of New York's Public Service Commission and Department of Public Service (DPS) to adopt MRPs has several root causes. Regulatory cost savings can be sizable, since New York's economy is large and there are six investor-owned electric utilities (and even more investor-owned gas utilities) to regulate.[117] MRPs also have been facilitated by New York's long-standing use of forward test years in rate cases. One of the earliest MRPs, for Orange & Rockland Utilities, was motivated in part by concerns about performance incentives. The Commission stated in approving the plan:

> Economic regulation, like most acts of market intervention, can have unintended and undesirable consequences. In the case of a regulated monopoly, the consequence most frequently watched for and least easily avoided is operating inefficiency within the firm, resulting from the "cost plus" nature of price controls. In theory, the [MRP] should encourage greater operating efficiency, because the period of regulatory lag during which the company would be allowed to retain savings from productivity gains would be longer.[118]

Reducing regulatory cost has also been cited in the Commission's support of MRPs. For example, in a 2008 rate case decision for Consolidated Edison, the Commission discussed the drawbacks of annual rate cases.

> We generally prefer multi-year rate plans in instances where the terms are broadly seen to be better than those that might result from a litigated one-year rate case. In addition, we note that this proceeding includes many of the same, or similar, issues and major cost drivers as did the Company's last one-year electric rate case. These circumstances raise a significant concern that the public benefit might not be optimized if the upcoming Consolidated Edison electric rate filing — the third in three years — ultimately boils down to consideration of the same, or similar, issues on which parties largely just replicate arguments we have already carefully reviewed and either accepted or rejected. We also question how well the public interest may be served by the demands on time and resources of the Company, DPS Staff, and other parties in the face of continual annual rate proceedings.[119]

The relatively poor performance of several New York utilities after a series of storms including Superstorm Sandy led the governor to issue an order establishing a commission, called the Moreland Commission on Utility Storm Preparation and Response (Moreland Commission), to investigate and review the storm preparedness of New York's electric utilities, the adequacy of regulatory oversight, and the jurisdiction, responsibility, and mission of New York's energy agency and authority functions.[120] The findings of the Moreland Commission encouraged the governor to push for a reassessment of electric utility regulation more generally. We discuss some Moreland Commission findings further below.

---

[117] A seventh investor-owned electric utility, Long Island Lighting, was transferred to the state-owned Long Island Power Authority during the 1990s.
[118] New York Public Service Commission (1990).
[119] New York Public Service Commission (2009), p. 282.
[120] Moreland Commission (2013a).

In 2014 New York's Public Service Commission initiated a generic proceeding to consider how the regulatory system of power distributors and their marketplace roles should evolve in an era of rapid change in distribution, metering, and DER costs and technologies.[121] This came to be called the "REV" proceeding after a Department of Public Service Staff report entitled *Reforming the Energy Vision*.

Track One of the proceeding considered appropriate roles of power distributors going forward. Utilities are envisioned as distributed system platform providers that accommodate customer-side DERs and energy service companies and may offer new services that use smart grid technologies. Utilities are now required to file Distribution System Integration Plans that among other things, consider the use of DERs to avoid capex. The first filings were made last summer.[122] Track Two of the proceeding has addressed miscellaneous ratemaking issues such as rate designs and MRP design. We discuss the outcomes further below.

Plan Designs

New York rate plans have featured forecasted ARMs.[123] Since decoupling has been common, most ARMs have effectively been revenue caps.[124] A "one-way" net plant reconciliation ("claw back") mechanism has been added to MRPs in recent years which returns to customers benefits of capex underspends.[125] Plans typically have a term of only three years. In the early 1990s and since 2007, plans also typically have included revenue decoupling and PIMs for utility DSM. Where New York utilities do not have an approved MRP but have revenue decoupling, they often have filed frequent rate cases. MRPs also typically have featured asymmetrical ESMs that share only surplus earnings.

Service quality PIMs are common in New York and are sometimes extensive. There are PIMs for customer service as well as reliability. In addition to these PIMs, service quality standards for SAIDI and CAIDI have been in place since 1991 which, if breached, require a corrective action plan to be filed with the Commission. Consolidated Edison's most recent plan had separate PIMs for its radial and network systems. This plan also featured PIMs for performance following major events (e.g., outages) and a wide variety of asset management activities.

New York plans during the late 1990s and early 2000s were somewhat different from plans that were approved in the early 1990s and after 2007. These plans did not feature revenue decoupling or DSM PIMs, but retained ESMs and service quality PIMs. Several plans featured rate freezes often tied to restructuring plans or merger approvals. A plan for Niagara Mohawk had a 10-year term.

The Commission issued an order on Track Two of its REV proceeding in 2016, including the design of its regulatory system.[126] Among the specific issues addressed are the following:

- The net plant reconciliation mechanism will be reformed to enable utilities to profit from DERs that displace previously approved capital projects. Because this will often be achieved through increased operating expenses, rather than capital expenses, the existing mechanism would require utilities to forfeit approved capital earnings. This creates a disincentive for utilities to adopt lower cost DER alternatives. To address this, the Commission will permit utilities to retain earnings on previously approved, traditional utility capital projects included

[121] New York Public Service Commission (2014a).
[122] Walton (2016a).
[123] Indexed ARMs have, however, been proposed by utilities on several occasions.
[124] From the late 1990s to mid-2000s, revenue decoupling was not featured in New York regulation. These plans were price caps where base rates were specified for each year of the plan.
[125] An underspend occurs if utility capex is less than the budget which the ARM provides.
[126] New York Public Service Commission (2016a).

in base revenue, even if these projects do not materialize, until rates are reset in the next rate case. To qualify for this treatment, a utility must demonstrate that DSM or other types of DERs displaced the capital project. The Commission expressed interest in considering further modifications to the claw back mechanism in the future, such as sharing any realized savings between the utility and customers over a longer time horizon.

- As utilities transition to a platform provider role, the Commission expects a growing share of their income to be Platform Service Revenues,[127] new revenues arising from the operation or facilitation of distribution-level markets.

- *Earnings Adjustment Mechanisms* are New York's term for performance incentive mechanisms. They are to focus on outcomes, rather than on utility inputs or the attainment of specific program targets, and are not restricted to items under the utility's direct control. The Commission expects these adjustment mechanisms to be most important in the near term, serving as a "bridge" to the time when markets provide utilities with a sizable share of revenue in the form of platform services revenues.

  To avoid encouraging utilities to grow rate base, the Commission stated that Earnings Adjustment Mechanisms should not take the form of basis-point adjustments to earnings (though they may be designed in reference to basis-point changes and fixed in dollar amounts before the mechanisms take effect). Mechanisms also generally should avoid estimated counterfactuals in order to reduce controversy and cost. In addition, they should be financially meaningful, encourage strategic, portfolio-level approaches beyond narrow programs, and generally be structured on a multiyear basis.

  Though specific metrics and associated Earnings Adjustment Mechanisms will be worked out in future proceedings, the Commission provided requirements and guidance in several areas:

  - *System Efficiency.* The Commission will require utilities to propose system efficiency Earnings Adjustment Mechanisms that address both peak reduction and load factor. Initial proposals should include only the possibility of positive adjustments.

  - *Energy Efficiency.* Pending recommendations from the Clean Energy Advisory Council based on State Energy Plan and Clean Energy Standard goals, energy efficiency Earnings Adjustment Mechanisms will be redesigned. One focal point will be systemwide electric usage intensity (e.g., measured as kWh per capita, kWh per customer or kWh per unit of GDP).

  - *Interconnection.* An Earnings Adjustment Mechanism will address interconnection of distributed generation and storage projects over 50 kW. It will include a threshold tied to meeting timeliness requirements, and a positive adjustment based on evaluations by interconnection customers of application quality and applicant satisfaction. Negative adjustments may also be considered in individual utility proceedings. The Track Two order required the utilities to develop an Earnings Adjustment Mechanism for distributed generation connection timeliness, customer satisfaction with distributed generation interconnection processes and audits of failed distributed generation interconnection applications.

[127] One potential problem with Platform Service Revenues is that margins from them are netted off of the revenue requirement in each rate case. Another is that competitors will endeavor to limit the role of utilities in the provision of new services. MRPs can help utilities retain margins from these new revenues for several years.

- *Customer Engagement.* The Commission declined to implement an Earnings Adjustment Mechanism related to general customer engagement. However, the Commission will consider proposals in this area. For example, Earnings Adjustment Mechanisms could reward utilities for increased customer participation in time-varying rates or adoption of ground-source heat pumps and electric vehicles.

- *Scorecards.* The Commission plans to use scorecard metrics to track utility progress, which could serve as the basis for Earnings Adjustment Mechanisms in the future.

- Utilities may also earn new revenues from displacing traditional infrastructure projects with non-wires alternatives (NWAs) in other ways. The Brooklyn Queens Demand Management program of Consolidated Edison (Con Ed) is the best-known example.[128] Approved by the Commission in 2014, its goal is to use DERs to delay or offset the need for traditional infrastructure upgrades in a portion of the Brooklyn and Queens boroughs.[129] In the absence of this program, upgrades needed by 2017 would have an estimated cost of approximately $1 billion and included a new area substation, a new switching station at an existing station, and new subtransmission feeders.[130]

  To overcome the disincentive for Con Ed to pursue NWA projects, the Commission adopted the following performance incentives contingent on satisfactory performance on the company's existing reliability PIMs:[131]

  1. Con Ed is permitted to earn its authorized overall rate of return (as approved in its most recent electric rate case) on all deferred Brooklyn-Queens program costs up to a cap. These amounts would be recovered over a 10-year period.

  2. The utility can earn up to an additional 100 basis points (incremental to its authorized rate of return on equity) on program costs contingent on performance.

  An NWA incentive mechanism was approved in 2016 which gives Central Hudson Gas and Electric a 30 percent share of savings associated with delaying investments in traditional power plant structures and reductions in wholesale capacity requirements. Program costs will be amortized and recovered over the subsequent five-year period.[132]

- The Commission declined to extend the terms of MRPs from three to five years in recognition of the need for a high level of regulatory oversight during the early REV transitional period. However, the Commission stated that longer plans had significant potential to achieve long-term benefits and declined to preclude parties from pursuing longer plans if desired.

Consolidated Edison was the first utility to have its rate case litigated after the Track Two decision was issued. This placed the company in the position of being the first to implement several REV features.[133] A separate decision on the same day as the rate case decision approved an incentive mechanism that allowed

[128] For further discussion, see Walton (2016b).
[129] New York Public Service Commission (2014b).
[130] Concurrently with the BQDM program, Con Ed is undertaking about 17 MW of traditional infrastructure investments.
[131] The utility proposed an additional shareholder incentive in its application. This proposal was a shared savings mechanism, under which the utility would have retained a 50 percent share of the annual net savings realized by customers. The Commission rejected this proposal, however, believing that the other two incentive mechanisms were sufficient.
[132] New York Public Service Commission (2016b).
[133] In the case of New York State Electric & Gas and Rochester Gas & Electric, Earnings Adjustment Mechanisms are being developed as a compliance filing to the rate case.

Con Ed to receive 30 percent of the net benefits of NWA projects, except on the Brooklyn Queens Demand Management program.[134] Costs of NWA projects will be recovered over a 10-year period. The net plant reconciliation mechanism was revised to allow Con Ed to use the revenue requirements that would otherwise be refunded to customers as a result of capex underspends from successful DER deployments to offset the revenue requirements of any related non-wires alternative project first.

Earnings adjustment mechanisms and metrics were approved to encourage superior Consolidated Edison performance in several areas.

- In the area of energy efficiency and demand response, two metrics are relied on to assess Con Ed's performance. The first encourages Con Ed to increase its incremental gigawatt-hour (GWh) savings from energy efficiency programs. The second metric encourages Con Ed to improve its demand response effectiveness as measured by incremental system peak megawatt (MW) reductions from energy efficiency programs.

- With respect to deployment of incremental DERs, a metric encourages incremental use of DERs from solar energy, combined heat and power, battery storage, demand response and beneficial electrification, such as thermal storage, heat pumps and electric vehicle charging.

- Measurement of customer load factors is intended to encourage Con Ed to improve those of poor load factor customers. This metric is customer-specific and compares the customer's average load to their peak. Due to the need to conduct further research on this metric, no targets or incentives were assigned to this metric for the first year.

- Metrics also measure Con Ed's weather-normalized average use adjusted for incremental beneficial usage. One measures residential use per customer; another measures commercial use per employed person in Con Ed's service territory.

- Separate metrics are used to assess Con Ed's performance on distributed generation interconnection timeliness, customer satisfaction with distributed generation interconnections, and independent audits of failed distributed generation interconnection applications. Development of specific targets was deferred beyond the rate case, so that no Earnings Adjustment Mechanism will apply for the first rate year.

All of the proposed Earnings Adjustment Mechanisms will be reviewed each year for potential revisions. The incentives increase for each Earnings Adjustment Mechanism during the term of the MRP, with the maximum reward exceeding $50 million in year three of the plan.

[134] New York Public Service Commission (2017).

Outcomes

Utility Cost

Table 6 and Figure 8 compare the power distributor productivity trends of New York electric utilities to the averages for our full U.S. electric utility sample. From 1980–1993, before MRPs became commonplace, the MFP growth of New York power distributors averaged 0.98 percent annually. This was 51 basis points above the average for sampled power distributors nationally. Over the 1994–2014 period during which MRPs have been prevalent, the MFP trend of the New York utilities averaged 0.54 percent annually, whereas the average for our full national sample was a similar 0.45 percent. Capital productivity growth was more rapid in New York but O&M productivity growth was slower. Evidence that MRPs have improved cost performance is therefore not strong. This is not surprising since New York's approach to MRP design is conservative, with short rate case cycles.

Table 6. How the Power Distributor MFP Growth of New York Utilities Compared to That of Other U.S. Electric Utilities: 1980–2014*

	New York Average			U.S. Sample Average		
	MFP	**O&M PFP**	**Capital PFP**	**MFP**	**O&M PFP**	**Capital PFP**
1980	0.78%	-1.47%	1.42%	-0.49%	-4.19%	1.24%
1981	1.57%	1.73%	1.42%	0.17%	-2.42%	1.25%
1982	-0.28%	-4.42%	1.63%	0.87%	-1.20%	1.53%
1983	1.75%	1.82%	1.65%	0.51%	-0.38%	0.98%
1984	2.28%	1.81%	2.37%	1.27%	-0.22%	1.79%
1985	1.74%	-0.19%	2.39%	0.95%	-0.21%	1.37%
1986	1.89%	2.03%	1.82%	0.91%	0.88%	0.97%
1987	0.84%	-1.83%	1.78%	0.44%	-0.12%	0.68%
1988	1.94%	2.09%	1.87%	0.57%	1.55%	0.24%
1989	1.29%	1.73%	0.98%	0.26%	0.00%	0.23%
1990	0.01%	-1.19%	0.56%	0.18%	0.64%	-0.05%
1991	-1.65%	-4.97%	-0.12%	-0.03%	0.58%	-0.32%
1992	1.38%	4.27%	0.18%	0.48%	1.61%	0.10%
1993	0.16%	-0.35%	0.35%	0.45%	1.19%	0.12%
1994	1.67%	4.18%	0.61%	0.94%	2.44%	0.29%
1995	0.65%	0.12%	0.82%	0.94%	3.58%	-0.04%
1996	0.29%	-0.54%	0.59%	0.11%	0.67%	-0.13%
1997	0.16%	-1.63%	0.96%	1.53%	4.68%	0.39%
1998	-0.29%	-5.04%	1.70%	0.67%	0.73%	0.71%
1999	1.70%	1.78%	1.45%	1.08%	2.24%	0.52%
2000	0.60%	1.22%	0.18%	0.89%	0.86%	0.73%
2001	2.23%	2.96%	1.91%	1.20%	2.73%	0.61%
2002	-0.33%	-5.18%	1.18%	0.79%	2.73%	0.33%
2003	1.51%	1.37%	1.66%	-0.03%	-1.50%	0.43%
2004	0.90%	3.65%	-0.53%	0.41%	0.76%	0.22%
2005	-1.50%	-1.35%	-1.46%	-0.07%	-0.25%	0.09%
2006	-1.08%	-2.58%	-0.01%	-0.52%	-1.07%	-0.21%
2007	2.10%	3.91%	0.47%	-0.12%	0.00%	-0.02%
2008	-0.16%	-0.54%	0.58%	-0.99%	-2.06%	-0.09%
2009	2.26%	3.65%	0.32%	1.01%	2.73%	-0.46%
2010	-1.32%	-3.61%	0.90%	-0.27%	-0.47%	0.05%
2011	3.79%	7.39%	0.72%	0.50%	0.05%	0.50%
2012	1.19%	0.67%	0.53%	1.29%	2.90%	0.58%
2013	-2.93%	-6.18%	-0.14%	0.03%	0.40%	-0.05%
2014	-0.09%	-1.02%	0.51%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.72%**	**0.12%**	**0.89%**	**0.45%**	**0.53%**	**0.43%**
1980-1993	**0.98%**	**0.08%**	**1.31%**	**0.47%**	**-0.16%**	**0.72%**
1994-2014	**0.54%**	**0.15%**	**0.62%**	**0.45%**	**0.99%**	**0.24%**
2008-2014	**0.39%**	**0.05%**	**0.49%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs for a majority of New York's electric utilities were in effect.

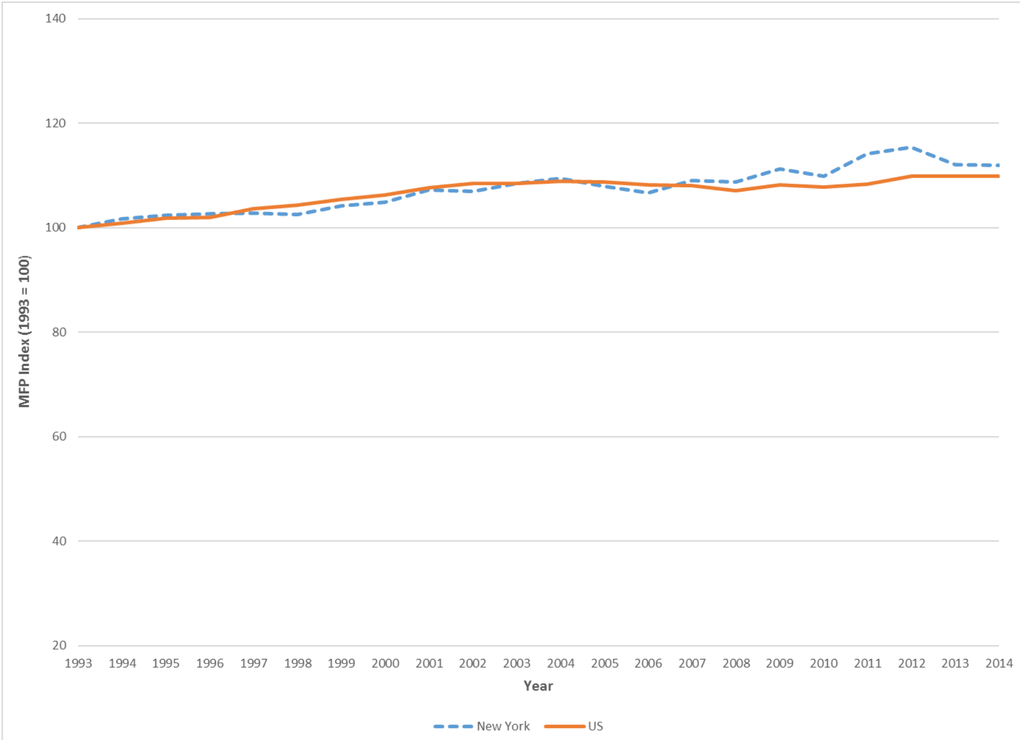


Figure 8. Comparison of Multifactor Productivity Trends of New York Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of New York distributors has modestly exceeded industry norm under MRPs.

Rate Designs

In recent years New York utilities have had some of the highest residential customer charges in the United States. AMI is not pervasive.[135] The Commission recently directed utilities to develop strategies to increase opt-in of mass market (i.e., residential and small commercial) customers to time-of-use rates.[136] Utilities are to develop promotional and customer engagement tools with reference to best practices in states where participation in opt-in time-varying pricing programs is higher.

Utilities also will offer Smart Home Rates as demonstration projects. These rates will combine granular time-varying rates with location and time-based compensation for DERs, in a way that is managed automatically to optimize value for both the customer and system. Smart Home rates are intended to allow a customer to be compensated for multiple services (e.g., load shifting, peak reduction, voltage regulation).

In the longer term, the Commission supports time-sensitive rates for both commodity and delivery services. It has directed its staff to propose a study of the potential bill impacts of a range of mass-market rate reforms, including time-of-use and demand charges. The Commission identifies Smart Home Rates as “the model for a rate design that should become the widely-adopted norm as markets mature.”[137]

[135] At least one utility, Consolidated Edison, is beginning a large-scale deployment of AMI.
[136] New York Public Service Commission (2016a).
[137] New York Public Service Commission (2016a), p. 135.

Service Quality

New York's customer service and reliability PIMs generally have been successful. Over the past five years, New York utilities have generally had stable outage frequency and duration (with major storms excluded). In a 2016 staff report analyzing the customer service PIMs, staff concluded:

> With one exception…the electric and gas utilities' performance on measures of customer service quality in 2015 was satisfactory. The [customer service PIMs] currently in place at the utilities in New York State establish strong standards for performance and put significant amounts of shareholder earnings at risk for nonperformance. Overall, these mechanisms have been effective in encouraging companies to make customer service a corporate priority and providing criteria for ensuring that the quality of customer service remains at satisfactory levels.[138]

In spite of these successes there have been some concerns about the utilities' reliability performance. For example, Consolidated Edison was the subject of a 2006–2007 investigation about reliability due in part to complaints by the legislature. Superstorm Sandy had impacts that were particularly severe, leading the Moreland Commission to conclude in its final report that the utilities had not done enough to effectively respond to severe storms.[139]

6.4 MidAmerican Energy

MidAmerican Energy is a VIEU based in Des Moines that provides electric service in most of Iowa and portions of two adjacent states. The company operated under a sequence of MRPs without intervening rate cases for more than a decade through a series of settlements approved by the Iowa Utilities Board. The settlements had many common features, including rate freezes that extended to charges for energy procured.

Plan Designs

MidAmerican's first MRP began with a 1997 general rate case settlement that featured a three-and-a-half-year rate case stayout.[140] Residential rates were reduced in two steps at the outset. Rates for commercial and industrial customers were not directly reduced. Instead, amounts allocated for these reductions were to be used to fund negotiated contracts with customers or unbundled pricing retail access pilots. The energy adjustment clause was eliminated, exposing the company to fluctuations in prices of energy commodities but permitting it to benefit if high prices in bulk power markets bolstered margins from sales in these markets. A capital cost tracker was included in the plan to address costs of plant additions at the Cooper Nuclear Station. An earnings sharing mechanism (ESM) refunded a share of any earnings surpluses to customers.[141] An off-ramp was included to allow rate cases in the event that earnings were excessively low or high. Iowa law required utilities to offer DSM programs. Costs of these programs were tracked, but no DSM PIMs were approved. Service quality monitoring was instituted in the early 2000s through a change to the state's administrative code.

This plan also allowed MidAmerican to utilize additional marketing flexibility through waivers of existing flexible pricing rules. The company could provide discounts based on the cost to serve individual customers without being required to offer the same discount to all competing customers. The pricing floor

[138] New York State Department of Public Service (2016), pp. 13–14.
[139] Moreland Commission (2013b).
[140] Iowa Utilities Board (1997).
[141] The term revenue sharing is often used instead of earnings sharing in Iowa.

was set at the short-run marginal cost of serving that customer. Contracts in excess of five years were permitted.

Subsequently, approved settlements made small changes to the framework but continued the rate case stayout.[142] The customers' share from the earnings sharing mechanism was redirected into a source of funding for new plants. The capital tracker for Cooper plant additions expired.

Through separate legislation, Iowa electric utilities, including MidAmerican, gained unusual certainty with regard to future ratemaking treatment of generating plant additions. Instead of cost trackers, this certainty has been in the form of ratemaking principles to be applied to new facilities when they are added to the utility's rate base. These principles may include a prudence decision up to a cost cap, the allocation of plant costs to Iowa ratepayers, allowed ROE for the life of the plant, and plant service life.

Throughout the 1997–2013 period, MidAmerican's tariffed base rates did not increase. For residential customers, they decreased by $15 million. The company was nevertheless able to handle effects of several severe weather events and environmental compliance while building a coal-fired generating unit, a gas-fired combined cycle plant, and more than 1,800 MW of wind generation. These assets were added to the utility's rate base years after they entered service, which allowed them to be added at less than their gross plant value due to depreciation. The customer share of earnings yielded by the ESM-funded accelerated depreciation of the coal-fired Walter Scott, Jr. Energy Center Unit 4 exceeded $300 million.[143]

Surplus earnings were aided by bulk power market sales margins. In 2003 testimony, a MidAmerican witness stated:

> In Iowa rate cases prior to the adoption of revenue sharing in 1997, the appropriate treatment of wholesale margins was a contested issue. Since the adoption of revenue sharing, these margins have been shared with retail customers. In fact, since revenues from Iowa retail operations have consistently produced returns below 12% [the threshold for revenue sharing], the revenue sharing mechanism has essentially been a mechanism for sharing these wholesale margins with retail customers.[144]

Declines in bulk power market prices after 2007 helped trigger an off-ramp that resulted in a cost tracker being added to the plan. Other stresses identified by the company in requesting a tracker included environmental, coal and coal transportation costs. The company filed a full rate case in 2013, resulting in a new MRP that phased in a $135 million base rate increase over three years. This MRP also reinstituted an energy adjustment clause. Variances from test year revenue levels resulting from sales for resale continue to be shared solely through the ESM.

Outcomes

Cost Performance

The infrequency of rate cases and the unlikely ability of poorly managed distributor costs to trigger rate cases gave MidAmerican incentive to contain distributor costs that approached those in competitive markets. Table 7 and Figure 9 compare the power distributor productivity growth of MidAmerican to averages for our full U.S. electric utility sample. From 1980 to 1995, before the start of MRPs,

[142] Iowa Utilities Board (2001; 2003).
[143] Fehrman (2012), p. 3.
[144] Gale (2003), pp. 24–25.

MidAmerican's power distributor MFP growth fell by 1.37 percent annually. This was 190 basis points below the MFP growth trend of sampled power distributors nationally. Over the 17-year period over which MidAmerican Energy operated without a rate case (1997–2013), the MFP of its power distributor services averaged 1.16 percent annual growth. That compares to the 0.42 percent trend for our full sample of U.S. power distributors during the same period. The MFP growth differential therefore averaged 74 basis points in the years of the MRPs. The capital productivity growth of MidAmerican was especially rapid.

Service Quality

In 2015, staff of the Iowa Utilities Board performed a review of reliability performance of the state's two large investor-owned electric utilities. It found that between 2002 and 2014, reliability metrics for both companies were stable. This report also showed that MidAmerican's budgeted transmission and distribution expenses had risen between 2002 and 2005, plateaued until 2008, and fell off for 2009, 2010 and 2011, coinciding with dropping bulk power prices.

DSM Programs

In the eight years for which data were available since 2006, Iowa has averaged a 10.25 average ranking (out of 50) in ACEEE's scorecard on the percent of electric revenues devoted to energy efficiency spending.

Table 7. How the Power Distributor MFP Growth of MidAmerican Energy Compared to That of Other U.S. Electric Utilities: 1980–2014*

Year	MidAmerican Energy			U.S. Sample Average		
	MFP	**O&M PFP**	**Capital PFP**	**MFP**	**O&M PFP**	**Capital PFP**
1980	-1.93%	-4.26%	-0.78%	-0.49%	-4.19%	1.24%
1981	-2.73%	-5.09%	-1.58%	0.17%	-2.42%	1.25%
1982	-0.58%	3.85%	-2.54%	0.87%	-1.20%	1.53%
1983	1.20%	0.45%	1.46%	0.51%	-0.38%	0.98%
1984	1.89%	1.51%	2.00%	1.27%	-0.22%	1.79%
1985	-0.91%	2.81%	-1.80%	0.95%	-0.21%	1.37%
1986	-0.31%	-2.19%	0.11%	0.91%	0.88%	0.97%
1987	-3.56%	-4.46%	-3.35%	0.44%	-0.12%	0.68%
1988	-1.58%	-1.40%	-1.63%	0.57%	1.55%	0.24%
1989	-2.83%	-5.80%	-1.94%	0.26%	0.00%	0.23%
1990	-1.73%	-1.63%	-1.76%	0.18%	0.64%	-0.05%
1991	-1.82%	0.89%	-2.71%	-0.03%	0.58%	-0.32%
1992	-2.57%	1.99%	-3.92%	0.48%	1.61%	0.10%
1993	-0.02%	2.36%	-0.70%	0.45%	1.19%	0.12%
1994	-0.03%	1.26%	-0.40%	0.94%	2.44%	0.29%
1995	-4.42%	2.64%	-6.55%	0.94%	3.58%	-0.04%
1996	-0.19%	2.55%	-0.99%	0.11%	0.67%	-0.13%
1997	-0.06%	-3.21%	0.84%	1.53%	4.68%	0.39%
1998	-0.44%	-6.77%	1.45%	0.67%	0.73%	0.71%
1999	1.20%	3.47%	0.54%	1.08%	2.24%	0.52%
2000	1.97%	-1.61%	3.04%	0.89%	0.86%	0.73%
2001	-0.02%	-3.98%	1.30%	1.20%	2.73%	0.61%
2002	1.15%	3.17%	0.43%	0.79%	2.73%	0.33%
2003	0.48%	-1.19%	1.10%	-0.03%	-1.50%	0.43%
2004	1.15%	-1.15%	2.13%	0.41%	0.76%	0.22%
2005	0.58%	-0.01%	0.88%	-0.07%	-0.25%	0.09%
2006	1.27%	2.15%	0.72%	-0.52%	-1.07%	-0.21%
2007	-0.42%	-3.61%	2.59%	-0.12%	0.00%	-0.02%
2008	0.85%	1.50%	-0.27%	-0.99%	-2.06%	-0.09%
2009	6.10%	9.84%	0.58%	1.01%	2.73%	-0.46%
2010	2.00%	1.35%	2.48%	-0.27%	-0.47%	0.05%
2011	1.99%	3.30%	1.21%	0.50%	0.05%	0.50%
2012	2.54%	3.77%	1.87%	1.29%	2.90%	0.58%
2013	0.75%	-2.73%	2.42%	0.03%	0.40%	-0.05%
2014	2.32%	1.20%	2.85%	-0.03%	-1.41%	0.56%
Average Annual Growth Rates						
1980-2014	**0.04%**	**0.03%**	**-0.03%**	**0.45%**	**0.53%**	**0.43%**
1980-1995	**-1.37%**	**-0.44%**	**-1.63%**	**0.53%**	**0.23%**	**0.65%**
1997-2013	**1.16%**	**0.38%**	**1.24%**	**0.42%**	**0.90%**	**0.23%**
2008-2014	**2.37%**	**2.61%**	**1.59%**	**0.22%**	**0.30%**	**0.15%**

*Shading indicates years when MRPs were in effect.

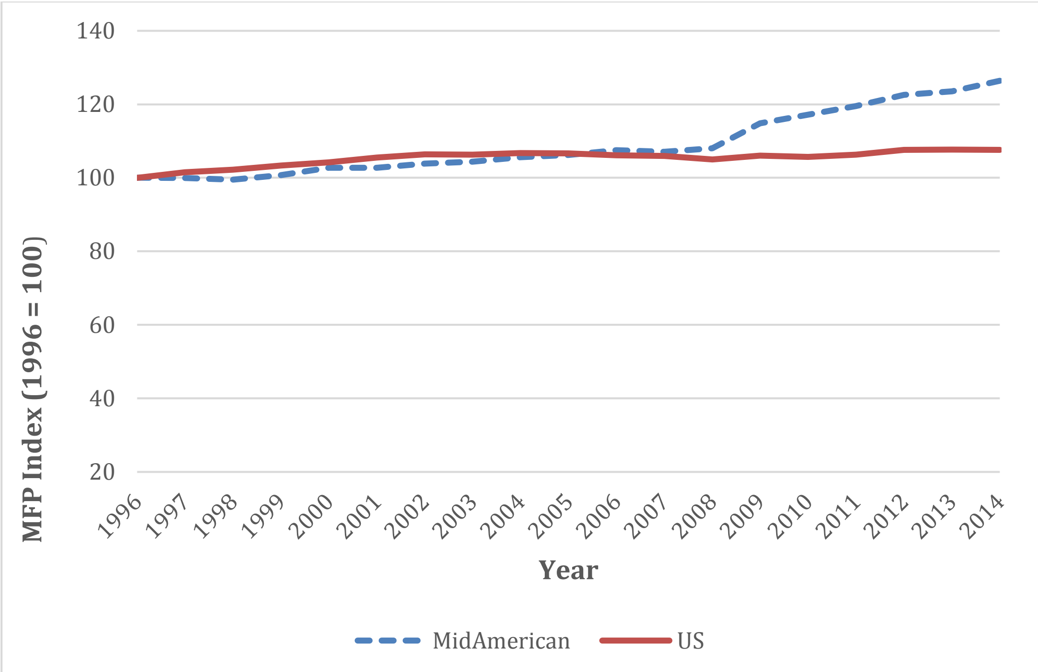


Figure 9. Comparison of Multifactor Productivity Trends of MidAmerican Energy and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of MidAmerican exceeded the industry norm under its MRPs.

6.5 Other U.S. Electric Utilities With Extended Rate Stayouts

We noted above that many U.S. electric utilities have avoided general rate cases for lengthy periods. These utilities have been able to operate without rate cases for various reasons. In some cases, utility costs were likely to grow slowly due, for example, to recent completion of one or more large generating stations. Some utilities were able to slow cost growth with mergers or acquisitions. Others may have started their stayout periods with favorable initial rates due to high allowed rates of return. Some operated under an MRP for part of the period or a rate freeze during transition to retail power market competition and were not required to file a rate case upon their conclusion.

Table 8 identifies U.S. electric utilities in our sample that have experienced rate stayouts exceeding 12 years since 1980. About half of these utilities were vertically integrated throughout the sample period. Others started as VIEUs but restructured during the period.

We calculated productivity trends of these utilities as power distributors during the years of their rate stayouts and compared these trends to average annual productivity growth rates of our full U.S. sample during the same years. Table 8 presents results. We found that multifactor productivity growth of utilities during extended rate stayouts exceeded that of the full U.S. sample during the same period by 29 basis points on average. Operation and maintenance and capital productivity growth were both superior. During other years of the full 1980–2014 sample period, MFP growth of these utilities exceeded MFP growth of the full U.S. sample by less than a basis point on average. This evidence suggests that extended rate stayouts lowered distributor costs.

Table 8. Difference Between Company and U.S. Power Distributor MFP Trends During Extended Stayout Periods

	Stayout Period			Stayout Period MFP Trend			Stayout Period O&M PFP Trend			Stayout Period Capital PFP Trend		
Company	Start	End	Duration*	Company	US Sample	Difference	Company	US Sample	Difference	Company	US Sample	Difference
Baltimore Gas and Electric Company	1993	2010	18	0.30%	0.45%	-0.15%	1.42%	1.11%	0.31%	-0.02%	0.20%	-0.21%
Dayton Power and Light Company	1992	2014	23	0.49%	0.45%	0.04%	1.76%	1.02%	0.74%	0.07%	0.23%	-0.15%
Duke Energy Carolinas, LLC	1991	2007	17	0.65%	0.51%	0.14%	2.91%	1.29%	1.62%	-0.10%	0.22%	-0.32%
Duke Energy Progress, LLC	1988	2012	25	0.64%	0.45%	0.19%	2.42%	1.09%	1.32%	-0.10%	0.19%	-0.29%
Duquesne Light Company	1988	2006	19	1.04%	0.52%	0.53%	1.61%	1.27%	0.34%	0.96%	0.22%	0.74%
El Paso Electric Company	1995	2009	15	0.76%	0.46%	0.30%	2.58%	1.12%	1.46%	-0.82%	0.20%	-1.02%
Fitchburg Gas and Electric Light Company	1985	1999	15	-0.35%	0.63%	-0.98%	0.10%	1.36%	-1.27%	-0.30%	0.34%	-0.64%
Florida Power & Light Company	1984	2001	18	0.99%	0.71%	0.27%	2.78%	1.32%	1.46%	0.24%	0.46%	-0.22%
Indiana Michigan Power Company	1993	2007	15	0.41%	0.55%	-0.14%	1.41%	1.32%	0.09%	-0.09%	0.27%	-0.36%
Indianapolis Power & Light Company	1995	2014	20	0.97%	0.42%	0.55%	1.38%	0.91%	0.47%	0.85%	0.24%	0.62%
Kentucky Power Company	1991	2005	15	0.41%	0.62%	-0.22%	1.28%	1.54%	-0.25%	-0.06%	0.27%	-0.33%
Kentucky Utilities Company	1983	1999	17	0.61%	0.66%	-0.05%	0.37%	1.17%	-0.80%	0.62%	0.46%	0.16%
Kingsport Power Company	1992	2014	23	0.26%	0.45%	-0.19%	0.70%	1.02%	-0.32%	0.19%	0.23%	-0.04%
Massachusetts Electric Company	1995	2009	15	1.27%	0.46%	0.81%	1.93%	1.12%	0.81%	0.75%	0.20%	0.54%
Metropolitan Edison Company	1993	2006	14	1.61%	0.60%	1.01%	1.88%	1.41%	0.47%	1.51%	0.29%	1.22%
ALLETE (Minnesota Power)	1994	2008	15	1.50%	0.46%	1.04%	1.23%	1.10%	0.13%	1.61%	0.25%	1.35%
MDU Resources Group, Inc.	1987	2001	15	1.13%	0.65%	0.49%	1.07%	1.56%	-0.49%	1.15%	0.27%	0.88%
Niagara Mohawk Power Corporation	1995	2009	15	1.64%	0.46%	1.18%	3.03%	1.12%	1.91%	0.35%	0.20%	0.14%
Nstar Electric	1992	2005	14	0.15%	0.67%	-0.52%	0.92%	1.61%	-0.69%	-0.26%	0.31%	-0.57%
Ohio Edison Company	1990	2007	18	1.23%	0.49%	0.74%	1.24%	1.26%	-0.02%	1.19%	0.21%	0.99%
Ohio Power Company	1995	2011	17	0.46%	0.42%	0.04%	1.43%	0.96%	0.47%	0.13%	0.21%	-0.09%
Otter Tail Corporation	1993	2007	15	0.02%	0.55%	-0.53%	-0.36%	1.32%	-1.68%	0.40%	0.27%	0.14%
PECO Energy Company	1990	2010	21	0.91%	0.41%	0.50%	1.19%	1.09%	0.10%	0.74%	0.16%	0.58%
Pennsylvania Electric Company	1984	2006	23	0.82%	0.58%	0.23%	1.32%	1.07%	0.25%	0.64%	0.39%	0.24%
Pennsylvania Power Company	1988	2014	27	0.62%	0.42%	0.20%	1.31%	0.97%	0.33%	0.35%	0.20%	0.15%
Potomac Edison	1994	2010	17	1.71%	0.45%	1.27%	2.24%	1.11%	1.14%	1.48%	0.20%	1.28%
Tampa Electric Company	1993	2008	16	0.95%	0.46%	0.50%	1.67%	1.11%	0.56%	0.75%	0.25%	0.51%
Duke Energy Kentucky, Inc.	1992	2006	15	0.84%	0.59%	0.25%	2.99%	1.43%	1.56%	0.01%	0.28%	-0.27%
West Penn Power Company	1995	2014	20	1.29%	0.42%	0.86%	2.49%	0.91%	1.58%	0.84%	0.24%	0.60%
Averages												
Stayout Period Average				**0.80%**	**0.52%**	**0.29%**	**1.60%**	**1.20%**	**0.40%**	**0.45%**	**0.26%**	**0.19%**

* Period is inclusive of both endpoints. End dates in January and start dates in December were assigned values one year earlier and later respectively.

6.6 Statistical Tests of Productivity Impacts

The productivity growth rates of individual utilities are quite volatile from year to year. Differences between the annual productivity growth rates of utilities operating under MRPs and annual full sample growth rates may therefore not reflect the impact of the plans. A statistical technique called *hypothesis testing* can be used to infer whether a utility's productivity growth is impacted by an MRP or, if instead, the observed difference between the productivity trends of individual utilities operating under MRPs and the full sample is a coincidence caused by volatility. We conducted hypothesis tests, called *T-tests*, to evaluate whether the average productivity trend of a utility under an MRP or stay out was significantly greater than the productivity trend of the full sample during the same years.

The first T-test was applied to observations of the differences in the MFP trends between utilities operating under a stay out and the full sample during the stay out period. The null hypothesis was that the difference in productivity trends is equal to zero. The alternative hypothesis is that the difference is greater than zero or, on average, utilities operating under a stayout have higher productivity trends than the full U.S. sample during the stayout period. The sample (N=29) consists of the number of "stayout utilities" in Table 8. The mean difference in the productivity trend is .29 percent, and the standard deviation is .53 percent. The t-statistic for this sample is 2.914, which is greater than the 5 percent one-sided critical value of 1.701. Thus, we can reject the null hypothesis in favor of the alternative hypothesis that companies operating under a stayout have a higher productivity trend during the stayout period than the full sample.

A second T-test was applied to observations of the differences between the productivity trends of utilities operating under formal MRPs as well as stayouts and the trend for the full sample in the same years. The null and alternative hypothesizes were the same as in the first test. The sample (N=40) consists of the utilities in the first test plus the California and New York utilities that have operated under an MRP, MidAmerican Energy, and Central Maine Power. The mean difference in the productivity trend is .22 percent and the standard deviation is .61 percent. The t-statistic for this sample is 2.224, which is greater than the 5 percent one-sided critical value of 1.683. Thus, we can again reject the null hypothesis in favor of the alternative hypothesis. The average difference in the productivity trend of .22 percent is half of the productivity trend of the full sample over the 1980–2014 time period, suggesting that MRPs have an economically significant effect on utility operations.

6.7 PBR for Ontario Electric Utilities

The Ontario Energy Board has emerged in recent years as a top practitioner of PBR.[145] The event that drove innovation was the transfer of responsibility to the Board in the late 1990s to regulate more than 200 provincial power distributors. In addition to power distributors, the Board regulates large provincially owned transmission and generation companies and two large gas utilities.

Power distributors regulated by the Board are remarkably varied. Hydro One, which provides most transmission services in Ontario, also provides distribution services to many towns and unincorporated areas. In addition, large distributors serve Ottawa and Toronto. Most other distributors serve small towns, suburbs or rural areas of the province, and some have just a few hundred or thousand customers. Many of these distributors are municipally owned while the largest, Hydro One Networks, is provincially owned.

[145] PEG Research has advised the Board on PBR for many years, performing several productivity and benchmarking studies.

Despite long experience with cost of service regulation (for gas utilities), the Board opted to use MRPs in power distributor regulation.[146] The Board stated in a draft policy decision three reasons why use of PBR would be helpful in electric utility regulation:

1. With passage of [a bill restructuring the electricity industry], the Board will have the task of regulating a large number of diverse utilities in the province. Since PBR has the potential to provide an expedient mechanism for adjusting rates over time as circumstances change, it is expected to result in fewer rate reviews before the Board and, hence, a lesser regulatory burden.

2. PBR would allow the Board to establish minimum service quality and reliability standards and maintain compliance with these standards.

3. PBR can provide greater incentives for cost reduction and productivity gains compared to those available under traditional cost of service regulation while protecting the interests of consumers.[147]

The Board has since approved a sequence of multiyear rate plans. PBR is called *incentive regulation* (IR) and rate plans are called *incentive regulation mechanisms* (IRMs). The first plan (IRM1) began in 2001. The Board extended this plan to March 2005 to allow utilities additional time to "explore the incentives for improvements and savings provided by the current PBR regime." However, IRM1 was suspended well before its termination date as a result of price spikes in Ontario's new bulk power market. Bill 210, enacted in December 2002, froze existing rates until May 2006 unless approval was otherwise granted by the Minister of Energy.[148]

Rates were adjusted in May 2006 based on rate cases filed in 2005. Between 1999 and May 2006, distributors therefore operated without rate cases and received only one or two modest base rate increases. During this period, utilities had strong incentives to contain costs, and some utilities may have deferred some expenditures.

IRM2 used the May 2006 rates as a starting point. Roughly a third of all distributors were then scheduled for rate cases in each year of the 2008–2010 period. After these rate cases (called *rebasings*), distributors switched over to IRM3. Terms of these plans were initially fixed at three years plus a rebasing year. This was later extended, resulting in plans for some companies lasting five years. Extension was partly based on the Board's in-depth reexamination of its ratemaking practices, called "A Renewed Regulatory Framework for Electricity," which began in 2010. A fourth generation IRM and some optional alternative MRP approaches resulted from these deliberations.

Plan Design

Attrition Relief Mechanism

All four IRMs featured indexed price caps. Macroeconomic inflation measures have been used in some plans and industry-specific measures in others. X factors have commonly had two components: a productivity factor reflecting the MFP trend of a peer group and a stretch factor. The peer groups in first and fourth generation IRMs were broad samples of Ontario power distributors, whereas the peer group in the third generation IRM was a broad sample of U.S distributors.

[146] The Board has subsequently embraced MRPs for regulation of provincial gas distributors.
[147] Ontario Energy Board (1998), p. 3.
[148] Legislative Assembly of Ontario (2002).

Stretch factors in third and fourth generation IRMs have varied between utilities based on results of statistical benchmarking studies commissioned by the Board. The benchmarking study in the fourth generation PBR uses an econometric model of total cost and is updated annually. Details of this benchmarking methodology are discussed in Appendix B.3.

Capital Cost Trackers

Capital cost treatments have evolved over Ontario's four IRMs. Supplemental revenue for capex was not available in the first IRM. A separate Ontario policy led to the use of trackers to finance costs of AMI deployment. In the proceeding to approve IRM2, distributors requested supplemental revenue for capex. This request was rejected due to a lack of perceived need, but distributors claiming a need for high capex were permitted to file a rate case early. The Board expressed concerns about special treatments of capital in its decision:

> In a capital intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd Generation IRM because it would require special consideration to be implemented effectively.[149]

During the proceeding that led to IRM3, a number of utilities again argued that an indexed price cap would not fund their special capex needs. The Board responded by adding to the plans an Incremental Capital Module that could provide distributors with supplemental capex funding. The Board described this as "reserved for…circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[150] The eligibility criteria for supplemental capex funding subsequently evolved but have consistently required that the capex funded by an Incremental Capital Module not be recoverable in rates, be prudent and the distributors' most cost-effective option, and exceed a materiality threshold. An eligibility formula ensures that forecasted total capex exceeds funding expected from depreciation and higher revenue from price cap index escalation and growth in billing determinants by a certain percentage (currently 10 percent).

Distributors are required to report their actual capex annually. Variances between forecasted and actual capex are reviewed by the Board to determine whether they are material enough to warrant a true-up in a subsequent rate case. Cost overruns are reviewed for prudence, while material underspends result in refunds to ratepayers.

Around 15 of approximately 70 Ontario power distributors have received approval for revenue from Incremental Capital Modules. These modules are typically used to address costs of large capital projects. About two-thirds of applications filed under the program included transformer-related assets as the focal point of the funding request.[151]

In 2014 the Board made "Advanced" Capital Modules rather than Incremental Capital Modules the major source of supplemental capital revenue in IRMs. Utilities must apply in advance, at the time of their rate cases, for supplemental funding of projects that are detailed in five-year Distribution System Plans. Reviews of Advanced Capital Module requests thus coincide with a review of projects proposed in Distribution System Plans, allowing for greater regulatory efficiency. An Incremental Capital Module

[149] Ontario Energy Board (2006), p. 37.
[150] Ontario Energy Board (2008), p. 31.
[151] Ontario Energy Board (2014), p. 7.

remains available for projects not included in a Distribution System Plan, as well as for projects that are in the plan whose eligibility for supplemental funding could not be determined in the rate case, or projects that expand after the plan is presented.

Other Plan Provisions

Terms of incentive regulation mechanisms in Ontario have varied over the years but have typically been four or five years. Reliability PIMs have never been used in Ontario power distributor regulation. However, reliability metrics and targets have been used routinely since IRM1.

Demand-side management PIMs and LRAMs have been offered as an incentive for distributors' DSM programs. A third-party administrator also offers DSM programs.

An earnings sharing mechanism to address overearnings was established for IRM1 but was abandoned in later plans. Some Custom IR plans include such a mechanism where distributor underspending is a concern.

New Plan Options

The Renewed Regulatory Framework deliberations resulted in two additional options to address the diversity of Ontario distributors.

- Custom IR is designed for distributors expecting several years of high capex. ARMs are based on forecasts of O&M and capital cost. Forecasts should be informed by Board-sponsored productivity and benchmarking analyses. Distributors operating with a Custom IR plan do not have the option to request supplemental capital funding. Custom IR plans have recently been granted to several of the larger distributors.

- The Annual IR index is designed for distributors that do not expect to undertake large capital projects. This option features a price cap index with an inflation — X formula, but the X factor is fixed to reflect the high end of the stretch factor range in IRM4 for all plan years. Utilities that choose the Annual IR index cannot obtain supplemental capital funding. The term of a plan with an Annual IR index is not fixed. The availability to distributors of IRM4 and the Annual IR index is a good example of the use of menus in MRP design.

Scorecards

Part of the implementation of the Renewed Regulatory Framework has been the development of a performance scorecard for Ontario distributors. The scorecard includes data on a distributor's cost, earnings, customer service quality, reliability, DSM and safety performance.

Figure 10 provides an example of a scorecard which was posted on the website of the Board.[152] Cost performance is addressed by two unit cost metrics and the outcome of the econometric benchmarking study that the Board updates annually. Financial metrics include a comparison of the company's ROE to its regulated targets. There are also metrics for less traditional areas, such as peak load management and the quality of service to renewable generation customers.

[152] Scorecard - Hydro Ottawa Limited (2015), http://www.ontarioenergyboard.ca/documents/scorecard/2014/Scorecard%20-%20Hydro%20Ottawa%20Limited.pdf.

Results are presented in a manner that informs the reader of the utility's performance. For example, a company's billing accuracy is presented along with the target. The trend in performance is indicated for several metrics.

Outcomes

Cost Performance

Table 9 and Figure 11 present productivity trends of Ontario power distributors over the 2003–2011 period. This sample period excludes early years of operation under MRPs in Ontario, including the years of the rate freeze. Some distributors in the sample period we consider may have been catching up on their capex after years of deferrals.

Our results differ from those relied upon by the Board to set X factors in IRM4 because we have changed the output index to rely solely on customers, in order to make results more comparable to those from our U.S. productivity research for Berkeley Lab.[153] We have removed

2012 from our calculations due to concerns about cost data for that year.[154] Note also that the sample excludes Ontario's two largest distributors, Hydro One and Toronto Hydro Electric.

The table shows that Ontario distributors' multifactor productivity grew on average by 0.45 percent annually from 2003 to 2011. This exceeded the U.S. trend of -0.01 percent for these years by 4 basis points. O&M productivity averaged 0.76 percent annually while capital productivity growth averaged 0.26 percent annually. The year-by-year results show that O&M, capital and multifactor productivity grew most rapidly during the 2003–2005 period, the last years of the rate freeze. MFP growth then slowed and was negative in two years.

[153] The original results can be found in Kaufmann, Hovde, Kalfayan, and Rebane (2013). Our results were updated using the working papers: http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework/Measuring%20Performance%20of%20Electricity%20Distributors.

[154] While data for 2012 are available, use of these data is problematic for several reasons. For example, Ontario distributors were in the process of changing accounting systems from Canadian Generally Accepted Accounting Principles to the International Financial Reporting Standards, likely making data less comparable.

Scorecard - Hydro Ottawa Limited

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	97.30%	97.40%	97.40%	98.30%		90.00%	
		Telephone Calls Answered On Time		82.10%	82.90%	82.50%	82.20%	80.30%		65.00%	
	Customer Satisfaction	First Contact Resolution					85.2%	84.1%			
		Billing Accuracy					99.6%	99.61%		98.00%	
		Customer Satisfaction Survey Results					90%	83%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	1	0	1	0	1			0
			Rate per 10, 100, 1000 km of line	0.186	0.000	0.178	0.000	0.182			0.076
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.05	2.44	1.31	1.64	1.59			at least within 1.05 - 2.44
		Average Number of Times that Power to a Customer is Interrupted		0.77	1.40	1.13	1.36	0.86			at least within 0.77 - 1.40
	Asset Management	Distribution System Plan Implementation Progress					105%	94%			
	Cost Control	Efficiency Assessment				3	3	3			
		Total Cost per Customer [1]		$536	$529	$569	$579	$623			
		Total Cost per Km of Line [1]		$29,776	$28,793	$31,107	$33,222	$36,169			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			14.13%	28.85%	45.57%	70.53%			85.26MW
		Net Cumulative Energy Savings (Percent of target achieved)			37.74%	65.64%	88.69%	110.71%			374.73GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.45	1.43	1.18	1.07	0.86			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.22	1.32	1.37	1.64	1.65			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	9.42%	9.42%	9.42%			
			Achieved		7.86%	9.41%	7.80%	8.06%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: up down flat target met target not met

Figure 10. Sample Ontario Performance Metrics Scorecard.

Table 9. Productivity Trends of Ontario Power Distributors: 2003–2011

	Output		Inputs						Productivities					
	Total Customers[1]		Capital[1]		O&M[1]		Multifactor[2]		Capital		O&M		Multifactor	
Year	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth	Level	Growth
		[A]		[B]		[C]		[D]		[E = A-B]		[F = A-C]		[G = A-D]
2002	2,528,664		100		100		100.00		100.00		100.00		100.00	
2003	2,590,817	2.43%	101	1.01%	102	1.77%	101.30	1.29%	101.43	1.42%	100.66	0.66%	101.14	1.13%
2004	2,647,118	2.15%	103	1.66%	100	-1.51%	101.79	0.48%	101.92	0.49%	104.41	3.66%	102.84	1.67%
2005	2,703,821	2.12%	104	1.65%	99	-1.14%	102.42	0.61%	102.40	0.47%	107.87	3.26%	104.40	1.51%
2006	2,748,114	1.62%	105	0.80%	101	1.50%	103.51	1.06%	103.25	0.82%	108.01	0.12%	104.99	0.56%
2007	2,781,589	1.21%	108	2.44%	105	3.82%	106.62	2.96%	101.99	-1.23%	105.22	-2.61%	103.17	-1.75%
2008	2,823,654	1.50%	109	1.16%	106	1.67%	108.08	1.36%	102.34	0.34%	105.04	-0.17%	103.28	0.15%
2009	2,849,054	0.90%	109	0.19%	107	0.44%	108.39	0.29%	103.07	0.70%	105.52	0.45%	103.95	0.61%
2010	2,885,251	1.26%	111	1.80%	104	-2.39%	108.61	0.20%	102.52	-0.54%	109.45	3.65%	105.08	1.06%
2011	2,919,186	1.17%	113	1.30%	108	3.28%	110.87	2.06%	102.38	-0.13%	107.16	-2.11%	104.12	-0.89%
Average Annual Growth Rates:														
2003-2011		**1.60%**		**1.33%**		**0.83%**		**1.15%**		**0.26%**		**0.76%**		**0.45%**

Notes:

[1] Data are from PEG Working Papers: Part II - TFP and BM database calculation, filed with PEG's report "Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board" on November 21, 2013 (and updated on January 24, 2014).

[2] This is a Törnqvist index using the total cost shares of capital and OM&A as weights.

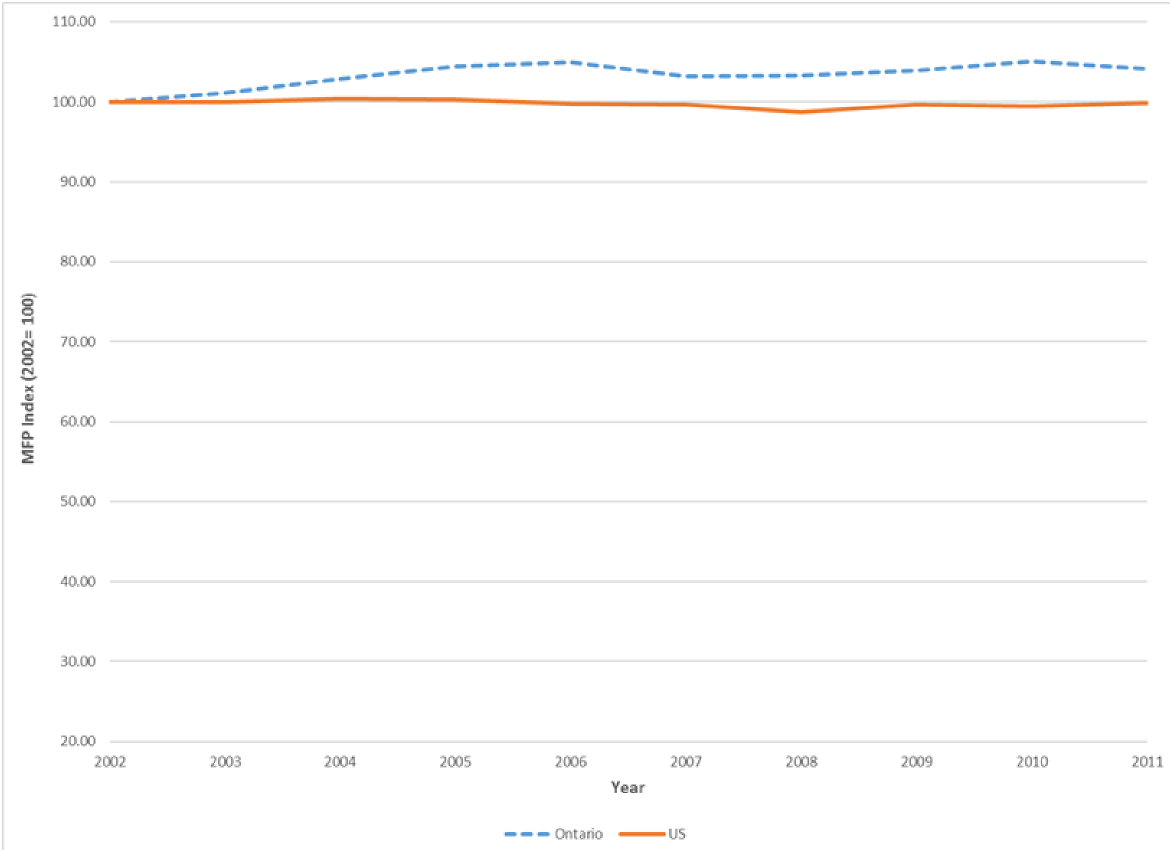


Figure 11. Comparison of Multifactor Productivity Trends of Ontario Distributors and the U.S. Sample During Multiyear Rate Plan Periods. The MFP trend of Ontario distributors exceeded the industry norm under MRPs.

Consolidation

Since the late 1990s, Ontario's power distribution industry has consolidated from more than 200 distributors that existed prior to PBR to about 70 distributors. Hydro One Networks has purchased more than 80 distributors. The Ontario government has noted on several occasions that the industry could become more efficient with greater distributor consolidation. Consolidation may have spurred productivity growth.

Service Quality

Effects of the Ontario MRPs on utility service quality are unclear, potentially a result of data the Board has been gathering. Reported reliability metrics do not exclude major events, leading to potentially large year-to-year variations in performance due to weather events beyond distributors' control. In addition, the period of operation under MRPs (2005–2012) has witnessed the rollout of AMI and SCADA systems. These deployments are often linked to a worsening of measured reliability because more outages are detected by automatic reporting systems.

Some observers have suggested that Ontario distributors had high levels of service quality at the beginning of the MRPs, even to the point of arguing that some utilities had engaged in "gold-plating" their systems. These observers find that during the 2000s, which encompassed IRM1, a rate freeze, and IRM2, reliability suffered.

> [R]eliability has declined continuously from 2000 to 2008; degradation has become progressively worse. Results in the middle years [during the rate freeze] (2003-2005) are significantly worse than the earlier [IRM1] years (2000-2002), and results in the last years (2006-2008) [in which rates were reset and IRM2 was in effect] significantly worse than the middle.[155]

A 2010 Board staff report presented more mixed results:

> The [customer] surveys indicate that the majority of consumers are generally satisfied with current levels of system reliability, with 89% of residential consumers and 92% of business consumers reporting that they are "somewhat satisfied" or "very satisfied" with the reliability of electricity supply. However, over 75% of respondents in both groups indicated that, despite being generally satisfied, they still believe it is important for distributors to continue to work to reduce the number of outages…. There was a strong consensus amongst many participants that the Board should focus on ensuring that system reliability levels are maintained. These participants believe that the current regime is adequate for the purposes of ensuring continued sustainability and reliability…. Ratepayer groups that supported the development of a new reliability regime were in the minority. Some ratepayer representatives suggested that reliability has declined almost continually over the last 8 years.[156]

6.8 Power Distribution MRPs in Great Britain[157]

The power distribution industry of Great Britain also has a history very different from that of the United States. Until 1990, British electric utilities were not investor-owned. In the intervening years, these utilities have been privatized and restructured into separate generation, transmission and distribution operations. End users are billed by retailers, not distributors. This arrangement reduces the role of distributors in provision of DSM programs. Regulatory requirements of British utilities are codified in their licenses, rather than tariffs, administrative codes or laws.

There are currently 14 power distributors, eight gas distributors, three electric transmitters and one gas transmitter in Britain. The sizable task of regulating these utilities has been assigned to the Office of Gas and Electricity Markets (Ofgem). Ofgem also regulates gas and electric commodity markets.

---

155 Cronin and Motluk (2011).
156 Ontario Energy Board (2010), p. 7–10.
157 A 2016 Berkeley Lab report (Lowry and Woolf) discussed the British system of energy utility regulation. This section provides additional history and plan design details and discusses notable outcomes.

Since privatization, British energy utilities have operated under a sequence of MRPs called *price controls.* The British approach to price controls has its roots in a 1983 document by British economist Stephen Littlechild, which relied on five criteria to evaluate regulatory options:[158]

- protect against monopoly power
- encourage efficiency and innovation
- minimize regulatory cost
- promote competition
- maximize proceeds from privatization

Traditional cost of service regulation was rejected by policymakers after scoring poorly on four of the five criteria. The one criteria where cost of service regulation performed well was protecting against monopoly power.

Littlechild proposed to regulate rate growth with an index using an inflation – X formula. Regulators have refined various features of the plans over the years in their periodic price control reviews. To date there have been five completed generations of price controls, with the sixth price control beginning in 2015. Ofgem undertook a substantial review of its regulatory practices beginning in 2008. The revised regulatory system that resulted from these deliberations is called *RIIO* (Revenues = Incentives + Innovation + Outputs).

Plan Design

Plan Term

British MRPs have traditionally had five-year terms. With the adoption of RIIO, the term of plans was extended to eight years. This strengthens performance incentives but has complicated the task of developing and reviewing plans.

Attrition Relief Mechanism

Price controls for power distributors in Britain originally featured price caps but now feature revenue caps. Caps of both kinds have been escalated by hybrid methods. Allowed revenue trajectories are established based on multiyear total cost forecasts. Principal components are forecasts of the value of the current capital stock and of capital spending, depreciation, the return on capital, and O&M spending. Because of the focus on component costs, the British approach to ARM design is sometimes called the *building block* method.

Britain's Retail Price Index (RPI) has been used as the inflation measure of the revenue cap indexes. Given forecasts of total cost, billing determinants and inflation, past plans have selected combinations of initial rates and an X factor such that forecasted revenue equals forecasted cost. The revenue cap escalator in RIIO has an implicit X factor of zero.

Use of forecasts to establish allowed revenue led to concerns by Ofgem and its predecessor, the Office of Electricity Regulation, about utility exaggerations of capex requirements. For example, underspends occurred in a period when utilities had forecasted high capex due to an "echo effect" when facilities installed in a past capex surge approached the end of their service lives. In its 1994–1995 price control review, the regulator accepted the need for a high level of replacement capex, noting that facilities from a

[158] Littlechild (1983). Littlechild subsequently served as director general of the electricity regulator.

prior capex surge were approaching retirement age. The regulator nonetheless reduced individual company total capex proposals by as much as 25 percent because not all of the capex was deemed necessary.

In its next price control review, the agency compared distributors' actual capex during the expiring price control to the budgets that had been approved. Figure 12 shows that actual capex was lower than the regulator's approved levels. The regulator came to the conclusion that the "echo effect" was less pronounced than it had expected.[159]

The regulator suspected that some utilities had misrepresented their capex needs. This experience encouraged the regulator to consider some implications of extensive capex underspends in developing a new price control.[160] Ofgem began by reassessing its policy on underspending:

> Ofgem would expect such companies to retain the benefit of their under-spend. Given that, to a significant extent, the nature and timing of capital expenditure (particularly non-load related expenditure) is discretionary, measures need to be introduced to ensure that companies are only rewarded for genuine efficiency not timing benefits obtained through manipulation of the periodic regulatory process.
>
> In this context, it is particularly important to ensure that companies do not have a perverse incentive to 'achieve' periodic delays in capital expenditure, such that they regularly under-spend Ofgem's forecasts, thereby gaining a financial benefit, and then claim a higher allowance for the subsequent period in respect of the capital expenditure which has not been undertaken.… Further where [distributors] underspend in one period and then forecast an increase in expenditure in the next, this will be carefully scrutinized.[161]

The regulator further stated that:

> The unavoidable information asymmetry between regulator and regulated companies is a major issue especially since, under the present regime, regulated companies have an incentive to overstate required expenditures when discussing future price controls with the regulator.[162]

[159] Offer (1999), p. 46.
[160] During the course of the proceeding, Offer merged with the British gas regulator Ofgas to become Ofgem.
[161] Ofgem (1999), p. 41.
[162] Ofgem (1999), p. 7.

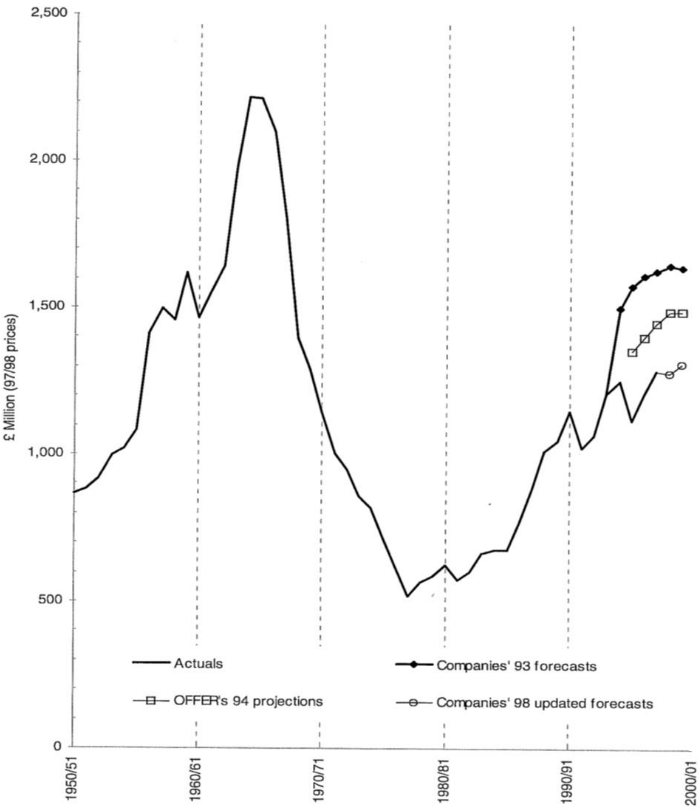


Figure 12. Distribution Business Capital Expenditures (1997/98 Prices). A capex surge during the period 1993–2000 was due to an "echo effect" from a past capex surge that was lower than forecasted.[163]

Ofgem penalized three distributors in its final decision which had provided exaggerated forecasts of capex and operating expenditures (opex). Nevertheless, it became apparent that forecasting overstatements had continued. Ofgem found that capex was being underspent by utilities under the first three years of the new price control.[164] Many power distributors were also providing forecasts describing a need for capex that was more than 20 percent greater than previous forecasts.[165]

Due in part to such experiences, Ofgem has over the years commissioned numerous statistical benchmarking and engineering studies to develop its own independent view of required cost growth. In 2004, Ofgem added to rate plans an Information Quality Incentive (IQI) to encourage more accurate capex forecasts. This complicated PIM, an example of an incentive-compatible menu, is discussed further in Appendix A.3.

Distributors that have well-justified business plans at an early stage of the RIIO proceeding can be "fast-tracked." Fast-tracking allows the distributor to receive approval of its business plans as much as a year earlier than would otherwise be the case and avoid more intense scrutiny of its business plan. This enables the distributor a greater opportunity to focus on executing its business plan during the run-up to the new MRP.

Another innovative feature of RIIO is its focus on total expenditures (totex) to level the playing field between capex and opex. Ofgem has explained the rationale for a totex focus:

[163] Offer (1999), p. 45.
[164] Ofgem (2004a).
[165] Ofgem (2004b).

> The incentives to manage different types of costs under the price control are not equal. These imbalances may distort the decisions that [distributors] need to make between capex and opex solutions and create boundary issues. This is not in customers' interests as it may lead to [distributors] seeking to outperform the settlement by favoring capex over opex (or vice versa). This may lead to inefficient network development and higher charges for customers in the short or long term….
>
> These rules create two undesirable effects:
>
> - Incentives are distorted toward adopting capex rather than opex solutions. This means that [distributors] are not incentivized to minimize total lifetime costs as they are sometimes better off by adopting a capex solution rather than a cheaper opex solution due to the way that the different expenditures are treated.
>
> - Boundary issues are created. There is an incentive to record expenditure in the areas with the highest rates of capitalization even if the expenditure was not technically in that area. This requires significant policing of the cost reporting of [distributors].[166]

To address these problems, Ofgem decided to equalize the incentives between opex and capex for most cost categories.[167] Instead of traditional expensing and capitalization rules, Ofgem fixed the amount of total expenditures that could be capitalized at 85 percent. Newly capitalized costs would be recovered over a 45-year period, while existing rate base costs would be recovered over a 20-year period. The remaining 15 percent would be expensed.

<u>Performance Metric System</u>

RIIO features complicated performance metric systems that include several PIMs. Metrics in this system are called *outputs.* The performance incentive mechanisms in RIIO place a sizable share of distributor revenue at risk, prompting some commentators to call RIIO a "results-based" approach to regulation. However, the unusually large sensitivity of earnings to performance mechanisms in RIIO is due mainly to the Information Quality Incentive.

With respect to service quality, Ofgem adopted guaranteed reliability standards early on, later adding guaranteed standards of performance for connections. One example of a guaranteed standard is that distributors are required to restore service within 12 hours in normal weather conditions. Distributors must make predetermined payments directly to customers each time a minimum performance standard is not met. Ofgem also developed a reliability PIM called the *Interruptions Incentive Scheme* that addresses distributors' outage frequency and duration performance.

Ofgem has expanded its customer satisfaction PIM over the years into a Broad Measure of Customer Satisfaction. This encompasses the number of complaints that a distributor has and an assessment of customer satisfaction with distributors' responsiveness with regard to outages, connections and general inquiries. Ofgem has also experimented with PIMs to encourage reductions in line losses.

Distributors are required to report annually on numerous additional metrics. These have expanded over the years from cost and revenue reporting to include measures that are not commonly reported in the United States, including the health of assets, substation utilization levels and air emissions. Business

[166] Ofgem (2010), p. 107.
[167] Costs that were not provided this treatment include many types of administrative and general expenses, pensions and several costs that receive supplemental funding, discussed later in this section.

Carbon Footprint metrics include distributors' annual electricity losses in addition to their direct carbon emissions.

Ofgem reviews distributors' annual reports on these metrics and issues its own report summarizing distributors' performance. Reports feature a scorecard with "traffic lighting," using red to indicate poor performance, green to indicate good performance, and yellow to indicate performance in between.

RIIO also changed asset health metrics into a risk index. The risk index is a composite measure of asset health and criticality indexes, reflecting risks of asset failures for a distributor. The asset health index measures the likelihood of an asset failure, while the criticality index measures the impact of a potential asset failure. The risk index has become the basis for a PIM with a possible penalty or reward of 2.5 percent of avoided or incurred costs.

RIIO has also increased use of discretionary financial incentives. A stakeholder engagement incentive encourages distributors to engage with customers and incorporate their input in decisions and to identify vulnerable customers and take efforts to ensure their energy needs are met. An incentive for connections engagement assesses a distributor's effort in formulating and pursuing strategies for providing and improving connection services to large customers, as well as a distributor's use of information learned from these customers to improve these services. A load index measures substation loading on a distributor's primary network.

Revenue Decoupling

While being described as a "price control," Ofgem today uses revenue caps. A "correction factor" refunds or charges customers for variances between actual and allowed revenue. In past plans, sales volume and customer growth increased the company's allowed and actual revenue to some extent.[168] However, this linkage was eventually eliminated, resulting in revenue decoupling that continues through RIIO today.

Cost Trackers

British MRPs often feature mechanisms similar to cost trackers for various costs that are difficult to control. For example, most pension costs have been tracked. Trackers also have been put in place for an assortment of special projects including load reinforcement, high value projects and rail electrification. Supplemental revenue can only be requested at one or two prespecified periods during the rate plan. Another variant on cost trackers is supplemental allowances that distributors can access for specific projects. These allowances have been developed for various purposes, including improvement in the reliability of service to "worst served customers," workforce renewal, distributor innovation efforts, and to encourage distributors to begin making changes toward a low carbon future.

Outcomes

From 2008–2010, as part of the RPI-X@20 process to modernize its regulatory system, Ofgem undertook an extensive review of effects of its price controls. Reviews are also held at the end of each price control. In these reviews, Ofgem indicated that many MRP features had functioned well. For example, in 2009 the regulator stated:

> We have found that allowed revenue have declined since RPI-X regulation was introduced and we expect network charges to have followed a similar trend. Improvements in operating

[168] The percentage of revenue growth tied to the growth in revenue drivers, including customer and sales growth, was determined for each rate plan.

> efficiency and stability in the allowed cost of capital have facilitated these declines. Capital investment has been increasing and the reliability of the supply to customers has improved. These have all been driven at least partly by the regulatory framework…
>
> Our analysis reveals changes in recent years, however. Allowed revenue has stabilized or increased, reflecting increased investment. Operating efficiency improvements are expected to continue, but the scale may be limited compared to the period since RPI-X regulation...
>
> We have also found evidence that the regulated networks have generally managed to beat the regulatory settlement. Whilst this in itself is not necessarily cause for concern, there are questions about the extent to which companies are able to outperform and whether those companies earning the highest returns are indeed those that perform best for consumers.[169]

Cost Performance

Studies of multifactor productivity trends of British power distributors like those we have undertaken for North American distributors have been hampered by poor data. In particular, a consistent time series dataset is not available for many years, as the definitions of costs have changed over time.[170]

Ofgem commissioned a study of historic and expected productivity trends of British power distributors and the U.K. economy.[171] The study found that from program year 1991–1992 to program year 2001–2002, the British distributors averaged annual MFP growth of 4.3 percent. The opex productivity trend was 7.9 percent while the capital productivity trend was 1.2 percent. These MFP results were substantially higher than those of the U.K. economy as a whole and U.S. power distributors for similar time periods. However, the MFP measurement methodology was different.

In its RPI-X@20 review, Ofgem found that during the course of the price controls, real controllable operating costs per unit of energy distributed declined by 3.1 percent per year.[172] This decline exceeded the targets set by Ofgem in the price control reviews. In addition, distributors often underspent their capex budgets.

A major focus of Ofgem reviews of distributors' performance is comparisons of actual and allowed spending. The regulator found that 12 of 14 distributors had underspent their allowance. Ofgem attributed this outcome to several factors: improvements in efficiency, with unit costs for asset replacement work falling significantly; falling input prices; and a drop in reinforcement, connection and high value projects due to economic conditions. However, distributors had not delivered on their commitments in some areas, such as flood risk reduction programs.[173]

Reliability

The RPI-X@20 review assessed the reliability performance of power distributors under price controls. It found that the frequency and duration of outages had declined about 30 percent between 1990 and 2008. These trends continued, with a further 20 percent reduction in outage frequency and 30 percent reduction in outage duration between program year 2009–2010 and program year 2014–2015.[174]

---

[169] Ofgem (2009a), p. 26.
[170] Ofgem (2009e).
[171] Information comparable to what we have gathered on the MFP trends of U.S. power distributors is unavailable.
[172] Real controllable operating costs were defined as operating costs less depreciation and "atypical" items.
[173] Ofgem (2015), p. 22.
[174] Ofgem (2015), p. 45.

RIIO

In February 2017, Ofgem released its first annual report on experience under RIIO.[175] The regulator reported that 12 of 14 distributors were spending less than they were allowed.[176] After the first year, distributors expected to underspend their allowances by 3 percent for the entire term of RIIO.

The report also noted that distributors had managed to over-earn by about 300 basis points on average. Ofgem believed that ROE performance was "predominantly driven by all [distributors] performing well against the Interruptions Incentive Scheme."[177] All distributors earned rewards under the scheme.

Distributors also had strong performances in several other areas:

- All distributors decreased their business carbon footprint and sulfur hexafluoride leaks during the first year of RIIO.

- Distributors also significantly improved their times to quote new connections. The industry average for the first year of RIIO was 46 percent to 49 percent lower than the target.[178]

- No distributors were penalized under the Incentives on Connections Engagement, as Ofgem was pleased with quality and detail of distributors' submissions.

All distributors received awards from the Broad Measure of Customer Service, and only one distributor was penalized as a result of poor customer satisfaction survey score.

[175] Ofgem (2017).
[176] On average, the distributors spent 9 percent less than their allowance for the first year of RIIO. These areas of underspending were partly offset by increased spending on inspections, repairing faults on the networks, and service quality.
[177] Ofgem (2017), p. 13.
[178] Ofgem (2017), p. 33.

7.0 Conclusions

The electric utility industry has played a key role over the years in the high performance of the U.S. economy. The industry was largely built under the cost of service approach to utility regulation. This regulatory system sets base rates in general rate cases at levels that compensate utilities for the costs they incur for capital, labor and materials. The scope of trackers that expedite recovery of utility costs has expanded in some jurisdictions to encompass costs of capital and other base rate inputs, as well as energy.

We have shown in this report that the efficacy of cost of service regulation (COSR) varies with business conditions. When conditions favor utilities, as often was the case in the years when COSR became an American tradition, rate cases are infrequent, performance incentives are strong, and regulatory cost is restrained. When business conditions are unfavorable, utilities file frequent rate cases or seek tracker treatment for more costs, or do both. As a consequence, performance incentives are weaker and regulatory cost is higher.

Multiyear rate plans are a salient alternative to COSR for electric utilities. Extensive experience has accumulated with these plans. Regulators have typically approved MRPs on the grounds that they strengthen performance incentives while reducing regulatory cost. Plans have had diverse provisions, and extensive experimentation has occurred.

MRPs can improve the efficiency of regulation. With less time spent on general rate cases, costs of regulation can be reduced, or resources can be redeployed to other useful activities like rate design and distribution system planning. In principle, MRPs that do not impair utility performance or harm customers could be adopted solely on the basis of better regulatory efficiency.

It is difficult to assess the impacts of MRPs and rate case frequency on utility cost performance. Costs of utilities are, after all, influenced by many other business conditions (e.g., severe storms and system age) as well as by their regulatory system. This report reviewed impacts of regulation on utility cost performance using two analytical tools: numerical incentive power analysis and empirical research on utility productivity trends.

Both lines of research suggest that MRPs (and, more generally, infrequent rate cases) can materially improve utility cost performance. For example, multifactor productivity growth of the U.S. electric, gas and sanitary sector was found to be considerably slower relative to that of the economy in a period of frequent rate cases than it was in periods when rate cases were much less frequent. We also found that the MFP growth of investor-owned electric utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the U.S. electric utility norm. Stronger incentives produced cost savings of 3 percent to 10 percent after 10 years.

Our incentive power research suggests that *modest* steps in the direction of MRPs from traditional regulation produce only modest improvements in utility cost performance. This is also consistent with our empirical research, which showed that the MFP growth of California and New York utilities, which typically operated under conservative MRPs, were similar to or worse than the U.S. electric utility norm on balance. More robust MRPs — such as those with five-year plans, no earnings sharing, efficiency carryover mechanisms, and avoidance of rate cases between plans — can potentially produce larger gains. Recent innovations in MRP design, such as advances in efficiency carryover mechanisms, can increase incentive power.

Our incentive power research and case studies have important implications. First, utility performance and regulatory cost should be on the radar screen of state utility regulators, consumer groups and utility managers. We have shown that key business

conditions facing utilities today are less favorable than in prior periods when COSR worked well. This can lead to increased rate case frequency and expanded use of cost trackers which weaken utility incentives for improved cost performance.

Notwithstanding potential benefits of MRPs, they have not been adopted for energy utilities in most U.S. jurisdictions.[179] Several reasons can be advanced.

- COSR is well established in the United States, and some commissions are accomplished practitioners. When challenges emerge to the continuation of COSR, quick fixes such as revenue decoupling to address problems related to declining average use and expanded use of cost trackers have been more appealing to many regulators than the more extensive changes required to implement MRPs. State regulators also have tended to resist sweeping change in the direction of cost-plus regulation such as formula rate plans.

- Continuing evolution of COSR will slow diffusion of MRPs. For example, capital cost trackers can be incentivized. Use of PIMs to encourage cost-effective use of DERs can be expanded.

- It can be difficult to design MRPs that generate strong utility performance incentives without undue risk and that share benefits of better performance fairly with customers.

- Some adverse conditions (e.g., need for high capex) which give rise to frequent rate cases and expansive cost trackers under COSR have proven challenging to accommodate under MRPs.

- MRPs invite strategic behavior and plan design controversies. The dollars at stake invite stakeholders to energetically defend their positions. In proceedings to approve plans with indexed ARMs, for example, controversy over X factors has been common.

- Transitional regulatory systems that limit risks of bad outcomes from MRPs through such means as earnings sharing mechanisms and relatively short plan terms often do not generate substantially greater performance improvements than traditional COSR.[180]

- Utilities in most states have not proposed MRPs. While this may reflect their perception of the regulatory climate in their jurisdictions, many utilities may believe that they will make more money (or make the same money more easily) from frequent rate cases and more expansive cost trackers than under an MRP.

- Many consumer advocates are unsure of their role in an MRP system of regulation. Under COSR, consumer advocates intervene in each general rate case to reduce the revenue requirement. The substantial long-term cost to customers of slow productivity growth due to COSR is less visible. The lost opportunity for consumer advocates to spend more time on other regulatory issues may also be underappreciated.

- A key advantage of MRPs is the ease with which they can address brisk inflation. However, inflation has been slow in recent years.

- The impetus for PBR in many countries has come more from regulators and other policymakers than it has from utilities. Regulatory commissions in U.S. states typically have a less daunting

[179] For another discussion of why MRPs are not more popular in the United States, see Costello (2016).
[180] These transitional plans may nonetheless be important stepping stones to more effective regulatory systems.

mandate than regulators in other countries, who often have national jurisdictions with numerous utilities. This reduces the appeal of streamlined regulation.

Notwithstanding these considerations, we believe that use of MRPs is likely to increase in electric utility regulation over time.

- Key business conditions that trigger general rate cases are more likely to deteriorate than to improve in coming years. For example, inflation is more likely to rebound than to slow further due, for example, to rising bond yields. Penetration of customer-side DERs is likely to increase.

- Use of MRPs is already growing in the regulation of vertically integrated U.S. electric utilities.

- Continuing innovation in the United States, Canada and other countries will produce better MRP approaches. For example, regulators are becoming more skilled at designing plans for utilities engaged in accelerated grid modernization. Incentive compatible menus and efficiency carryover mechanisms help to ensure customer benefits.

- A growing number of power distributors will complete accelerated modernization programs and enter a period of more routine capex requirements that pose fewer problems for MRP design.

The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay.[181] Evidence gathered for this report suggests that MRPs did not impair reliability, but this evidence was anecdotal. Lack of data is a major barrier to more comprehensive research on reliability and bill impacts.

[181] In addition, more refined statistical tests of the impacts of MRPs can be devised.

8.0 References

Alberta Utilities Commission, 2012. “Rate Regulation Initiative: Distribution Performance-Based Regulation,” Decision 2012-237, September.

Arizona Corporation Commission, 2012. In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return, Docket No. E-01345A-11-0224, Decision 73183, May 24.

Berg, W., et al., 2016. “The 2016 State Energy Efficiency Scorecard,” Report U1606, *American Council for an Energy-Efficient Economy*. http://aceee.org/sites/default/files/publications/researchreports/u1606.pdf

Bonbright, J., Danielsen, A., and Kamerschen, D., 1988. “Principles of Public Utility Rates,” *Public Utilities Reports, Inc*.

Braeutigam, R. and Quirk, J., 1984. “Demand Uncertainty and the Regulated Firm,” *International Economic Review* 25 (1): 47.

California Public Utilities Code, 2001. SEC.10, Section 739.10 as amended by Assembly Bill X1 29 (Kehoe).

California Public Utilities Commission, 1976. Decision 85559.

California Public Utilities Commission, 1978. Decision 88835, Case 10261.

California Public Utilities Commission, 1980a. Decision 92497 for Southern California Gas.

California Public Utilities Commission, 1980b. Decision 92549 for Southern California Edison.

California Public Utilities Commission, 1981. Decision 93887 in Cases 60153, 58545, and 58546.

California Public Utilities Commission, 1994. Order Instituting Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation, R.94-04-031 and I.94-04-032.

California Public Utilities Commission, 2003. *Application of Pacific Gas & Electric Company for Authority to Increase Electric and Gas Revenue Requirements to Reflect an Attrition Revenue Adjustment for the Year 2002.* Decision 03-03-034, Application 02-06-019, March 13.

California Public Utilities Commission, 2007a. *Application of San Diego Gas & Electric Company (U 902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design*. Decision 07-04-043, Application 05-03-015, April 16.

California Public Utilities Commission, 2007b. Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs, at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/73172.pdf

California Public Utilities Commission, 2008a. Decision 08-09-038, Investigation 06-06-014.

California Public Utilities Commission, 2008b. *Southern California Edison Company’s (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism*. Decision 08-04-039, Application 07-07-026, September 18.

California Public Utilities Commission, 2013. Decision 13-09-023, Rulemaking 12-01-005. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M076/K775/76775903.PDF

California Public Utilities Commission, 2015a. Decision Approving Settlement, Case 13-12-005, Decision 15-10-027, October.

California Public Utilities Commission, 2015b. Decision 15-07-001, Rulemaking 12-06-013. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF

California Public Utilities Commission, 2016. Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot, R-14-10-003, December. http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=171555623

Central Maine Power, 1998. Annual Report to the Securities and Exchange Commission, Form 10-K for 1998.

Chandrashekeran, S., Zuckerman, J., and Deason, J., 2015. "Raising the stakes for energy efficiency: A qualitative case study of California's risk/reward incentive mechanism," *Utilities Policy*, October, 79–90.

Colorado Public Utilities Commission, 2015. In the matter of Advice Letter no. 1672 – Electric of Public Service Company of Colorado to Revise the General Rate Schedule Adjustment (GRSA) Rider Applicable to all Electric Base Rate Schedules and Revise the Transmission Cost Adjustment (TCA) to Remove Costs that have been shifted to Base Rates to become effective July 18, 2014. Decision No. C15-0292, Proceeding No. 14AL-0660E, March 31.

Comnes, G. A., Stoft, S., Greene, N., and Hill, L. J., 1995. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues*, Berkeley Lab, November. https://emp.lbl.gov/sites/all/files/REPORT%20LBNL-37577.pdf; http://eande.lbl.gov/sites/all/files/publications/performance-based-ratemaking-for-electric-utilities-review-of-plans-and-analysis-of-economic-and-res.pdf.

Costello, K., 2016. *Multiyear Rate Plans and the Public Interest*. National Regulatory Research Institute, Report No. 16-08.

Crew, M., and Kleindorfer, P., 1987. "Productivity Incentives and Rate-of-Return Regulation." In *Regulating Utilities in an Era of Deregulation.* New York, St. Martin's Press.

Crew, M., and Kleindorfer, P., 1992. "Incentive Regulation, Capital Recovery and Technological Change." In *Economic Innovations in Public Utility Regulation.* Massachusetts, Kluwer Academic Publishers.

Crew, M., and Kleindorfer, P., 1996. "Incentive Regulation in the United Kingdom and the United States: Some Lessons." *Journal of Regulatory Economics* 9, 211–225.

Cronin, F. J. and Motluk, S., 2011. "Ten years after restructuring: Degraded distribution reliability and regulatory failure in Ontario," *Utilities Policy* 19 (4), December.

Duke Energy, 2015. NC GreenPower Program, Electricity No. 4, North Carolina First Revised Leaf No. 324, https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/ncgreenpower.pdf?la=en.

Edison Electric Institute, *Rate Case Summary*, Various Issues.

Energy Information Administration, Financial Statistics of Major US Investor-Owned Electric Utilities. Various Issues.

Federal Communications Commission, 1990. In the Matter of Policy and Rules Concerning Rates for Dominant Carriers, CC Docket 87-313, Second Report and Order, Adopted September 19.

Federal Energy Regulatory Commission, 2015. Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December.

Fehrman, W., 2012. Iowa Utilities Board, Docket RPU-2012-0001, Direct Testimony, February 21.

Florida Public Service Commission, 2013. In re: Petition for increase in rates by Florida Power & Light Company. Order No. PSC-13-0023-S-EI, Docket No. 120015-EI, January 14.

Gale, B., 2003. Iowa Utilities Board, Docket RPU-03-1, Direct Testimony, May 27.

Glaser, John L., 1993. "Multifactor Productivity in the Utility Services Industries," *Monthly Labor Review*, May: 34–49.

Graffy, E. and S. Kihm, 2014. "Does Disruptive Competition Mean a Death Spiral for Electric Utilities?" *Energy Law Journal* 35(1): 1–44.

Institute for Electric Innovation, 2014. State Electric Efficiency Regulatory Frameworks.

Iowa Utilities Board, 1997. *In Re: MidAmerican Energy Company.* Dockets APP-96-1 and RPU-96-8, Order Approving Settlement, Granting Waivers, and Requiring Additional Information, June 27.

Iowa Utilities Board, 2001. *In Re: MidAmerican Energy Company.* Dockets RPU-01-3 and RPU-01-5, Order Approving Settlement with Modifications, Dec. 21.

Iowa Utilities Board, 2003. *In Re: MidAmerican Energy Company*, Docket RPU-03-1, Order Approving Stipulation and Agreement, Oct. 17.

Joskow, P., and MacAvoy, P., 1975. "Regulation and the Financial Condition of the Electric Power Companies in the 1970's," in *The American Economic Review* 65 (2): 295–301.

Kahn, A., 1970. *The Economics of Regulation: Principles and Institutions,* (MIT Press) original printings in 1970 and 1971, reprinted edition in 1988.

Kaufmann, L., and Lowry, M. N., 1995. "Performance-Based Regulation: The State of the Art and Directions for Further Research," prepared for Electric Power Research Institute.

Kaufmann, L., 2007. *Service Quality Regulation for Detroit Edison: A Critical Assessment,* prepared for Detroit Edison and Michigan Public Service Commission Staff for Michigan PSC Case No. U-15244.

Kaufmann, L., Getachew, L., Rich, J., and Makos, M., 2010. *System Reliability Regulation: A Jurisdictional Survey*, prepared for the Ontario Energy Board and filed in Case EB-2010-0249.

Kaufmann, L., Hovde, D., Kalfayan, J., and Rebane, K., 2013. *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*, issued Nov. 5, 2013, and corrected on Dec. 19, 2013 and Jan. 24, 2014, in Ontario Energy Board Case EB-2010-0379.

Laffont, J., and Tirole, J., 1993. *A Theory of Incentives in Procurement and Regulation*. MIT Press, Cambridge and London.

Lazar, J., Weston, F., and Shirley, W., 2016. "Revenue Regulation and Decoupling: A Guide to Theory and Application," Regulatory Assistance Project, November.

Legislative Assembly of Ontario, 2002. Bill 210, Chapter 23, *An Act to amend various Acts in respect of the pricing, conservation and supply of electricity and in respect of other matters related to electricity,* December. http://www.ontla.on.ca/bills/bills-files/37_Parliament/Session3/b210ra.pdf

Littlechild, S., 1983. "Regulation of British Telecommunications' Profitability: Report to the Secretary of State," February.

Louisiana Public Service Commission, 2014. *In re: Application of Cleco Power LLC for: (i) Extension of its Formula Rate Plan (FRP), First Authorized by LPSC Order No. U-30689, Issued October 28, 2010; and (ii) Consolidation of Docket No. U-32153 with this Docket*, Order No. U-32779, Docket No. U-32779, June 27.

Lowry, M. N., Hovde, D., 2016. "PEG Reply Evidence," filed as Exhibit 20414-X0468 in Alberta Utilities Commission proceeding 20414, as revised on June 22.

Lowry, M. N., Hovde, D., Getachew, L., and Makos, M., 2009, "Statistical Support for Public Service of Colorado's Forward Test Year Proposal," filed in Colorado PUC Docket 09AL-299E as Exhibit No. MNL-1.

Lowry, M. N., Hovde, D., Getachew, L., and Makos, M., 2010, "Statistical Analysis of Public Service of Colorado's Forward Test Year Proposal," filed in Colorado PUC Docket 10-AL-963G as Exhibit No. MNL-1.

Lowry, M. N., Hovde, D., Kalfayan, J., Fourakis, S., and Makos, M., 2014, "Benchmarking PS Colorado's O&M Revenue Requirement," filed in Colorado PUC Docket 14-AL-0660E as Attachment No. AKJ-2.

Lowry, M. N., and Kaufmann, L., 1994. "Price Cap Designer's Handbook," for Edison Electric Institute.

Lowry, M. N., and Kaufmann, L., 2002. "Performance-Based Regulation of Utilities," *Energy Law Journal* 23, October 22.

Lowry, M. N., Makos, M., and Waschbusch, G., 2015. "Alternative Regulation for Emerging Utility Challenges: 2015 Update," for Edison Electric Institute.

Lowry, M. N., and Woolf, T., 2016. *Performance-Based Regulation in a High Distributed Energy Resources Future*, for Lawrence Berkeley National Laboratory, Future Electric Utility Regulation series, https://emp.lbl.gov/future-electric-utility-regulation-series.

Maine Public Utilities Commission, 1993. Docket 92-345, Order dated Dec. 14.

Maine Public Utilities Commission, 1995. Detailed Opinion and Subsidiary Findings. Docket No. 92-345 (II), Jan. 10.

Maine Public Utilities Commission, 2008. Order Approving Stipulation, Docket No. 2007-215, July 1.

Maine Public Utilities Commission, 2014. Order Approving Stipulation, Docket No. 2013-00168, Aug. 25.

Moody's Public Utility Manual, 1995. Volume 2

Moreland Commission on Utility Storm Preparation and Response, 2013a. Interim Report, January 7.

Moreland Commission on Utility Storm Preparation and Response, 2013b. Final Report, June 22.

New York Public Service Commission, 1990. Opinion No. 90-24, Cases 89-E-175, 89-E-176.

New York Public Service Commission, 2009. Order Setting Electric Rates, Case 08-E-0539, April 24.

New York Public Service Commission, 2014a. Order Instituting Proceeding, Case 14-M-0101.

New York Public Service Commission, 2014. Order Establishing Brooklyn/Queens Demand Management Program, New York Public Service Commission, Case 14-E-0302.

New York Public Service Commission, 2016a. "Order adopting a ratemaking and utility revenue model policy framework," Case 14-M-0101. May 19.

New York Public Service Commission, 2016b. "Order implementing with modification the proposal for cost recover and incentive mechanism for non-wire alternative project", Case 14-E-0318, July.

New York Public Service Commission, 2017. "Order Approving Shareholder Incentives," Case 15-E-0229, January.

New York State Department of Public Service, 2016. "2015 Utility Service Quality Report," filed in New York PSC Case 16-M-0296.

Offer, 1999. "Review of Public Electricity Suppliers 1998-2000, Distribution Price Control Review: Consultation Paper," May.

Ofgem, 1999. "Reviews of Public Electricity Suppliers (1998–2000), Distribution Price Control Review: Draft Proposals."

Ofgem, 2004a. Electricity Distribution Price Control Review Policy Document, March.

Ofgem, 2004b. Electricity Distribution Price Control Review Initial Proposals, June.

Ofgem, 2009a. Performance of the Energy Networks under RPI-X.

Ofgem, 2009b. Regulating Energy Networks for the Future: RPI-X @ 20: History of Energy Network Regulation.

Ofgem, 2009c. DPCR5 Final Proposals Incentives and Obligations, Ref 145/09.

Ofgem, 2009d. Electricity Distribution Price Control Review 5 Final Proposals - Incentives and Obligations, December 7.

Ofgem, 2009e. Electricity Distribution Price Control Review Methodology and Initial Results Paper, Ref 47/09.

Ofgem, 2010. "Electricity Distribution Price Control Review Final Proposals Incentives and Obligations."

Ofgem, 2014. "RIIO-ED1: Final determinations for the slow-track electricity distribution companies." November.

Ofgem, 2015. "Electricity Distribution Company performance 2010 to 2015."

Ofgem, 2017. "RIIO-ED 1 Annual Report 2015–2016."

Ontario Energy Board, 1998. *Ontario Energy Board Draft Policy on Performance Based Regulation*.

Ontario Energy Board, 2006. *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, Dec. 20.

Ontario Energy Board, 2008. *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, EB-2007-0673, Sept. 17.

Ontario Energy Board, 2010. *Staff Report to the Board: Electricity Distribution System Reliability Standards*, EB-2010-0249, March 31.

Ontario Energy Board, 2014. *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, EB-2014-0219, Sept. 18.

Settling Parties in Massachusetts, 1999. D.T.E. 99-47. "Rate Plan Settlement," Nov. 29.

St. John, J., 2015. "California's Major Residential Rate Reform: The Solar-Friendly Alternative," Greentech Media, May 26. https://www.greentechmedia.com/articles/read/californias-major-residential-rate-reform-the-solar-friendly-alternative.

Theil, H. 1965. "The Information Approach to Demand Analysis. *Econometrica* 33: 67–87.

Törnqvist, L., 1936. "The Bank of Finland's Consumption Price Index." *Bank of Finland Monthly Bulletin* 10: 1–8.

Vermont Public Service Board, 2016. Order in Docket 8337, March.

Virginia Acts of Assembly, 2015. Senate Bill 1349, *An Act to amend and reenact 56-599 of the Code of Virginia, relating to electric utility regulation; suspension of regulatory reviews of utility earnings; integrated resource plan schedule*, February.

Walton, Robert, 2016a. "DER Providers Push for More Cost Data as New York Utilities Issue Distribution System Plans Under REV." *Utility Dive*, July 11.

Walton, Robert, 2016b. "The Non-Wire Alternative: Con Ed's Brooklyn-Queens Pilot Rejects Traditional Grid Upgrades," *Utility Dive*, Aug. 3.

Whited, M., Woolf, T., Napoleon, A., 2015. *Utility Performance Incentive Mechanisms: A Handbook for Regulators.* Synapse Energy Economics. March 9.

Williams Consulting, 2007. *CMP Distribution Plant Evaluation – Final Report.* Prepared for the Maine Public Utilities Commission and filed in MPUC Docket No. 2005-705.

York, D., and Kushler M., 2011. "The Old Model Isn't Working: Creating the Energy Utility for the 21st Century," American Council for an Energy-Efficient Economy, September.

Appendix A. Further Discussion of Multiyear Rate Plan Designs

This appendix discusses some topics in incentive plan design in greater detail. We consider earnings sharing mechanisms (ESMs), Z factors, marketing flexibility and Ofgem's Information Quality Incentive.

A.1 Earnings Sharing Mechanisms

Earnings sharing mechanisms share earnings variances that arise when a utility's return on equity (ROE) deviates from a commission-approved target. Treatment of earnings variances may depend on their magnitude. For example, there are often dead bands in which the utility does not share smaller variances (e.g., less than 100 basis points from the ROE target) with customers. Beyond the dead band there may be one or more additional bands in which earnings are shared in different proportions between customers and the utility.[182] While some ESMs share both surplus and deficit earnings, others share only surplus earnings. This maintains an incentive for companies to become more efficient to avoid under-earning.

Whether or not to add an ESM is one of the more difficult decisions in multiyear rate plan (MRP) design. The offsetting pros and cons of ESMs may help to explain why they are only featured in about half of current U.S. and Canadian MRPs. On the plus side, an ESM can reduce risks that revenue will deviate substantially from cost. Unusually high or low earnings may be undesirable to the extent that they reflect windfall gains or losses, poor plan design, data manipulation, or strategic deferrals of expenditures. Reduced likelihood of extreme earnings outcomes can help parties agree to a plan and make it possible to extend the period between rate cases.

On the downside, ESMs weaken utility performance incentives. Permitting marketing flexibility can be complicated in the presence of an ESM because discounts available to some customers can affect earnings variances that are shared with all customers.[183] ESM filings can be a source of controversy. Customers may complain, for example, if the ROE never gets outside the dead band so that surplus earnings are shared. There is less need for an ESM if the plan features other risk mitigation measures such as inflation indexing, Z factors or revenue decoupling.

A.2 Z Factors

A Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings. Many MRPs have explicit eligibility requirements for Z factor events. Here is a typical list of requirements.

<u>Causation</u>: The costs must be clearly outside of the base upon which rates were derived.

<u>Materiality</u>: The costs must have a significant impact on utility finances. Materiality can be measured based on individual events, cumulative impacts of multiple events, or both.

[182] An ESM is therefore sometimes referred to as a "banded ROE."
[183] This problem can be contained by sharing only the utility's earnings surpluses.

Outside of Management Control: The cost must be attributable to events outside of management's ability to control.

Prudence: The cost must have been prudently incurred.

One of the primary rationales for Z factor adjustments is the need to adjust revenue for effects of changes in tax rates and other government policies on the utility's cost. Another rationale for Z factors is to adjust for effects of miscellaneous other external developments on utility costs which are not captured by inflation and X factors. Z factors can potentially reduce operating risk, without weakening performance incentives for the majority of costs. Z factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most benefits of MRPs.

A.3 Marketing Flexibility

Need for Flexibility

Regulators have long acknowledged the need to afford utilities some flexibility in fashioning rate and service offerings. A utility's need for marketing flexibility is greater to the extent that demand for its services is complex, changing and elastic (i.e., sensitive) with respect to the terms of services offered. When demand is elastic, rates that are too high produce more bypass of utility services.[184] Demand elasticity is greater when customers have alternative ways to meet their needs which are competitive with respect to cost and quality. Elasticity is also greater for products that are "discretionary" in the sense that they do not address a customer's most basic needs.

While "core" customers have fewer options and lower elasticities of demand for basic services, electric utilities have long relied on marketing flexibility to customize terms of service to large-volume customers. These customers play a larger role in the earnings of VIEUs than they do in the earnings of UDCs. One reason is that UDCs do not profit from sizable sums these customers pay for power supplies. Another is that some of these customers take service at transmission voltage and do not pay for many distribution-level costs. In addition, all types of utilities desire flexibility when marketing underutilized capacity in competitive markets (e.g., leasing land in transmission corridors).[185]

Interest among electric utilities in marketing flexibility is growing as demand for power services is becoming more complex, changeable and sensitive to terms of service that utilities offer. For example, advanced metering infrastructure, other smart grid technologies, distributed storage, and plug-in electric vehicles open the door to a variety of new utility services. Large-load customers have a growing interest in customized green power services to meet corporate goals. Distributed generation and storage pose a growing competitive challenge in some jurisdictions. However, for the foreseeable future regulators will likely control terms of service to distributed generation and storage customers carefully.

Marketing flexibility can also help utilities encourage customers to use their services in less costly ways. For example, AMI makes it more cost-effective to offer time-varying tariffs to

[184] Uneconomic bypass occurs when a customer would use a system more at a lower rate that still exceeds the cost of service. When uneconomic bypass is reduced, customers make more contributions to fixed costs that lower rates for other customers.

[185] Margins from "other revenues" benefit retail customers by, for example, reducing the retail revenue requirement in rate cases.

residential and small business customers. These tariffs can encourage reduced loads at times when the cost of electricity is especially high and slow the need for costly upgrades for substations and load-following generation capacity.

Flexibility Measures

Marketing flexibility runs the gamut from greater effort by regulators to approve new rates and services by traditional means to "light-handed" regulation and even decontrol of certain utility offerings.[186] Light-handed regulation typically takes the form of expedited approval of new or revised rate and service offerings. These offerings may be subject to further scrutiny at a later date, such as in the next rate case. Pricing floors are often established based on marginal or incremental cost of service to ensure that customers of new rates and services contribute to margin.

Regulators most commonly grant marketing flexibility for rate and service offerings with certain characteristics. Generally speaking, flexibility is encouraged where new offerings are likely to benefit target customers while also benefitting other customers — for example, by increasing contributions to margins so that contributions by other customers can be reduced. Optional offerings have often been accorded expedited treatment by regulators because targeted customers are protected by their recourse to service under standard tariffs, as well as offerings by potential third-party providers that compete with the utility.

Several kinds of offerings may be deemed optional, such as:

1. A discount from rates in a standard tariff, offered to particular customers — for example, due to relatively high elasticity of their demands for utility services

2. An optional tariff that is available to all qualifying customers, such as a time-sensitive rate for electric vehicle charging

3. Special (negotiated) customer-specific contracts for utility services

4. A new premium quality service for customers prepared to pay for better quality

5. A discretionary service such as lighting on a backyard power pole

6. Special service packages (which may include standard services as components), such as a rate for a bundle of services that includes premium quality service and electric vehicle charging

Why MRPs Facilitate Marketing Flexibility

MRPs facilitate marketing flexibility for several reasons. Less frequent general rate cases reduce the chore of deciding how to allocate the revenue requirement between a complex and changing mix of market offerings. Multiyear rate plans also reduce concerns about cross-subsidies between service classes because infrequent rate cases and other plan provisions, such as service baskets, insulate core customers from potentially adverse consequences of marketing flexibility.[187] To the

[186] Decontrol of utility rate and service offerings is typically limited to markets that are robustly competitive.
[187] Cost trackers create a "back door" to cross-subsidization unless discounting of tracked costs is prohibited.

extent that the utility's earnings losses from special terms of services for certain customers can't be recovered from other customers, regulators are more confident that discounts are prudent.

In addition to facilitating marketing flexibility, MRPs create a special need for flexibility since rate cases are less frequently available as occasions for redesigning rates. Special proceedings to redesign rates in a revenue-neutral way can occur during an MRP. Alternatively, utilities may be permitted (or required) to gradually change rate designs during a rate plan in accordance with commission-approved goals. For example, the commission could approve a phase-in of time-sensitive usage charges.

MRPs can also strengthen utility incentives to improve marketing because the utilities are able to keep resultant margins longer. For example, under MRPs utilities have greater motivation to discourage load patterns that are especially costly. Under price caps, utilities have more incentive to encourage large-load customers to expand their operations.

Marketing Flexibility Precedents

Electric utilities have long been granted flexibility by regulators in rates and services they offer to some of the markets they serve. For example, rates utilities charge for use of their assets in various competitive markets are frequently not addressed by state regulators. Examples include sales in bulk power markets and rental of surplus office space. Light-handed regulation is sometimes accorded to special contracts for large-load customers with price-elastic demands or an interest in customized green power services.[188] However, special contracts for utility services require specific approval in many jurisdictions.

Multiyear rate plans have been extensively used to regulate utilities in industries where market-responsive rates and services are a priority. The example of Central Maine Power is discussed in Section 6 in this report. However, MRPs have not to date played a large role in fostering electric utility marketing flexibility. One reason is that many MRPs to date have applied to utility distribution companies, which traditionally had less need for special pricing for large-load customers.

A.4 Britain's Information Quality Incentive

Britain's Information Quality Incentive (IQI) rewards distributors for making conservative cost forecasts and then performing better.[189] The IQI is essentially a menu consisting of cost forecast-allowed revenue combinations. It currently applies to most operation and maintenance (O&M) expenses and capex. Each utility is asked to give a cost forecast and is eventually given an allowed revenue amount based on this forecast. The IQI's input on allowed revenue is in two parts: *ex-ante* allowed revenue and an IQI adjustment factor. By announcing its cost forecast, the utility implicitly chooses both its *ex-ante* allowed revenue and an IQI adjustment factor formula.

The *ex-ante* allowed revenue is a weighted average of the regulator's and the utility's cost forecasts. The regulator's forecast receives 75 percent weight while the utility's forecast receives

[188] Duke Energy (2015).
[189] Ofgem states that distributors with "less well justified capex forecasts, as compared with the views of Ofgem's consultants would be permitted to spend above the amounts that they had justified to Ofgem but [these distributors] would receive relatively lower returns for underspending. In contrast, those [distributors] that had better justified their forecasts, and were in line with the views of the consultants, would be rewarded with a higher rate of return and a stronger incentive for efficiency." See Ofgem (2009b), p. 38.

25 percent weight. This treatment alone greatly reduces the payoff to the distributor from a high cost forecast. The substantial weight assigned to the regulator's forecast reflects the large investment it makes in engineering and consulting services to develop an independent review of future cost.

The IQI adjustment factor is composed of an incentive rate and an additional income factor. The incentive rate specifies sharing, between utilities and customers, of variances between the utility's actual expenditures and the allowed revenue for these expenditures it was granted *ex ante*. The utility's share of these variances increases as the difference between the utility's cost forecast and regulator's own forecast decreases. The additional income factor, also referred to as an upfront reward or penalty, provides an immediate incentive for the utility to provide a cost forecast that is at or below Ofgem's own forecast.

Together these provisions make the menu "incentive compatible." The utility is rewarded when its cost forecast is low and its actual cost is similar. The IQI discourages a strategy of proposing a high forecast and subsequently incurring low costs.

Figure A-1 shows the IQI menu developed for the 2010-2015 plan:[190]

- The first row is a ratio of the utility's cost forecast to the regulator's cost forecast. A ratio of less than 100 means the utility has presented a lower cost forecast than the regulator, while a ratio above 100 means the utility's cost forecast is higher than the regulator's.

- The second row is the utility's share of what it over- or underspends relative to the *ex-ante* allowed revenue. The utility's share of these variances increases when its cost forecast is low. This feature provides greater incentives for the utility to cut costs and provide a forecast that is not inflated.

- The third row is the *ex-ante* revenue the utility can collect, expressed as a percentage of the regulator's cost forecast. This is much closer to Ofgem's forecast than to the utility's.

- The fourth row is the additional *ex post* income the utility can collect, expressed as a percentage of the regulator's cost forecast. This is a reward for a low cost forecast.

Values in the second section of Figure A-1, labeled IQI Adjustment Factor, illustrate possibilities for additional revenue (expressed as a percentage of Ofgem's cost forecast) which the utility can collect once it reports actual expenditures for the price control period. The amount of additional revenue depends on how the company's forecast compares to Ofgem's forecast and to the company's ultimate expenditures. The revenue adjustment is more favorable to the utility to the extent that its expenditures are low relative to its own forecast and Ofgem's forecast. The highest reward is offered for spending less than a utility forecast that was low relative to Ofgem's forecast.

[190] There have not been any major changes to the IQI methodology since this matrix was established.

Utility's cost forecast (% of Ofgem's cost forecast)	95	100	105	110	115	120	125	130	135	140
Utility's share of under/over spending (incentive rate)	0.53	0.5	0.48	0.45	0.43	0.4	0.38	0.35	0.33	0.3
Ex-ante allowed revenue (% of Ofgem's cost forecast)	98.75	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Ex-post additional income (% of Ofgem's cost forecast)	3.09	2.5	1.84	1.13	0.34	-0.5	-1.41	-2.38	-3.41	-4.5
Actual utility expenditure (% of Ofgem's cost forecast)	**IQI Adjustment Factor (% of Ofgem's cost forecast)**									
90	7.69	7.5	7.19	6.75	6.19	5.5	4.69	3.75	2.69	1.5
95	5.06	5	4.81	4.5	4.06	3.5	2.81	2	1.06	0
100	2.44	2.5	2.44	2.25	1.94	1.5	0.94	0.25	-0.56	-1.5
105	-0.19	0	0.06	0	-0.19	-0.5	-0.94	-1.5	-2.19	-3
110	-2.81	-2.5	-2.31	-2.25	-2.31	-2.5	-2.81	-3.25	-3.81	-4.5
115	-5.44	-5	-4.69	-4.5	-4.44	-4.5	-4.69	-5	-5.44	-6
120	-8.06	-7.5	-7.06	-6.75	-6.56	-6.5	-6.56	-6.75	-7.06	-7.5
125	-10.69	-10	-9.44	-9	-8.69	-8.5	-8.44	-8.5	-8.69	-9
130	-13.31	-12.5	-11.81	-11.25	-10.81	-10.5	-10.31	-10.25	-10.31	-10.5
135	-15.94	-15	-14.19	-13.5	-12.94	-12.5	-12.19	-12	-11.94	-12
140	-18.56	-17.5	-16.56	-15.75	-15.06	-14.5	-14.06	-13.75	-13.56	-13.5
145	-21.19	-20	-18.94	-18	-17.19	-16.5	-15.94	-15.5	-15.19	-15

Figure A-1. IQI Matrix for Ofgem's 5th Distribution Price Control Review.[191] IQI Matrix is an incentive compatible menu intended to encourage utilities to make low expenditure forecasts and then outperform them.

Suppose, by way of illustration, that a utility made a forecast that was just 5 percent above Ofgem's. Its *ex ante* allowed revenue would be only 1.25 percent above Ofgem's forecast, but it would be entitled to a fairly high 48 percent of surplus earnings and additional income equal to 1.84 percent of Ofgem's forecast. If its actual cost turned out to be the same as its forecast, it would garner an additional reward equal to 0.06 percent of Ofgem's forecast.

[191] Ofgem (2009c), p. 111. Presented here with some small changes to be more easily understood.

Appendix B. Details of the Technical Work

This appendix provides more technical details of two lines of research presented in this report. One is the numerical incentive power research. The other is the empirical research on power distributor productivity. We also discuss some statistical benchmarking concepts.

B.1 Incentive Power Research[192]

This section discusses incentive power research that PEG has conducted over the years on behalf of several utilities and regulatory commissions.[193] Implications of this research are summarized in Section 5 of this report.

Overview of Research

Our incentive power research considers how the performance of utilities differs under alternative regulatory systems that feature various performance-based regulation (PBR) features as well as systems that resemble traditional rate regulation. The research can be used to explore multiyear rate plan (MRP) design options such as earnings sharing mechanisms and alternative plan terms.

At the heart of our research is a mathematical optimization model of the cost management of a company subject to rate regulation. We consider a company facing business conditions like those of a large energy distributor. In the first year of the decision problem, we assume for our example calculations that total annual cost is around $500 million for a company of average efficiency. Capital accounts for a little more than half of total cost. The annual depreciation rate is a constant 5 percent, the weighted average cost of capital is 7 percent, and the income tax rate is 30 percent.

Some assumptions have been made in the model to simplify the analysis. There is no inflation or output growth that would cause cost to grow over time.[194] The utility's revenue will be the same year after year in the absence of a rate case.

The company has opportunities to reduce its cost through cost reduction initiatives. Two kinds of cost reduction projects are available. Projects of the first type lead to temporary (specifically, one-year) cost reductions. Projects of the second type involve a net cost increase in the first year in exchange for *sustained* reductions in future costs. Projects in this category vary in their payback periods. The payback periods we consider are one year, three years and five years. For projects of each kind, there are diminishing returns to additional cost reduction effort in a given year. In total, we consider eight kinds of cost reduction projects — four for O&M expenses and four for capex. In our simulations, the company is permitted to pass up each kind of project in a given year (so that there is zero effort) but cannot choose *negative* levels of effort which constitute deliberate waste. This is tantamount to assuming that deliberate waste is recognized by the regulator and disallowed.

The company can increase earnings by undertaking cost containment projects, but experiences employee distress and other *unaccountable* costs when pursuing such projects. These costs are assumed to occur in

[192] Further details of this research can be requested from the authors.
[193] Our research in this area was for several years spearheaded by Travis Johnson, a graduate of the Massachusetts Institute of Technology and Stanford Business School who is now a professor at the McCombs School of Business at the University of Texas.
[194] The comparatively low weighted-average cost of capital reflects these assumptions.

the first year of the initiative. We have assigned these unaccountable costs a value, in the reckonings of management as it crafts a business plan, that is about one quarter the size of the *accountable* upfront costs.

The company is assumed to choose the cost containment strategy that maximizes the net present value of earnings, less the unaccountable costs of performance improvement just discussed, given the regulatory system, income tax rate and available cost reduction opportunities. We are interested in examining how the company's cost management strategy differs under alternative regulatory systems.

<u>Reference Regulatory Systems</u>[195]

We have developed five "reference" regulatory systems that constitute useful comparators for MRPs:

One is "cost plus" regulation, in which a company's revenue is exactly equal to its cost every year. This has no real-world counterpart, since even traditional regulation requires at least a one-year rate case cycle and some incentive, once rates are set, to cut costs of base rate inputs. Another reference system is full externalization of the ratemaking process so that rates are no longer trued up periodically to the company's costs. Such an outcome would be obtained if the company were to embark on a permanent revenue cap regime.

The other three reference regimes approximate traditional regulation. In each, there is a predictable cycle of rate cases in which revenue is reset to the company's cost. We consider cycles of one, two and three years.

<u>Multiyear Rate Plans</u>

We considered various types of MRPs in our incentive power research. In most of these plans, there is no stretch factor shaving the revenue requirement mechanistically from year to year. The plans differ with respect to several kinds of provisions:

- *Plan term.* We consider terms of three, five, six and 10 years.

- *Impact of earnings sharing.* Plans considered also vary with respect to the earnings sharing specification. We consider earnings sharing mechanisms that have various company/customer allocations of earnings variances. Company shares considered are zero, 25 percent, 50 percent and 75 percent. None of the mechanisms considered have dead bands or multiple sharing bands, as these complicate calculations.

- *How rates change with rate case.* Our characterization of the rate case is important in modeling both traditional regulation and the MRP regimes. We assume in most model runs that rates in the initial year of the new regulatory cycle are, with one qualification, set to reflect the cost of service in the last year of the previous regulatory cycle.[196] The qualification is that any upfront *accountable* costs of initiatives for sustainable cost reductions that are undertaken in the historical reference year are amortized over the term of the plan.

- *Efficiency carryover mechanisms.* We also have considered the impact of some stylized efficiency carryover mechanisms. In one mechanism, the revenue requirement at the start of a new plan is based on a percentage (α%) of the cost in the last year of the previous plan and (1-

[195] The tables presented later in this appendix present results for these various scenarios.
[196] This is reasonable considering the lack of inflation and the stability of demand.

α)% on the revenue requirement in that year. This effectively permits the company to share (1-α)% any deviation between its cost and the revenue requirement. We consider alternative values of α, ranging from 90 percent to 50 percent.

In addition, we considered an efficiency carryover mechanism in which the revenue requirement in the first year of a new rate plan is adjusted for a percentage of the variance between an exogenous benchmark value of cost in the last plan year and the actual cost incurred. The revenue requirement for the first year of the new MRP is thus a weighted average of the benchmark and actual cost. The same result can be achieved by positing that the revenue requirement in year t is based 50/50 on the cost and the benchmark in year t-1.

- *Avoided rate case option.* We also have considered a menu approach to incenting long-term efficiency gains. It gives the company the option at the end of the plan to start the new plan without a rate case. The revenue requirement for the next plan is in this eventuality established on the basis of a predetermined formula. The formula we consider is a stretch factor reduction in the revenue requirement established in the preceding rate case.[197] The company can thus avoid a rate case if it agrees to a starting revenue requirement for the new plan that regulators believe offers value to customers.

Another decision that must be made in comparing alternative regulatory systems is what occurs at the conclusion of a plan. Our view is that the best way to compare the merits of alternative systems is to have them repeat themselves numerous times. For example, we examine the incentive impact of five-year plan terms by examining the cost containment strategy of a company faced with the prospect of a lengthy series of five-year plans.

Identifying the Optimal Strategy

Numerical analysis was used to predict the utility's optimal strategy. Under this approach we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility's objective function. An advantage of numerical analysis in this application is that it permits us to consider regulatory systems of considerable realism.

Research Results

Tables B-1 to B-3 present a summary of results from the incentive power model. For each of several regulatory systems the tables show the net present value of cost reductions from the operation of the system over many years. In the columns on the right-hand side of the tables, we report the average percentage reduction in the company's total cost that results from the regulatory system. We report outcomes for the first and second plan and the long run. We discuss here only the long-run results.

Results are presented for 10 percent, 30 percent and 50 percent levels of initial operating inefficiency. We focus here on the 30 percent results since our benchmarking research over the years has suggested that this is a normal level of operating inefficiency. Table B-1 presents the 30 percent results. Tables B-2 and B-3 show that performance gains from more incentivized regulatory systems are generally larger for less efficient companies. Changes in productivity from the various PBR mechanisms are greatest in Table B-3 (companies starting with 50 percent inefficiency) and smallest in Table B-2 (companies starting with 10 percent inefficiency).

[197] In a world of input price and output growth, a more complex formula would be required.

Results for Reference Regulatory Systems

Table B-1 shows that no cost reduction initiatives are undertaken under cost plus regulation. This reflects the fact that there is no monetary reward for undertaking cost reduction initiatives, all of which involve unaccountable costs. At the other extreme, a complete externalization of future rates such as might occur if rate cases were never held again produces performance improvements relative to cost plus regulation that, over many years, accumulate to a net present value (NPV) of more than $2 billion. Average annual performance gains of 2.71 percent (or 271 basis points) are achievable in the long run.

As for the traditional regulatory systems, the system with a *three*-year cycle incents companies to achieve long-run savings with an NPV of about $900 million — a major improvement over cost plus regulation but less than half of the savings that are potentially available from efficiency initiatives. Average annual performance gains rise from zero to 0.90 percent. The fact that some cost savings occur under traditional regulation is not surprising inasmuch as the assumed three-year regulatory cycle permits some gains to be reaped from temporary cost reduction opportunities and from projects with one-year payback periods. A two-year rate case cycle produces only 0.66 percent annual performance gains.

Table B- 1 Results From the Incentive Power Model: 30% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	657	**29%**	1.19%	0.66%
3 Year Cost of Service	899	**39%**	1.22%	0.90%
Full Rate Externalization	2299	**100%**	3.93%	2.71%
Impact of Plan Term				
Term = 3 years	899	**39%**	1.22%	0.90%
Term = 5 years	1318	**57%**	1.93%	1.41%
Term = 6 years	1428	**62%**	1.96%	1.58%
Term = 10 years	1664	**72%**	2.35%	2.23%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1318	**57%**	1.93%	1.41%
Company Share = 75%	1075	**47%**	1.29%	1.17%
Company Share = 50%	966	**42%**	1.14%	1.01%
Company Share = 25%	879	**38%**	1.03%	0.88%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	990	**43%**	1.29%	1.07%
Externalized Percentage = 25%	1336	**58%**	1.80%	1.66%
Externalized Percentage = 50%	1799	**78%**	3.41%	2.15%
5-Year Plans, Extern				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1469	**64%**	2.07%	1.55%
Externalized Percentage = 25%	1598	**70%**	2.30%	1.76%
Externalized Percentage = 50%	1989	**86%**	3.00%	2.27%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	1535	**67%**	2.26%	1.93%
Externalized Percentage = 25%	1824	**79%**	3.68%	2.29%
Externalized Percentage = 50%	2016	**88%**	3.84%	2.54%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1621	**70%**	2.34%	1.80%
Externalized Percentage = 25%	1908	**83%**	3.08%	2.31%
Externalized Percentage = 50%	2109	**92%**	3.57%	2.56%
Rate Option Plans				
3-Year Plans				
No rate option	899	**39%**	1.93%	0.90%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2.5%	899	**39%**	1.93%	0.90%
5-Year Plans				
No rate option	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 2.5%	1318	**57%**	1.93%	1.41%

*** = measured by the average year-over-year percent decrease in costs**

Table B-2 Results From the Incentive Power Model: 10% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	436	**29%**	1.08%	0.57%
3 Year Cost of Service	623	**42%**	1.02%	0.76%
Full Rate Externalization	1496	**100%**	2.64%	2.32%
Impact of Plan Term				
Term = 3 years	623	**42%**	1.02%	0.76%
Term = 5 years	811	**54%**	1.10%	1.15%
Term = 6 years	976	**65%**	1.19%	1.30%
Term = 10 years	1088	**73%**	1.48%	1.73%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	811	**54%**	1.10%	1.15%
Company Share = 75%	723	**48%**	0.97%	0.97%
Company Share = 50%	653	**44%**	0.87%	0.84%
Company Share = 25%	602	**40%**	0.83%	0.73%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	672	**45%**	1.09%	0.87%
Externalized Percentage = 25%	887	**59%**	1.32%	1.36%
Externalized Percentage = 50%	1123	**75%**	1.87%	1.80%
5-Year Plans, Extern				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	932	**62%**	1.20%	1.27%
Externalized Percentage = 25%	1025	**69%**	1.36%	1.47%
Externalized Percentage = 50%	1239	**83%**	1.91%	1.90%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	623	**42%**	1.02%	0.76%
Externalized Percentage = 10%	1037	**69%**	1.65%	1.64%
Externalized Percentage = 25%	1182	**79%**	2.08%	1.94%
Externalized Percentage = 50%	1253	**84%**	2.48%	2.16%
5-Year Plans				
Externalized Percentage = 0%	811	**54%**	1.10%	1.15%
Externalized Percentage = 10%	1033	**69%**	1.42%	1.42%
Externalized Percentage = 25%	1229	**82%**	1.97%	1.83%
Externalized Percentage = 50%	1280	**86%**	2.41%	2.26%
Rate Option Plans				
3-Year Plans				
No rate option	623	**42%**	1.02%	0.76%
Yearly rate reduction = 1%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	1496	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	623	**42%**	1.02%	0.76%
Yearly rate reduction = 2.5%	623	**42%**	1.02%	0.76%
5-Year Plans				
No rate option	811	**54%**	1.10%	1.15%
Yearly rate reduction = 1%	1496	**100%**	2.64%	2.32%
Yearly rate reduction = 1.5%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2%	811	**54%**	1.10%	1.15%
Yearly rate reduction = 2.5%	811	**54%**	1.10%	1.15%

*** = measured by the average year-over-year percent decrease in costs**

Table B-3. Results From the Incentive Power Model: 50% Initial Inefficiency

	Net Present Value ($m) of Cost Redutions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Regulatory Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	905	**30%**	1.33%	0.75%
3 Year Cost of Service	1430	**47%**	2.36%	1.05%
Full Rate Externalization	3022	**100%**	4.75%	3.05%
Impact of Plan Term				
Term = 3 years	1430	**47%**	2.36%	1.05%
Term = 5 years	1778	**59%**	2.29%	1.65%
Term = 6 years	2143	**71%**	2.37%	1.82%
Term = 10 years	2520	**83%**	3.29%	2.42%
Impact of Earnings Sharing Mechanism				
5-year plans				
No Sharing	1778	**59%**	2.29%	1.65%
Company Share = 75%	1603	**53%**	2.06%	1.36%
Company Share = 50%	1520	**50%**	1.96%	1.22%
Company Share = 25%	1354	**45%**	1.75%	1.02%
Impact of Efficiency Carryover Mechanism 1 (Previous Revenue as Benchmark)				
3-Year Plans, Extern				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	1551	**51%**	2.48%	1.21%
Externalized Percentage = 25%	2017	**67%**	3.17%	1.90%
Externalized Percentage = 50%	2481	**82%**	4.08%	2.42%
5-Year Plans, Extern				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	1979	**65%**	2.52%	1.81%
Externalized Percentage = 25%	2279	**75%**	2.75%	2.02%
Externalized Percentage = 50%	2666	**88%**	3.68%	2.60%
Impact of Efficiency Carryover Mechanism 2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	1430	**47%**	2.36%	1.05%
Externalized Percentage = 10%	2202	**73%**	3.58%	2.20%
Externalized Percentage = 25%	2531	**84%**	4.30%	2.61%
Externalized Percentage = 50%	2793	**92%**	4.61%	2.84%
5-Year Plans				
Externalized Percentage = 0%	1778	**59%**	2.29%	1.65%
Externalized Percentage = 10%	2309	**76%**	2.81%	2.04%
Externalized Percentage = 25%	2558	**85%**	3.68%	2.54%
Externalized Percentage = 50%	2880	**95%**	4.35%	2.88%
Rate Option Plans				
3-Year Plans				
No rate option	1430	**47%**	2.36%	1.05%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	3022	**100%**	4.75%	3.05%
5-Year Plans				
No rate option	1778	**59%**	2.29%	1.65%
Yearly rate reduction = 1%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 1.5%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2%	3022	**100%**	4.75%	3.05%
Yearly rate reduction = 2.5%	1778	**59%**	2.29%	1.65%

*** = measured by the average year-over-year percent decrease in costs**

Impact of Plan Term

Consider now the effect of extending the plan term beyond the conventional three-year rate case cycle. Extending the term from three years to five years increases annual performance gains by about 51 basis points in the long run. Evidently, stronger performance incentives elicit better performance. Extending the term from three years to 10 years increases average annual performance gains by 133 basis points.

The benefits of a longer plan term are greater when rate cases would be more frequent under traditional regulation. For example, if rate cases would otherwise be held every two years, a five-year MRP with no earnings sharing produces 75 basis points of additional annual performance gains in the long run.

Impact of Earnings Sharing

The third panel of Table B-1 shows that the addition of earnings sharing mechanisms (ESMs) reduces cost savings compared to a plan of the same duration with no sharing mechanism. For example, a five-year plan in which the company keeps 75 percent of earnings variances produces only 27 basis points of additional performance gains annually in the long run compared to a three-year rate case cycle.

However, plans with an earnings sharing mechanism can deliver more cost savings than a pattern of frequent rate cases. For example, a five-year plan with 75/25 sharing produces 51 more basis points of annual performance gains than traditional regulation with a two-year cycle.

Impact of Efficiency Carryover Mechanism

Let's consider now the impact of the efficiency carryover mechanism that uses the predetermined revenue requirement from the previous plan as the benchmark. The fourth panel of Table B-1 shows that, in the context of a five-year rate plan, assigning the benchmark a weight of 25 percent produces 35 basis points of additional performance gains. Of greater interest perhaps is that it boosts the performance gains from a three-year plan by a substantial 76 basis points. Thus, this efficiency carryover mechanism can give a three-year plan considerable incentive power.

Let's turn now to the alternative efficiency carryover mechanism approach in which cost in the historical reference year is compared to a *fully external* benchmark such as that produced by an econometric model developed using industry data. Remarkably, the fifth panel of Table B-1 shows that assigning the benchmark a weight of only 25 percent more than doubles the cost savings produced by three-year plans. This suggests that a benchmark-based efficiency carryover mechanism has the potential to strengthen performance incentives rather dramatically. With a *five*-year rate case cycle, the effect of the same 25 percent externalization is still substantial, but more modest than in a three-year cycle. This is mainly due to the fact that more of the potential cost savings are achieved by the five-year term.

Impact of Rate Case Avoidance

Let's turn now to the impact of rate case avoidance. The sixth panel of Table B-1 shows that, in three-year plans with stretch factors of 1 percent, 1.5 percent and 2 percent, this approach produces the same dramatic cost efficiency savings that would result from full rate externalization. Evidently, the company judges that with a high level of cost containment effort it can get its costs permanently below the cost growth target and acts accordingly.

Conclusions

Our incentive power research for this report yields important results on the consequences of alternative regulatory systems. Most fundamentally, the results show that the frequency of rate cases can have a material impact on utility cost performance. Under COSR, performance will be considerably better when rate cases typically occur every three years than when they typically occur every two years. Thus, the favorability of business conditions affects operating performance.

Our research also shows that an MRP with a five-year rate case cycle can simulate the stronger incentives, especially when rate cases are more frequent than every three years. In addition, an MRP should have advantages when the alternative is pervasive cost trackers. Incentives are weakened under an ESM. We also show that adding innovative plan provisions on the frontier of PBR, such as efficiency carryover mechanisms and menus, can materially strengthen performance incentives. Many of the real-world plans reviewed in this report did not have these incentive power "turbochargers."

B.2 Utility Productivity Research

We presented results of our utility productivity research in Section 6 of this report. This section of Appendix B discusses productivity and revenue cap indexes, sources of productivity growth, and productivity trends of U.S. power distributors. We also provide mathematical details of the calculations.

Productivity Indexes

The Basic Idea

A productivity index is the ratio of an output quantity index (Outputs) to an input quantity index (Inputs):

$$Productivity = \frac{Outputs}{Inputs} \qquad [B1]$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. The growth trend of a productivity trend index can then be shown mathematically to be the *difference* between the trends in the output and input quantity indexes.

$$trend\ Productivity = trend\ Outputs - trend\ Inputs. \qquad [B2]$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile but tends to grow over time. The volatility is typically due to fluctuations in output, the uneven timing of certain expenditures, or both. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are considered in the input quantity index. Some indexes measure productivity in the use of a single input class such as labor. A *multifactor* productivity index measures productivity in the use of multiple inputs.

The output (quantity) index of a firm or industry summarizes trends in the scale of operation. Growth in each output dimension that is itemized is measured by a subindex. One possible objective of output research is to measure the impact of output growth on company *cost.* In that case, the sub-indexes should measure the dimensions of the "workload" that drive cost. If there is more than one pertinent scale variable, the weights for each variable should reflect the relative cost impacts of these drivers.[198] A productivity index calculated using a cost-based output index may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

Economies of scale are a second source of productivity growth. These economies are available in the longer run if cost tends to grow more slowly than output. A company's potential to achieve incremental scale economies depends on the pace of its output growth. Incremental scale economies (and thus productivity growth) will typically be reduced when output growth slows.

A third important source of productivity growth is change in inefficiency. Inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth rises (falls) when inefficiency diminishes (increases). The lower the company's current efficiency level, the greater the potential for productivity growth from a change in inefficiency.

Another driver of productivity growth is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. A good example for an electric power distributor is the share of distribution lines that are undergrounded. An increase in the share of lines that are undergrounded will tend to slow multifactor productivity growth (because of the higher capital requirements) but accelerate O&M productivity growth (since there is less line maintenance).

Finally, consider that in the short to medium run a utility's productivity growth is driven by the position of the utility in the cycle of asset replacement. Productivity growth will be slower to the extent that the need for replacement capex is large relative to the existing stock of capital.

Revenue Cap Indexes

Index research provides the basis for revenue cap indexes. The following basic result of cost research is a useful starting point:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Outputs} \qquad \text{[B3]}$$

The cost trend is the difference between the trends in input price and productivity indexes plus the trend in operating scale as measured by a cost-based output index. This result provides the rationale for a revenue cap escalator of the following general form:

$$\textit{growth Revenue} = \textit{growth Input Prices} - X + \textit{growth Outputs} \qquad \text{[B4a]}$$

where

$$X = \overline{MFP} + \textit{Stretch}. \qquad \text{[B4b]}$$

[198] The sensitivity of cost to the change in a business condition variable is commonly measured by its cost "elasticity." Elasticities can be estimated econometrically using data on the operations of a group of utilities. A multiple category output index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver.

Here X, the "X factor," is calibrated to reflect a base MFP growth target ($\overline{MFP}$). A "stretch factor" is often added to the formula which slows revenue cap index growth in a manner that shares with customers the financial benefits of performance improvements expected during the MRP. Since the X factor often includes *Stretch,* it is sometimes said that the index research has the goal of "calibrating" (rather than solely determining) X.

For electric power distributors, the number of customers served is a useful scale variable for a revenue cap index. Relation [B3] can then be restated as:

$$\begin{aligned} &\textit{trend Cost} \\ &\quad = \textit{trend Input Prices} - (\textit{trend Customers} - \textit{trend Inputs}) + \textit{trend Customers} \\ &\quad = \textit{trend Input Prices} - \textit{trend } MFP^N + \textit{trend Customers} \qquad \text{[B5a]} \end{aligned}$$

where MFP^N is an MFP index that uses the number of customers to measure output.

Rearranging the terms of [B5a] we obtain:

$$\begin{aligned} &\textit{trend Cost} - \textit{trend Customers} \\ &= \textit{trend (Cost/Customer)} = \textit{trend Input Prices} - \textit{trend } MFP^N. \qquad \text{[B5b]} \end{aligned}$$

This provides the basis for the following revenue per customer index formula:[199]

$$\textit{growth Revenue/Customer} = \textit{growth Input Prices} - X + Y + Z \qquad \text{[B6]}$$

where

$$X = \overline{MFP^N} + \textit{Stretch.}$$

Productivity Trends of U.S. Power Distributors

Data

The primary source of our cost and quantity data is FERC Form 1. Selected Form 1 data were for many years published by the U.S. Energy Information Administration (EIA).[200] More recently, the data have been available electronically in raw form from FERC and in more processed forms from commercial vendors. FERC Form 1 data used in this study were obtained directly from government agencies and processed by PEG Research. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the Form 1 in 1964 (the benchmark year for our study, described further below)

[199] This general formula for the design of revenue cap indexes is currently used in the PBR plans of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro to develop a plan featuring revenue per customer indexes. Revenue per customer indexes were previously used by Southern California Gas and Enbridge Gas Distribution, the largest gas distributors in the United States and Canada, respectively.

[200] This publication series had several titles over the years. A recent title is Financial Statistics of Major US Investor-Owned Electric Utilities.

and that, together with any important predecessor companies, have reported the necessary data continuously. To be included in the study the data also were required to be of good quality and plausible. One important quality criterion was that there were no major shifts in cost between the distribution and transmission plant. Data from 86 utilities met our standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the productivity trends of U.S. power distributors.

Table B-4 lists the companies from which data were drawn. Most broad regions of the United States are well-represented.[201]

Scope of Research

The total cost of power distributor services considered in the study was the sum of applicable O&M expenses and capital costs. Reported costs of any gas services provided by combined gas and electric utilities in the sample were excluded.[202] We also excluded expenses for purchased power and customer service and information. The featured results employed a geometric decay approach to capital cost measurement that is explained further below. Capital cost is the sum of depreciation expenses, a return on the value of net plant, taxes and capital gains.

We calculated indexes of growth in the O&M, capital, and multifactor productivity of each sampled utility in the provision of power distributor services. Simple arithmetic averages of those growth rates were then calculated for all sampled companies.

---

[201] Unfortunately, the requisite customer data are not available for most Texas distributors.
[202] Gas service costs of combined gas and electric utilities are itemized on FERC Form 1 for easy removal. We exclude customer service and information expenses because on FERC Form 1 these include DSM expenses.

Table B-4. Companies Included in Our Power Distributor Productivity Research

Alabama Power	MDU Resources Group
ALLETE (Minnesota Power)	Metropolitan Edison
Appalachian Power	MidAmerican Energy
Arizona Public Service	Mississippi Power
Atlantic City Electric	Monongahela Power
Avista	Narragansett Electric
Baltimore Gas and Electric	Nevada Power
Central Hudson Gas & Electric	New York State Electric & Gas
Central Maine Power	Niagara Mohawk Power
Cleco Power	Northern States Power - MN
Cleveland Electric Illuminating	Northwestern Public Service
Connecticut Light and Power	Nstar Electric
Consolidated Edison	Ohio Edison
Dayton Power and Light	Ohio Power
Delmarva Power & Light	Oklahoma Gas and Electric
Duke Energy Carolinas	Orange and Rockland Utilities
Duke Energy Florida	Otter Tail Power
Duke Energy Indiana	Pacific Gas and Electric
Duke Energy Kentucky	PacifiCorp
Duke Energy Ohio	PECO Energy
Duke Energy Progress	Pennsylvania Electric
Duquesne Light	Pennsylvania Power
El Paso Electric	Portland General Electric
Empire District Electric	Public Service Company of Colorado
Entergy Louisiana	Public Service Company of Oklahoma
Entergy Mississippi	Public Service Electric and Gas
Entergy New Orleans	Rochester Gas and Electric
Fitchburg Gas and Electric Light	San Diego Gas & Electric
Florida Power & Light	South Carolina Electric & Gas
Georgia Power	Southern California Edison
Green Mountain Power	Southern Indiana Gas and Electric
Gulf Power	Superior Water, Light and Power
Idaho Power	Tampa Electric
Indiana Michigan Power	Toledo Edison
Indianapolis Power & Light	Union Electric
Jersey Central Power & Light	United Illuminating
Kansas City Power & Light	Virginia Electric and Power
Kansas Gas and Electric	West Penn Power
Kentucky Power	Western Massachusetts Electric
Kentucky Utilities	Wheeling Power
Kingsport Power	Wisconsin Electric Power
Louisville Gas and Electric	Wisconsin Power and Light
Massachusetts Electric	Wisconsin Public Service

Number of Sampled Companies: 86

The major tasks in a power distributor's operation are the local delivery of power and the reduction of its voltage. Most power is delivered to end users at the voltage at which it is consumed. U.S. distributors also typically provide an array of customer services such as metering and billing.

Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity trends. We used as a proxy for output growth the growth in the total number of retail customers served.

In calculating input quantity trends, we broke down the applicable cost into those for distribution plant, general plant, labor, and material and service (M&S) inputs. The cost of labor was defined for this purpose as O&M salaries and wages and pensions and other benefits. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The growth of the multifactor input quantity index is a weighted average of the growth in quantity subindexes for labor, materials and services, and power distribution plant.

Sample Period

The full sample period for which productivity results were calculated was 1980-2014.[203]

Index Results

Table B-5 summarizes our productivity research for the full sample. Over the full 1980-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was about 0.45 percent. Customer growth averaged 1.16 percent annually, whereas input growth averaged 0.70 percent. O&M productivity growth averaged 0.53 percent while capital productivity growth averaged 0.43 percent. O&M productivity growth was much more volatile than capital productivity growth.

[203] In other words, 1980 was the earliest year for growth rate calculations.

Table B-5. U.S. Power Distribution Productivity Trends

	Output	Inputs	PFP O&M	PFP Capital	MFP
1980	1.77%	2.26%	-4.19%	1.24%	-0.49%
1981	1.66%	1.49%	-2.42%	1.25%	0.17%
1982	1.63%	0.76%	-1.20%	1.53%	0.87%
1983	0.96%	0.45%	-0.38%	0.98%	0.51%
1984	1.60%	0.33%	-0.22%	1.79%	1.27%
1985	1.71%	0.76%	-0.21%	1.37%	0.95%
1986	1.70%	0.79%	0.88%	0.97%	0.91%
1987	1.77%	1.33%	-0.12%	0.68%	0.44%
1988	1.47%	0.90%	1.55%	0.24%	0.57%
1989	1.49%	1.23%	0.00%	0.23%	0.26%
1990	1.42%	1.25%	0.64%	-0.05%	0.18%
1991	1.17%	1.20%	0.58%	-0.32%	-0.03%
1992	1.12%	0.64%	1.61%	0.10%	0.48%
1993	1.41%	0.96%	1.19%	0.12%	0.45%
1994	1.39%	0.45%	2.44%	0.29%	0.94%
1995	1.40%	0.46%	3.58%	-0.04%	0.94%
1996	1.16%	1.05%	0.67%	-0.13%	0.11%
1997	1.37%	-0.16%	4.68%	0.39%	1.53%
1998	1.54%	0.87%	0.73%	0.71%	0.67%
1999	0.81%	-0.27%	2.24%	0.52%	1.08%
2000	1.37%	0.48%	0.86%	0.73%	0.89%
2001	1.59%	0.39%	2.73%	0.61%	1.20%
2002	1.17%	0.38%	2.73%	0.33%	0.79%
2003	1.14%	1.17%	-1.50%	0.43%	-0.03%
2004	1.06%	0.66%	0.76%	0.22%	0.41%
2005	1.07%	1.14%	-0.25%	0.09%	-0.07%
2006	0.51%	1.03%	-1.07%	-0.21%	-0.52%
2007	1.02%	1.14%	0.00%	-0.02%	-0.12%
2008	0.54%	1.53%	-2.06%	-0.09%	-0.99%
2009	0.26%	-0.75%	2.73%	-0.46%	1.01%
2010	0.45%	0.72%	-0.47%	0.05%	-0.27%
2011	0.28%	-0.22%	0.05%	0.50%	0.50%
2012	0.39%	-0.91%	2.90%	0.58%	1.29%
2013	0.44%	0.41%	0.40%	-0.05%	0.03%
2014	0.65%	0.68%	-1.41%	0.56%	-0.03%
Average Annual Growth Rates					
1980-2014	**1.16%**	**0.70%**	**0.53%**	**0.43%**	**0.45%**
1996-2014	**0.88%**	**0.49%**	**0.77%**	**0.25%**	**0.39%**
2008-2014	**0.43%**	**0.21%**	**0.30%**	**0.15%**	**0.22%**

Over the more recent 1996-2014 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors was similar, at 0.39 percent. Customer growth slowed modestly to average 0.88 percent annually, while input growth averaged 0.49 percent annually. O&M productivity growth accelerated to average 0.77 percent, while capital productivity growth slowed to average 0.25 percent.

Since 2007 the MFP growth of power distributors has slowed modestly, averaging 0.22 percent annually. This is mainly due to a slowdown in O&M productivity growth, which averaged 0.30 percent annually. Capital productivity growth slowed slightly to average 0.15 percent.

Table B-6 provides the annual growth rates in the MFP indexes for the individual utilities in our sample. We report results for the full sample period (1980-2014) and for the 1996-2014 and 2008-2014 sample periods.

<u>Additional Details on Productivity Research</u>

Input Quantity Indexes. The quantity subindex for labor is the ratio of salary and wage expenses to a regionalized salary and wage labor price index.[204] The quantity subindex for M&S inputs is the ratio of the expenses to the GDPPI. Details of the capital quantity index are provided below.

The summary quantity indexes for O&M, capital, and all inputs were of chain-weighted Törnqvist form.[205] This means that their annual growth rate was determined by the following general formula:

$$ln\left(Inputs_t / Inputs_{t-1} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot ln\left(X_{j,t} / X_{j,t-1} \right) \qquad [B7]$$

where in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost

[204] The growth rate of the labor price index was calculated for most years as the growth rate of the national employment cost index (ECI) for the salaries and wages of the utility sector plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole.
[205] For seminal discussions of this index form, see Törnqvist (1936) and Theil (1965).

Table B-6. Power Distributor MFP Trends of Individual U.S. Electric Utilities

	Average Annual MFP Growth Rate		
Distributor	**1980-2014**	**1996-2014**	**2008-2014**
Alabama Power	-0.52%	-0.61%	-0.50%
ALLETE (Minnesota Power)	0.86%	1.32%	0.54%
Appalachian Power	0.12%	0.38%	-0.29%
Arizona Public Service	0.39%	0.88%	0.98%
Atlantic City Electric	0.37%	0.10%	-1.37%
Avista	0.41%	0.09%	-0.71%
Baltimore Gas and Electric	0.35%	-0.06%	-1.08%
Central Hudson Gas & Electric	0.81%	-0.04%	-0.45%
Central Maine Power	0.66%	0.79%	0.28%
Cleco Power	-0.14%	-0.35%	-0.42%
Cleveland Electric Illuminating	0.40%	0.49%	0.05%
Connecticut Light and Power	0.41%	-0.10%	0.03%
Consolidated Edison	0.06%	-0.45%	-0.44%
Dayton Power and Light	0.84%	0.35%	-0.93%
Delmarva Power & Light	0.60%	0.71%	-1.08%
Duke Energy Carolinas	-0.04%	1.09%	0.75%
Duke Energy Florida	0.64%	0.38%	1.00%
Duke Energy Indiana	0.58%	0.08%	-0.09%
Duke Energy Kentucky	0.35%	0.54%	-1.24%
Duke Energy Ohio	0.58%	0.81%	-0.87%
Duke Energy Progress	0.56%	0.65%	1.35%
Duquesne Light	0.64%	0.73%	0.04%
El Paso Electric	0.88%	0.45%	-0.17%
Empire District Electric	-0.09%	-0.26%	-0.65%
Entergy Louisiana	0.63%	0.71%	1.86%
Entergy Mississippi	-0.01%	-0.17%	0.40%
Entergy New Orleans	0.43%	-0.54%	4.37%
Fitchburg Gas and Electric Light	0.34%	0.22%	0.98%
Florida Power & Light	0.84%	0.66%	1.06%
Georgia Power	0.40%	1.11%	1.09%
Green Mountain Power	0.82%	0.52%	1.05%
Gulf Power	0.21%	0.28%	-0.39%
Idaho Power	1.29%	1.48%	1.23%
Indiana Michigan Power	0.30%	-0.02%	-0.46%
Indianapolis Power & Light	0.81%	1.17%	0.86%
Jersey Central Power & Light	0.68%	0.63%	0.84%
Kansas City Power & Light	1.01%	0.76%	0.37%
Kansas Gas and Electric	0.70%	0.57%	0.18%
Kentucky Power	-0.71%	-0.56%	-1.42%
Kentucky Utilities	0.18%	0.01%	-2.38%
Kingsport Power	0.46%	0.23%	-1.33%
Louisville Gas and Electric	0.33%	0.20%	-2.39%
Massachusetts Electric	0.96%	1.10%	0.72%
MDU Resources Group	0.61%	0.76%	1.01%
Metropolitan Edison	1.25%	1.42%	1.06%

Table B-6 (continued) Power Distributor MFP Trends of Individual U.S. Electric Utilities

Distributor	1980-2014	1996-2014	2008-2014
MidAmerican Energy	0.04%	1.22%	2.37%
Mississippi Power	-1.18%	-1.42%	0.65%
Monongahela Power	0.10%	0.57%	0.54%
Narragansett Electric	0.80%	0.57%	-0.03%
Nevada Power	0.99%	1.12%	1.67%
New York State Electric & Gas	1.02%	1.57%	1.51%
Niagara Mohawk Power	0.54%	0.81%	0.68%
Northern States Power - MN	0.73%	0.26%	1.06%
Northwestern Public Service	0.30%	0.68%	1.01%
Nstar Electric	0.40%	0.59%	1.14%
Ohio Edison	0.97%	1.34%	1.02%
Ohio Power	0.28%	0.45%	-0.20%
Oklahoma Gas and Electric	0.14%	-0.07%	-0.49%
Orange and Rockland Utilities	0.82%	0.32%	0.07%
Otter Tail Power	0.00%	0.04%	0.37%
Pacific Gas and Electric	0.24%	-0.04%	0.10%
PacifiCorp	0.08%	1.18%	2.26%
PECO Energy	0.91%	0.16%	-0.21%
Pennsylvania Electric	0.84%	0.94%	1.15%
Pennsylvania Power	0.60%	0.75%	0.51%
Portland General Electric	0.57%	-0.72%	0.10%
Public Service Company of Colorado	0.72%	0.01%	0.90%
Public Service Company of Oklahoma	0.00%	-0.43%	0.07%
Public Service Electric and Gas	0.80%	0.76%	0.49%
Rochester Gas and Electric	1.05%	0.64%	0.97%
San Diego Gas & Electric	-0.31%	-0.41%	0.21%
South Carolina Electric & Gas	0.16%	0.21%	0.02%
Southern California Edison	-0.08%	-0.45%	-1.47%
Southern Indiana Gas and Electric	0.29%	-0.03%	-1.19%
Superior Water, Light and Power	0.57%	0.31%	-0.40%
Tampa Electric	0.97%	0.80%	0.42%
Toledo Edison	1.07%	1.13%	0.94%
Union Electric	0.38%	0.25%	0.45%
United Illuminating	-0.72%	-1.51%	-5.50%
Virginia Electric and Power	0.65%	0.88%	0.64%
West Penn Power	0.83%	1.38%	1.73%
Western Massachusetts Electric	0.75%	1.01%	0.42%
Wheeling Power	0.11%	-0.19%	-1.06%
Wisconsin Electric Power	0.41%	0.11%	0.74%
Wisconsin Power and Light	-0.04%	-0.29%	-0.38%
Wisconsin Public Service	0.82%	0.57%	2.31%
Full Sample Averages	**0.45%**	**0.39%**	**0.22%**

The growth rate of each summary index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable total cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends. The annual growth rate in each company's productivity index is given by the formula:

$$
\begin{aligned}
& ln\left(\frac{Productivity_t}{Productivity_{t-1}} \right) \\
& = ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}} \right) - ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right)
\end{aligned}
\qquad [B8]
$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Capital Cost Measurement. A service price approach is used to measure capital costs. This approach has a solid basis in economic theory and is widely used in scholarly empirical work. In the application of the general method used in this study, the cost of a given class of utility plant *j* in a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year ($XK_{j,\,t-1}$):

$$CK_{j,t} = WKS_{j,t} \bullet XK_{j,\,t-1} \qquad [B9a]$$

It can then be shown mathematically that:

$$growth\ CK_{j,t} = growth\ WKS_{j,t} + growth\ XK_{j,\,t-1} \qquad [B9b]$$

In constructing both indexes we used the geometric decay approach. We took 1964 as the benchmark year. The values for these indexes in the benchmark year are based on the net value of plant as reported in FERC Form 1. We estimated the benchmark year (inflation-adjusted) value of net distribution plant by dividing this book value by a triangularized weighted average of 37 values of an index of utility construction cost for a period ending in the benchmark year.[206] The construction cost index (WKA_t) was the applicable regional Handy-Whitman index of the cost of the relevant asset category.[207]

The following formula was used to compute subsequent values of each capital quantity index:

$$XK_{j,t} = (1-d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [B10]$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant. The economic depreciation rate was set at 4.34 percent for distribution plant. It is based on a weighted average of economic depreciation rates for different types of distribution assets. The depreciation rate also reflects declining balance parameters that were 0.91 for structures and 1.65 for equipment.

---

[206] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This make sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

[207] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

Following is the full formula for the capital service price indexes for each asset category:

$$WKS_{j,t} = [CK_{j,t}^{Taxes} / XK_{j,t-1}] + d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{\left(WKA_{j,t} - WKA_{j,t-1}\right)}{WKA_{j,t-1}}\right]. \quad \text{[B11]}$$

The first term in the expression corresponds to the cost of taxes and utility franchise fees ($CK_{j,t}^{Taxes}$). The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

The calculation of [B11] requires an estimate of the rate of return on capital (r_t). We employed a weighted average of rates of return for debt and equity.[208] Prior to 1995, we relied on a 50/50 average of the average yield on AA utility bonds and ROE using data from Moody's.[209] For subsequent years, we relied on a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data and the average allowed rate of ROE approved in electric utility rate cases for each year as reported by the Edison Electric Institute.[210]

B.3 Statistical Benchmarking

Quantitative performance benchmarking commonly involves one or more gauges of activity. These are sometimes called *key performance indicators* (KPIs) or *metrics.* The values of these indicators for a utility are compared to benchmark values that reflect performance standards. Given information on the cost of a utility and a certain cost benchmark one might, for instance, measure its cost performance by taking the ratio of the two values:

$$\textit{Cost Performance} = Cost^{Actual} / Cost^{Benchmark}.$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in the calculation of benchmarks and are sometimes used in performance appraisals. An approach to benchmarking that features statistical methods is called *statistical benchmarking.*

Econometric Benchmarking

Cost benchmarks should reflect the cost pressures a utility faces. The impact of external business conditions on the costs of utilities can be estimated using statistics. Consider, by way of example, the following simple model of power distributor cost. In a given year t, the cost of power distributor h ($C_{h,t}$) is a function of the number of customers it serves ($N_{h,t}$) and the market wage rate ($W_{h,t}$):

$$C_{h,t} = a_0 + a_1 N_{h,t} + a_2 W_{h,t} \quad \text{[B12]}$$

The parameters a_1 and a_2 determine the impact of the business conditions on cost.

[208] This calculation was made solely for the purpose of measuring productivity trends and does not prescribe appropriate rate of return levels for utilities.
[209] Moody's Public Utility Manual (1995).
[210] Edison Electric Institute.

A branch of statistics called *econometrics* has developed procedures for estimating the parameters of economic functions using historical data.[211] The parameters of a utility cost function can be estimated using historical data on the costs incurred by a group of utilities and the business conditions that they faced. Abundant, high quality data are available for this purpose from the federal government. The sample used in model estimation is typically a "panel" data set that pools time series data for several companies.

Tests can be constructed for the hypothesis that the parameter for a candidate cost driver equals zero. A variable is deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence.

A cost function fitted with econometric parameter estimates may be called an *econometric cost model.* We can use such a model to predict a company's cost given local values for cost driver variables. These predictions are econometric benchmarks. Cost performance can be measured by comparing a company's cost in year *t* to the cost projected for that year and company by the econometric model. There is no need to choose a peer group because the methodology uses the exact business conditions faced by the benchmarked company.

Suppose, for example, that we wish to benchmark the cost of a hypothetical utility called Eastern Edison. We might then predict the cost of Eastern Edison in period *t* using the following model constructed from [B12]:

$$\hat{C}_{Eastern,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Eastern,t} + \hat{a}_2 \cdot W_{Eastern,t} \ . \qquad [B13]$$

Here $\hat{C}_{Eastern,t}$ denotes the predicted cost of the company, $N_{Eastern,t}$ is the number of customers it served, and $W_{Eastern,t}$ measures the wage rate in its region. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = C_{Eastern,t} \big/ \hat{C}_{Eastern,t} \ .$$

Table B-7 provides details of the econometric model of total power distributor cost that is used to set stretch factors in the IRM4 multiyear rate plan in Ontario. There is one input price variable (a capital price index), three scale variables (the number of customers, the retail delivery volume, and peak demand), two additional business conditions (average line length and a system age variable), and a trend variable. Note that the number of customers is the scale variable with the highest parameter estimate and t statistic. This model has a translogarithmic functional form so that, in addition to the "first order terms" representing the basic business condition variables, there are interaction and quadratic terms for the price and output variables. Model parameters were estimated using Ontario data

[211] The estimation of model parameters is sometimes called regression.

Table B-7. Econometric Cost Model for Ontario[212]

VARIABLE KEY

Input Price:	WK = Capital Price Index
Outputs:	N = Number of Customers
	C = System Capacity Peak Demand
	D = Retail Deliveries
Other Business Conditions:	L = Average Line Length (km)
	NG = % of 2012 Customers added in the last 10 years
	Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.6271	85.5530
N*	0.4444	8.0730
C*	0.1612	3.2140
D*	0.1047	3.4010
WKxWK*	0.1253	4.5320
NxN	-0.3776	-1.6160
CxC	0.1904	0.9340
DxD*	0.1646	2.1660
WKxN*	0.0536	3.4540
WKxC	0.0100	0.7200
WKxD	-0.0001	-0.0100
NxC	0.1415	0.7040
NxD	0.0674	0.6790
CxD*	-0.1990	-2.3070
L*	0.2853	13.9090
NG*	0.0165	2.4110
Trend*	0.0171	12.5700
Constant*	12.815	683.362
System Rbar-Squared	0.983	
Sample Period	2002-2012	
Number of Observations	802	

***Variable is significant at 95% confidence level**

[212] Kaufmann, Hovde, Kalfayan, and Rebane (2013), p. 58.

GRID
MODERNIZATION
LABORATORY
CONSORTIUM
U.S. Department of Energy

1 Cyclotron Road
Mail Stop 90-4000
Berkeley, CA 94720
510-486-4000

http://gridmodernization.labworks.org/

Determination of the Second-Generation X Factor for the AUC Price Cap Plan for Alberta Electric Distribution Companies

Mark E. Meitzen, Ph.D.

Vice President
Christensen Associates
March 21, 2016

Table of Contents

1. Introduction

1.1. Qualifications

1. My name is Mark E. Meitzen. I am a vice president at Christensen Associates, an economic consulting and research firm. My business address is 800 University Bay Drive, Suite 400, Madison, Wisconsin. I have been at Christensen Associates since 1990. Prior to that, I was a regulatory economist at Southwestern Bell Telephone Company in St. Louis, Missouri, and I was a member of the economics faculty at the University of Wisconsin–Milwaukee and Eastern Michigan University.
2. I have a B.S. in economics from the University of Wisconsin-Oshkosh and a M.S. from the University of Wisconsin-Madison. I received my Ph.D. in economics from the University of Wisconsin-Madison.
3. Among my various duties at Christensen Associates, I have consulted with firms in a number of network industries, including the telecommunications, electricity, postal, and railroad industries. I have consulted with these industries on a variety of issues including incentive regulation, productivity, costing, and pricing. I have also provided testimony on these issues in regulatory proceedings.
4. I have co-authored a number of productivity studies conducted by Christensen Associates, including numerous analyses performed for former Regional Bell Operating Companies, the United States Telephone Association, the National Cable Television Association, and the Stentor companies in Canada. I have analyzed incentive regulation issues for various network industries including the telecommunications, electric utility, and postal industries. I also directed the Christensen Associates team that analyzed incentive regulation options for Peru's newly-privatized telecommunications industry.
5. Among the articles and reports I have co-authored, I have published articles on total factor productivity, incentive regulation in network industries (electric, gas, and telecommunications), and cross-subsidization issues in electric utility industries. I

was also a principal author of a study of U.S. railroad competition issues commissioned by the U.S. Surface Transportation Board.

6. My curriculum vitae can be found in Appendix A.

1.2. Outline of Evidence

7. In Section 2, I present an overview of the AUC price cap plan for Alberta electric distribution companies. In Section 3, I discuss the establishment of the current X factor for the AUC plan that was based on NERA's TFP study of the U.S. electric distribution industry. Section 4 presents my update of the NERA TFP study. Finally, in Section 5, I present my recommended approach for the X factor in the second-generation of the AUC price cap plan for Alberta electric distribution companies. While it is my opinion that the NERA study is, for the most part, methodologically sound, I strongly disagree with NERA's recommendation in AUC Proceeding 566 that was adopted by the AUC that the entire historical period of the study, dating back to 1972, should be used to determine the forward-looking X factor. In my opinion, more recent history based on moving averages of 10 and 15 years provides a more reliable basis for establishing the X factor.

2. Overview of the AUC Price Cap Plan for Electric Distribution Companies

2.1. Review of Commission's PBR Principles

8. In AUC Decision 2012-237, the Commission spelled out five principles to guide the development of PBR in Alberta that were established in AUC Bulletin 2010-20: [1]

- **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

[1] AUC Decision 2012-237, p. 7.

- **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
- **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
- **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
- **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

9. Dr. Weisman provided an economic interpretation of these principles in his July 2011 submission in AUC Proceeding 566. Overall, Dr. Weisman opined that "The AUC's PBR principles are well grounded in the theory and practice of regulatory economics …"[2] I agree with this assessment and believe that the AUC's Principles provide a proper framework for establishing and updating its price cap plan for Alberta electric distribution companies.

2.2. AUC Price Cap Formula

10. The cornerstone of the AUC PBR plan is based on what is referred to as price cap regulation. A pure price cap formula has the general form of "I – X," where I is a measure of input inflation and X is a measure of productivity growth. Under price cap regulation, the rates that can be charged by the regulated company are governed by a formula that effectively limits changes in rates to some measure of inflation, adjusted for the company's ability to offset inflation with gains in productivity, i.e., the "I – X" formula sets a ceiling on price changes for services that are subject to the price cap. The price cap approach to regulation is based on the

[2] Dennis L. Weisman, Ph.D., "The EDTI PBR Framework: Commission Principles and Economic Foundations," July 22, 2011, p. 3.

proposition that in competitive markets the prices charged for a product or service are determined by the prices of the inputs used to produce the product or service, adjusted for any productivity gains exhibited in combining those inputs to produce the product or service.

11. The price cap formula adopted in AUC Decision 2012-237 augments the "pure" (I – X) price cap formula and has the form:

$$\%\Delta P = (I - X) +/- Y +/- Z +/- K$$

Where

$\%\Delta P$ = allowed change in capped price

I = inflation factor

X = productivity factor

Y = recurring flow through items, collected through Y factor rate adjustments

Z = one-time exogenous adjustments

K = capital trackers collected through K factor rate adjustments.

12. The X factor in the AUC price cap plan is discussed at greater length below. Regarding the other adjustment factors in the plan, the I factor in the AUC price cap plan represents the changes in industry input prices over the term of the PBR plan, consisting of a weighted average of labor costs and other input costs.[3] Y and Z factors provide flexibility for the regulator and the regulated firm to address cost increases that are outside of management's control. K factors provide sources of revenue in addition to that generated by the I – X mechanism to accommodate special circumstances for capital spending.

[3] Labor costs are represented by Alberta average weekly earnings (AWE) for the previous July through June period and other input costs are represented by the Alberta consumer price index (CPI) for the previous July through June period. Weights for the I factor are 55 percent for AWE and 45 percent for CPI. See AUC Decision 2012-237, p. 52.

13. A Y factor accounts for recurring costs, outside the control of management, that the regulated firm passes through to ratepayers. A Y factor acts as a cost pass-through, with changes in these costs leading to changes in the price cap on a dollar-for-dollar basis. Property tax changes, for example, could be treated as Y factors. According to the Commission:

> In a PBR plan, Y factor costs are those costs that do not qualify for capital tracker treatment or Z factor treatment and that the Commission considers should be directly recovered from customers or refunded to them. Y factor costs in turn, could either be costs the company is required to pay to a third party … or other Commission-approved costs incurred by the company for flow through to customers.[4]

14. A Z factor is an exogenous one-time cost[5] that is recovered through a special price increase charged to ratepayers. A Z factor is also an adjustment for changes in costs that are outside the control of the regulated firm's management, but it is designed for changes that only occur infrequently during the term of the price cap. Generally, the regulator reviews each petition for a Z factor, determining whether it meets the criteria that it set out for Z factors at the beginning of the price cap period. For a cost change to be eligible for Z factor treatment, the cost change must be outside the control of the regulated firm, not be implicit in the inflation factor, and be of "material" size. According to the Commission:

> A Z factor is ordinarily included in a PBR plan to provide for exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.[6]

[4] AUC Decision 2012-237, p. 131.
[5] Z factors could also be exogenous one-time revenues.
[6] AUC Decision 2012-237, p. 108.

15. A K factor or capital tracker is designed for circumstances when necessary capital expenditures cannot be reasonably expected to be recovered through rates established by the pure I – X price cap formula. According to the Commission:

> A capital tracker mechanism in a PBR plan is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project required by an external party cannot reasonably be expected to be recovered through the I – X mechanism. The Commission concludes that a structured criteria-based approach provides the most objective method for assessing whether projects qualify as capital trackers.[7]

2.3. Basis of the X Factor in the AUC Price Cap Formula

16. As discussed below, the Commission's approach to setting the X factor spelled out in Decision 2012-237 is based on industry expected annual productivity growth. The productivity concept used in the AUC price cap formula is total factor productivity (TFP), which is defined as the ratio of total output to total input:

$$\text{TFP} = \frac{\text{Total Output}}{\text{Total Input}}$$

17. Thus, industry productivity gains are measured as the percentage change in TFP, which is computed as the percentage change in total output less the percentage change in total input:[8]

$$\%\Delta TFP = \%\Delta Total\ Output - \%\Delta Total\ Input$$

[7] AUC Decision 2012-237, p. 124.

[8] Given that the I factor in the AUC price cap plan measures input inflation as opposed to output inflation, the X factor is based on industry TFP growth. If, on the other hand, the I factor would have been based on a measure of output inflation (as is common in most U.S. telecommunications price cap plans), the X factor would have to make adjustments for differences in productivity and input price growth between the industry and the overall economy. See AUC Decision 2012-237, pp. 87-89. As summarized on p. 89 of the Decision:

> [S]ince both components of the approved I factors can be considered input-based price indexes, there is no need in this case for the Commission to consider an adjustment to TFP for an input price differential or productivity differential in the calculation of the X factor.

18. Total output consists of all the services produced by the relevant unit of production (e.g., a firm or an industry). Total input includes all resources used by the unit of production in providing those services. Typically, TFP studies have three components of total input: capital, labor, and materials. TFP is widely recognized as a comprehensive measure of productive efficiency because, unlike measures of partial productivity, such as labor productivity, TFP provides a measure of the contribution of all inputs used in the production of total output.

19. Given that the X factor in the AUC PBR plan appropriately calls for industry expected productivity growth (per the Commission),[9] it must be determined what productivity growth metric best represents forward-looking productivity growth. In this case, this involves determining the appropriate time frame of the historical measurement of TFP that translates into forward-looking productivity and the appropriate industry grouping that best represents the Alberta electric distribution industry. As discussed below, both of these dimensions were debated during the Commission's previous proceeding, AUC Proceeding 566.[10]

3. Determination of the Current X Factor in the AUC PBR Plan

20. The X factor in the AUC PBR plan consists of expected industry productivity growth and a stretch factor. The current X factor in the AUC PBR plan for the Alberta electric distribution utilities is 1.16 percent, consisting of TFP growth of 0.96 percent and a stretch factor of 0.20 percent. In this section, I review the Commission's Decision 2012-237 that established this X factor.

[9] AUC Decision 2012-237, pp. 52-53.
[10] The use of expected productivity in setting the X factor provides incentives for productivity gains by the regulated firm. In contrast, if the X factor were to be based on actual changes in the regulated firm's productivity, price cap regulation would function similar to cost of service regulation. See Jeffrey I. Bernstein and David E.M. Sappington, "Setting the X Factor in Price-Cap Regulation Plans," *Journal of Regulatory Economics,* Vol. 16, 1999, p. 9.

3.1. Commission's Productivity Criteria Outlined in AUC Decision 2012-237

21. Regarding productivity, the Commission stated a clear preference for expected industry productivity growth as the basis of the X factor. This is consistent with standard, accepted practice. For example:

> [T]he objective of the PBR plan sought by the Commission is to emulate the incentives experienced by companies in competitive markets where prices move according to the productivity of the industry in question rather than with the particular costs of a company.[11]

> In general terms, the X factor can be viewed as the expected annual productivity growth during the PBR term.[12]

22. The Commission also expressed that productivity studies used to establish X (including the NERA study it commissioned) should be based on publicly available data and use a transparent methodology:

> In its September 8, 2010 letter to the parties, the Commission included the use of publicly available data and a transparent methodology as part of the requirements for NERA to meet in respect of its TFP study contributing to a PBR plan.[13]

> … [T]he significance of the objectivity, consistency, and transparency of the TFP analysis to be employed in calculating the X factor cannot be understated.[14]

I agree that it is important that the process of determining the X factor should be based on consistent and transparent methods so that the results of the analysis are amenable to replication.

[11] AUC Decision 2012-237, p. 60.
[12] AUC Decision 2012-237, pp. 52-53.
[13] AUC Decision 2012-237, p. 72.
[14] AUC Decision 2012-237, p. 73.

3.2. The NERA Productivity Study

23. The AUC retained NERA to conduct a productivity study for purposes of setting the X factor. NERA originally submitted its study in 2010[15] and submitted a slightly revised study in 2012 for the first-generation PBR plan.[16] The NERA study estimates total factor productivity growth for the electric distribution function of 72 U.S. utilities over the period between 1972 and 2009. Generation, transmission, and overhead functions are not considered in the analysis. Most of the data used come from the FERC Form 1.

24. Output in the NERA study is measured as a Tornqvist index of residential, commercial, industrial, and public sales, using revenue-based weights. Capital is computed using a perpetual inventory "one-hoss shay" method, with the capital prices and quantities computed on a consistent basis (i.e., the capital rental price is dual to the one-hoss shay capital quantity). The perpetual inventory method uses the 1964 book value of distribution plant in service, the Handy-Whitman index for distribution plant, annual additions to plant, and retirements from plant. The benchmark capital stock quantity is calculated by applying a trailing weighted-average of Handy-Whitman prices to the 1964 book value of plant. Additions to plant are deflated by the current year's Handy-Whitman index value, while retirements are deflated by the Handy-Whitman index lagged by the assumed average lifetime of distribution plant.

25. The quantity of labor is based on an estimate of full-time equivalent employees. Through 2001, this is based on the number of full-time employees, plus one-half of the number of part-time employees. Because the FERC Form I no longer contained employee data after 2001, for the years 2002 to 2009, growth in the U.S. Bureau of Labor Statistics series of wages and salaries in the utilities sector is used to construct

[15] NERA, "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," December 30, 2010.

[16] NERA, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative," February 22, 2012.

a constant dollar estimate of labor input. The cost of materials is residually obtained by subtracting distribution labor costs from distribution operations and maintenance cost. The quantity of materials is obtained by deflating the cost of materials by the Gross Domestic Product Price Index.

26. As I discuss below, it is my opinion that the methodology employed in the NERA study is generally sound and provides an appropriate basis for determining the updated X factor. However, there is one critical adjustment required for updated NERA results to form an appropriate basis of the forward-looking X factor for Alberta electric distribution utilities. Namely, the time frame to use from the historical time period estimated by NERA.[17] I strongly disagree with NERA's original assessment that the entire historical period of the study, dating back to 1972, should be used in establishing the forward-looking X factor.

3.3. Interpretation and Application of the NERA Study in AUC Decision 2012-237

27. In the Commission's opinion, the NERA study met the criteria it established for determining the X factor. The Commission adopted the full study for the 72 companies over the 1972 to 2009 period:

> [T]he Commission opted for an approach to set the X factor based on the average rate of productivity growth in the industry … For this purpose, the Commission engaged NERA to conduct a TFP study applicable to Alberta gas and electric companies. … The study was based on a population of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP of the distribution component of the electric companies. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[18]

---

[17] As discussed below, it was also debated in AUC Proceeding 566 whether the entire sample of companies or some subset of companies included in the NERA study best represented the Alberta electric distribution industry. At this time, I rely on the entire sample of companies.

[18] AUC Decision 2012-237, p. 59.

28. Two areas of controversy in adopting the full NERA study were the appropriate time frame to use and the firms to include for establishing expected industry productivity growth for the purpose of setting the X factor for Alberta electric distribution companies.

29. Regarding the appropriate time frame, there was disagreement between NERA and other experts in the proceeding whether the entire sample period should be used for establishing X:

> NERA recommended the use of its full set of data from 1972 to 2009 … The majority of other parties recommended a substantially shorter period.[19]
>
> The companies' experts contended that NERA's sample period, especially the early part of it, was not relevant for estimating the industry's current TFP trends or the trends that might be expected to prevail during the PBR term.[20]

30. The Commission agreed with NERA that there was no structural break in the series and adopted the full period of the NERA study:

> The Commission agrees with NERA's view that a deviation from reliance on the longest period of available data requires support that a structural break in the industry has occurred. The Commission also agrees that the determination of whether a structural break has occurred demands the scrutiny of academic experts, peer review and testing by parties independent of the current proceeding.[21]
>
> With respect to the electric industry restructuring, the Commission observes that NERA used data only on the distribution portion of the sampled companies' businesses. In the Commission's view, this approach sufficiently mitigates

[19] AUC Decision 2012-237, p. 61.
[20] AUC Decision 2012-237, p. 62.
[21] AUC Decision 2012-237, p. 65.

> the concerns about the impact of industry restructuring on the TFP estimate.[22]
>
> In the Commission's view, NERA's approach of using the longest time period available allows a smoothing out of the effects of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle.[23]

As discussed below, NERA's criteria for use of anything other than the full 1972-2009 time period for establishing the X factor for the electric distribution industry are specious and create a non-credible, almost impossible standard for determining the appropriate forward-looking X factor from the historical record.

31. While there was general agreement that NERA's use of U.S. data was appropriate (particularly given that comparable Canadian data are not available), there were a number of parties that opined that a subsample of U.S. companies that better represented conditions faced by companies in Alberta was better-suited for establishing the X factor than was the entire sample of 72 U.S. companies. However, the Commission disagreed with this position and chose to use the entire sample of U.S. companies in the NERA database:

> [T]he Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities. … [T]he Commission agrees … that given the generally perceived similarity of both the utility regulatory systems in Canada and the United States, as well as the organization of the utility industries in the two countries, the U.S. power distribution industry TFP growth trend is a reasonable starting point in establishing a productivity estimate for the Alberta companies.[24]

---

[22] AUC Decision 2012-237, p. 65
[23] AUC Decision 2012-237, p. 66.
[24] AUC Decision 2012-237, p. 71.

> Under the approach adopted by the Commission, the focus of the TFP study is on the industry productivity growth rate, not levels. As NERA explained, in this case the manifest differences between the companies in terms of their geographic areas and climatic conditions, operational characteristics, regulatory regime, size or any other consideration do not matter as much to the study as it only deals with the average of year to year changes in productivity growth. As such, the unique cost features of any particular company cancel out in the process.[25]
>
> The Commission agrees with NERA's characterization that the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta.[26]

In my opinion, the entire sample of companies contained in the sample used by NERA was and continues to be an appropriate approach for the AUC price cap plan.

3.4. Stretch Factor

32. A stretch factor is often added to the X factor of first-generation PBR plans to account for the expected increase in productivity growth as an industry transitions from traditional cost of service regulation to PBR. Since the X factor is often based on studies of historic productivity growth whose data represent a period before the industry moves to PBR, the stretch factor is seen as a forward-looking adjustment to the historically-measured productivity growth to account for the changes in incentives:

> The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.[27] … The Commission agrees with Dr. Weisman that the transition from cost of service regulation to PBR provides an opportunity to realize

[25] AUC Decision 2012-237, p. 70.
[26] AUC Decision 2012-237, p. 70.
[27] AUC Decision 2012-237, p. 100.

> more easily-achieved efficiency gains (the "low hanging fruit") due to increased incentives.[28]

Moreover, as the Commission has appropriately noted, the stretch factor is typically based on the regulator's judgement and is not quantitatively based:

> [T]he determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a "definitive analytical source" like the TFP study represents. … Taking into account the fact that the companies are moving from a cost of service regulatory framework to PBR, and being cognizant of the uncertainties associated with the change in regulatory framework, the Commission is taking a conservative approach to setting a stretch factor. … The Commission has considered the recommended stretch factors and finds a 0.2 per cent stretch amount to be reasonable.[29]

As Dr. Weisman notes in his evidence, beyond first-generation PBR plans, the case for including a stretch factor becomes weaker in subsequent generations of a plan.[30]

3.5. Summary

33. Ultimately, the AUC established an X factor of 1.16 percent, based on TFP growth of 0.96 percent from the full NERA sample of companies over the 1972-2009 period, and a stretch factor of 0.2 percent.

> [T]he Commission finds that no adjustments to the industry TFP growth rate are required when establishing the X factors for the companies. Accordingly, the Commission finds that the X factor to be used in the PBR plans of the electric and gas distribution companies prior to consideration of a stretch factor is 0.96 per cent. … [T]he Commission determined that a stretch factor of 0.2 per cent will apply to the companies' PBR plans for the duration of the PBR term. Accordingly, the

[28] AUC Decision 2012-237, pp. 100-101.
[29] AUC Decision 2012-237, p. 104.
[30] Dennis L. Weisman, "Designing the Second-Generation PBR Framework: Commission Principles and Economic Foundations," March 21, 2016, Section 5.2.

> Commission finds that the total X factor for the electric and gas distribution companies, inclusive of a stretch factor, will be 1.16 per cent.[31]

4. Update of the NERA Study

34. As I noted above, it is my opinion that the methodology employed in the NERA study is generally sound and provides an appropriate basis for determining the updated X factor. Below, I report updated results through 2014 for TFP growth estimated using the NERA methodology. In the next section I assess the updated results to determine the appropriate forward-looking X factor in the second-generation price cap plan for the Alberta electric distribution industry.

4.1. Updating Procedure and Methodological Adjustments

35. Data are now available to extend the NERA study through 2014. Most of the data used to update the NERA study come from the FERC Form 1 reports submitted by the regulated utilities. The FERC Form 1 reports provide a comprehensive look at the financial and operating performance of each reporting utility. The U.S. Federal Energy Regulatory Commission posts the company data on their web site and provides software that can be used to download and view these data. We used this software to download the needed FERC Form 1 data and add those data to the NERA database.

36. The FERC database shows that some utilities in the NERA database did not submit FERC Form 1 reports for all years. In these cases, utilities stopped reporting data because they were merged with other operating companies. The following is the list of utilities that did not submit reports in all years and the last year when they did report: Central Illinois Light Company (2010), Columbus Southern Power Company (2010), Illinois Power Company (2010), and Central Vermont Public Service Corporation (2012).

---

[31] AUC Decision 2012-237, p. 107.

37. In the original NERA study, the Gross Domestic Product Price Index was used in the construction of the quantity of materials. Specifically, the quantity of materials was derived by dividing the cost of materials by the Gross Domestic Product Price Index. I updated the Gross Domestic Product Price Index using data published on the U.S. Bureau of Economic Analysis web site. I also obtained updated values of the Handy-Whitman indexes used to convert book values of additions and retirements to constant dollar values in the construction of capital input.

38. NERA constructed the price of capital input using data on annual yields that it obtained from a variety of sources. The annual yields are used to impute expected future rates of return on investment. I was unable to access the data sources used by NERA to update its values of the annual yields, so I used the 2009 values for the subsequent years. I note that the price of capital is only used to weight the quantity of capital relative to other inputs, so that this alternative approach to measuring the price of capital does not significantly affect the results of the TFP analysis and the results of my update are reliable.

39. In updating the NERA results I discovered an error in its measurement of labor input. Up until 2001, companies reported their number of full-time and part-time employees across all utility operations (total employees). NERA constructed a quantity of labor input for distribution by converting the total number of employees to a full-time equivalent number and then multiplying this by the ratio of distribution salaries to total salaries. Beginning in 2002, companies no longer reported the total number of full-time and part-time employees, so NERA extended these series by a constant dollar measure of distribution salaries. Since NERA was extending the total number of full-time and part-time employees, and not the count of distribution full-time and part-time employees, it would have been correct to extend the series using constant dollar total salaries, not constant dollar distribution salaries. I made this correction for all years after 2001 in my update. Once I extend the number of full-time equivalent employees using this alternative method, I

multiply this by the ratio of distribution salaries to total salaries to get distribution labor input.

4.2. Results

40. Table 1 summarizes the results of my update of the NERA TFP study through 2014. The top portion of Table 1 shows annual average growth over the time frame of the initial NERA study for the entire 1972-2009 period, and the bottom portion of Table 1 shows updated results through 2014. The results through 2009 are slightly different than those of the initial NERA study because of the correction to the labor input measure and revisions to the Bureau of Economic Analysis Gross Domestic Product Price Index. As noted above, a number of experts disagreed with NERA's assessment that the entire time period should be used for determining the X factor.[32] As representative of that disagreement, I also include the 1999-2009 and 1999-2014 periods in Table 1. Results for individual years are found in Appendix B Table B.1.

Table 1
Electric Distribution Industry Output, Input, and TFP Growth
1972-2014

	Output	Input	TFP
1972-2009	2.10%	1.12%	0.98%
1999-2009	0.69%	1.29%	-0.60%
2009-2014	0.16%	1.44%	-1.28%
1972-2014	1.87%	1.16%	0.71%
1999-2014	0.51%	1.34%	-0.83%

41. Table 1 shows that the negative trend in electric distribution industry TFP growth previously documented for the 1999-2009 period has continued and has

[32] For example, EPCOR witness Cicchetti recommended the 1999-2009 period, Fortis witness Frayer and AltaGas witness Schoech recommended the 2000-2009 period, and CCA witness Lowry recommended the 1988-2007 period. See AUC Decision 2012-237, pp. 62-63.

accelerated. The decline in TFP growth has been largely driven by a decline in output growth and that trend has continued, and has even accelerated, into the 2009-2014[33] period as output growth substantially diminished from its 0.69 percent annual average over the 1999-2009 period to an annual average growth of 0.16 percent over the 2009-2014 period. In contrast, input growth has remained relatively constant and actually increased somewhat in the 2009-2014 period.

42. Independent research published in the *Electricity Journal* finds that this reduction in output growth can be explained by a change in the long-term relationship between growth in economic activity and electricity use. Since the 1970s, electricity use and GDP had grown at comparable rates. However, the ratio of electricity consumption to GDP has been on a downward trend since the mid-1990s and, since 2007, the economy has generated GDP growth with almost no net growth in electricity demand:

> [T]he correlation between electricity consumption and GDP expansion diverged after about 1996, when the GDP growth rate greatly exceeded the electricity consumption rate. … Electricity consumption growth and GDP growth occurred at a similar pace from 1973 to 1996; however, after 1996, the correlation deviated significantly. … [E]lectriciy consumption has remained flat from 2007 to 2014, even as real GDP grew 8 percent.[34]

The TFP data presented here reflects the findings of this research as it shows lower TFP growth resulting from the noted reduction in electricity consumption growth and, consequently, lower output growth. As shown in Table 2, over the period 1996 to 2014, output grew at an annual rate of 0.75 percent, input grew at an annual rate of 1.39 percent, and TFP grew at an annual rate of -0.64 percent. This is in contrast to much higher average TFP growth in the 1972-1996 period, which was largely

[33] The updated results have growth rates beginning in 2010 with the base year of 2009 for the 2010 growth rate. Thus, standard practice is to refer to this period as 2009-2014.
[34] Richard F. Hirsh and Jonathan G. Koomey, "Electricity Consumption and Economic Growth: A New Relationship with Significant Consequences?" *The Electricity Journal,* November 2015, Vol. 28, Issue 9, p. 75.

driven by significantly greater output growth. During the 1972-1996 period, output growth averaged 2.70 percent, input growth averaged 0.98 percent, and TFP growth averaged 1.72 percent. Finally, coincident with the flat electricity consumption noted over the 2007-2014 period, output growth dropped sharply to an annual average rate of -0.72 percent, input grew at an annual rate of 1.35 percent, and TFP grew at an annual rate of -2.07 percent.

Table 2
Electric Distribution Industry Output, Input, and TFP Growth:
Periods Marked by Changes in Energy Consumption-Economic Growth Relationship

	Output	Input	TFP
1972-1996	2.70%	0.98%	1.72%
1996-2014	0.75%	1.39%	-0.64%
2007-2014	-0.72%	1.35%	-2.07%

43. Figure 1A shows electric distribution industry output, input, and TFP depicted graphically for the 1972-2014 period and Figure 1B focuses on TFP.[35] Consistent with the independent research cited, it is clear from Figure 1A that the primary driver of the reduction in TFP growth to its current negative state has been negative output growth. Figure 2 presents the annual growth rates in electric distribution industry TFP from 1972 to 2014.

[35] Both of these figures show index levels based at 1972 = 1.0.

Figure 1A
Electric Distribution Industry Output, Input, and TFP
1972-2014

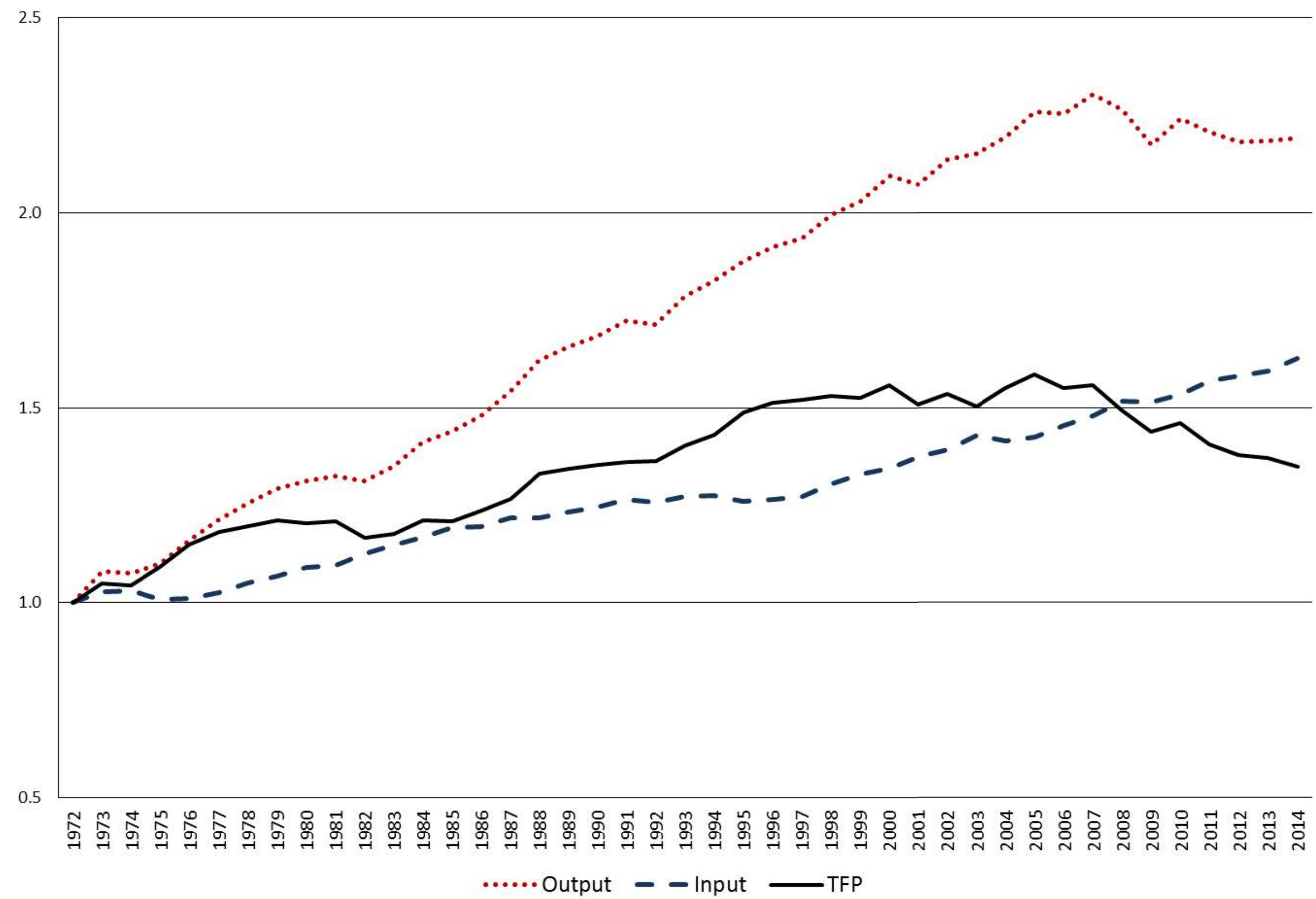
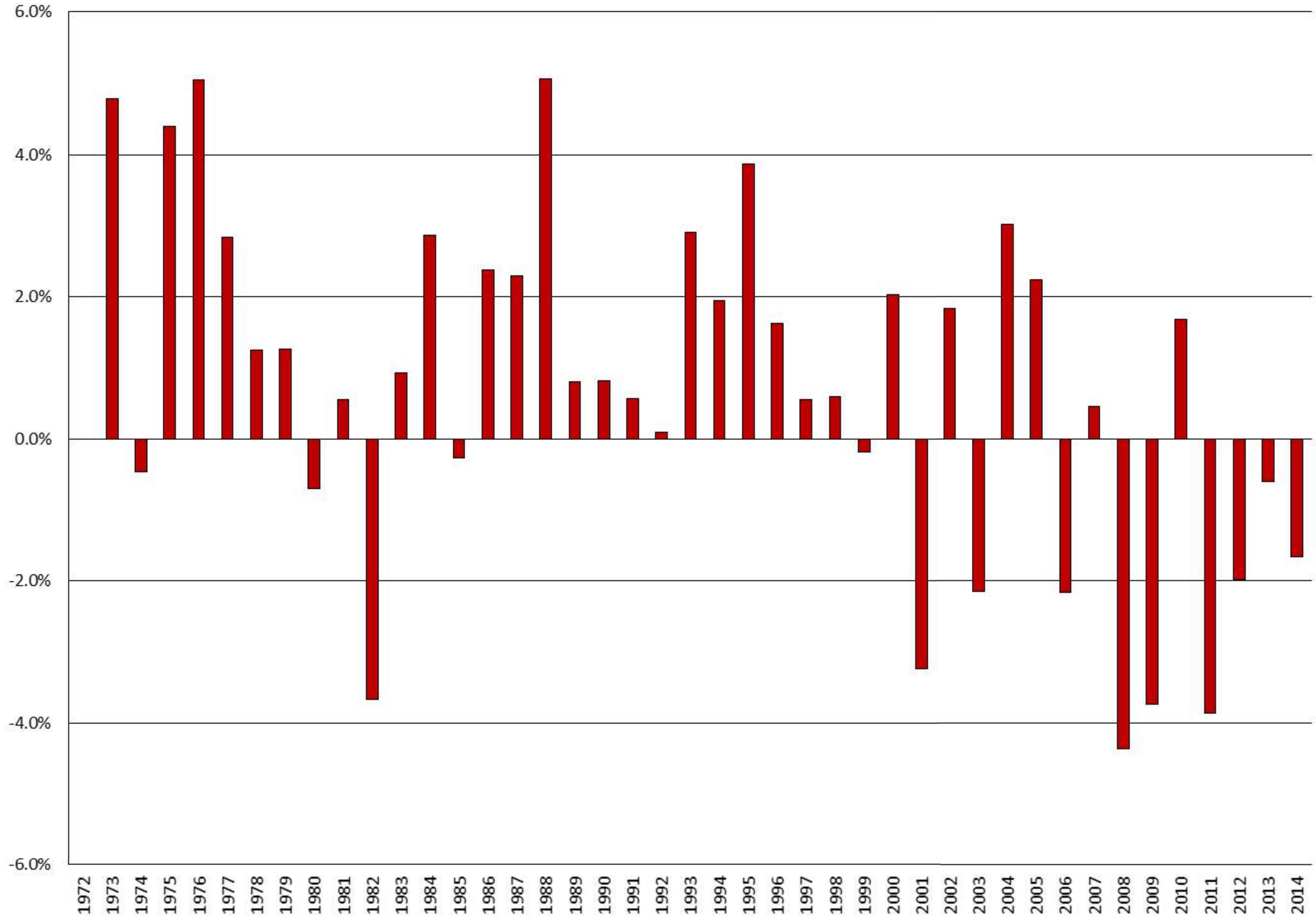


Figure 1B
Electric Distribution Industry TFP
1972-2014

Figure 2
Electric Distribution Industry Annual TFP Growth
1972-2014



5. Determination of the X Factor for AUC's Second-Generation PBR Plan

44. While it is my opinion that the NERA study is, for the most part, methodologically sound, I strongly disagree with NERA's original assessment that the entire historical period of the study, dating back to 1972, should be used in establishing the forward-looking X factor. In this section, I first respond to NERA's justification for using the entire 1972-2009 time period for establishing the X factor in the AUC price cap plan. Next, I assess NERA's recommendation in the context of predicting the forward-looking X factor. I then provide my opinion of the appropriate application of the updated NERA study for determining the second-generation X factor.

5.1. NERA's Justification for Using the Entire 1972-2009 Time Period for Establishing the X Factor is Misguided

45. NERA's position that the entire 1972-2009 time period should be used to determine the X factor is untenable. In fact, NERA's own academic research and its 2010 submission in AUC Proceeding 566 clearly show that the series has changed over time, rendering its position that the entire time period be used not credible:

> TFP growth … fluctuates considerably year to year and … in more recent years exhibits sharp declines. The fastest TFP growth occurred in 1976 at 4.96 percent while the slowest TFP growth occurred in 2008 at -5.26 percent.[36]

46. NERA's reasoning that use of any other period for determining the X factor must be based on disinterested or scholarly sources is a red herring; it imposes an impractical, unnecessary standard on the determination of the X factor.

> [T]here is no evidence of which we are aware, from disinterested or scholarly sources outside this proceeding, of

[36] Jeff D. Makholm, Agustin J. Ros, and Meredith A. Case, "Total Factor Productivity and Performance-Based Ratemaking for Electricity and Gas Distribution," presented at the 31st Annual Eastern Conference of the Center for Research in Regulated Industries, May 2012, p. 14. Also see NERA, "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," December 30, 2010, p. 17.

> an event or a circumstance that so changed the nature of the utility businesses tracked by the FERC Form 1 as to invalidate the relevance of the longest period represented by those data. … We know of no *ex ante* basis to be selective regarding the time period used to compute average TFP growth for the industry. In the absence of such external or scholarly reasons for truncating the time period, we continue to support the use of the largest time period available for empirical study as the most objective basis for the TFP component of a well-structured PBR plan.[37]

While there is no doubt that witnesses in this proceeding are providing testimony on behalf of interested parties, in my opinion it serves no useful purpose to impose such an unreasonable condition on a rational, valid investigation of the appropriate value for the forward-looking X factor for the Alberta electric distribution industry.

47. NERA's position is logically flawed and demonstrably false. To illustrate, at one point, NERA blindly asserts that, "The conventional assumption that the industry productivity and input prices are characterized by a stable trend is valid."[38] NERA provides no support for its claim that the alleged stable trend represents "the conventional assumption," and it employs strained logic to avoid testing the unconfirmed assertion of a stable trend:

> We have not attempted a structural break test, as we have seen no evidence from outside this proceeding to lead us to believe that the nature of the utility distribution business has changed in a way that would require such a break to be imposed on the available Form 1 data.[39]

This statement by NERA is nothing more than a smokescreen to cover its flawed approach. NERA's reasoning is fallacious as a matter of scientific inquiry as it is fully

[37] NERA, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative," February 22, 2012, p. 5.
[38] NERA, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative," February 22, 2012, p. 16.
[39] NERA, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative," February 22, 2012, p. 16.

contradicted by the types of "structural break" tests suggested by NERA itself.[40] These tests do not require *a priori* or independent evidence of the existence of such a break as a pre-condition for testing. By design, the tests are purely statistical and "let the data do the talking;" the procedures are entirely dependent on the data and do not depend on, or require, any other information outside of the data.

48. NERA's unsupported, faulty assertions only serve to divert attention from the determination of an informed, reasoned approach to the appropriate determination of the X factor. Bolstered by its erroneous and curious reasoning, NERA largely ignored the arguments and evidence set forth by various parties in AUC Proceeding 566. In contrast to NERA's reticence to admit there may have been relevant changes in the industry or that distant history was not relevant for the purposes of establishing the AUC X factor, a number of witnesses in AUC Proceeding 566 documented a variety of factors that would cause the trend rate of growth in the TFP data series to change over time. For example, the following were among the reasons provided for why the entire 1972-2009 period was inappropriate for establishing the forward-looking X factor:

- Changes in investment trends
- Technology deployments
- Changes in operating practices
- Changes in customer consumption patterns
- Regulatory incentives
- Industry restructuring
- Business cycles[41]

[40] NERA, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative," February 22, 2012, pp. 15-16. It should be noted that NERA's discussion is not comprehensive as it does not include all possible approaches for these types of tests.

[41] See AUC Decision 2012-237, pp. 61-63.

49. While there may have been disagreement over the precise events and dates provided by the various witnesses, changes in the industry did have a significant impact on industry TFP growth, and the trend relied upon by NERA did change over time (as evidenced by Tables 1 and 2). At the very least, these factors provide ample evidence that using the TFP series dating back to 1972 was not an appropriate basis for establishing the forward-looking X factor. In addition, as I have cited above, disinterested, scholarly research has documented that the relationship between economic activity and electricity consumption has significantly changed in more recent years,[42] further invalidating NERA's false and untested assertion of the existence of a stable trend in industry TFP.

5.2. NERA's Recommendation as a Predictor of the Forward Looking X Factor Fails

50. As noted above, the Commission has appropriately interpreted the X factor as representing the expected annual productivity growth over the term of the price cap plan and, thus, forward looking:

> In general terms, the X factor can be viewed as the expected annual productivity growth during the PBR term.[43]

Therefore, per the Commission, the role of a TFP study in determining the X factor is as a predictor of expected annual productivity growth over the course of the subsequent price cap term.

51. When viewed as a reasonable predictor of forward-looking productivity growth and the X factor, NERA's recommendation of average TFP growth of 0.96 percent over the 1972-2009 period (to which a 0.20 percent stretch factor was added for an X factor of 1.16 percent) is not supported by the available evidence and, thus, fails as a

[42] Richard F. Hirsh and Jonathan G. Koomey, "Electricity Consumption and Economic Growth: A New Relationship with Significant Consequences?" *The Electricity Journal,* November 2015, Vol. 28, Issue 9, pp. 72-84.
[43] AUC Decision 2012-237, pp. 52-53.

valid approach for determining the X factor.[44] As documented above, industry TFP growth over the 2009-2014 period averaged -1.28 percent per year, meaning that NERA's recommendation over-predicted TFP growth by 2.24 percentage points per year. In essence, the original X factor based on NERA's recommendation contained a stretch factor that was more than 11 times the stated stretch factor of 0.20 percent. The significant magnitude of this over-prediction can be illustrated by noting that, based on EPCOR's 2012 revenue requirement, this would amount to a revenue reduction of $3.2, or approximately 7.5 percent of EDTI's net income.[45]

52. To further put this sizeable over-prediction in context, Figure 3 shows the cumulative difference in price cap indexes between the X factor based on NERA's recommendation and the actual path of TFP growth over the 2009-2014 period.[46] As shown in Figure 3, by the end of the five-year price cap period, rates would have been 11.6 percent higher under the average actual industry TFP growth over this period (plus a 0.20 percent stretch factor) than they were under the implemented price cap with the 1.16 percent X factor based on NERA's recommendation. Clearly, the over-prediction of the X factor by NERA's method and the resulting constraint it put on rates contributed to the overall capital funding shortfall experienced by EPCOR with cumulative K factor amounts that were higher than would be the case had the X factor been set at a reasonable value.

53. When viewed in the context of the Commission's PBR Principles, it is clear that the X factor based on NERA's proposal did not meet the objectives embodied in these

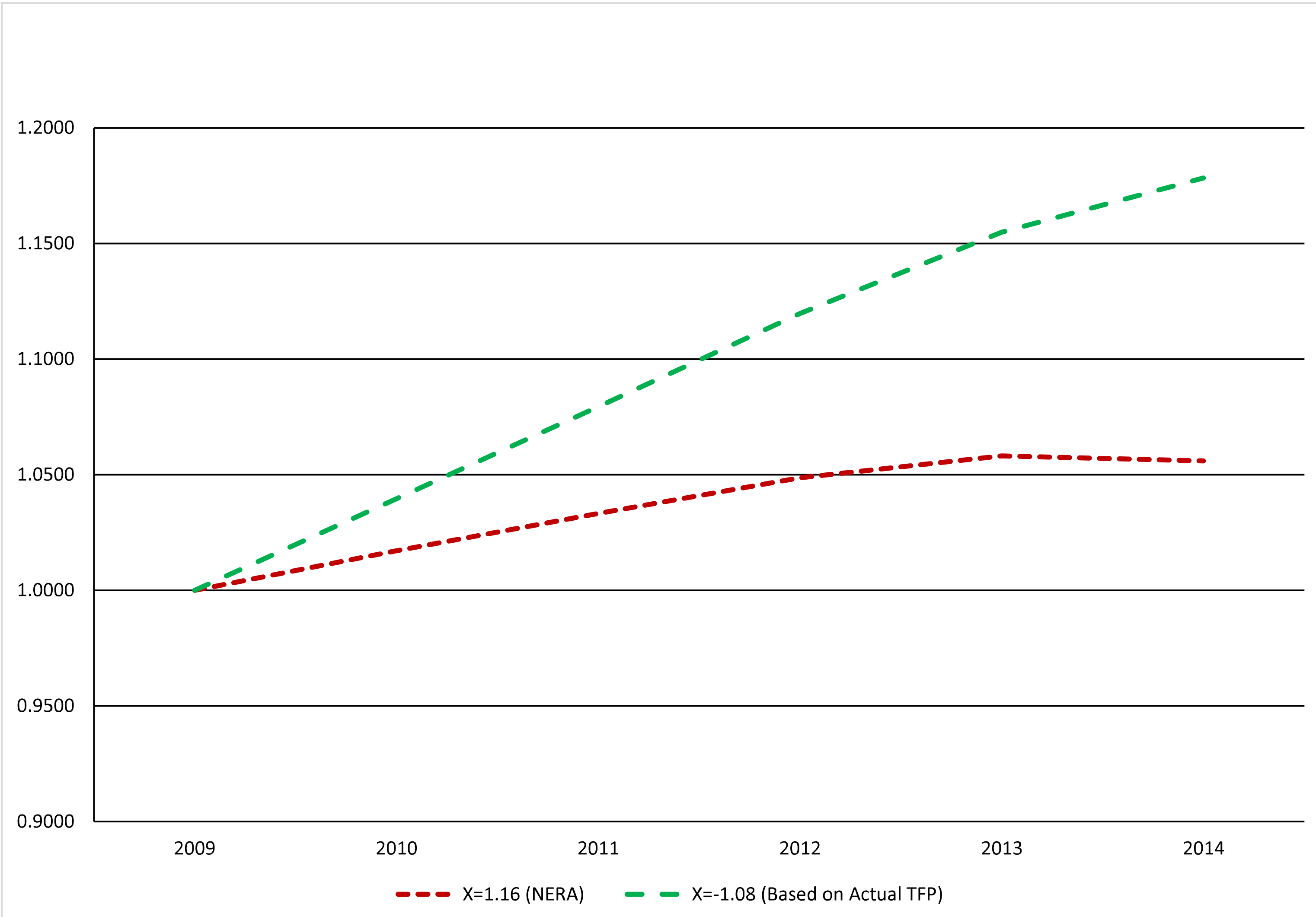
[44] CCA witness Lowry recommended using the 1988-2007 time frame of the NERA study. This would have produced an X factor of 0.83 percent (excluding the stretch factor) with the updated NERA data. The 1999-2009 period recommended by EPCOR witness Cicchetti would have produced an X factor of -0.60 percent (excluding the stretch factor), and the 2000-2009 period recommended by Fortis witness Frayer and AltaGas witness Schoech would have produced an X factor of -0.90 percent (excluding the stretch factor) with the updated NERA data.

[45] Approved 2012 Revenue Requirement = $143.6 million, EDTI 2012 Rule 005 Filing, Schedule 1, line 17; Approved 2012 Return = $42.7 million, EDTI 2012 Rule 005 Filing, Schedule 2, 2012 Decision, line 4; revenue reduction = 2.24% × $143.6 million = $3.2 million; portion of net income = $3.2 million ÷ $42.7 million = 7.5%.

[46] Given that Figure 3 illustrates alternative paths of the price cap index over time, a 0.20 percent stretch factor is added to both the NERA recommended TFP growth and the actual average 2009-2014 TFP growth.

Principles. A more appropriately calibrated X factor would have allowed the Commission to better achieve the goals stated in its PBR Principles of creating the same efficiency incentives as those found in competitive markets, providing the company with a reasonable opportunity to recover its prudently incurred costs, and having both customers and regulated companies share in the benefits of PBR.

Figure 3
Comparison of Price Cap Indexes with X Factors Based on NERA and Actual TFP Growth
2009-2014



5.3. The Second-Generation X Factor for the 2018-2022 Period

54. Just as the entire 1972-2009 time period was not appropriate for determining the X factor for the initial AUC price cap plan, the entire updated period, 1972-2014, is not appropriate for determining the second-generation X factor for the Alberta electric distribution industry. NERA's proclamation of a "stable trend" over the entire period is simply not true for either the original sample or for the updated sample. Moreover, use of this "trend" as a predictor of the forward-looking X factor was and continues to be fundamentally deficient.[47]

55. What is relevant in this case is not a discourse on what the long-term trend in industry TFP is or ought to be, but what is a good-faith, reliable estimate of the forward-looking X factor over the next five years of the plan, 2018-2022, at which time another review will take place. In this respect, the goal is to use the historical TFP series to produce a reasonable basis for the second-generation X factor. In achieving this goal, it is important to satisfy the Commission's desire for a transparent methodology that does not "cherry pick" results. By the same token, it is counterproductive to strive for an "optimal" methodology that is totally objective and devoid of judgement. This is simply not possible as any reasonable methodology will involve a degree of judgement. In this case, given the performance of electric distribution industry TFP, reasonable methodologies will likely produce a TFP basis for the second-generation AUC X factor less than zero.[48]

---

[47] I have examined a variety of structural break tests following NERA's recommendation that such tests should be used to assess whether there are any changes in the trend of TFP growth that could inform the determination of the X factor. The choice of tests, their application and results are a matter of judgement as unanimity does not exist regarding the appropriate testing procedure. I conclude that, in this application, these types of tests do not provide a clear consensus on break points and, thus, do not provide an unambiguous, objective approach for determining the forward-looking X factor as implied by NERA.

[48] In addition to my recommended approach outlined below, average TFP growth over other periods that could be considered as a basis for the forward-looking X factor also produce negative results. For example, average annual TFP growth over the last five years of available data (2010-2014) was -1.28 percent, over the last 10 years of available data (2005-2014) was -1.40 percent, and over the last 15 years of available data (2000-2014) was -0.83 percent.

56. As cited above, the parties in AUC Proceeding 566 had recommended various time periods in the NERA series to establish the best estimate of TFP growth for the forward-looking X factor. Abstracting from the particular years recommended or the events that were the basis of the recommendation, these recommendations generally spanned a 10- to 15-year period. Taking a neutral position on the factors underlying these recommendations, this span of years provides a sufficiently long period that overcomes transient, short-run shocks that could influence TFP growth (such as with a 5-year average) and also avoids anchoring the forward-looking estimate with values from the distant past that no longer provide a reasonable basis for establishing a forward-looking X factor.

57. While judgement cannot be completely eliminated in the process of determining an appropriate X factor, by basing it on a moving average approach using the latest 10 or 15 years of available TFP data, independent of particular events and varying interpretations of these events, the Commission's concern with cherry-picking dates or time periods would be addressed. In my opinion, this approach is superior to the NERA approach for "smoothing out of the effects of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle." [49] Absent clear, unambiguous evidence of factors calling for specific time periods, this moving average approach best balances the desire for objectivity and transparency with the need to determine a reasonable and appropriate X factor.

58. For these reasons, I recommend basing the X factor for the second-generation AUC price cap plan on an average of the most recent 10- and 15-year intervals of industry TFP growth (the "10/15 moving average"). This approach effectively weights the most recent 10 years more heavily than the earliest five years of the 15-year

[49] AUC Decision 2012-237, p. 66.

interval.[50] Thus, more recent experience counts more as a basis for the X factor, but this is tempered by the longer term represented by the earliest five years of the longer interval.[51] Given the volatility of the electric distribution TFP series, this approach provides a balance between using more recent data that are likely to more heavily influence the short-term future (which is the relevant time frame for determining the forward-looking X factor) with the stability provided by longer-term averages. I further recommend that these averages would be rolled forward to the end point of the latest available at the time the next price cap review takes place. Averaging over these intervals that are specified without regard to particular events eliminates a significant degree of subjectivity in determining the appropriate interval for forecasting the forward-looking X factor.

59. To illustrate the appropriate use of historical TFP growth as a basis for a forward-looking X factor, Figures 4a and 4b compare the 10/15 moving average and the NERA approach of using all available data to that point predict future TFP growth over the next five years. The figures run between 1987 and 2009, as 1987 is the first year in the series for which a 15-year average can be computed, and 2009 is the last year in series for which a forward-looking five-year average can be computed. Figure 4a shows the actual values of the 10/15 moving average, the NERA average, and next five-year average at that point in time, and Figure 4b shows the percentage point difference between the respective 10/15 and NERA averages and the next five-year average at that point in time. So, for example, in Figure 4a the plots for 1987 show the following:

- the “10/15” line shows the 10/15 year moving average in 1987;

[50] Specifically, for the 15 years in the average, each of the most recent 10 years has a weight that is 2.5 times the weight of each of the earliest five years. The weight for each of the most recent 10 years is 8.33 percent and the weight for each of the earliest five years is 3.33 percent.

[51] I have not included a stretch factor in my recommendation. As I noted above, in principle, stretch factors are implemented in first-generation PBR plans and, *ceteris paribus*, represent a transition to expected greater TFP growth due to a switch from cost of service regulation to PBR.

- the "NERA" line shows the average over the 1972-1987 period (all available data to that point); and
- the "Next 5 Yrs" line shows actual average growth over the 1988-1992 period.

The last data point in Figure 4 occurs in 2009 since the last five-year average TFP growth occurs after 2009 (i.e., 2010-2014). In this case, the plots for 2009 show the following:

- the "10/15" line shows the 10/15 moving average in 2009;
- the "NERA" line shows the average over the 1972-2009 period (all available data to that point); and
- the "Next 5 Yrs" line shows actual average growth over the 2010-2014 period.

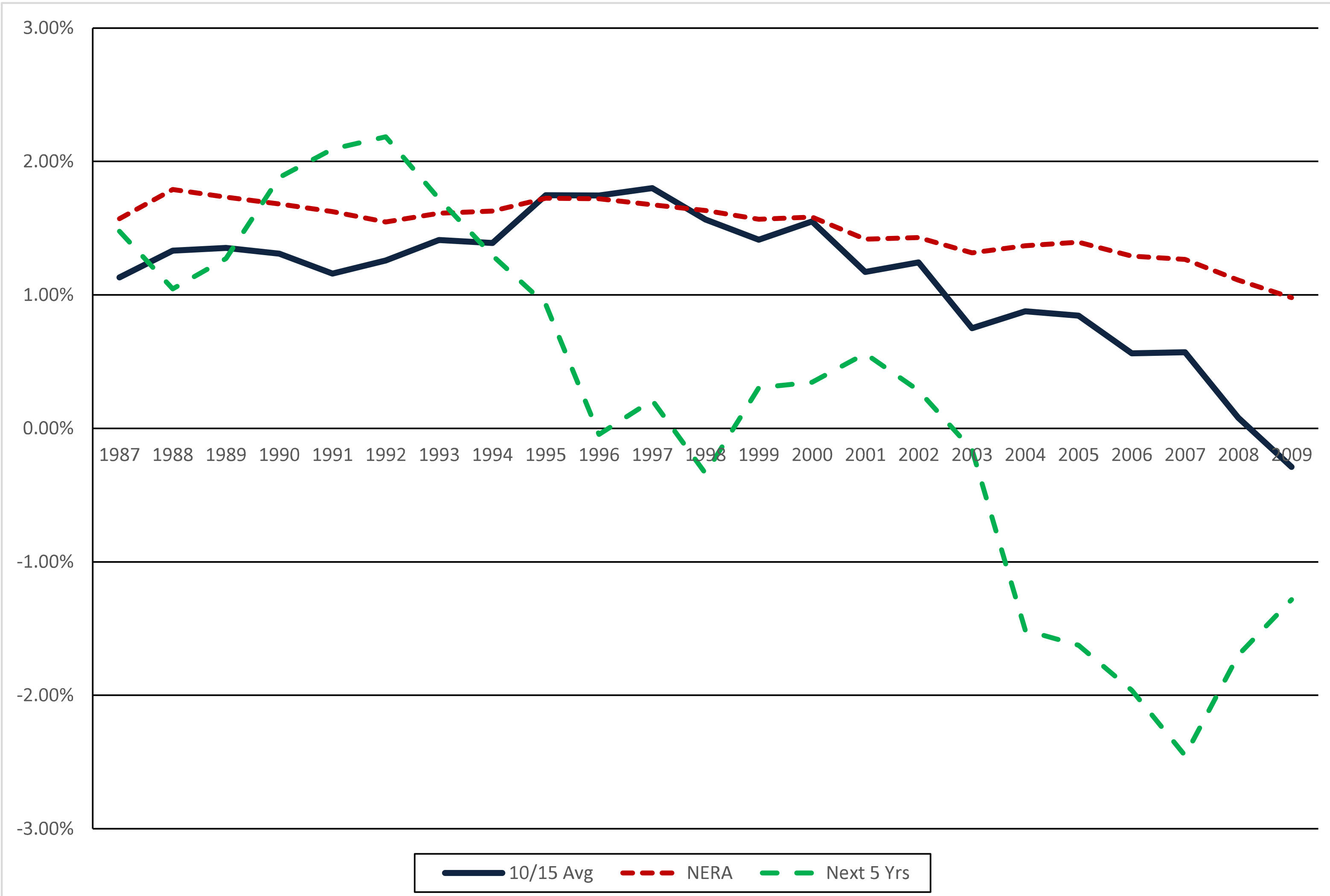
60. Figures 4a and 4b demonstrate that the 10/15 moving average has been a progressively better predictor of the next five-year average TFP growth than the NERA approach every year since 1998. The gap between the two approaches has grown wider over time as old, irrelevant data has become increasingly problematic for the NERA approach. In 1998, the gap between the two approaches was only 0.07 percentage points, but by 2009 the gap had widened to 1.27 percentage points.

61. The results are qualitatively the same if either the 10-year or 15-year moving average is used in place of the 10/15 moving average. Use of a five-year moving average also provides generally similar results but is much more volatile.[52] Considering the results of these sensitivity analyses leads me to conclude that my

[52] See "Figure 4 Sensitivity" in backup. Appendix C contains charts comparing the alternative projections. As I stated above, reasonable methodologies will likely produce a TFP basis for the second-generation X factor less than zero. In this regard, given the similarity of results, a 10- or 15-year moving average would be acceptable as a basis for the X factor. As a benchmark that further reinforces the notion of a negative X factor, the post-1996 period (1996-2014) demarcated by the change in the relationship between economic activity and energy consumption noted above, experienced an average TFP growth of -0.64 percent. Furthermore, as I discussed above, the authors of the NERA study have recognized "sharp declines" in TFP growth in more recent years.

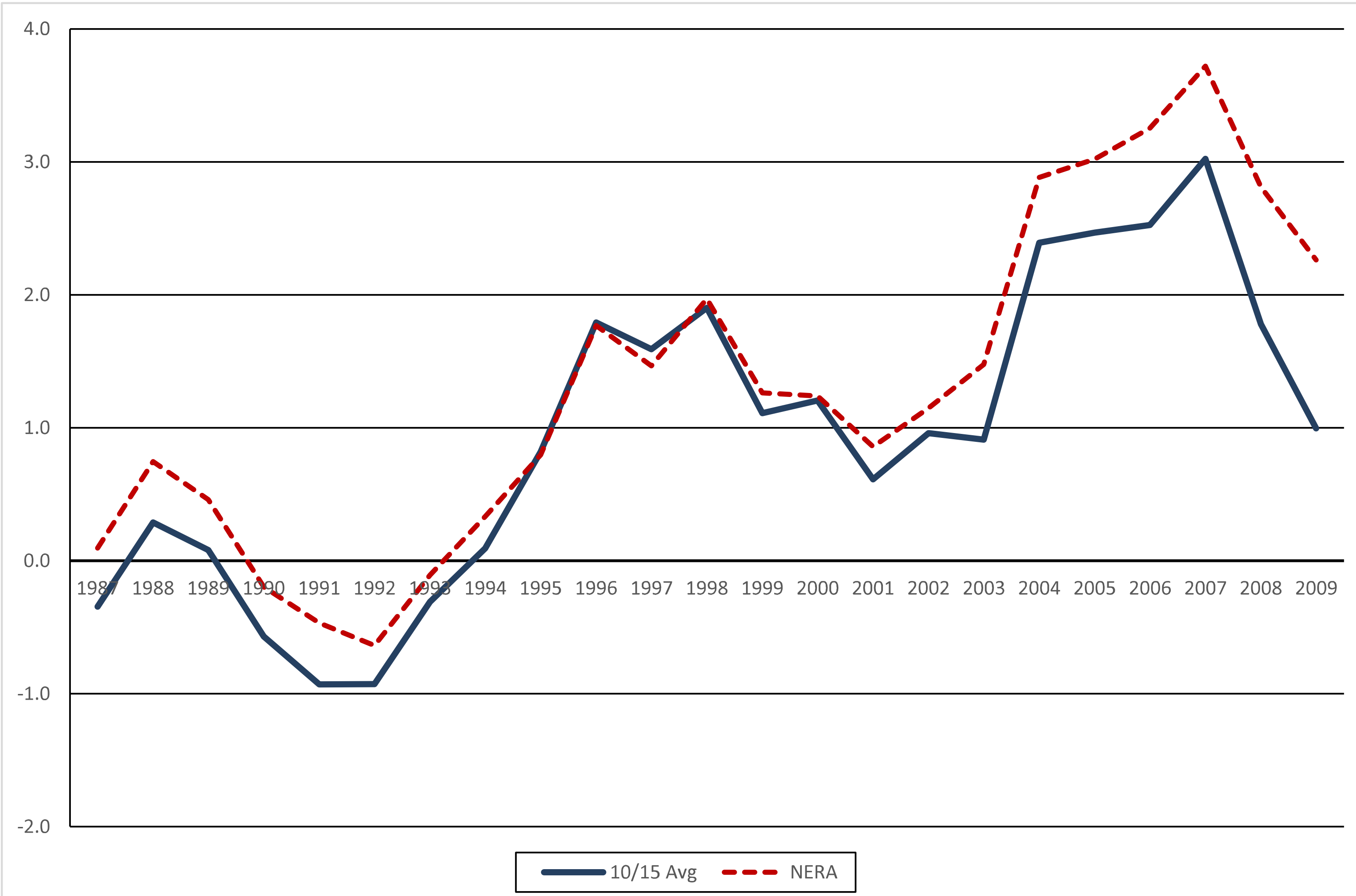
recommended approach produces a reasonable and conservative basis for the forward-looking X factor; it weights recent experience more heavily—which is important for relatively short-term forecasts in which the near-term future is likely to be more heavily influenced by more recent experience—but it is not unduly influenced by short-term volatility.

Figure 4a
Comparison of 10/15 Moving Average, NERA Average and Next Five-Year Average TFP Growth
1987-2009



36

Figure 4b
10/15 Moving Average and NERA Approach Differences Relative to Next Five-Year Average TFP Growth
1987-2009



62. For example, as Table 3 shows, the 10/15 moving average for intervals ending in 2014 produces an X factor of -1.11 percent.[53] In my opinion, this approach is a reasonable and appropriate basis for the second-generation X factor in the AUC price cap plan.

Table 3
Average Annual Growth Rates for 10- and 15-Year Intervals Ending in 2014

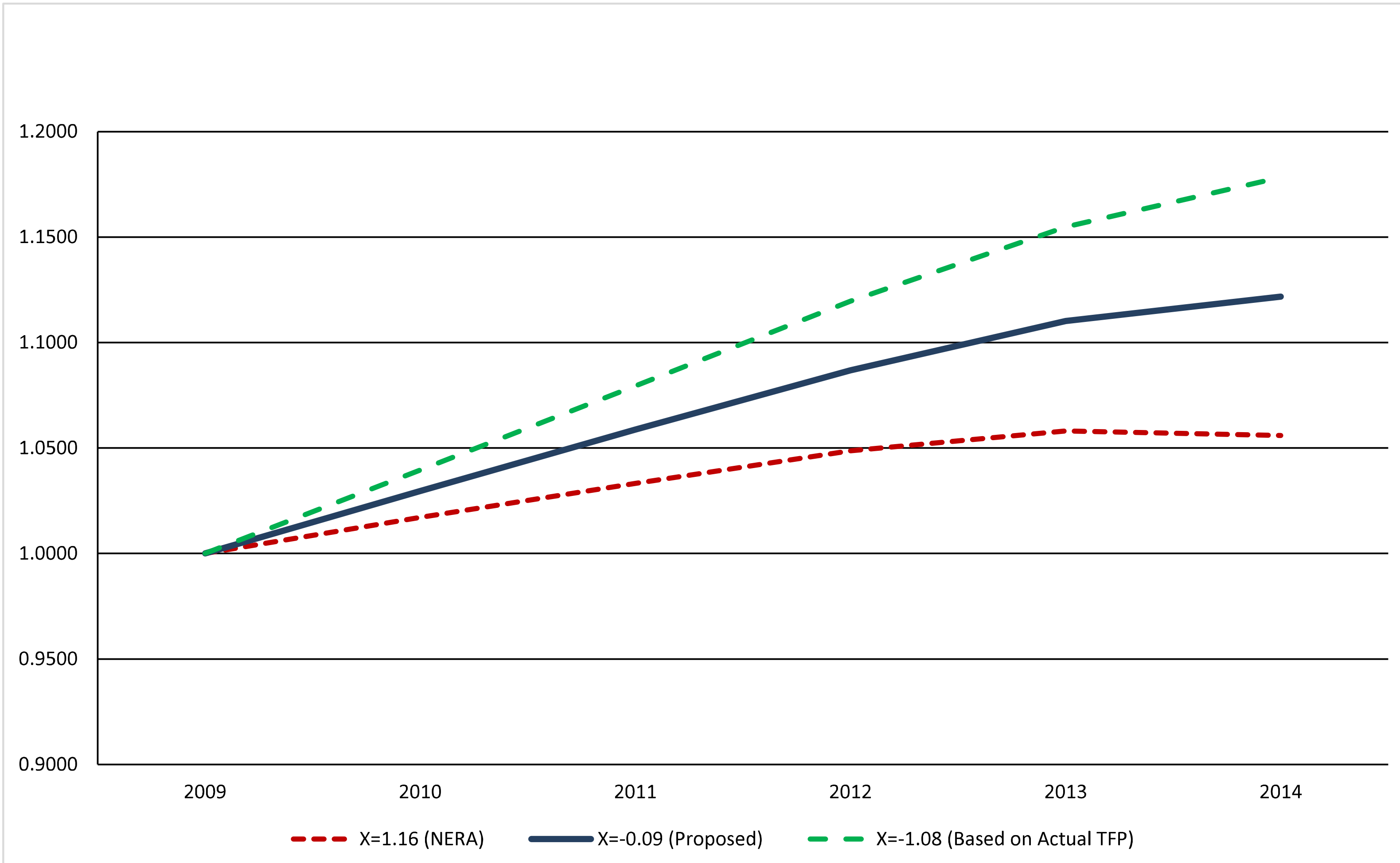
	Output	Input	TFP
10 Years, 2005-2014	-0.01%	1.39%	-1.40%
15 Years, 2000-2014	0.51%	1.34%	-0.83%
Average	0.25%	1.36%	-1.11%

Had this approach been used with data through 2009 at the time of AUC Proceeding 566, the TFP basis for the first-generation X factor would have been -0.29 percent, consisting of a 10-year interval (2000-2009) average of -0.60 percent and a 15-year interval (1995-2009) average of 0.03 percent. If a stretch factor of 0.20 would be added recognizing that this was a first-generation X factor, the result would have been an X factor of -0.09 percent.[54] Figure 5 replicates the comparison of price cap indexes based on the adopted NERA proposal and actual average TFP growth over the 2009-2014 period from Figure 3, and adds the price cap index based on 10- and 15-year averages through 2009. It can be seen that the proposed X factor based on the 10/15 moving average would have performed much better than the NERA-based X factor. Cumulatively, at the end of this period, the price cap with the 10/15 X factor would have been 6.2 percent higher than the price cap with the NERA-based X factor. Furthermore, as noted above, a more reasonable X factor would have lessened the severity of the capital funding shortfall experienced by EPCOR and

[53] As noted above, I have not included a stretch factor in my recommendation.
[54] If the stretch factor were viewed as being set roughly proportionate to the TFP estimate (e.g., 20 percent relative to NERA's TFP estimate), it could be argued that the stretch factor would have also been lower had the 10/15 moving average been used as a basis of the first-generation X factor. For example, 20 percent of the absolute value of the -0.29 TFP basis would have produced a stretch factor of 0.06 and the resulting X factor would have been -0.23 (= -0.29 + 0.06).

would have resulted in lower amounts to be recovered outside of the "I – X" index under K factors.

Figure 5
Comparison of Price Cap Indexes with X Factors Based on NERA, 10/15 Moving Average and Actual TFP Growth
2009-2014



40

6. Conclusion

63. It is my opinion that during the next five years of the AUC PBR plan until the next review, the 10/15 X factor would: (1) best balance the objectives of determining a reasonable X factor with the desire to minimize result-oriented analyses; (2) best address the needs of the industry to fund future investments and have the opportunity to recover its prudently incurred costs; (3) adequately protect Alberta consumers; and (4) enable the Commission to fulfill the goals of its PBR Principles that seek to design PBR so as to create the same incentive structure as a competitive market, stress regulatory efficiency and the balancing of the interests of regulated firms and their customers.

Appendix A

Mark E. Meitzen

RESUME

January 2016

Address:

Laurits R. Christensen Associates, Inc.
800 University Bay Drive, Suite 400
Madison, Wisconsin 53705-2299
Telephone: 608.231.2266
Fax: 608.231.2108
Email: memeitzen@LRCA.com

Academic Background:

Ph.D., University of Wisconsin–Madison, 1982, Economics
M.S., University of Wisconsin–Madison, 1979, Economics
B.S., University of Wisconsin–Oshkosh, 1976, Economics

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc., 1998–present
Director-Telecommunications, Laurits R. Christensen Associates, Inc., 1993–1998
Senior Economist, Laurits R. Christensen Associates, Inc., 1990–1993
Regulatory Economist, Southwestern Bell Telephone Company, 1988–1990
Regional Economist, Southwestern Bell Telephone Company, 1986–1988
Adjunct Faculty, Saint Louis University, St. Louis, Mo., 1987–1990
Visiting Assistant Professor of Economics, University of Wisconsin-Milwaukee, 1984–1985
Assistant Professor of Economics, Eastern Michigan University, 1981–1984

Professional Experience:

I have experience as an expert witness in civil litigation cases on a range of issues, including antitrust, intellectual property, breach of contract, and employment issues. I have computed economic damages in a number of employment-related areas including wrongful termination, pay and promotion discrimination, and personal injury. In the antitrust area, I have experience with price fixing, predatory pricing, market definition, and market power issues. In the intellectual property area, my experience includes patent infringement, copyright infringement, and trade secret cases. I also have expertise in the economic analysis of network industries including telecommunications, railroad, electricity and postal. I was the Principal Investigator for NCFRP 24, *Preserving and Protecting Freight Infrastructure and Routes* and was a primary author of the study of the U.S. freight railroad industry commissioned by the U.S. Surface Transportation Board.

Publications:

"Minnesota Freight Rail Economic Development," prepared for the Minnesota Department of Transportation and the Minnesota Department of Employment and Economic Development, November 2013.

"Preserving and Protecting Freight Infrastructure and Routes," *TR News* No. 284, Jan-Feb 2013.

"NCFRP Report 16: Preserving and Protecting Freight Infrastructure and Routes," Transportation Research Board of the National Academies, 2012.

"Preserving and Protecting Freight Infrastructure and Routes," *Proceedings of the ASME/ASCE/IEEE 2012 Joint Rail Conference*, April 2012 (with L. Loftus-Otway, R. Grow, N. Hutson, and A. Bruening).

"Railroad Performance Under the Staggers Act," *Regulation,* Vol. 33, No 4 – Winter 2010–2011 (with B.K. Eakin, A.T. Bozzo, and P.E. Schoech).

"Incentive Regulation in Network Industries: Experience and Prospects in the U.S. Telecommunications, Electricity and Natural Gas Industries," *Review of Network Economics*, Vol. 2, Issue 4 - December 2003, pp. 316–337, (with R. C. Hemphill and P. E. Schoech).

"Total Factor Productivity in the Telecommunications Industry," in *International Handbook on Telecommunications Economics*, G. Madden and S. Savage, eds., 2003, (with L. R. Christensen and P. E. Schoech).

"Pricing Network Elements Under the Telecommunications Act of 1996: Back to the Future," *Comm/ENT*, Summer 2001, (with S. Massa and S. G. Parsons).

"Controlling for Cross Subsidization in Electric Utility Regulation," Edison Electric Institute, September 1998, (with L. Kaufmann and M. Lowry).

"Where Do We Go From Here?" *Public Utilities Fortnightly*, June 15, 1993, (with L. R. Christensen and P. E. Schoech).

"Recent State Legislation for Telecommunications: Brave New World or Bad Public Utility Law?" *George Mason University Law Review*, Vol. 14, No. 1, Fall 1991, (with A. C. Larson). Reprinted in *Public Utility Law Anthology*, Vol. 15, Part 2, July-December 1992, Allison P. Zabriske, ed., (Gaithersburg MD: International Library Book Publishers, Inc.) 1992, pp. 433–491.

"The Uses and Abuses of Stand-Alone Costs," *Utilities Policy*, April, 1992, (with A. C. Larson). Shorter, nontechnical version appeared as "The Use of Stand-Alone Cost in Public Utility Regulation," *National Estimator*, spring 1992.

"The Shared Cost Problem and Cash Cow Economics: Who Gets Milked?" *Public Utilities Fortnightly*, April 1, 1991.

"Diversification of Telephone Company Service Offerings and Cash Cow Economics: Who Gets Milked?" *Utilities Policy*, October 1990.

Cost and Pricing Principles for Telecommunications: An Anthology, Washington: United States Telephone Association, September 1990, (co-edited with A. C. Larson).

"The LEC's Transition to Full Competition: The Response of Regulation," *The Computer Lawyer*, July 1990, (with T. J. Schroepfer).

"Differential Compensation and Worker Turnover," *Journal of Economics*, 1989, (with L. Brannman).

"Differences in Male and Female Job Quitting Behavior," *Journal of Labor Economics*, 1986.

"The Impact of Unionism on Exit and Voice Decisions in the Labor Market," *Journal of Economics*, 1984, (with S. Hayworth).

"Empirical Analysis of the Rate of Worker Separation," in *Subsidizing On-the-Job Training*, Columbus, OH: National Center for Research in Vocational Education, 1982.

Presentations at Workshops and Professional Meetings:

"Preserving and Protecting Freight Infrastructure and Routes, Findings from NCFRP 24," Transportation Research Board Annual Meetings, January 2012.

"Preserving and Protecting Freight Infrastructure and Routes, Findings from NCFRP 24," Federal Highway Administration, Talking Freight Seminar, August 2011.

"Preserving and Protecting Freight Infrastructure and Routes," NCFRP24 Workshop, January 2011.

"Preserving and Protecting Freight Infrastructure and Routes," Minnesota Freight Advisory Committee, October, 2010.

"An Update to the Study of Competition in the U.S. Freight Railroad Industry," Midwest Association of Rail Shippers, July, 2010.

Overview of the Christensen Associates' Railroad Industry Studies," National Coal Transportation Association, September, 2009.

"Overview of the Christensen Associates' Railroad Industry Studies," Midwest Association of Rail Shippers, July, 2009.

"A Study of Competition in the Railroad Industry and Analysis of Proposals to Enhance Competition, A Progress Report," National Coal Transportation Association, April, 2008.

"A Study of Competition in the Railroad Industry and Analysis of Proposals to Enhance Competition, A Progress Report," Midwest Association of Rail Shippers, January, 2008.

"Economics of Price Erosion Using Available Data," Law Seminars International Patent Damages Workshop, Chicago, IL, April 2004.

"Economics of Price Erosion and Lost Convoyed Sales Using Available Data," Law Seminars International Patent Damages Workshop, Chicago, IL, April 2003 (with J. Cordray).

"Local Exchange Competition," Wisconsin Public Utility Institute, Madison, WI, April 2003.

"Patent Damages: Analyzing the Market But-For Infringement," presented to the Milwaukee Bar Association's Intellectual Property Section, May 2000, (with C. Degen).

"Implementation of Price Cap Regulation–The FCC Experience," Wisconsin Public Utility Institute, Madison, WI, September 1999.

"Costs of Universal Service," Wisconsin Public Utility Institute, Madison, WI, March 1997.

"Unbundled Network Elements and Economic Cost Standards," Wisconsin Institute of Certified Public Accountants, Madison, WI, October 1997.

"The Uses and Abuses of Stand-Alone Costs," Second Prize winner in the Research Awards Competition of the Eleventh Annual Southeastern Public Utilities Conference, Atlanta, GA, September 23, 1991.

"Diversification of Telephone Company Service Offerings and Cash Cow Economics: Who Gets Milked?" First Prize winner in the Research Awards Competition of the Tenth Annual Southeastern Public Utilities Conference, Atlanta, GA, August 1990. Also presented at the Third Annual Western Conference of the Rutgers University Advanced Workshop in Regulation and Public Utility Economics, San Diego, CA, July 1990.

"Financial Market Implications of Competition and Regulation in the Telecommunications Industry," Eighth Annual Conference of the Rutgers University Advanced Workshop in Regulation and Public Utility Economics, Newport, RI, May 1989.

"Foreign Trade in Telecommunications Equipment," Second prize winner in the papers competition held in conjunction with the Eleventh Annual Midwestern Telecommunications Conference, Minneapolis, MN, October 1988.

"Perspectives on Local Exchange Competition," Presented at the Seventh Bi-Annual Conference of the International Telecommunications Society, Cambridge, MA, June 1988.

"The Effects of Market Signals on the Construction of Incentive Contracts in a Principal-Agent Model: The Case of the Academic Labor Market," 1984 Atlantic Economics Society Conference, Montreal, Canada, (with B. Woodland).

"The Role of Voice Mechanisms in Workers' Participation in and Satisfaction with Unions," 1984 Midwest Economics Association Convention, Chicago, IL.

"Hedonic Wage Models and Worker Turnover," 1984 Midwest Economics Association Convention, Chicago, IL.

"The Impact of Unionism on Exit and Voice Decisions in the Labor Market," 1984 Missouri Valley Economics Association Convention, Kansas City, MO, (with S. Hayworth).

"Differences in Male and Female Job Quitting Behavior," 1983 Midwest Economics Association Convention, St. Louis, MO.

Non-Confidential Consulting Reports and Research Papers:

"Revisiting the CPI-Based Price Cap Formula for the U.S. Postal Service," 2012 Eastern Conference of the Center for Research in Regulated Industries, May 2012 (with P. Schoech and M. Kubayanda).

"An Update to the Study of Competition in the U.S. Freight Railroad Industry," prepared for the U.S. Surface Transportation Board, January 2010 (Christensen Associates).

"Supplemental Report to the U.S. Surface Transportation Board on Capacity and Infrastructure Investment," prepared for the U.S. Surface Transportation Board, March 2009 (Christensen Associates).

"A Study of Competition in the U.S. Freight Railroad Industry and Analysis of Proposals that Might Enhance Competition," prepared for the U.S. Surface Transportation Board, November 2008 (Christensen Associates).

"Comments of the Minnesota Department of Commerce," *in the Matter of Commission Investigation of Cost for Appropriate Level of Universal Service Support*, Minnesota Docket No. P999/CI-00-829 (Minnesota Department of Commerce).

"Productivity Performance of the Wisconsin Local Exchange Carrier Industry," and "Comments of Christensen Associates on Consultant Productivity Studies," January 2003, Wisconsin PSC Docket 1-AC-193, (with L. R. Christensen, P. E. Schoech, and S. M. Schroeder).

"Determination of the X Factor for the Regulation of Telefonica del Peru," August 2001, (with
P. E. Schoech, C. Smyser, and S. M. Schroeder).

"The Ameritech Illinois Total Factor Productivity Study," June 2000, Illinois Commerce Commission Docket 98-0252, (with P. E. Schoech and S. M. Schroeder).

"Market Power Study of the Potomac River, Benning Road, and Buzzard Point Power Plants," Final Report to Potomac Electric Power Company, April 2000, (with F. L. Alvarado, L. D. Kirsch, S. D. Braithwait, B. K. Eakin, S. L. Greene, R. Rajaraman, and J. D. Reaser).

"Price Cap Design and X Factor Estimation for Peruvian Telecommunications Regulation," Final Report to OSIPTEL, May 1999, (with L. R. Christensen, P. E. Schoech, L. D. Kirsch, C. A. Herrera, and S. M. Schroeder).

"Analysis of Benchmark Cost Proxy Model 3.0, Hatfield Model, Version 5.0 and Hybrid Cost Proxy Model," Federal Communications Commission, CC Docket 96-45, January 1998, (with A. T. Bozzo, T. Rutkowski, and T. Grau).

"Analysis of Benchmark Cost Proxy Model and Hatfield Release 3.1," Federal Communications Commission, CC Docket 96-45, April 1997, (with L. R. Christensen, P. E. Schoech, A. T. Bozzo, and T. Rutkowski).

"The TFPRP Provides the Best Basis for Determining the Rate of LEC TFP Growth," Federal Communications Commission, CC Docket 94-1, February 1997, (with L. R. Christensen and P. E. Schoech).

"Appropriate Standards for Cost Models and Methodologies," Federal Communications Commission, CC Docket 96-45, Final Report to United States Telephone Association, February 1997.

"Updated Results for the Simplified TFPRP Model and Response to Productivity Questions in FCC's Access Reform Proceeding," Federal Communications Commission, CC Docket 94-1, January 1997, (with L. R. Christensen and P. E. Schoech).

"Economic Evaluation of Proxy Cost Models for Determining Universal Service Support," Federal Communications Commission, CC Docket 96-45, January 1997.

"A Survey of X-Factor Experience in the United States," filed with Canadian Radio and Telecommunications Commission on behalf of Stentor Member Companies, June 1996, (with
L. R. Christensen and P. E. Schoech).

"An Evaluation of the Bell Canada, BC TEL, MTS NetCom Inc., and Maritime Tel & Tel Limited Total Factor Productivity Studies," filed with Canadian Radio and Telecommunications Commission on behalf of Stentor Member Companies, June 1996, (with L. R. Christensen and
P. E. Schoech).

"Total Factor Productivity Methods for Local Exchange Carrier Price Cap Plans: Reply Comments," Federal Communications Commission, CC Docket 94-1, March 1996, (with L. R. Christensen and P. E. Schoech).

"Total Factor Productivity Methods for Local Exchange Carrier Price Cap Plans," Federal Communications Commission, CC Docket 94-1, December 1995, (with L. R. Christensen and P. E. Schoech).

"Productivity of the Local Operating Telephone Companies Subject to Price Cap Regulation 1993 Update," Federal Communications Commission, CC Docket 94-1, January 1995, (with L. R. Christensen and P. E. Schoech).

"Productivity Growth in the Cable Television Industry," filed with Federal Communications Commission on behalf of the National Cable Television Association, June 1994, (with L. R. Christensen and P. E. Schoech).

"Productivity of the Local Operating Telephone Companies Subject to Price Cap Regulation," Federal Communications Commission, CC Docket 94-1, May 1994, (with L. R. Christensen and P. E. Schoech).

"Sources and Methods for the Ohio Bell Total Factor Productivity Study," Public Utilities Commission of Ohio, Case No. 93-487-TP-ALT, 1993, (with L. R. Christensen and P. E. Schoech).

"Sources and Methods for the Illinois Bell Total Factor Productivity Study," Illinois Commerce Commission, Case No. 92-0448, December 1992, (with L. R. Christensen and P. E. Schoech).

Expert Testimony – Regulatory Proceedings

Before the U.S. Surface Transportation Board, "Joint Verified Statement of B. Kelly Eakin, Mark E. Meitzen, and Philip E. Schoech," STB Ex Parte No. 722, Railroad Revenue Adequacy, September 2014.

Before the U.S. Surface Transportation Board, "Joint Verified Statement of B. Kelly Eakin and Mark E. Meitzen," STB Docket No. NOR 42121, Total Petrochemicals & Refining USA, INC. v. CSX Transportation, Inc., June 2013.

Before the U.S. Surface Transportation Board, "Joint Verified Reply Statement of B. Kelly Eakin and Mark E. Meitzen," STB Ex Parte No. 711, Petition for Rulemaking to Adopt Revised Competitive Switching Rules, May 2013.

Before the U.S. Surface Transportation Board, "Joint Verified Statement of B. Kelly Eakin and Mark E. Meitzen," STB Ex Parte No. 711, Petition for Rulemaking to Adopt Revised Competitive Switching Rules, March 2013.

Before the U.S. Surface Transportation Board, "Joint Statement of B. Kelly Eakin and Mark E. Meitzen," STB Docket No. NOR 42125, E.I. DuPont De Nemours and Company v. Norfolk Southern Railway Company, November 2012

Before the U.S. Surface Transportation Board, "Joint Verified Statement of B. Kelly Eakin and Mark E. Meitzen," STB Docket No. NOR 42123, M&G Polymers USA, LLC v. CSX Transportation, Inc., November 2012.

Before the U.S. Surface Transportation Board, "Joint Verified Statement of B. Kelly Eakin and Mark E. Meitzen," STB Ex Parte No. 705, Competition in the Railroad Industry, May 2011.

Before the U.S. Surface Transportation Board, "A Study of Competition in the U.S. Freight Railroad Industry and Analysis of Proposals that Might Enhance Competition, Final Report," November, 2008.

Client: Coal Shippers Coalition (2006)
Proceeding: Surface Transportation Board Ex Parte No. 657 (Sub-No. 1)

Client: AEP Texas North (2004)
Proceeding: Surface Transportation Board Docket No. 41191

Client: OSIPTEL (2003)
Proceeding: TdP Price Cap Implementation (Peru)

Client: OSIPTEL (2002)
Proceeding: TdP Price Cap Implementation (Peru)

Client: OSIPTEL (2001)
Proceeding: TdP Price Cap Implementation (Peru)
Client: Ameritech Illinois (2001)
Proceeding: ICC Docket No. 98-0252

Client: Texas Municipal Power Agency (2001)
Proceeding: Surface Transportation Board Docket No. 42056

Client: Reliant Energy HL&P (2000)
Proceeding: Texas SOAH Docket No. 473-00-1020, Texas PUC Docket No. 22355

Client: Frontier Communications (1999)
Proceeding: MPSC Case No. U-12049

Client: TDS Telecom (1998)
Proceeding: MPSC Case No. U-11815

Client: Mid-Plains Telephone (1997)
Proceeding: PSCW Dockets 3650-MA-100 and 5845-MA-100

Client: Washington Independent Telephone Association (1997)
Proceeding: WUTC Docket UT-960369

Client: Michigan Exchange Carriers Association (1997)
Proceeding: MPSC Case No. U-11448

Client: Wisconsin State Telephone Association (1996)
Proceeding: PSCW Docket 05-TI-137

Client: Ameritech Illinois (1995)

Proceeding: ICC Docket 95-0458

Client: Southwestern Bell Corporation Media Ventures (1994)
Proceeding: Maryland PSC Docket 8659

Client: Ameritech Illinois (1993)
Proceeding: ICC Docket 92-0211

Client: Urban Telephone Company (Wisconsin) (1992)
Proceeding: PSCW Docket 6050-TI-100

Appendix B

Table B.1
Electric Distribution Industry Output, Input and TFP Growth
1972-2014

	ΔOutput, %	ΔInput, %	ΔTFP, %
1972			
1973	7.636%	2.839%	4.797%
1974	-0.341%	0.121%	-0.462%
1975	2.319%	-2.090%	4.409%
1976	5.190%	0.129%	5.060%
1977	4.444%	1.609%	2.835%
1978	3.552%	2.304%	1.249%
1979	2.924%	1.658%	1.266%
1980	1.386%	2.091%	-0.705%
1981	1.076%	0.515%	0.561%
1982	-1.090%	2.575%	-3.666%
1983	2.860%	1.924%	0.936%
1984	4.615%	1.744%	2.872%
1985	1.875%	2.138%	-0.263%
1986	2.704%	0.320%	2.385%
1987	4.051%	1.758%	2.293%
1988	5.030%	-0.042%	5.072%
1989	2.191%	1.378%	0.813%
1990	1.688%	0.861%	0.827%
1991	2.290%	1.715%	0.575%
1992	-0.620%	-0.715%	0.096%
1993	4.130%	1.216%	2.915%
1994	2.249%	0.301%	1.949%
1995	2.691%	-1.176%	3.867%
1996	1.988%	0.354%	1.634%
1997	1.126%	0.564%	0.563%
1998	3.135%	2.543%	0.592%
1999	1.674%	1.855%	-0.181%
2000	3.105%	1.070%	2.035%
2001	-0.973%	2.266%	-3.239%
2002	3.023%	1.182%	1.841%
2003	0.647%	2.788%	-2.141%
2004	1.967%	-1.057%	3.024%
2005	2.934%	0.694%	2.240%
2006	-0.236%	1.930%	-2.166%
2007	2.245%	1.781%	0.464%
2008	-1.835%	2.526%	-4.361%
2009	-4.003%	-0.260%	-3.743%
2010	3.019%	1.336%	1.683%
2011	-1.555%	2.305%	-3.860%
2012	-1.138%	0.841%	-1.979%
2013	0.111%	0.711%	-0.599%
2014	0.338%	1.999%	-1.660%

Appendix C

Table C.1
Comparison of Alternative Projections with Next Five-Year TFP Growth
1987-2009

	5 Avg	10 Avg	15 Avg	10/15 Avg	NERA	Next 5 Yrs
1987	1.645%	0.693%	1.571%	1.132%	1.571%	1.477%
1988	2.472%	1.075%	1.589%	1.332%	1.790%	1.045%
1989	2.060%	1.030%	1.674%	1.352%	1.733%	1.272%
1990	2.278%	1.183%	1.436%	1.309%	1.682%	1.880%
1991	1.916%	1.184%	1.137%	1.161%	1.624%	2.092%
1992	1.477%	1.561%	0.954%	1.257%	1.548%	2.185%
1993	1.045%	1.758%	1.065%	1.412%	1.613%	1.721%
1994	1.272%	1.666%	1.111%	1.388%	1.628%	1.295%
1995	1.880%	2.079%	1.415%	1.747%	1.725%	0.929%
1996	2.092%	2.004%	1.487%	1.745%	1.721%	-0.046%
1997	2.185%	1.831%	1.769%	1.800%	1.675%	0.209%
1998	1.721%	1.383%	1.746%	1.564%	1.633%	-0.337%
1999	1.295%	1.284%	1.542%	1.413%	1.566%	0.304%
2000	0.929%	1.404%	1.696%	1.550%	1.583%	0.345%
2001	-0.046%	1.023%	1.321%	1.172%	1.417%	0.559%
2002	0.209%	1.197%	1.290%	1.244%	1.431%	0.284%
2003	-0.337%	0.692%	0.810%	0.751%	1.316%	-0.160%
2004	0.304%	0.799%	0.957%	0.878%	1.369%	-1.513%
2005	0.345%	0.637%	1.051%	0.844%	1.395%	-1.625%
2006	0.559%	0.257%	0.868%	0.562%	1.291%	-1.963%
2007	0.284%	0.247%	0.893%	0.570%	1.267%	-2.452%
2008	-0.160%	-0.249%	0.408%	0.080%	1.111%	-1.700%
2009	-1.513%	-0.605%	0.028%	-0.288%	0.979%	-1.283%

Figure C.1
Comparison of Alternative Projections with Next Five-Year TFP Growth – 1
1987-2009

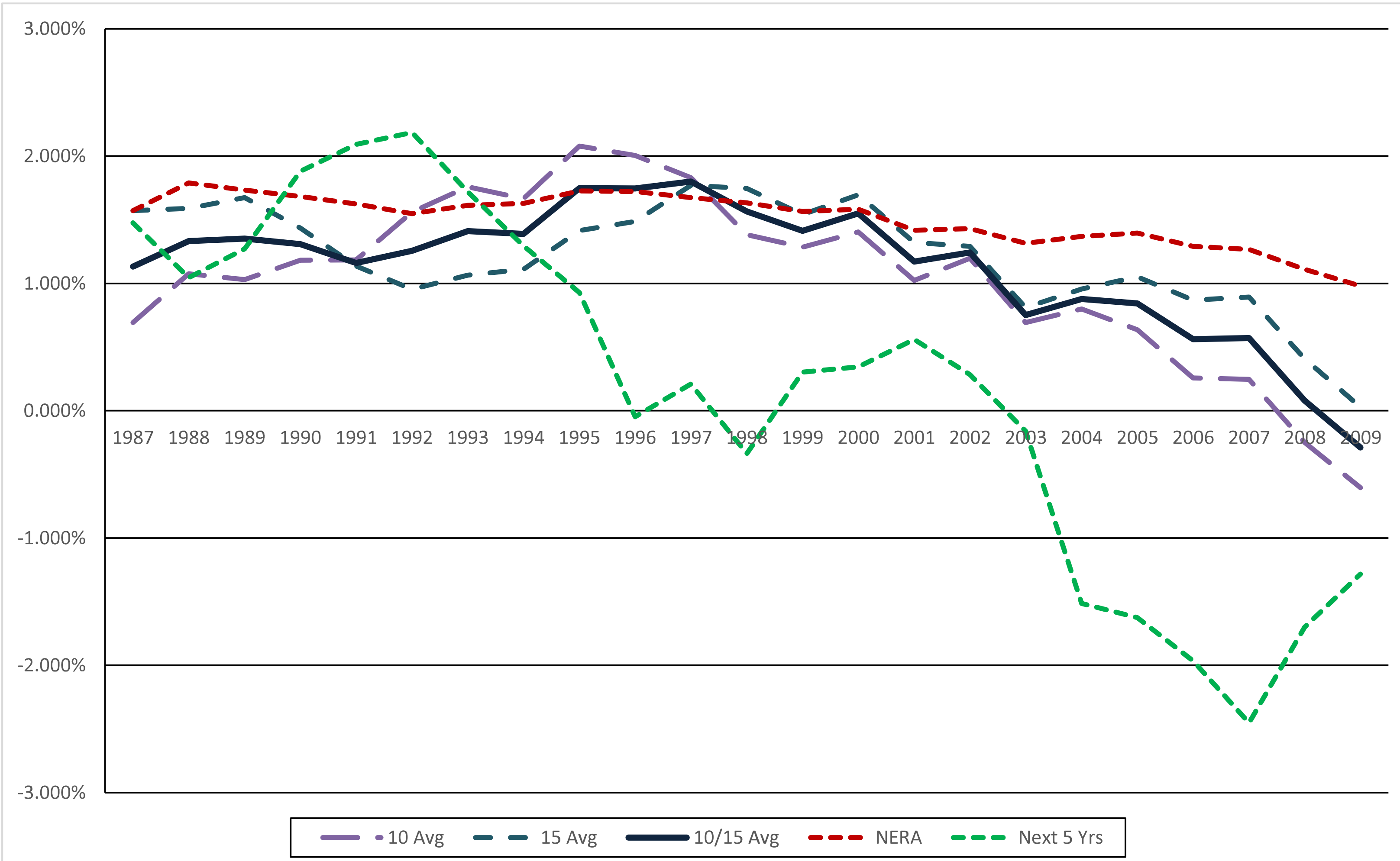
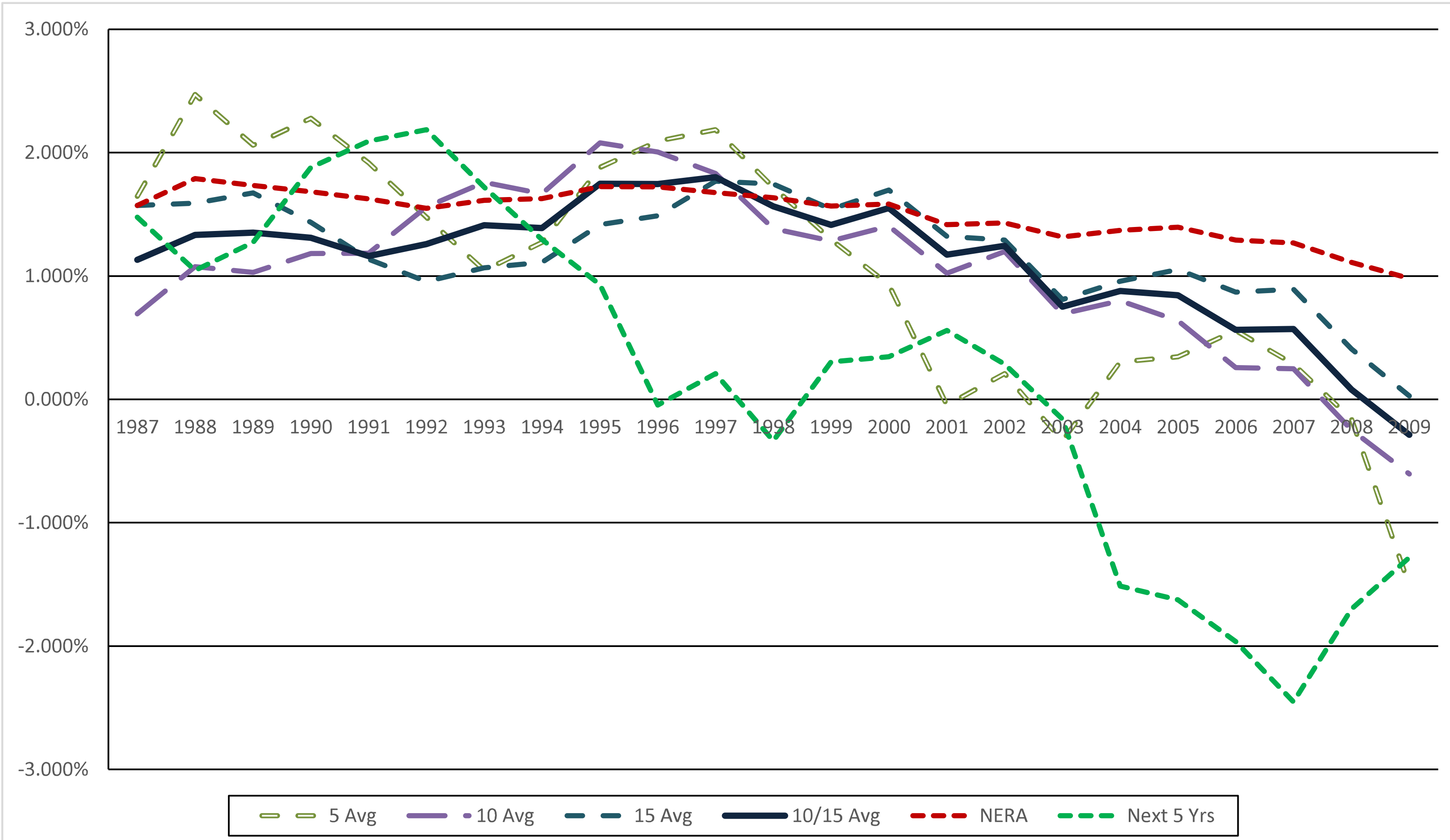


Figure C.2

53

**Comparison of Alternative Projections with Next Five-Year TFP Growth – 2
1987-2009**



54

Table C.2
Comparison of Differences Between Alternative Projections and Next Five-Year TFP Growth
1987-2009

	5 Avg	10 Avg	15 Avg	10/15 Avg	NERA
1987	0.168	(0.784)	0.094	(0.345)	0.094
1988	1.427	0.030	0.544	0.287	0.745
1989	0.788	(0.242)	0.402	0.080	0.460
1990	0.398	(0.697)	(0.444)	(0.571)	(0.198)
1991	(0.176)	(0.907)	(0.955)	(0.931)	(0.468)
1992	(0.709)	(0.625)	(1.231)	(0.928)	(0.638)
1993	(0.676)	0.038	(0.656)	(0.309)	(0.108)
1994	(0.023)	0.371	(0.184)	0.093	0.333
1995	0.952	1.150	0.487	0.819	0.797
1996	2.138	2.050	1.533	1.792	1.768
1997	1.976	1.622	1.559	1.590	1.466
1998	2.058	1.720	2.083	1.902	1.971
1999	0.991	0.980	1.239	1.109	1.262
2000	0.584	1.060	1.351	1.205	1.238
2001	(0.605)	0.464	0.761	0.612	0.857
2002	(0.074)	0.913	1.007	0.960	1.147
2003	(0.177)	0.852	0.970	0.911	1.476
2004	1.817	2.313	2.470	2.391	2.882
2005	1.969	2.261	2.676	2.469	3.020
2006	2.523	2.220	2.832	2.526	3.254
2007	2.736	2.699	3.345	3.022	3.719
2008	1.540	1.451	2.107	1.779	2.810
2009	(0.230)	0.678	1.312	0.995	2.263

Figure C.3
Comparison of Differences Between Alternative Projections and Next Five-Year TFP Growth – 1
1987-2009

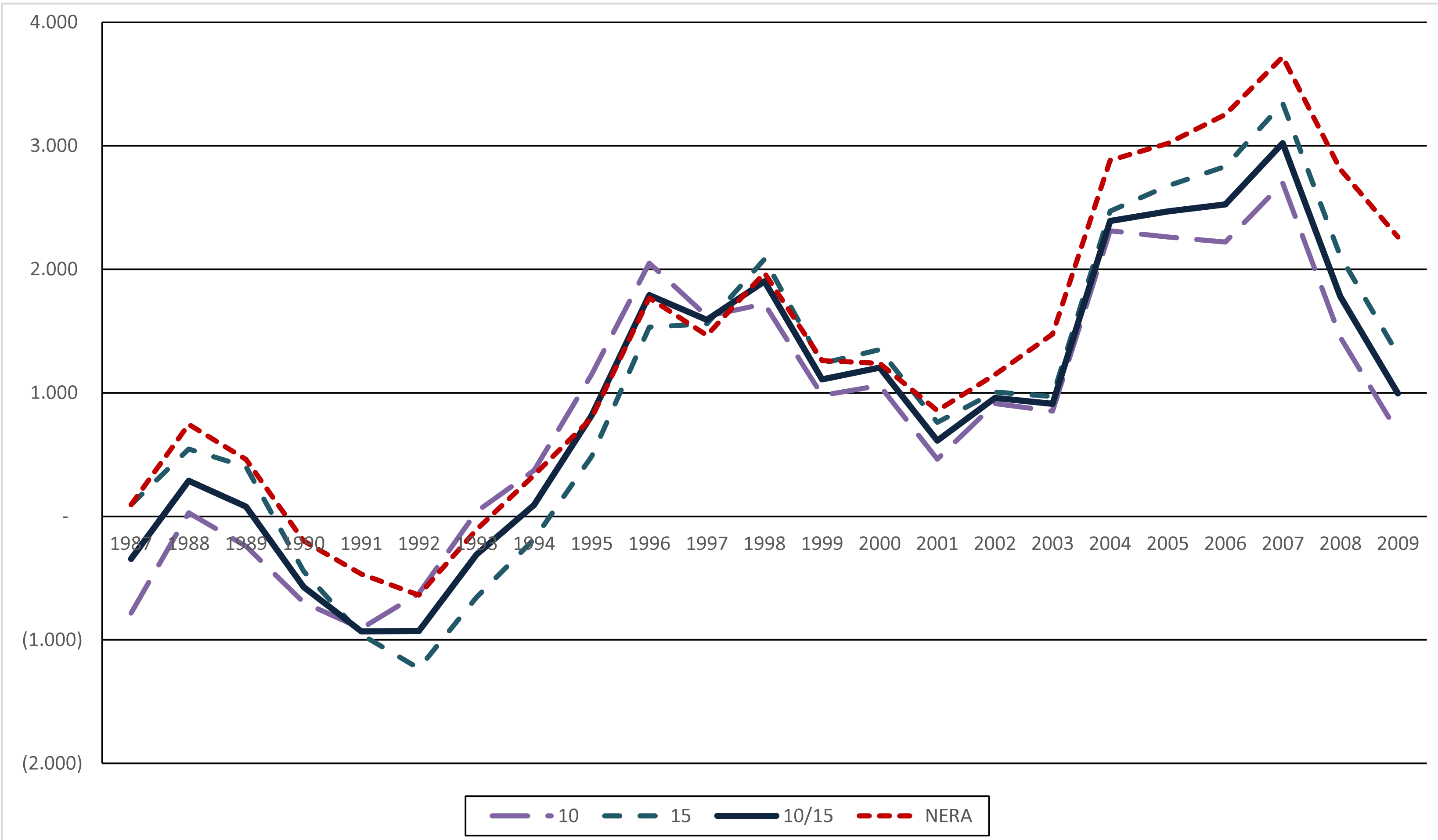


Figure C.4
Comparison of Differences Between Alternative Projections and Next Five-Year TFP Growth – 2
1987-2009

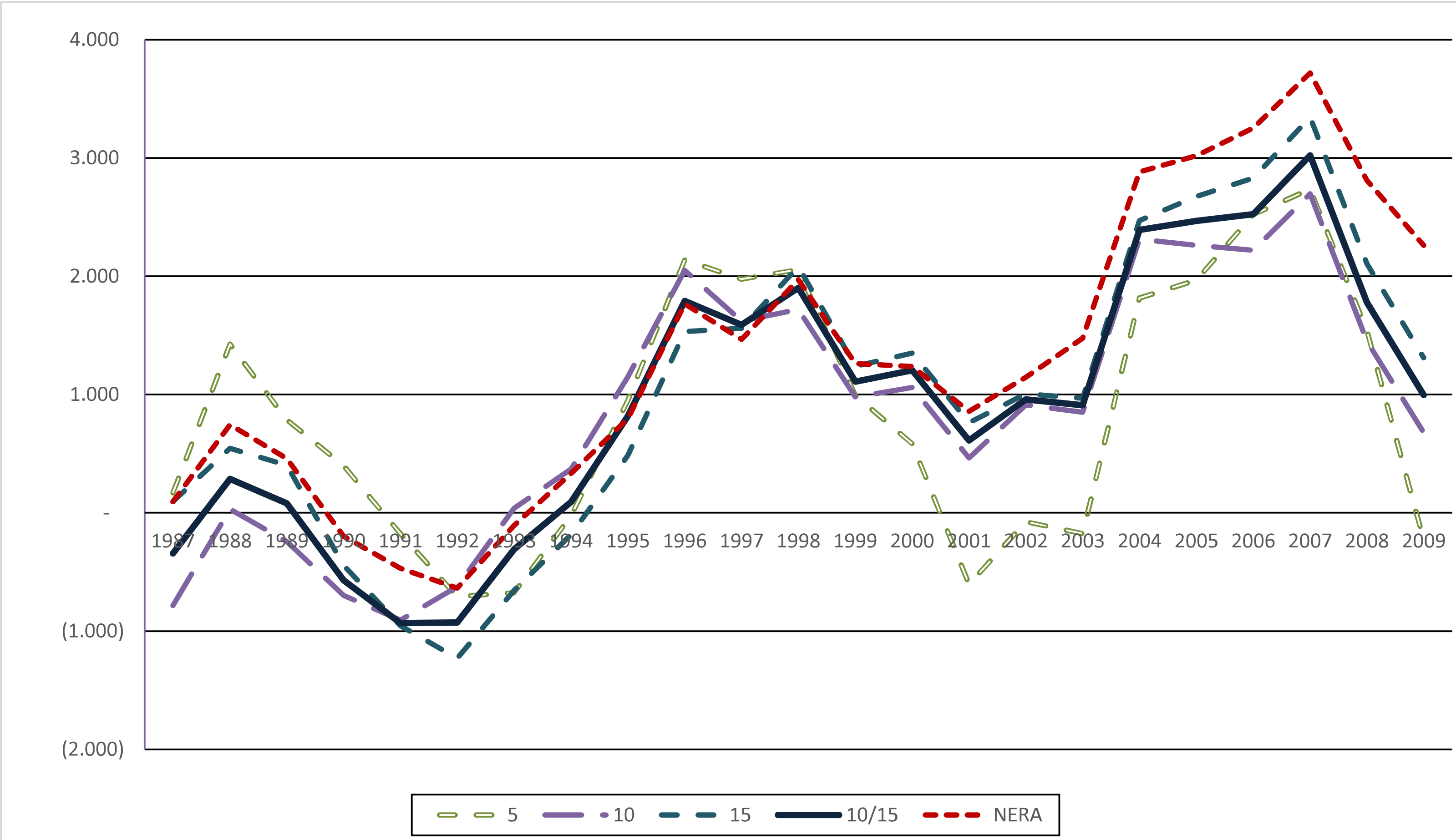


Exhibit No. ___

WRITTEN REPLY EVIDENCE

OF

DR. TOBY BROWN
DR. PAUL R. CARPENTER

FOR
ALTAGAS UTILITIES INC
ATCO ELECTRIC
ATCO GAS
ENMAX POWER CORPORATION
FORTISALBERTA INC

Proceeding ID No. 20414

May 2016

The Brattle Group
44 Brattle Street
Cambridge, Massachusetts 02138
617.864.7900

Exhibit No. ___

TABLE OF CONTENTS

I. INTRODUCTION

Q1. Who are the authors of this written evidence?

A1. Dr. Paul Carpenter and Dr. Toby Brown are co-authors of this written evidence. We are Principals of The Brattle Group, an economic consulting firm. Dr. Carpenter's office is at 44 Brattle Street, Cambridge, Massachusetts 02138 and Dr. Brown's office is at 201 Mission Street, Suite 2800, San Francisco, California 94105.

Q2. Did you file direct evidence in this proceeding?

A2. Yes. Our direct evidence was filed in March 2016.[1]

Q3. By whom have you been retained in this proceeding?

A3. The Brattle Group has been retained by AltaGas Utilities Inc., the ATCO Utilities (ATCO Electric and ATCO Gas), ENMAX Power Corporation, and FortisAlberta Inc.

Q4. What is the purpose of your reply evidence?

A4. Our reply evidence responds to the direct evidence of the witnesses retained by interveners in this proceeding (Dr. Lowry and Mr. Thygesen for the CCA, Mr. Bell and Mr. Simpson for the UCA), and we also comment on the submission filed by the City of Calgary. In addition we respond to matters raised in Information Requests.

In our reply evidence we have responded to the most important points made by the interveners. We note that several of the interveners in this proceeding appear to anticipate filing additional evidence and/or recommendations subsequent to their direct evidence and information responses. We may provide additional reply evidence depending upon AUC Rulings in relation to information responses filed subsequent to the original deadline for responding.

---

1 Exhibit 20414-X0056 through X0063.

While we have responded to the most important points made by the interveners, we have not responded to points that are unrelated to the issues set out in the AUC's Final Issues list.

Q5. How have you structured your reply evidence?

A5. Our reply evidence is structured to follow the issues and sub-issues set out in the AUC's final issues list. In section II we address rebasing, in section III we address TFP and the X-factor, and in section IV we address capital additions and the K-factor.

Q6. What conclusions have you reached in your reply evidence?

A6. In summary, the conclusions of our reply evidence are the following.

- Most interveners accept that rebasing is required and that it should be done on a cost of service basis. Mr. Thygesen proposed an excess return "claw back" proposal in his direct evidence that would be "retroactive ratemaking" and would destroy the incentives that the AUC is trying to create via PBR. He appears to have backtracked somewhat from that proposal in response to the AUC's IRs, such that it is not clear how, if at all, his "R-factor" proposal differs from regular cost-of-service rebasing.
- Dr. Lowry (PEG) introduced a new TFP study in his evidence that is based on FERC Form 1 data for US utilities, the same data source as was used in the NERA study commissioned by the AUC in Proceeding 566. Dr. Lowry bases his recommendations on only more recent data (the last 18 years), similar to the 15 years we recommended in our update of the NERA study in our direct evidence.
- The results of Dr. Lowry's study differ from the updated NERA study for a variety of reasons to do with technical methodological choices. As the AUC recognized in its Decision in Proceeding 566, experts can disagree as to the details of these TFP methodologies. Most, if not all, of Dr. Lowry's criticisms of the NERA methodology were fully tested in Proceeding 566, and the AUC adopted the NERA methodology.
- We recommend that the AUC continue to rely on the NERA TFP methodology for the second generation plans, and we continue to recommend our updated (and corrected) TFP trend using this study of –0.79%. This result is within the range of the results put forward in

the direct evidence of Dr. Meitzen (based on the NERA study) of –1.11%, and Dr. Lowry (using his complete sample) of +0.48%.

- With respect to the AUC's questions about incentives and regulatory burden associated with the treatment of capital expenditures in the next generation plans, intervener concerns in fact relate to assertions of "overcompensation" in the current plans, and not to the concerns of the AUC. Concerns about "overcompensation" are unrelated to the strength of incentives to control costs or to the ability of current plans to deliver benefits to customers. The benefits of PBR will be shared with customers at rebasing.
- The "overcompensation" claims of the interveners are based in part on two or three years of Rule 5 results for the current plans and a set of hypotheses, unsupported by evidence, as to how the next generation plans might operate. The Rule 5 results are irrelevant to assessing how future plans will operate, and they also say nothing about the strength of incentives or the magnitude of benefits to be shared with customers at rebasing.
- With respect to incentives, Mr. Bell claims that the incentives created by separating a utility's revenues from its costs are insufficient and that the AUC should introduce the concept of "scarcity", which he suggests involves creating an expectation that the utility would not earn a fair return. Mr. Bell's concept of "scarcity" has no foundation in economics or utility regulatory practice, and this proposal is contrary to AUC PBR principle 2.
- Interveners have not made proposals that would strengthen incentives to control costs under the capital mechanism.

II. REBASING

A. THE AUC'S REBASING ISSUES

Q7. What are the rebasing issues from the AUC's Issues List?

A7. The Issues List asks the following questions about rebasing:

> *1(a) How should going-in rates be set for the next PBR term?*
>
> *1(b) Is it necessary to rebase prior to the next generation of PBR? What would rebasing involve?*
>
> *1(c) What are the arguments for and against inserting a year of cost-of-service regulation after the current PBR term and prior to the start of the next generation PBR plan? What other possible methods are available to rebase rates for the start of the second generation PBR plans? Describe the arguments for and against these alternative approaches in terms of reducing regulatory burden, minimizing the perverse incentives inherent in a rate base rate of return application and enhancing the incentive properties of PBR.*
>
> *1(d) How should the efficiency carryover mechanism approved in the first generation PBR plans*[f/n omitted] *be incorporated into the rebasing process or next generation PBR plans?*

B. Overall approach to rebasing

Q8. How would you characterize the rebasing approach you recommend?

A8. As we explained in direct evidence, the objective of rebasing is to realign revenues and costs in the test year. Rebasing benefits customers because the realignment shares with customers the realized benefits of PBR that were accruing to the utility during the first plan term. It benefits the utility because it ensures that at the start of the second plan there is a reasonable opportunity to earn a fair rate of return. As such, we observe that the objective of rebasing and a traditional cost-of-service proceeding is the same. Since the objective of rebasing and traditional cost-of-service is the same, cost-of-service and rebasing proceedings are similar.

Q9. Is it necessary to rebase?

A9. Yes. If there were no rebasing, customers would not see any of the realized benefits of PBR. Rebasing also ensures that the utility has a reasonable opportunity to earn a fair rate of return at the start of the next PBR plan. In the jurisdictions with which we are familiar, rebasing takes place at the end of each PBR term.[2]

Q10. Do interveners agree with your recommendations on rebasing?

A10. We have found it difficult to interpret some of the intervener evidence in relation to rebasing, as we discuss below, but we believe that with the possible exceptions of Mr. Thygesen and Mr. Bell, the intervener witnesses agree that rebasing on a cost-of-service basis is required. For example, Dr. Lowry's evidence states "A full rebasing of rates to actual costs is probably needed in the new plan".[3] Mr. Simpson's evidence states "The UCA is of the view that rebasing is the primary mechanism by which benefits of PBR are shared with customers, and that rebasing must occur prior to the next generation of PBR plans being implemented".[4] Mr. Bell's evidence, in response to a question asking whether rebasing is necessary, includes a long discussion beginning with the answer "yes" and concluding with "…a rebasing is mandatory".[5] As we explain below, it is unclear whether the rebasing recommendations of Mr. Bell and (separately) Mr. Thygesen would in practice be any different from rebasing on a cost-of-service basis.

The submission of the City of Calgary contains options ranging from rebasing to not rebasing. One of those options is to rebase on a cost-of-service basis,[6] although the City of Calgary did not provide a recommendation or rationale for preferring one option over the others.

Q11. What is the evidence of Mr. Thygesen on rebasing?

A11. Mr. Thygesen's evidence suggested that rebasing on a cost-of-service basis could be used but was not required, and that it would be possible to "tweak the parameters of

---

2 For example, California, Great Britain and Australia.

3 Direct evidence of Dr. Lowry, p. 74.

4 Direct evidence of Mr. Simpson, p.10.

5 Direct evidence of Mr. Bell, Q/A 18.

6 Submission of the City of Calgary, sections 12.3.2 through 12.3.8.

the existing plan"[7] in order to establish going-in rates for the next PBR term. However, in responses to information requests about what the suggestion to "tweak" plan parameters meant, Mr. Thygesen appeared to endorse a cost-of-service rebasing.

Q12. What does Mr. Thygesen mean by "tweaking the parameters of the existing plan"?

A12. Mr. Thygesen's evidence does not include a detailed explanation of which plan parameters would be "tweaked" or what "tweaking" means in this context. The evidence states "Accordingly, the simplest solution is to tweak the formula and to adjust rates to bring the profits levels back to the GCOC rate. This is in essence resets the plan to the approved return level from which the utilities during the next round of PBR can find ways to make savings".[8]

Q13. Is Mr. Thygesen's suggestion that going-in rates should be determined on a "rate of return" basis?

A13. Mr. Thygesen suggests that returns should be brought back to the GCOC-determined[9] level. Mr. Thygesen's direct evidence seems to imply that his suggestion would involve "clawing back" returns earned during the first generation plan. This would be similar to "trueing up" rates to actual costs over the plan period, and the suggestion would be equivalent to "pure" cost of service regulation, which has even weaker incentives to control costs than traditional cost-of-service regulation in Alberta. This suggestion would effectively eliminate any incentives to control costs in the next generation plan. It would also appear to involve retroactive or retrospective ratemaking, in that gains/losses for a prior rate period would effectively be factored into current rates after the fact, something that is usually regarded as impermissible.

---

[7] Direct evidence of Mr. Thygesen, paragraphs 127–130.

[8] *Ibid*., paragraph 128, as modified in response to IR CCA-AUC-2016May 6-1c.

[9] Our understanding is that the ROE authorized in a generic cost of capital (GCOC) proceeding is used in subsequent proceedings that need a revenue-requirement calculation, such as a general rate case (or a rebasing proceeding). During the term of a PBR plan the concept of an "authorized ROE" is not meaningful except in certain narrow circumstances such as a K-factor calculation.

However, in responses to information requests, Mr. Thygesen clarified that his suggestion is that the authorized rate of return should be targeted in an expected sense.[10] Presumably this would involve setting rates (prospectively) so that the utilities are expected to earn the authorized rate of return, with no subsequent true up. Mr. Thygesen states that "since the adjustment going into the next PBR term is designed to target the GCOC rate, whether the amendment is via changes to the PBR formula or a COS rebasing seems secondary to the objective of bringing costs and revenues into alignment with the GCOC allowed return".[11] In response to an information request from the AUC about his rebasing proposal, Mr. Thygesen mentioned an "R-factor": "The R factor differs from earnings sharing as the driver for the R factor is to equalize costs and rates such that the GCOC rate is forecast to be earned. The R factor also differs from the stretch factor as the R factor does not include any estimates of future efficiencies that can be achieved. Efficiencies forecasts are the purview of X and stretch."[12] It seems as though the so-called "R-factor" is calculated to bring rates back into line with costs (on a forecast basis). It is unclear how, if at all, this suggestion differs from regular cost-of-service rebasing.

Q14. Have you seen reference to an "R-factor" in connection with PBR plans in other jurisdictions or in the literature?

A14. No, we have not.

Q15. Did Mr. Thygesen explain how his "tweaking" proposal differs from regular cost-of-service rebasing?

A15. No. However, Mr. Thygesen's evidence did include a discussion of what should happen if there is a "conventional cost of service rebasing". The discussion includes the statement that "Under no circumstances should what appear to be significantly

---

[10] See response to IR CCA-AUC-2016May 6-1b.

[11] *Ibid.*

[12] Response to IR CCA-AUC-2016May 6-1c.

higher than I-X increases in O&M be passed on to customers."[13] While the exact meaning of this statement is not clear to us, it seems to imply that in a cost-of-service rebasing, irrespective of the level of forecast test-year O&M costs, the maximum amount of test year O&M costs that would be incorporated into test year rates is somehow calculated from authorized 2012 O&M costs (the last test year)[14] by escalating by I – X.[15] We do not understand how such a proposal is consistent with cost-of-service rebasing, how it is consistent with the AUC's PBR principles, or what kind of economic logic might be underpinning it. There is no reason to believe that 2018 O&M should be below 2012 O&M (as escalated by I – X) or that all amounts over this level should automatically be excluded from rates.

Q16. Is it reasonable to suggest that, if PBR is operating effectively, O&M costs should not have increased faster than I – X during the current plan term?

A16. No, it is not. If the PBR plan were O&M only, the expectation at the outset of the plan would be that the utility would be able to control O&M costs within I – X (where the X-factor would be an O&M partial factor productivity trend). O&M cost outcomes after-the-fact could be either above or below the I – X trend depending on the utility's success in controlling costs and on external factors. However, the Alberta PBR plans are not O&M only, and the X-factor in the plans was not designed to reflect only expected O&M productivity improvements. Even if the plans had been designed in such a way, it would still be necessary to realign revenues and test-year costs in rebasing at the end of the plan. Under the more comprehensive PBR plan that has in fact been implemented in Alberta, base revenue escalating at I – X is intended to cover all costs except those capital-related costs eligible to be recovered via the K-

---

[13] Direct evidence of Mr. Thygesen, paragraph 131.

[14] Presumably 2014 for ENMAX.

[15] The electric utilities have a price cap PBR plan and the gas utilities a revenue-per-customer cap plan. As appropriate, references in our reply evidence to "I – X" should be taken to read "I – X + G" where G is growth in billing determinants.

factor.[16] During the plan term revenues and costs may diverge (apart from the K-factor), providing strengthened incentives to control costs. At the end of the plan term, for the reasons we gave above, rebasing should realign revenues and costs. The need to rebase is independent of how recorded costs have evolved during the prior plan term.[17]

Q17. What are legitimate expectations about how costs should evolve during the PBR plan term?

A17. There is a reasonable expectation that costs under PBR will be better controlled than they would have been under traditional cost-of-service regulation. This does not mean that costs will fall over time. Rather, the expectation at the outset of the plan is that costs (with the exception of the flow through or true-up items, including the K-factor) will increase at the same rate as base revenues. If it were otherwise, the plan would not provide a reasonable opportunity to earn a fair rate of return (AUC PBR principle 2). However, there is no guarantee that costs and revenues will in fact change at the same rate, and the associated risk is what provides the strengthened incentives to control costs under PBR. After-the-fact outcomes provide no evidence that going-in expectations were somehow incorrect or biased.

Q18. Have interveners provided suggestions on how rebasing might proceed?

A18. As noted above, Mr. Bell's evidence is that rebasing is required. However, his evidence also suggests an approach based on 2016 actuals plus "known and measurable changes", implying that this approach is different from a regular cost-of-service proceeding.[18] Mr. Bell's evidence states that "The advantage of [2016 actuals plus known and measurable changes for 2017] is that it would reduce the regulatory

---

[16] In addition, some costs are recovered on a pass-through basis via the Y- and Z-factors. The Y- and Z-factors are not in the scope of this proceeding.

[17] Assuming that the ECM, which does depend on recorded costs in the prior plan term, is calculated separately.

[18] Direct evidence of Mr. Bell, p. 26.

burden, as the start of the new proceeding would be 2016 actual costs." [19] While Mr. Bell responded to several information requests in relation to this portion of his evidence,[20] it is unclear whether and if so how this approach would differ from cost-of-service in practice. Since a regular cost-of-service proceeding assesses a forecast of test year costs, it is not clear how that would differ in practice from reviewing "known and measurable" changes between the last year of recorded data and the test year. It is therefore not clear how or why there would be a reduced regulatory burden relative to a regular cost-of-service proceeding. Mr. Bell has indicated that his approach would require testing of the rebasing application using standard minimum filing requirements.[21] Mr. Bell has not explained how his suggested approach could lead to a reduced regulatory burden. However, if by relying on recorded costs Mr. Bell's approach would preclude the utility from requesting recovery of costs it expects to incur in providing utility service in the test year, we do not consider that the approach would be a reasonable one, nor would it be consistent with the AUC's PBR principle 2.

Q19. What has the City of Calgary said about rebasing?

A19. The City of Calgary's submission describes five options for rebasing (plus a sixth option of not rebasing), but has not put forward a recommendation.[22] One option is standard cost-of-service rebasing, and the other four are variations on using "actual cost of service". We are not sure exactly what is meant by "actual cost of service" in this context, but assume that it means that the revenue requirement in the rebasing year would be set equal to recorded costs in one or more historical years.

---

[19] Direct evidence of Mr. Bell, p. 26.

[20] UCA-AUC-2016APR15-001,-002

[21] See response to information request UCA-AUC-2016APR15-001b.

[22] Submission of the City of Calgary, sections 12.3.2 through 12.3.8.

Q20. Is it reasonable to set going-in rates equal to recorded costs in one or more historical years?

A20. No, for the same reasons that traditional cost-of-service ratemaking does not operate in this way. Setting rates equal to recorded costs has poor incentive properties and is not consistent with providing a reasonable opportunity to earn a fair return. These suggestions are not consistent with the AUC's PBR principles (nor would they be acceptable in a cost-of-service context).

Q21. Would it be reasonable to set going-in rates equal to inflation-indexed recorded costs, as suggested by the UCA?

A21. We note that the UCA suggested setting going-in rates equal to recorded costs plus an I – X adjustment. For the same reasons we gave above to explain why it is necessary to rebase, and why it would not be reasonable to set going-in rates equal to recorded costs, it would not be reasonable to set going-in rates equal to recorded costs adjusted in this way.

C. Efficiency Carryover Mechanism

Q22. Is an Efficiency Carryover Mechanism part of the current PBR plans?

A22. Yes. The AUC determined that an Efficiency Carryover Mechanism (ECM) should be part of the first generation plans. The nature of the ECM is that it provides an additional incentive to control costs during the first plan term by providing extra revenue during the second plan term that is contingent on performance during the first plan. The design of the ECM was approved in Decision 2012-237.[23] However, because the results of the ECM and any additional revenues due cannot be calculated until after the end of the first plan term, no calculations have been made or ECM revenue collected. Therefore, while the design of the ECM has already been approved, there is no mechanism determined for performing the necessary calculations or collecting ECM revenues.

[23] Decision 2012-237, paragraph 775.

Q23. Is there any connection between the operation of the ECM and rebasing?

A23. No. ECM revenues may be collected during the rebasing test year, but we are otherwise not aware of any necessary connection between rebasing and the ECM.[24]

Q24. What have interveners said about the ECM?

A24. Mr. Bell's evidence suggests revisions to the ECM[25] and Dr. Lowry's evidence suggests alternative designs.[26] The City of Calgary submission comments on the ECM but does not make any recommendations.[27] The City of Calgary comments seem to suggest that an ECM requires or should contain a mechanism for providing additional PBR benefits to customers over and above the benefits that are shared with customers via rebasing.[28] But since the purpose of the ECM is to strengthen incentives for the utility to control cost, the benefits are indeed shared with customers at rebasing and no additional sharing mechanisms are necessary.

Q25. Do you consider that the ECM in the current plans should be revised before any ECM revenues are calculated and collected at the beginning of the second plan?

A25. No. The purpose of the ECM is to strengthen incentives during the first plan term. The utilities have presumably therefore been operating with the expectation that an ECM corresponding to Decision 2012-237 would be in place, and that any corresponding ECM revenues would be collected at the start of the second plan term. If the AUC were to change the design of the current plans' ECM now, that would in effect constitute retroactive or retrospective ratemaking. Moreover it would serve to weaken incentives associated with other aspects of the PBR plan design going forward, due to increased uncertainty that the PBR design would be changed mid-term again in the future.

---

[24] See our direct evidence at Q/A 39-40.

[25] For example, Mr. Bell's evidence states "there is no reason that the AUC cannot revise the way ECMs are applied" (Direct evidence of Mr. Bell, Q/A 23).

[26] See, for example, CCA-AUC-2016APR15-007 (Revised).

[27] Submission of the City of Calgary, section 12.2.4.

[28] See also response to information request CALGARY-AUC-2016APR15-001, section headed "ECM".

Q26. Would it be possible to implement a different ECM in the next generation PBR plans?

A26. Yes. A new ECM (to apply from the start of the next plan, presumably with corresponding ECM revenue adjustments made at the start of the plan after next) could be implemented in the next PBR plan if the AUC identified improvements to the ECM design. However, our reading of the AUC's Final Issues list is that redesigning the ECM for the next generation PBR plans is not within the scope of this proceeding.

Q27. Is the economic logic underpinning the need for an ECM the same in the next PBR plan term as in the current term?

A27. Yes, it is.

Q28. Do you have any comments on the ECM proposals put forward by Dr. Lowry?

A28. We have not reviewed Dr. Lowry's ECM proposals in great detail, in part because we understand that such redesign is not within the scope of this proceeding. However, we observe that Dr. Lowry's proposals seem both complex and not completely specified. Furthermore, they do not conform to what we would usually understand by the term ECM. An ECM is a mechanism for modifying the revenues collected in one plan term according to performance in the preceding plan term, as a way of improving the incentives facing the utilities during the preceding term. For example, an ECM might be designed to help maintain the strength of incentives to control costs in the latter part of the plan leading up to rebasing. In contrast, Dr. Lowry's suggestions do not appear to strengthen incentives in this way since they focus on test year costs rather than performance during the prior plan term.[29]

---

[29] "Moreover, by making the test year the focus of the appraisal rather than the years of the prior plan period, this ECM also guards against strategic deferrals and promotes a fair share of plan benefits for customers." (CCA-AUC-2016APR15-007 (Revised)).

III. TOTAL FACTOR PRODUCTIVITY AND THE "X-FACTOR"

A. THE AUC'S X-FACTOR ISSUES

Q29. What are the X-factor issues from the AUC's Issues List?

A29. The Issues List asks the following questions about the X-factor:

2(a) How should the X-factor be determined?

2(b) Are modifications required to the stretch factor in the next generation of PBR?

B. Total Factor Productivity (TFP) studies

1. The NERA TFP study

Q30. What is the NERA TFP study?

A30. In Proceeding 566 the AUC commissioned a TFP study from NERA as part of the AUC-initiated proceeding to develop a generic approach to PBR for distribution utilities in Alberta. The AUC said that the TFP study must[30]

- be applicable to Alberta gas and electric utilities;
- compare productivity for gas and electric utilities to economy wide productivity;
- make the comparison in a transparent manner;
- use publicly available data;
- be for use and testing in a regulatory proceeding and for adjusting rates for Alberta electric and gas utilities; and
- be filed in AUC Proceeding 566 – Rate Regulation Initiative prior to December 31, 2010.

NERA's study was filed in Proceeding 566 in December 2010. Subsequently, in July 2011 the utilities filed PBR applications, including expert evidence that addressed the X-factor and NERA's TFP study. Interveners also filed expert evidence, in December 2011. After reviewing the expert evidence from the utilities and interveners, NERA

---

[30] AUC letter of September 8th 2010.

filed a second round of evidence and a revised TFP study in February 2012. Finally the utilities, their experts and the intervener experts filed rebuttal evidence in April 2012.

The AUC ultimately relied on NERA's revised TFP study, filed in February 2012, to identify a TFP trend and to set an X-factor for the current round of generic PBR plans.[31]

Q31. What is the subject of NERA's TFP study?

A31. NERA's TFP study measures the trend rate of TFP growth in US electric distribution utilities.

Q32. Why did NERA measure TFP in US electric distributors rather than utilities in Canada (or Alberta)?

A32. NERA was of the view that the only suitable data for measuring distribution utility TFP is FERC Form 1:[32]

> *The extent to which PBR regulation transmits incentives to utility managements is critically dependent on the transparency, stability and objectivity of the formula that governs price movements between base rate cases. Creating an index number for relative industry TFP* [ie, relative to TFP growth in the economy as a whole] *with those attributes requires a high-quality, transparent and uniform source of data that is readily available to the parties of regulatory proceedings. Such data are collected by the Federal Energy Regulatory Commission ("FERC") for electricity and combination electricity/gas utilities in its "Form 1," which we use as the source of industry empirical data for this Study. We hold objective uniformity in source data for a TFP study to be of paramount importance when such a study is part of regulatory proceedings where the interests of consumers and investors traditionally vie with one another. The FERC Form 1 data is the only source of information that satisfies the criteria of transparency and objectivity for a broad population of industry participants.*

---

[31] NERA's revised TFP study identified a TFP trend of 0.96%. Decision 2012-237 set the X-factor equal to 1.16%, being the sum of the TFP trend and a "stretch" factor of 0.2%.

[32] *Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative*, pp. 3–4.

Furthermore, in Decision 2012-237, the AUC reported that:[33]

> *Regarding the use of U.S. data, the CCA and the ATCO companies indicated that there are no suitable Canadian data available to make a reliable TFP estimate for the gas or electric distribution industries in Canada. Furthermore, even if suitable data were available, it is uncertain whether there are enough utilities in Canada to make a TFP estimate reliable given the small sample size it would be based upon.* [f/n omitted]

And the AUC determined that:[34]

> *In these circumstances, it is the Commission's view that when it comes to the sample size and the use of U.S. data in TFP studies, the relevant question to ask is not whether the companies in the sample are similar to the Alberta utilities, but: (i) whether the sample in the TFP study is reflective of the productivity trend in the U.S. power distribution industry, and (ii) whether the U.S. industry TFP trend represents a reasonable productivity trend estimate for the Alberta companies… …With regard to the second question, the Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities. As NERA and PEG pointed out, unlike in the United States, there is no Canadian central repository of public data due to the lack of standardized accounting across provinces with respect to utility operating reports.* [f/n omitted] *Because of this data problem, regulators in Canada have used U.S. data. For example, the Ontario Energy Board, in several decisions, used U.S. data in establishing its PBR plans.* [f/n omitted]
>
> *Mindful of the existing Canadian data limitations, the Commission agrees with NERA, the CCA, the ATCO companies and EPCOR that given the generally perceived similarity of both the utility regulatory systems in Canada and the United States, as well as the organization of the utility industries in the two countries, the U.S. power distribution industry TFP growth trend is a reasonable starting point in establishing a productivity estimate for the Alberta companies.* [f/n omitted]

---

[33] Decision 2012-237, paragraph 329

[34] Decision 2012-237, paragraphs 338, 341–2.

Q33. Did you rely on NERA's TFP study in your direct evidence in this proceeding?

A33. Yes. We updated the NERA TFP study to include data for the years since NERA submitted it, but we did not otherwise alter the study methodology.[35,36] TFP studies are complex and there are numerous elements of the methodology where experts may disagree. Many of these methodology questions were debated in the several rounds of written evidence, two rounds of written IRs and oral hearings in Proceeding 566. Since the NERA TFP study methodology was subject to extensive testing in Proceeding 566 over a period of well over 12 months, and since the AUC relied on the results of the NERA TFP study, we continued to rely on it for the purposes of this proceeding.

Q34. What changes did you make to the TFP study NERA filed in February 2012 for the purposes of your direct evidence?

A34. We added five years of more recent data to the study. We also removed five (of the seventy-two) utilities in the study. Four utilities ceased filing FERC Form 1 after 2009 and for one utility we were unable to reconcile data from 2010 onwards with the data for 2009 and earlier in the NERA study.

Q35. Did you make any other changes to the methodology?

A35. No. We calculated new TFP results for the five years 2010 through 2014. We then combined these new results with the results NERA prepared.

---

35 We note that in commenting on the AUC's proposed issues list for this proceeding, interveners requested that the NERA TFP study be updated: "Accordingly, the Customers respectfully request that the Commission reconsider its position and retain NERA to perform an update to its last TFP study." (as quoted in the AUC's Final Issues List, paragraph 30).

36 As we explain below, after filing our direct evidence we implemented a correction to NERA's methodology that Dr. Meitzen identified. The results we present in this reply evidence incorporate that correction.

Q36. Was the NERA TFP study relied on by other experts in Proceeding 566?

A36. Yes. Expert evidence filed by the utilities in Proceeding 566 generally relied on the NERA TFP study in relation to TFP and the X-factor.[37]

Q37. What TFP trend did you identify in your direct evidence?

A37. In our direct evidence we explained that results from the earlier period of NERA's study should not be relied on. We demonstrated that, using only results from NERA's study filed in February 2012, relying on data only from 1994/5 onwards gave a TFP estimate that was consistent with subsequent TFP results, whereas relying on data for the whole of NERA's 1972/3 to 2008/9 period produced a TFP estimate that was not consistent with subsequent TFP results. We explained that it would therefore be reasonable to use a start date for the updated TFP study somewhere between 1994/5 and 2004/5.[38]

Using a start date of 1994/5 the TFP trend was −0.34%; using a start date of 1999/2000 the TFP trend was −0.89%; and using a start date of 2004/5 the TFP trend was −1.37%. We recommended a start date of 1999/2000 (a corresponding TFP trend of −0.89%) as an appropriate balance between including more years to avoid volatility and including fewer years to avoid relying on older and potentially out-of-date data.[39]

Q38. Have you made any adjustments to these figures?

A38. Yes. Dr. Meitzen's direct evidence points out a logical inconsistency in the way that NERA's methodology calculated the labor quantity sub-index. NERA's methodology requires the total number of utility employees, which NERA estimated based on

---

[37] "The Commission also observes that all of the companies' experts used NERA's study as a starting point for their X factor recommendations despite expressing some reservations about particular aspects of the study and offering various adjustments primarily relating to the sample period. [f/n omitted]" (Decision 2012-237, paragraph 414).

[38] In the tables and figures prepared by NERA and by Dr. Lowry, an annual figure for TFP growth labelled 1999 means the increase from 1998 to 1999. We adopt the same convention.

[39] Direct evidence, Q/A 61.

changes in wage bills. However, rather than using changes in total wage bill, NERA used the distribution-only wage bill. As Dr. Meitzen's evidence points out, "Since NERA was extending the total number of full-time and part-time employees, and not the count of distribution full-time and part-time employees, it would have been correct to extend the series using constant dollar total salaries, not constant dollar distribution salaries."[40] It is straightforward to implement this correction because NERA's spreadsheets already contain the total salary information. Implementation therefore simply required switching the input for the calculation from distribution wages (the data field labelled "DWGSAL" in NERA's database) to total wages (labelled "TWGSAL"). The correction identified by Dr. Meitzen has the effect of increasing the TFP trend by about 0.1% (see Table 1 below).

Q39. Is that the only adjustment you made?

A39. Yes. The trend we identified in our direct evidence was calculated by taking the TFP results from the last five years and combining them with the TFP results for 1999/2000 through 2008/9 which had been prepared by NERA in Proceeding 566. Since in our direct evidence we did not make any changes to NERA's methodology, it was not necessary to "recalculate" results for earlier years. However, the correction identified by Dr. Meitzen does change the results for earlier years. The results we present in this reply evidence, and our new recommendation, therefore uses updated calculations for all years 1999/2000 through 2013/14.

Q40. What are the updated results and how do they compare to the results in your direct evidence?

A40. We have updated the results to take account of Dr. Meitzen's correction. The resulting annual TFP results are shown in the response to BRATTLE-AUC-2016APR15-007(d), column [3]. Using these figures we have updated our estimates of the TFP trend. The updated estimates are compared with the results from our direct

---

[40] Direct evidence of Dr. Meitzen, paragraph 39.

evidence in Table 1. Table 1 shows that the correction identified by Dr. Meitzen has a small impact on the TFP results (of about 0.1%).

Table 1
Updated TFP trend estimates

		1994–2014	1999–2014	2004–2014
Direct evidence	[1]	-0.34%	**-0.89%**	-1.37%
Including Dr. Meitzen's correction	[2]	-0.24%	**-0.79%**	-1.32%

Sources:
[1]: Direct evidence, Q/A 61.
[2]: Workpaper 1.
Notes: Figures in bold are the corresponding recommendation.

Q41. Does the correction discussed above change the results of the statistical tests you reported in your direct evidence?

A41. No. In our direct evidence we showed that the 1972–2009 TFP trend is statistically different from the 1994/1999–2009 TFP trend; the 1972–2009 TFP trend is statistically different from the 2009–2014 trend; and the 1994/1999–2009 TFP trend is not statistically different from the 2009–14 trend.

We repeated those tests after applying Dr. Meitzen's correction. The results were the same.[41]

Q42. Have you conducted other statistical testing since filing your direct evidence?

A42. Yes. An AUC IR asked for some additional statistical tests. The results of these tests[42] are also consistent with the statistical tests reported in our direct evidence.

Q43. What is the significance of the "benchmark year" in the NERA TFP study?

A43. In a TFP study a "capital quantity index" is typically constructed as a running total of distribution plant. Because TFP studies use real dollars and do not always use the

[41] See Workpaper 4.

[42] See response to BRATTLE-AUC-2016APR15-008.

same depreciation pattern as in regular utility accounts, the capital quantity index is constructed using additions in each year of the study rather than using gross (or net) plant balances. However, it is necessary to make an assumption about the "opening balance" at the start of the TFP study,[43] since accounting data will not be available back to the inception of the utility. The opening balance in the "benchmark year" has to be developed using either net or gross plant balances in that year. In NERA's methodology, the opening balance in the benchmark year is derived from net plant. In Proceeding 566, Dr. Lowry disputed NERA's use of net plant and argued that gross plant should have been used instead. NERA's response to Dr. Lowry was to insist that net plant was the correct approach.

Q44. Have you calculated TFP results from the updated NERA study using both net and gross plant in the calculation of the capital quantity in the benchmark year?

A44. Yes. We made calculations based on gross plant rather than net plant in response to an IR from the AUC. The impact on the TFP results was small (about 0.1%).[44]

Q45. For the results you present in this reply evidence and for your recommendations, do you use the original NERA methodology (net plant) or do you use gross plant as Dr. Lowry said that NERA should have done in Proceeding 566?

A45. Since this issue of net versus gross plant was debated in Proceeding 566 and since the AUC accepted NERA's recommended methodology, we did not adjust the methodology, and we continue to rely on NERA's original specification (net plant). However, we also note that the impact of this issue on the resulting TFP estimates is small, and we would not expect any of our conclusions or recommendations to turn on this issue.

---

43 We understand that in order to reduce the influence of this assumption on the results of the study, it is usual to extend the construction of the capital index back in time to a point significantly earlier than the start of the TFP study.

44 See BRATTLE-AUC-2016APR15-007(d), compare the last and second-last columns.

Q46. What did Dr. Lowry say about this issue in Proceeding 566?

A46. Dr. Lowry argued that a gross plant value, instead of a net plant value, would be consistent with NERA's calculation of capital quantity using the "one hoss shay" method. By using a net plant value, Dr. Lowry believed that NERA had underestimated its capital quantity in the benchmark year, resulting in a downward bias in its measured productivity trend.[45] In response, NERA noted that Dr. Makholm had used this approach in previous work, and that the practice of using net plant value discounted by a triangularized weight is widely used in published MFP studies.[46] We note that Dr. Lowry asserted in Proceeding 566 that switching from net to gross plant resulted in a change to the TFP result of about 1% (from 0.85% to 1.82% over the 1972–2009 period, and from –1.09% to –0.07% over the 2000–2009 period).[47] We believe this assertion to be in error, and, as we explained above, we found the difference to be of the order of 0.1%.

Q47. Have other witnesses in this proceeding relied on the NERA TFP methodology?

A47. Yes. Dr. Meitzen relied on the NERA TFP methodology. He updated the study to include results from the last five years, as we did. Dr. Meitzen identified a TFP trend of –1.11% on which he based his X-factor recommendation. Dr. Meitzen also considers that the full data series reaching back to 1972 should not be relied on, and he showed that an estimate based on a shorter time period is a "better predictor of the next five-year average TFP growth than the NERA approach every year since 1998."[48] Dr. Meitzen prefers a "10/15 method" which is the average of the most recent ten-year and fifteen-year TFP trends. In Table 2 we compare Dr. Meitzen's results with the results we obtained.

---

45 Proceeding 566, Exhibit 307, PEG evidence in AUC RRI, page 37.

46 Proceeding 566, response to AUC-NERA-16.

47 See Proceeding 566, response to AUC-CCA-14. We note that in addition to switching from net plant to gross plant, PEG also changed NERA's triangularized weighted average of the Handy-Whitman index to a simple average of the Handy-Whitman index.

48 Direct evidence of Mr. Meitzen, paragraph 60.

Table 2

Comparison of TFP trend estimates: Dr. Meitzen

		1999–2014	2004–2014	Average
Dr. Meitzen's evidence	[1]	-0.83%	-1.40%	**-1.11%**
Updated NERA study	[2]	**-0.79%**	-1.32%	-1.05%

Sources:
[1]: Exhibit 74, EDTI Next Generation PBR Plan Submission, Table 3.
[2]: Workpaper 1.
Notes: Figures in bold are the corresponding recommendation.

Q48. How do you interpret the comparison shown in Table 2?

A48. The bolded figures in Table 2 are the trends on which we and Dr. Meitzen relied to make X-factor recommendations. These figures are close (differ by about 0.3%), but most of the difference is accounted for by the different time periods involved, as Table 2 shows. Using consistent time periods, the difference is less than 0.1%.

Q49. Do you disagree with Dr. Meitzen's approach of relying on the average of a ten-year and a fifteen-year TFP trend?

A49. While we continue to base our recommendation on a fifteen-year trend, we consider Dr. Meitzen's approach to be acceptable also. In our direct evidence we explained that it is important to rely only on more recent data, and that a start year between 1994/5 and 2004/5 (respectively producing a 20-year trend or a 10-year trend) would be acceptable. We chose a 15-year trend, whereas Dr. Meitzen has chosen an average of the 10-year and 15-year trends. Both approaches are consistent with the evidence and logic in our direct evidence.

Q50. Did Dr. Meitzen adjust the NERA methodology in any way?

A50. We understand that, other than correcting the calculation of the labor quantity index, as explained above, Dr. Meitzen did not make any changes to the NERA methodology. Dr. Meitzen removed four utilities from the study whereas we additionally removed one more. Also Dr. Meitzen did not update the capital price index in the same way that we did. However, it is evident from Table 2 that these differences did not have a large impact on the TFP results.

Q51. Did the other witnesses in this proceeding rely on the NERA methodology also?

A51. No. Mr. Bell does not discuss TFP and does not make an X-factor recommendation (other than to opine that a negative X-factor signals that productivity is falling, contrary to the intent of PBR).[49] Mr. Simpson does not mention TFP or X. Mr. Thygesen does not address TFP or the X-factor in his evidence. The submission of the City of Calgary likewise does not address TFP or the X-factor, except to assert that the X-factor should be positive.[50] Dr. Lowry's evidence, however, contains results of a new TFP study (the "PEG TFP study"), as well as some criticisms of the NERA study. We discuss the PEG TFP study further below.

Q52. Do you agree that a negative X-factor signals that productivity is falling and that this is contrary to the intent of PBR?

A52. A negative TFP trend means that productivity—as defined in the specification of the TFP study—has been falling over the period of the study. We are aware of several instances where negative TFP growth has been observed. For example, PEG filed reports in Ontario and in New Zealand recently that identified negative TFP trends for electric distribution.[51] In addition, NERA's 2010 report in Proceeding 566 identified a negative TFP trend for the Canadian economy as a whole.[52]

We consider that the intent of PBR is to strengthen incentives to control costs and to reduce the regulatory burden. Thus, as we have explained above,[53] it is reasonable to

---

49 Evidence of Mr. Bell, Q/A 25.

50 Written Submission of the City of Calgary, p. 54.

51 In Ontario, *Empirical Research in Support of Incentive Rate-Setting: 2012 Update, Report to the Ontario Energy Board*, PEG (September 2013); in New Zealand, *Review of Economic Insights' Report Electricity Distribution Productivity Analysis: 1996-2013*, PEG, August 2014.

52 NERA report *Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative*, Table 4.

53 See Q17 above.

expect that a utility's costs, after some period of time under PBR, will be lower than that same utility's costs would have been had it operated under cost-of-service. PBR does not offer a guarantee that the absolute level of costs will fall over time.

Q53. Did the AUC commission a new TFP study for this proceeding?

A53. No. In commenting on the proposed scope of this proceeding, interveners requested that the NERA TFP study be updated.[54] The AUC's response was to say:[55]

> *In Decision 2012-237, the Commission approved an X factor of 1.16 per cent based on a TFP of 0.96 and a stretch factor of 0.2 per cent. While the Commission will not sponsor a new TFP growth study at this time, the Commission will consider potential changes to the X factor in this proceeding. The Commission recognizes that the X factor is distinct from the TFP growth number, and, as such, will consider evidence with respect to the X factor even if a revised TFP growth study is not available on the record of this proceeding. Finally, the value of the stretch factor in a next generation PBR plan is a new issue meriting consideration in this proceeding and shall remain on the final issues list.*

2. The PEG TFP study

Q54. Is the PEG TFP study reported in Dr. Lowry's evidence similar to the TFP study which Dr. Lowry submitted in Proceeding 566?

A54. No. In Proceeding 566 Dr. Lowry submitted a TFP study of US gas distribution utilities. In this proceeding Dr. Lowry's TFP study is of US electric utilities.

Q55. Is the PEG TFP study similar to the NERA study?

A55. The two studies are similar in that both are aiming to estimate the same thing, namely the trend rate of productivity growth of the US electric distribution industry. Furthermore, both studies essentially rely on the same data source (FERC Form 1

---

[54] See footnote 35 above.

[55] Final Issues List, paragraph 34.

accounting data),[56] and the PEG study focuses on more recent data as we recommend. There are differences in the detail of the methodology employed, however. The "technical" differences include the following.[57]

- PEG's study uses a "chain-weighted" index, whereas NERA's uses a "multilateral" index.
- NERA's TFP calculations put more weight on larger utilities, whereas PEG's calculations are simple averages.
- The capital quantity index is calculated using different depreciation methods in the two studies: NERA's uses the "one hoss shay" method, whereas PEG's uses "geometric decay." In addition, NERA's study assumes a service life of 33 years for distribution assets, whereas PEG's study assumes 44 years for distribution assets and 16 years for common plant.
- There are differences between the two studies in the price indexes used, for example to calculate the materials and services quantity index.
- The PEG study includes a wider range of cost categories: whereas NERA's study includes only costs labelled as "distribution" in the FERC accounts, PEG's study includes some expenses and wages related to customer accounts, A&G, and some general plant.

In addition, there are other differences which are not technical in nature but relate to the scope of what the studies include. The identity of the utilities in the studies is different: the updated NERA study has 67 utilities and the PEG study has 88 utilities (55 are common to both). Also the PEG study bases the output index on the number of customers served by each utility, whereas NERA's output index is based on the kWh sold.[58]

---

[56] Both additionally rely on other sources for certain data items, but all utility accounting cost data comes from FERC Form 1 in both studies (the two studies do not use the same line items, however).

[57] Unless otherwise stated, when we refer to the NERA methodology we are referring to the updated study as described in this reply evidence.

[58] We understand that there has been some dispute over whether the data on which NERA methodology relies to calculate the output index represents kWh sold (but not kWh distributed on behalf of other retailers of electricity), kWh distributed, or both. We do not believe these distinctions to be material to the TFP results. See Q75 and Q76.

We discuss these differences further below.

Q56. Does the PEG study meet the requirements that the AUC set out in Proceeding 566?

A56. The key requirements that the AUC set out are that the TFP study should use publicly-available data and be transparent. Our understanding is that the PEG TFP study described in Dr. Lowry's evidence does rely on publicly-available data.

The PEG TFP study is based on processing the input data (FERC Form 1 accounting information and other items) in a statistical package called Statistical Software Tools (SST). While some analytical tasks are more easily carried out in computer code rather than in a spreadsheet, it is often more difficult to review and check computer code. Most professionals are familiar with spreadsheets, but fewer are able to read computer code. The PEG analysis runs in a type of computer code that is not widely used. We have not seen this code used before by anyone apart from by PEG, and the software needed to run the code is not commercially available as far as we are aware. The analysts who assisted us with this proceeding had to "learn" enough of the SST language to enable them to read the PEG code. They were able to do so sufficiently to permit them to run simple modifications to the PEG model (described below), but it would have been easier by far if the model had been built in a spreadsheet or one of the three statistical analysis packages most commonly taught to undergraduates.[59]

We note that Proceeding 566 provided for extensive testing of the NERA methodology over a period of more than a year, with two rounds of written evidence and IRs subsequent to the TFP study being made available. The opportunity to test the PEG study in this proceeding is more limited.

---

[59] These packages are R, Stata and SAS.

Q57. Are the results of the PEG study and the updated NERA TFP study similar?

A57. Table 3 below shows that the TFP results of the two studies are different. PEG's TFP study produces a trend rate of productivity growth which is between about 1.1% and 1.5% faster than the updated NERA study (depending on the time period for the comparison).[60]

Table 3

Comparison of TFP trend estimates: PEG

		1996–2014	1999–2014	2000–2014
PEG study	[1]	0.48%	0.49%	0.46%
Updated NERA study	[2]	-0.59%	**-0.79%**	-1.02%
Difference	[3]	-1.07%	-1.28%	-1.48%

Sources:
[1]: Workpaper 2.
[2]: Workpaper 1.
[3]: [2] - [1].
Notes: [1] shows results for PEG's full sample. Dr. Lowry's recommendation is based on a sub-sample (not shown). Figures in bold are the corresponding recommendation.

We examine the differences between the two studies in more detail below.

Q58. Are both the NERA and the PEG studies aiming to estimate the TFP trend for the whole of the electric distribution sector (the "industry") in the US?

A58. Yes. We understand that both studies include all utilities for which good quality data could be obtained.[61] They are thus intended to represent the industry as a whole.

Q59. What other TFP results are in Dr. Lowry's evidence?

A59. Table 3 above shows the results for the "full" sample of 88 utilities over the 1997–2014 period. Dr. Lowry's evidence also includes TFP results for a "rapid growth" sub-sample, and for a "Mountain west" sub-sample. We understand that the idea behind presenting TFP results for sub-samples of the utilities in the main study is to

---

[60] See Workpaper 2.

[61] See PEG's sample selection methodology in CCA's response to CCA-Utilities-2016APR15-04.

benchmark the Alberta utilities against a set of US utilities which are "similar" rather than against the whole of the electric distribution industry in the US.

Q60. Is the approach of selecting sub-samples a helpful one in your opinion?

A60. No, it is not. There are many ways in which one utility may differ from another (for example, service territory size, customer density, customers per line mile, peak demand, average load factor, penetration of distributed solar photovoltaic, various dimensions of climate, average asset age and so on). In our view it is not possible to disentangle the parameters which may be relevant for determining the scope for productivity improvement from those which are not relevant. We agree with NERA and with the AUC that the logic of the TFP approach to the X-factor is that the X-factor should represent industry-wide productivity growth:[62]

> *The Commission agrees with NERA's characterization that the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta.* [citation to NERA's second report in Proceeding 566, paragraph 38]

We have therefore not examined the PEG sub-samples.

Q61. What is the relevance of the PEG TFP results that exclude a fraction of capex?

A61. We understand that Dr. Lowry has re-run the PEG TFP study having reduced all of the capital additions reported on the FERC Form 1 for each utility by 10%. This naturally produces a higher TFP result, since it creates a new capital quantity index that grows more slowly. We consider these results to be irrelevant: first, the resulting TFP estimate does not represent the TFP trend of the US industry, nor does it represent anything about the industry in Alberta, and second, removing 10% of the additions (rather than some other proportion) is entirely arbitrary.

[62] Decision 2012-237, paragraph 337.

Q62. How do the results of the PEG study in this proceeding compare to results of other TFP studies conducted by PEG?

A62. We have not surveyed all of PEG's prior TFP studies.[63] But in Table 4, we show the results of the PEG study in this proceeding and results from two other recent studies where all three studies are based on FERC Form 1 data for US electric distributors.

Table 4

PEG electric utilities TFP results

Year	Alberta, 2016	British Columbia, 2013	Vermont, 2008
	[1]	[2]	[3]
1997	1.56%		2.37%
1998	-1.15%		0.39%
1999	0.80%		0.00%
2000	0.97%		1.64%
2001	0.99%		2.55%
2002	1.70%	1.07%	1.11%
2003	-1.43%	-0.33%	0.09%
2004	1.40%	2.83%	1.28%
2005	1.19%	1.43%	0.91%
2006	-0.01%	0.58%	-0.09%
2007	0.01%	0.14%	
2008	-0.25%	1.62%	
2009	0.84%	0.90%	
2010	0.41%	-0.05%	
2011	0.51%	1.12%	
2012	1.16%		
2013	-0.01%		
2014	-0.10%		
Full sample	0.48%	0.93%	1.03%
Common period	0.57%	1.12%	0.66%

Sources and notes:
[1]: Exhibit 83, CCA tables in PEG evidence, Table 5a.
[2]: BCUC project 39087, Intervener Evidence C6-9, Table 5a.
[3]: Workpaper 3.
Notes: All growth rates are computed logarithmically.

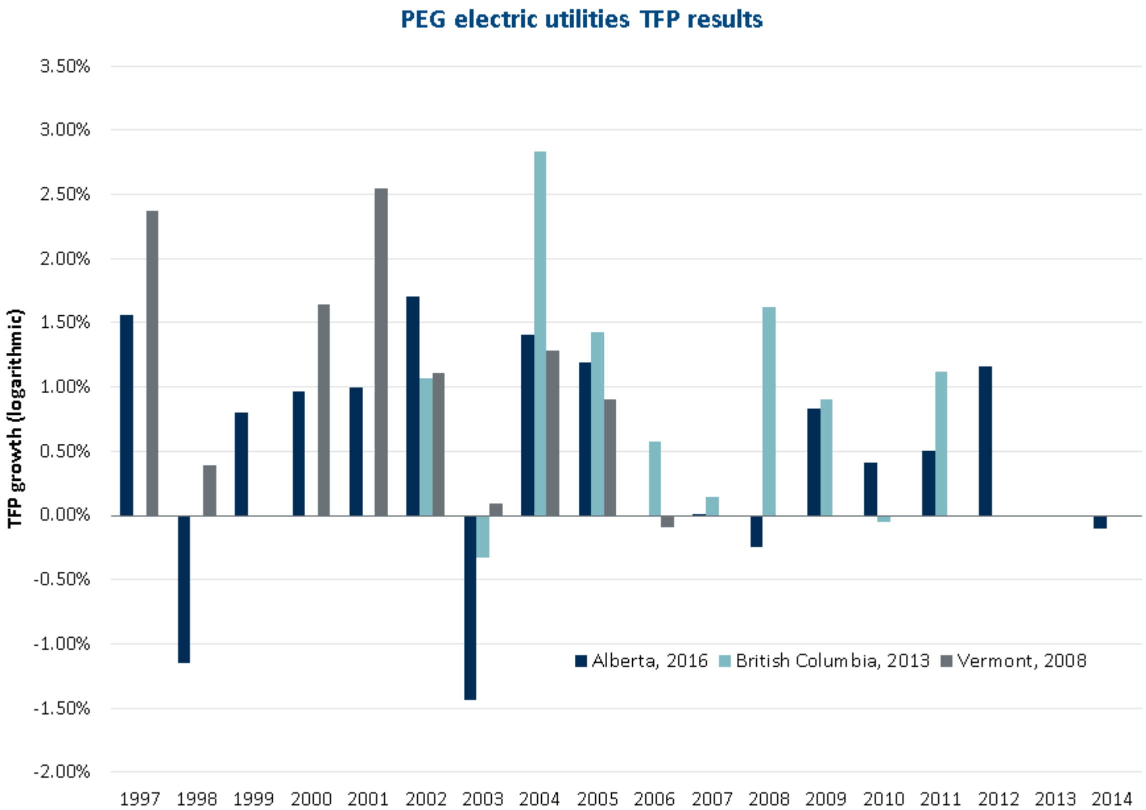
[63] See CCA's response in CCA-Utilities-2016APR15-07.

Q63. Were the three PEG TFP study methodologies the same?

A63. We understand that there are some differences in the details of the methodologies. Table 4 suggests that these methodology differences have an impact on the resulting estimates of the TFP trend.

Since these studies are for different time periods, we also examined the TFP results for individual years. Here the differences are more pronounced.

Figure 1



Source: Table 4.

Q64. Have you seen a similar pattern in PEG's gas distribution utility TFP studies?

A64. Yes. Table 5 below is some analysis of PEG gas TFP studies from Proceeding 566. It shows a similar pattern.

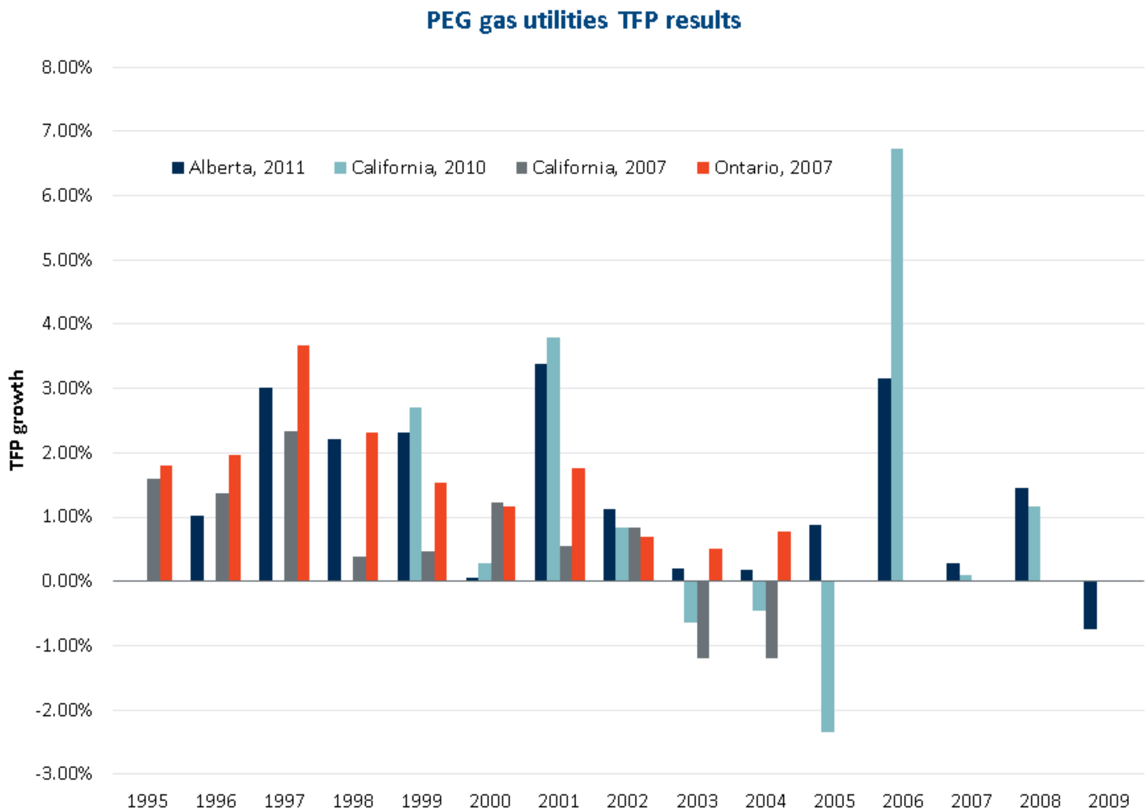
Table 5

PEG gas utilities TFP results

Year	Alberta, 2011	California, 2010	Ontario, 2007	California, 2007
	[1]	[2]	[3]	[4]
1995			1.80%	1.60%
1996	1.02%		1.96%	1.38%
1997	3.01%		3.66%	2.33%
1998	2.21%		2.32%	0.38%
1999	2.32%	2.70%	1.54%	0.47%
2000	0.06%	0.29%	1.16%	1.22%
2001	3.39%	3.79%	1.77%	0.56%
2002	1.12%	0.84%	0.70%	0.83%
2003	0.21%	-0.65%	0.52%	-1.19%
2004	0.18%	-0.47%	0.77%	-1.21%
2005	0.89%	-2.35%		
2006	3.16%	6.72%		
2007	0.29%	0.09%		
2008	1.45%	1.17%		
2009	-0.75%			
Full sample	1.32%	1.21%	1.62%	0.64%
Common period	1.21%	1.08%	1.08%	0.11%

Sources and notes:
[1] - [4]: Proceeding 566, Hearing exhibit 0595.01.AE-566.

Figure 2



Source: Table 5.

Q65. What conclusions do you draw from the differences in the PEG TFP results outlined above?

A65. If we take the studies at face value, and without investigating whether each individually is robust, we observe that different TFP studies that are essentially measuring the same thing (the TFP trend of US electric distribution utilities or US gas distribution utilities) can produce very different results. The TFP trends seem to vary by 0.5% to 1.0% or so, and the results for individual years can vary by even more. This variation must be due to detailed methodology choices that differ from one study to the next (even though the studies summarized above were all prepared by PEG analysts).

3. TFP methodology

Q66. Have you investigated how the differences between the PEG and NERA TFP studies influence the TFP results?

A66. Yes. As we explained above, there are differences between the two studies in terms of what they include (for example, which utilities are in the sample). There are also various "technical" differences in methodology, such as the depreciation method used to calculate the capital quantity index. Since the results of the PEG and NERA studies are quite different, we have investigated whether the differences result from differences in methodology, time period, output index or sample selection.

Q67. Do differences in the period analyzed explain the differences in results?

A67. No. Dr. Lowry's results, and our recommendations based on the updated NERA study, employ similar time periods (1999/2000 onwards in our case, and 1996/7 onwards for Dr. Lowry). Furthermore, we showed above (Table 3) that the two studies still have quite different results when the time periods are aligned.

Q68. Does the TFP study put forward by Dr. Lowry in this proceeding rely on the same set of electric utilities as the NERA TFP study which you updated in your direct evidence?

A68. No. The TFP study put forward by Dr. Lowry in this proceeding is based on a sample of 88 utilities whereas the updated NERA study is based on a sample of 67 utilities. Of these two samples, 55 utilities are in both studies.

Q69. Of the utilities which are in the NERA sample but not in the PEG sample, are you able to identify why those utilities were not included by PEG?

A69. Yes. We understand that both studies consider all major US electric distribution utilities. Dr. Lowry examines all utilities with complete FERC Form 1s and EIA-861 forms and uses three /criteria[64] to select his final sample of 88 utilities. First, he removes from his sample utilities that have had large transfers between transmission and distribution classifications; this corresponds to seven utilities in the NERA sample. Second, he removes from his sample utilities that have undergone major consolidations or divestitures that cannot be corrected; this corresponds to three utilities in the NERA sample. Finally, he removes from his sample utilities that have other problems, such as misclassification of general plant; two of the utilities that Dr. Lowry identifies in this step are in the NERA sample. In total, 12 of the utilities in the updated NERA study are removed by applying Dr. Lowry's criteria, leaving 55 utilities that are in both studies.

Q70. Did Dr. Lowry remove from his sample all utilities which underwent consolidations or divestitures?

A70. No. We understand that, where possible, Dr. Lowry's approach was to retain utilities that were the subject of consolidation or divestiture activity by making necessary adjustments to the data (such as combining the data for "predecessor" utilities in the years before a consolidation).[65] Dr. Lowry made adjustments for 14 of the utilities that are common to both studies for that reason.

Q71. Have you identified why those utilities which are in the PEG sample but not in the NERA sample were not included in the NERA sample?

A71. No.

Q72. Does the fact that the PEG and NERA studies include different utilities influence the TFP trends?

A72. Not to any great degree, no. Table 6 shows the results of the two studies with their respective full samples, and adjusted so that both studies use data only for the same

---

[64] Dr. Lowry's sample selection criteria are explained in his response to an information request (CCA-Utilities-2016APR15-04).

[65] See Exhibit 106, PEG working papers background, "Company List with Predecessors" tab.

set of 55 utilities. In both cases the results for the smaller sample are within about 0.1% of the original result, showing that the differences between the studies relate more to the details of the TFP methodology than to the identity of the utilities included in the study.

Table 6

1999–2014 TFP trends

	Full samples	55 common utilities	41 common utilities
	[1]	[2]	[3]
Updated NERA study	-0.79%	-0.77%	-0.73%
PEG study	0.45%	0.56%	0.45%

Sources and notes:
[1]: These are the 67 utilities in the updated NERA study, and the 88 utilities in the PEG study.
[2]: These are the 55 utilities that are common to both studies.
[3]: These are the 41 utilities that are common to both studies for which there has not been a history of major mergers or divestitures.

Table 6 also shows that the 14 utilities for which Dr. Lowry made adjustments to reflect the impact of significant consolidations or divestitures also do not have a major influence on the TFP results, either for the updated NERA study or for the PEG study.

Q73. How were you able to prepare the adjusted results in Table 6?

A73. We identified the lists of 55 or 41 common utilities as described above. For the NERA study we removed the utilities not in this list by deleting the respective rows in the spreadsheets performing the TFP calculations. For the PEG study, we modified the code provided by Dr. Lowry in his workpapers to "drop" unwanted utilities from the calculations.[66]

---

[66] This code is contained in the workpapers accompanying this evidence (spreadsheet named "Table 6.xls", tab "Code").

Q74. Have you investigated the impact of the fact that PEG methodology uses the number of customers as the output measure, whereas the NERA methodology uses the quantity of energy distributed?

A74. Yes. Since TFP growth is defined as the difference between the output index growth and the input index growth, a difference in the definition of the output index will result in a corresponding difference in the TFP estimate. In this case, the difference between a TFP estimate based on the number of customers and a TFP estimate based on the quantity of energy delivered is simply the difference between the growth in the quantity of energy and the growth in the number of customers (or, in other words, the growth in the "use per customer"). For electric distribution utilities, the growth in use per customer since 1999 is about –0.1%.[67] On this basis, therefore, we would not expect the TFP estimate to be sensitive to the definition of the output index.

Q75. Is that what PEG found?

A75. Yes. Table 7 shows Dr. Lowry's results (taken from response to CCA-AUC-009).[68] The TFP results from the PEG study are not strongly influenced by whether the output index is based on the number of customers or kWh. We note that the difference between the two versions of the PEG study shown in row [3] of Table 7 is not exactly the same as the change in use per customer we calculated (shown in row [4]). Dr. Lowry's kWh-based output index uses a revenue-weighted average of kWh across customer classes, whereas our calculation of change in use per customer simply divides total kWh by total number of customers.

[67] This figure is derived from volumes and number of customers data from PEG's workpapers for the 88 utilities in its sample. It is calculated as the total MWh divided by the total customers for each utility in each year. An average is taken first across the 88 utilities and then across all years.

[68] See tables in CCA-AUC Attachment 9f 1-4 and work papers in Attachment CCA-AUC Attachment 9f-5.

Table 7

Comparing TFP results with a consistent output index

		1996–2014	1999–2014
PEG study (number of customers)	[1]	0.48%	0.49%
PEG study (MWh)	[2]	0.49%	0.45%
Difference: [2] - [1]	[3]	0.02%	-0.05%
Change in average use	[4]	-0.06%	-0.14%

Sources and notes:
[1]: Based on PEG's tables filed in evidence, Table 5a.
[2]: Based on PEG's tables filed in IR, CCA-AUC Attachment 9f-1.
[3]: [2] - [1].
[4]: Based on volumes and number of customers data from PEG's workpapers filed in IR, CCA-AUC Attachment 9f-5.

Q76. What does Dr. Lowry say about the difference in the output measure?

A76. In an IR response, Dr. Lowry reported the results of two separate versions of the PEG TFP study, both with kWh as the output index.[69] To replicate NERA's methodology, PEG "constructed a three-category rather than four-category output index to resolve the differences [between the FERC Form 1 and EIA data sources]." That is, while the Form 1 classifies customer classes into residential, industrial, commercial, and other categories, EIA-86 makes other distinctions. PEG constructed an index composed of residential, commercial, and industrial, with all other classification grouped with commercial.[70] In the first version of the kWh-based output index, a combination of Form 1 data and EIA data was used (according to whichever source Dr. Lowry felt was the more reliable). This resulted in the TFP trends shown in Table 7 above which are almost the same as the TFP trends using number of customers as the output index. In the second version of the kWh-based output index, Dr. Lowry used Form 1 data only and did not use any EIA data. According to Dr. Lowry, this resulted in a "substantially lower TFP trend of –0.14% over the same period."[71]

[69] See tables in CCA-AUC Attachment 9f 1-4 and work papers in Attachment CCA-AUC Attachment 9f-5.

[70] See response to CCA-AUC-009(f).

[71] *Ibid.*

The "substantially lower" result of –0.14% seems to be driven by some spurious FERC Form 1 data for one utility in the PEG sample (which is not in the NERA sample): Central Maine Power Company exhibits a strange growth pattern from 2001 onwards. Central Maine Power Company reported volumes of 9,487,049 MWh in 2000; 2,004,629 MWh in 2001; 211,163 MWh in 2002; and 271 MWh in 2003.[72] Dr. Lowry did not make any adjustment for this anomalous data.

We have recalculated the results that we showed above for the 41 utilities common to both studies that have not undergone significant consolidations or divestitures (Central Maine Power Company is not in this set). The TFP result from the PEG study with combined Form 1 and EIA-861 delivery volumes is 0.46%; the result from the PEG study with Form 1 delivery volumes only is 0.32%.[73] Because we do not consider a difference in TFP results of 0.14% to be material, we conclude that neither the choice of output index (kWh or customers) nor the choice of data source (FERC Form 1 or combination of FERC Form 1 and EIA) has a significant influence on the TFP result.

Q77. If the methodology differences you discussed above do not have a large influence on the TFP results, what could explain the different TFP results of the two studies?

A77. We showed above that the choice of output index, time period and utilities included in the TFP studies do not seem to have a large influence on the results. We therefore conclude that the differences in the results are mainly associated with the combination of methodological differences we highlighted above, namely:

- "chain-weighted" versus "multilateral" index;
- weighted versus unweighted calculations;

---

72 See the volumes reported under "yret1" for the company with pegid 23 (outputdata.xlsx from CCA-PEG-009(f)).

73 These results are obtained by applying the code modification described in Table 6.xlsx [Code] tab to the MWh versions of the PEG code as provided in CCA-PEG-009(f).

- capital quantity index (benchmark year, depreciation method and assumption about asset lives);
- choice of price index; and
- narrow (distribution only) versus broader (distribution plus some customer accounts and A&G) scope of costs.

Q78. How do the methodologies differ in terms of the costs that are included?

A78. Whereas the NERA methodology includes distribution-only O&M expenses and additions to distribution plant (ie, FERC accounts labelled "distribution"), the PEG study also includes expenses associated with meter reading (part of "customer accounts"), and also includes some "general" plant and A&G expenses. Including these additional costs that are not directly labelled as "distribution" requires the allocation of some amounts to the distribution function.

Although meter reading expenses are reported on Form 1, wages and salaries related to meter reading are not. Thus, the PEG methodology allocates a portion of the total customer accounts wages and salaries assumed to be related to meter-reading, using the ratio of meter reading expenses to the total customer accounts expenses. Similarly, the PEG methodology allocates a portion of A&G expenses to the distribution function based on the ratio of distribution and meter reading expenses to total O&M expenses (excluding certain items such as energy purchase and production costs).

Q79. Is it better to include these additional meter reading and A&G costs in the TFP study?

A79. We consider that the scope of the TFP study—the costs included—should ideally match the distribution functions of the utility. On that basis, it might be reasonable to include meter reading expenses. However, it seems that in order to include meter reading expenses, it is necessary to allocate labor costs associated with meter reading. There is nothing wrong in principle with using an allocation in this way, but it is a source of uncertainty. There is no data on the actual labor cost associated with meter reading, so PEG's methodology makes the assumption that the share of total customer accounts *labor* associated with meter reading is the same as the share of total customer accounts *expenses* associated with meter reading.

Similarly, including some A&G expenses also requires allocation and an assumption about the appropriate fraction of total A&G expenses to associate with the distribution function.

Capturing additional distribution-related costs in this way comes at the expense of relying on additional and uncertain assumptions.

Q80. What is your view of the other technical differences you identified in the bullet-point list above?

A80. The technical differences in the list above are choices that must be made in the design of a TFP study. But we are not aware of "right answers". For example, the capital quantity index aims to summarize information about the stock of assets that are being used to provide utility service, so that the contribution to TFP growth of changes in the capital stock over time can be computed. For some assets, it may be the case that less service is provided by an older asset than a newer one: perhaps as a machine gets older and more worn, it cannot run at the same capacity and therefore cannot provide the same quantity of service as when it was new. For other assets, the amount of service provided stays fairly constant until the asset breaks and has to be replaced (for example, the amount of power that can be moved through a particular transformer does not depend on the age of the transformer: the transformer provides the same service every year until either it breaks or has to be replaced because the risk of failure is deemed unacceptable).

In our view, choices inevitably have to be made on these methodology questions, and those choices influence the results of the studies. However, we are not aware of any strong reasons for preferring one choice over another.

Q81. Were the technical choices listed above discussed in Proceeding 566?

A81. For the most part, yes. In Decision 2012-237 the AUC said:[74]

> *The Commission notes that in addition to the issues discussed in sections 6.3.2 to 6.3.7 above, PEG expressed a number of other concerns with NERA's study relating to the correct index form and the capital quantity index to use, among others.*[f/n omitted] *Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer. For instance, PEG advocated the use of a chain-weighted form of a Tornqvist-Theil index, while NERA preferred the use of a multilateral Tornqvist-Theil index.*[f/n omitted] *Similarly, PEG indicated that the correct capital quantity measure to use should be the inflation-adjusted value of gross plant, while NERA insisted on using the net plant value.*[f/n omitted] *Overall, the Commission considers that PEG's criticisms do not undermine the credibility of NERA's TFP study.*

Q82. What conclusions do you draw from comparing the TFP methodologies put forward by Dr. Lowry in this proceeding and by NERA in Proceeding 566?

A82. The TFP study prepared by Dr. Lowry in this proceeding uses a methodology that differs from that used by NERA in Proceeding 566 in several respects, as discussed above.

For the most part, the technical differences between the NERA and Lowry studies were raised in Proceeding 566 and debated there (one exception is the correction to the labor quantity sub-index identified by Dr. Meitzen which was not raised in Proceeding 566).[75] We have not seen any new evidence put forward in this proceeding relating to these technical issues relative to the evidence ventilated in Proceeding 566, so we see no reason to modify NERA's methodology.

---

[74] Decision 2012-237, paragraph 413.

[75] Dr. Lowry did critique NERA's labor quantity index in Proceeding 566, suggesting that NERA "recalculate the labor quantity by taking the difference between the growth in salaries and wages and the inflation in an appropriate salary and wage price index" (PEG evidence in Proceeding 566, page 36). This suggestion was adopted by NERA (NERA reply evidence in Proceeding 566, paragraph 17).

We note that all of the experts in this proceeding propose that the TFP trend should be identified from relatively recent data. Dr. Lowry's study period is from 1996/7 to 2013/14, Dr. Meitzen's is from 1999/2000 onwards and in our case we present data from 1994/5 to 2013/14.

4. Conclusions on TFP

Q83. Are the TFP results from the PEG and NERA TFP studies different?

A83. Yes. On the basis of the updated NERA study, we identify a TFP trend of −0.79%. In contrast, the PEG study produces a TFP trend of +0.48%. The differences are in the range 1.1% to 1.5% (depending on which range of years is used to identify the TFP trend).

Q84. What explains the differences in results?

A84. The differences are not due to the selection of utilities in the study, the time period or the nature of the output index. Rather the differences appear to be due to a combination of technical differences in the methodologies used.

Q85. Is it surprising that the results of the TFP study are apparently sensitive to technical methodology in this way?

A85. We believe that it is unusual for there to be more than one TFP study in evidence in a single proceeding, as there is here. However, we have seen that TFP studies prepared at different times or in different proceedings can produce quite different results. Certainly estimating TFP trends is not an exact science (for example, we note that TFP estimates produced by official government statistics agencies are often revised).

Q86. Since there is more than one study in evidence in this proceeding, and since the results of the different studies appear to be quite different, what approach to you recommend?

A86. We recommend that the AUC continue to rely on the NERA TFP methodology for the second generation plans, and we continue to recommend our updated (and corrected) TFP trend using the NERA study of −0.79%. This result is well within the range of the results put forward in the direct evidence of Dr. Meitzen (based on the NERA study) of −1.11%, and Dr. Lowry (using his complete sample) of +0.48%. This range of about 1.6% from low to high is not inconsistent with the variability in TFP trend results that we have observed between proceedings and even between studies performed by the same analysts.

C. X-factor recommendation based on the TFP results

1. X-factor recommendation

Q87. On what basis is an X-factor typically chosen in a PBR proceeding?

A87. One method for determining an X-factor is on the basis of a TFP study, as the AUC did in Proceeding 566. Another way is on the basis of a forecast of costs.

Q88. Are you aware of any other relevant methods?

A88. No. We are aware of variations on these methods, but the starting-point is either a forecast of the utility's own costs or an analysis of other firms in the industry.

We assume that the AUC will wish to continue with the TFP-based approach it has taken in the past. We note that there is no evidence on the record of this proceeding as to forecasts of costs for the next PBR plan term.

Q89. Are economy-wide estimates of TFP growth relevant for selecting a point estimate from the range of US utility TFP growth trends?

A89. Yes, we believe so. Over the past 15 years or so, TFP in the Canadian economy has not grown at all.[76] It is not reasonable to expect Canadian utilities to achieve productivity growth that is greater than that in the wider economy. We would therefore not recommend an X-factor greater than zero. The updated NERA study produces a point estimate of −0.79%, which we continue to recommend that the AUC use as an X-factor for the second generation plans.

---

[76] See Workpaper 7.

Q90. Is there anything inappropriate about a negative X-factor?

A90. No. As we explained above, the magnitude of the X-factor is irrelevant to the strength of incentives. In Proceeding 566 the AUC said:[77]

> *On this issue, the Commission agrees with the companies' argument that, in theory, the X factor does not necessarily have to be always positive. As NERA's and EPCOR's experts explained during the hearing, a negative TFP (and the resulting X factor) just means that a particular industry grows more slowly in its productivity than the economy as a whole or that input costs are growing faster in the industry than in the economy.*

In particular, the sign of the X-factor does not influence the strength of incentives to control costs.

Q91. With an X-factor recommendation based on a TFP trend, is it necessary to provide for the possibility of additional funding for capital investment?

A91. Yes. We address this issue below. If the X-factor were based on a forecast of costs during the PBR plan term, it would be possible to take into account necessary capital expenditures in determining the X-factor, and there might then be no need for a separate capital mechanism. With a TFP-based X-factor, the possibility of additional funding for capital investment should be part of the plan design (ie, a K-factor or similar, as discussed below).

2. Adjustments to the TFP-based X-factor recommendation

Q92. Should a stretch factor be included in the X-factor for the next generation PBR plans?

A92. No. The logic of a PBR plan based on a TFP study is that the industry-wide TFP trend is a reasonable expectation for productivity improvements for any one individual firm in the industry, and is therefore the basis for setting the X-factor. We are not aware of any reason for adding a "stretch factor" to the TFP trend (nor of any method for determining the size of a stretch factor).

---

[77] Decision 2012-237, paragraph 507.

Q93. What is the economic logic for a stretch factor?

A93. The economic logic for including a stretch factor (ie, setting the X-factor above the estimated TFP trend) is an assumption that a utility that has been operating under cost-of-service regulation may have some “ingrained inefficiencies” such that on exposure to the strengthened cost control incentives of PBR, it will be able easily and quickly to improve productivity more rapidly than the industry trend. As the AUC described it in Decision 2012-237, “The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.”[78]

Q94. Are you aware of any method for quantifying the magnitude of any inefficiencies and therefore the appropriate magnitude of a stretch factor?

A94. No. A stretch factor is implemented by exercising judgement on the part of the regulator.

Q95. If there were such inefficiencies at the start of the current PBR plans, what would the implications be?

A95. If there were ingrained inefficiencies at the start of the current PBR plans (or the start of the ENMAX FBR plan) then, by the logic of the stretch factor, the utilities would be able rapidly to remove those inefficiencies once the strengthened incentives of PBR came into effect. The removal of those inefficiencies would be reflected in costs recorded during the current plan term, and would therefore be incorporated into rates at the time of rebasing.

---

[78] At paragraph 479.

Q96. Is the "working out" of those inefficiencies dependent on the fact that the AUC included a stretch factor in the current plans?

A96. No. The speed with which inefficiencies are removed has nothing to do with the existence of a stretch factor or the magnitude of the X-factor since neither has an influence on the strength of cost control incentives under PBR. The AUC noted in Proceeding 566:[79]

> *Finally, the Commission agrees with the parties who argued that while the size of a stretch factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs.*[f/n omitted] *Similar to a discussion in Section 6.1 of this decision, the Commission considers that PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes).*[f/n omitted]

Q97. If the stretch factor is not necessary to encourage the utilities to remove any ingrained inefficiencies during the first plan term, what is its purpose?

A97. The purpose of the stretch factor during the first plan term was simply to provide the assumed benefits of PBR to customers more quickly than the alternative of waiting until rebasing. The existence of the stretch factor did not change the magnitude of the benefits seen by customers.

Q98. Is there any corresponding logic that suggests a stretch factor should be included in the next generation plans?

A98. No. We note that the stretch factor in the current plans will result in 2017 base rates that are 1% lower than they would have been without the stretch factor. Reducing the (base) revenue requirement by 1% because of assumed inefficiencies seems to us an aggressive assumption to have made for the current plans. There is equally no basis for assuming that there are further inefficiencies beyond the 1% yet to be worked out. We therefore recommend that there be no stretch factor in the next generation plans.

---

[79] At paragraph 500.

Q99. Have the interveners in this proceeding offered any method for quantifying the need for a stretch factor?

A99. No. Dr. Lowry has put forward an analysis of stretch factor precedents, and also a modeling approach (his "incentive power model").[80] Neither is specific to the current situation of the Alberta utilities, and we note that of the regulatory precedents cited by Dr. Lowry, the only ones relating to PBR plans currently in operation are those for Ontario, British Columbia and Alberta.[81] Given the fundamental differences between the overall PBR frameworks in these jurisdictions, we do not believe that they constitute relevant precedent. Dr. Lowry's model seems to be entirely hypothetical, so we consider that it cannot provide any guidance.

Q100. Are you aware of any other adjustments that need to be made to your TFP-based X-factor recommendation?

A100. No.

IV. CAPITAL ADDITIONS

A. THE AUC'S CAPITAL ADDITIONS ISSUES

Q101. What are the capital additions issues from the AUC's Issues List?

A101. The Issues List asks the following questions about capital additions:

> *3(a) Is an incremental funding mechanism such as capital trackers still required to provide adequate funding for capital additions in the next generation PBR plans?*

> *3(b) If incremental capital funding is needed, are there alternatives to the capital tracker mechanism available that will provide the necessary funding while increasing regulatory efficiency during the next generation PBR term, while creating stronger incentives for companies to achieve efficiencies? For example, while the Commission is not suggesting its support for any particular alternative approach, parties have proposed several alternatives to the capital tracker mechanism during the process of establishing the first*

---

[80] Information request response CCA-AUC-2016APR15-007 (Revised).

[81] Direct evidence of Dr. Lowry, Table 6.

> *generation PBR plans, including: (i) Attempting to determine the average rate of growth of capital in the total factor productivity study and requesting funding for additional growth of capital beyond this level.*[f/n omitted] *(ii) Modifying the X factor to accommodate the need for higher capital spending (a form of building-blocks PBR plan).*[f/n omitted] *(iii) Excluding all capital from the going-in rates and the I-X mechanism (a hybrid PBR plan that focuses on operations and maintenance expenses only).*[f/n omitted] *(iv) Combining the incremental funding needed for certain types of capital beyond what is provided by the I-X mechanism with the going-in rates (referred to as the "K-bar" approach).*[f/n omitted]
>
> *3(c) If incremental funding is needed, and an alternative to capital trackers is not adopted, can the incentives to achieve cost efficiencies on capital additions be improved and regulatory efficiency be achieved by making modifications to the current capital tracker mechanism to reduce the frequency and complexity of capital tracker–related applications? For example, while the Commission is not suggesting its support for any particular modification to the capital tracker mechanism, parties have proposed several modifications to the capital tracker mechanism during the process of establishing the first generation PBR plans, including: (i) Eliminate or limit the amount of the true-up that is permitted on capital trackers to provide an incentive to be more efficient than the initial forecast for each capital tracker project or program.*[f/n omitted] *(ii) Eliminate the forecast component of capital trackers, requiring the companies to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker.*[f/n omitted] *(iii) Other systemic mechanisms to incent project cost efficiencies and minimize regulatory burden, including streamlining options, particularly for multi-year capital tracker programs.*

Q102. How would you characterize the AUC's priorities concerning capital and the K-factor?

A102. We understand that experience during the current plans has been that the K-factor proceedings have been more contentious and more burdensome than had been hoped for at the outset of the process. In addition, projects and programs qualifying for K-factor funding have accounted for a large amount of capital expenditures in aggregate, but the K-factor does not provide the strengthened incentives to control costs that the I – X part of the PBR mechanism provides. As a result, the AUC appears to be focusing on:

- whether the K-factor mechanism is still required; and,

- if it is still required, whether it can be adjusted to strengthen incentives and/or to reduce the regulatory burden.

Q103. Have the intervener witnesses focused on these topics?

A103. No. In their evidence ostensibly relating to capital and the K-factor, the interveners' witnesses seem to focus mainly on whether the utilities are earning "too much" under the current plans.

Q104. Is there a connection between the intervener concerns about over-earning and the AUC's focus?

A104. No. The K-factor itself (as currently designed) cannot lead to over-earning since the K-factor revenue is trued up. Furthermore, as we explain below, to the extent that interveners are suggesting a backwards-looking focus on achieved earnings should be reflected in adjustments to plan parameters going forward, their suggestions would make incentives to control costs much weaker (through re-linking revenues to recorded costs).

Q105. What are the intervener's recommendations for capital and the K-factor?

A105. We review and respond to the intervener recommendations below. We note that in some cases it is difficult to discern from the material filed so far exactly what the interveners are recommending. We may provide additional reply evidence depending upon AUC Rulings in relation to information responses filed subsequent to the original deadline for responding.

1. Is a K-factor required

Q106. Is a capital mechanism required?

A106. Yes, under the generic PBR framework that the AUC has implemented in Alberta, a mechanism to provide additional revenue to support necessary capital additions is needed. As we explained in direct evidence, the approach to PBR in Alberta explicitly sets an X-factor based on the historical productivity trend measured for the electric distribution <u>industry</u> in the US. By definition, therefore, the evolution of base rates under the PBR plan cannot reflect the unique circumstances of any single utility. The K-factor provides additional revenue to support needed investment that is not reflected in the I – X trend of base rates.

Q107. Do interveners agree that a mechanism to provide additional revenue for necessary capital additions is required?

A107. Dr. Lowry seems to accept the need for some form of capital mechanism,[82] although it is not clear exactly what he recommends. Mr. Bell does not say whether a K-factor mechanism is required although he does provide a recommendation as to what it should look like if one were required.[83] Mr. Simpson suggests that the K-factor mechanism should be substantially curtailed or eliminated, but does not provide any details for how this should be done.[84] Mr. Thygesen recognizes the need for some kind of capital mechanism. He states that the need for an incremental funding mechanism can only be determined empirically, and that "In some circumstances an incremental funding plan will be required, in other circumstances it will not. The answer is dependent upon an examination of the fixed asset continuity schedule and forecasted changes."[85] The submission of the City of Calgary seems to recognize that a capital mechanism may sometimes be required: "Calgary anticipates that there is potential for capital expenditures that cannot be financed under the (I – X) mechanism".[86] We address below the City of Calgary's suggestion that the reopener mechanism be adapted to deal with capital requirements.[87]

---

[82] Dr. Lowry's written evidence does not clearly state whether or not he believes a K-factor mechanism to be required in the next generation PBR plans. He states "We believe that the need for capital trackers should eventually diminish in Alberta PBR plans…" (Direct evidence of Dr. Lowry, p. 24), but he does not seem to conclude on when the need for a K-factor mechanism will disappear.

[83] Direct evidence of Mr. Bell, Q/A 26–27.

[84] Direct evidence of Mr. Simpson, p.11.

[85] Direct evidence of Mr. Thygesen, paragraph 184.

[86] City of Calgary submission, p. 61.

[87] This suggestion was contained in the City of Calgary's response to information requests (CALGARY-AUC-2016APR15-003, -005).

It appears that, for the most part, the interveners recognize that a particular utility may sometimes require additional revenue over and above what is provided by I – X.

Q108. Is the need to recognize the "unique circumstances" of particular utilities the reason that the AUC introduced the K-factor mechanism in the current plans?

A108. Yes. In Decision 2012-237, the AUC said:[88]

> *The Commission recognizes that the TFP study used to determine the X factor adopted by the Commission in this proceeding measures the rate of productivity change of the distribution industry over time necessarily reflecting input costs including the types of capital expenditures and all of the types of year to year fluctuations in the need for capital referred to by the companies. Nevertheless, the Commission acknowledges that there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for some necessary capital expenditures. The way in which this is accomplished is through a capital factor (K factor) in the PBR plan.*

Q109. Do the incentive properties of the K-factor depend on the accounting test?

A109. No, they do not. We provided some recommendations for strengthening incentives to control capital costs in our direct evidence. None of those recommendations concern the accounting test. We address further below the intervener suggestions concerning the accounting test, which relate to historical earnings above the GCOC-determined level but not to incentives.

2. Improvements to strengthen incentives and/or reduce regulatory burden

Q110. What recommendations did you make in direct evidence that would result in strengthened incentives to control capital costs?

A110. We recommended two changes to the current capital mechanism that would strengthen incentives to control costs. First, we recommended that the existing K-factor be divided into two "groups".[89] Group one capital programs would continue as

88 Decision 2012-237, paragraph 549.

89 In information requests the AUC referred to "types".

currently (with applications every two years, and true-up to actual costs), but group two capital would not be trued up. Second, we recommended introducing an "F-factor for which additional revenue requirements would be forecast once at the beginning of the plan term with no true-up.

Q111. Have any of the interveners made similar suggestions?

A111. Yes. For example, (among other things) Dr. Lowry suggests limiting the true-up in the capital mechanism, either by sharing with customers the variances between actual and forecast costs, or by instating a deadband within which there is no true up.[90]

Q112. What is the key feature of these proposals that gives rise to the strengthened incentives?

A112. The strengthened incentives come from limiting the truing-up to actual costs, thereby helping to disconnect revenues from recorded costs, which is the defining feature of PBR.

Q113. Why are you not recommending that all supplemental capital funding come from an F-factor type mechanism?

A113. The F-factor has stronger incentives to control costs than the modified K-factor (group two), because the former runs for the whole of the PBR plan whereas the latter is re-forecast after two years. However, for some capital programs it is inherently difficult to forecast the amount of work that will need to be done (and/or the timing). For these programs the strengthened incentives of an F-factor or modified K-factor (group two) would come with unacceptably large risks that costs could turn out to be materially different from those forecast for reasons unconnected with success in controlling costs.

---

[90] Direct evidence of Dr. Lowry, p. 32. We note that the "deadband" described by Dr. Lowry is unrelated to the "deadzone" mentioned in information requests from the AUC (see response to information request BRATTLE-AUC-2016APR15-019).

Q114. In his evidence, Mr. Bell suggests that the PBR plans authorized by the AUC failed to introduce the concept of "scarcity" and that the introduction of capital trackers and the accounting test eliminates any scarcity. What does Mr. Bell mean by "scarcity" as it relates to PBR?

A114. It is unclear to us what Mr. Bell means by "scarcity" in this context. At one point in his evidence Mr. Bell says that "When the organization is expecting to make a reasonable return, managers are left to run their department. When the organization is not forecasting that it will earn an adequate return, it often requires a higher level of approval and oversight for all expenditures."[91] This statement leads us to believe that by "scarcity" Mr. Bell means that the AUC should abandon principle 2 and design the PBR plans such that the utilities are expected to earn less than their costs including a fair return on capital.

But later in his evidence Mr. Bell says that the introduction of "scarcity" does not deny the utility a reasonable opportunity to recover its costs, and he suggests that the experience of the utilities under PBR is that they have been earning more than their allowed returns.[92] If that is what he means by "scarcity", then Mr. Bell's complaint is no different than those interveners who suggest that there has been "overcompensation" in the first generation PBR plans.

Q115. What does Mr. Bell cite as support for his "scarcity" concept?

A115. Mr. Bell cites a series of Harvard Business Review articles on the management of innovation in organizations. These articles have no connection with the literature on, or economics of, incentive regulation. The examples they describe of how scarce resources can be harnessed to motivate managerial behavior may in fact be some of the tools that utility managers use in a PBR regime to achieve efficiencies. But this literature does not stand for the proposition that a regulated utility should be denied a

---

[91] Direct evidence of Mr. Bell, p.13.

[92] Direct evidence of Mr. Bell, pp.17–18.

reasonable opportunity to recover its costs by its regulator in order to create such incentives.

Q116. Do you agree that a PBR plan needs to provide a “scarcity” of revenue if incentives to control costs are to be strengthened?

A116. No. As we have explained (and as the AUC recognized in its decision in Proceeding 566), the strengthened incentives to control costs under PBR come from the disconnection between revenues and recorded costs. Incentives do not come from the level of revenues (high or low) per se, but from how the level of revenue is determined. If recorded costs are examined in determining revenue (as they are in a true-up proceeding) then incentives are not strengthened. If recorded costs are not an input to calculating revenue (as under I – X during the PBR plan term) then incentives are strengthened. We note that this proposition is not controversial. Dr. Lowry was asked to provide his opinion as to whether “scarcity” is a necessary element of a PBR plan that strengthens incentives to control cost, and the response was: “Dr. Lowry believes that an insensitivity of revenue to a utility’s cost is the chief determinant of whether a PBR plan strengthens incentives to control costs.”[93]

Q117. Have interveners made other suggestions for strengthening incentives within the capital mechanism?

A117. Yes. However, none of these suggestions are compatible with the AUC’s PBR principle 2 because they do not provide a reasonable opportunity to recover prudently-incurred costs, including a fair rate of return. For example, in addition to his more reasonable suggestions to limit K-factor true-up which we mentioned above, Dr. Lowry also suggests putting a hard cap on capital costs or denying recovery of costs above the forecast amount until the time of the next rate case, with no compensation for the extra costs that are incurred before that point.[94] These

---

[93] Information request response CCA-Utilities-2016APR15-016(b).

[94] Direct evidence of Dr. Lowry, p. 32.

suggestions would violate the AUC's principle 2. And while these suggestions would strengthen incentives, they only do so because they limit or remove the true-up.

Q118. Would it strengthen incentives to control costs if applications for additional funding were made retrospectively (ie, after the relevant assets had been placed into service)?

A118. No, this would not strengthen incentives. Incentives are strengthened where the utility will recover the same revenue whether it is successful in controlling costs or not. In such a situation, the difference between revenue and cost will be positive if the utility is successful in controlling costs, and will be smaller or negative if the utility is not successful. With a retrospective application for K-factor revenue, the revenue to be recovered will be equal to the recorded costs if the application is successful. Therefore there is no strengthened incentive: the utility will recover its costs for a project that meets the K-factor criteria. The utility would never recover more or less than its costs, therefore there is no strengthening of incentives relative to the current K-factor mechanism. We note that in discussing this suggestion Dr. Lowry said "This is presented as a way of incentivizing the tracker but can also mitigate the overcompensation problem."[95]

If the suggestion of retrospective applications were to be implemented (we recommend that it should not be) then it would be important for the determination of the additional revenue requirement to calculate the capital-related revenue requirement in the usual way, and for any revenue requirement that "predates" the application to be recovered together with an appropriate return. If this were not done, the mechanism would not conform to the AUC's PBR principle 2, as explained above.

---

[95] Direct evidence of Dr. Lowry, p. 35

Q119. What is the City of Calgary's recommendation concerning the K-factor?

A119. In response to information requests, the City of Calgary stated that the current capital tracker mechanism should be eliminated. It appears that the City of Calgary recommends that supplemental capital funding be available only if re-opener provisions have been triggered.[96]

Q120. How would the City of Calgary's proposal to use the re-opener provisions work?

A120. There is no economic logic in connecting the re-opener with providing additional funding for capital. Our understanding is that if the re-opener is triggered, the whole of the PBR plan and therefore the level of rates going forward could be re-determined. The City of Calgary's proposal therefore amounts to denying any additional revenue to support necessary capital investment unless the ROE falls below the re-opener triggers (300 basis points below the GCOC-determined ROE for two years or 500 basis points for one year). This suggestion is not consistent with the AUC's PBR principles. The City of Calgary also stated that: "This approach has the distinct advantage of significantly reducing the current regulatory burden associated with determining and setting ATCO Gas rates." We would expect the reopener process to involve at least as much of a regulatory burden as the existing K-Factor process.

3. Intervener concerns about "overcompensation"

Q121. What is the nature of the intervener concerns about "overcompensation"?

A121. Interveners appear to be concerned that the utilities have earned more than the GCOC-determined ROE in the first two years of the PBR plans. Furthermore, interveners have identified hypothetical concerns that the current PBR plans give the utilities more revenue than is needed for a reasonable opportunity to earn a fair rate of return.

---

[96] City of Calgary response to information request CALGARY-AUC-2016APR15-005.

Q122. What is the relevance of achieved ROEs to this proceeding?

A122. None. We consider that historically-achieved ROEs have no relevance to the current proceeding.[97] If the AUC were to examine achieved ROE in designing the parameters of the next generation plan, the unavoidable result would be that successful efforts to control costs in the current plans would lead to reduced revenues in the next generation plan. This inevitably undermines the incentive properties of the PBR plan, and would amount to a return to rate-of-return regulation.

Q123. If the utilities earn more than the GCOC-determined ROE during the first plan term, is that a signal that the current plan provides "too much" revenue?

A123. No. Conforming with the AUC's PBR principle 2, the current plans were designed to deliver revenue corresponding to a reasonable opportunity to earn the fair rate of return. The intent of PBR is that successful efforts to control costs will be rewarded with returns above the GCOC-determined level. An observation that a particular utility has in fact earned more than the GCOC-determined return could be a signal that the utility has been successful in controlling costs. Alternatively, it could be that events that are outside the control of the utility have contributed to earnings above the expected level.

The observation that a utility has in fact earned above the GCOC-determined level cannot be relevant to designing a future PBR plan. The next generation plans can only be assessed prospectively.

Q124. What is the nature of the intervener's hypothetical concerns that the current plan design would provide "too much" revenue during the next PBR plan term?

A124. The interveners hypothesize that, because the K-factor provides additional revenue for some capital programs with revenue requirements growing faster than I – X, there must be other capital programs with revenue requirements growing less rapidly than I

[97] The AUC has previously said that it "does not share the customer groups' view that company returns for 2013 and 2014, by themselves, indicate that the existing PBR plans should be subject to significant revision in the current proceeding" (Final Issues List, paragraph 13).

– X. They further hypothesize that, as a result of the capital programs with revenue requirements growing less rapidly than I – X, the PBR plan provides more revenue than is needed for a reasonable opportunity to earn a fair rate of return. These hypothetical concerns are described in detail in Dr. Lowry's evidence.[98]

Q125. What is Dr. Lowry's concern about an "echo"?

A125. We understand that the essence of Dr. Lowry's discussion of an "echo" effect is that if capital additions are made such that the total revenue requirement does not grow smoothly over time,[99] the utility's revenue requirement will grow faster than I – X at some points in time[100] and slower than I – X at other points in time.[101] As a result, according to Dr. Lowry, if a capital mechanism provides additional revenue to take account of the shortfall in those years where there is one, there will be "over compensation" in later years such that the utility is overall "substantially overcompensated". In Dr. Lowry's view, such an arrangement "denies customers the benefits of the base productivity growth target in both the short and the long run".[102]

Q126. Is Dr. Lowry correct that customers are denied the benefits of productivity growth in his stylized representation of the current ratemaking treatment in Alberta?

A126. No. At rebasing, the benefits of productivity growth are shared with customers. This is indicated in Dr. Lowry's table by the fact that revenues are equal to costs in every fifth year.

---

98 Direct evidence of Dr. Lowry, pp. 13–18.

99 Direct evidence of Dr. Lowry, Table 1, left-hand panel "Stable Productivity Growth".

100 Direct evidence of Dr. Lowry, Table 1, middle panel "Echo Effect', No Cost Tracker", first 10 years.

101 Direct evidence of Dr. Lowry, Table 1, middle panel "'Echo Effect', No Cost Tracker", years 12 onwards.

102 Direct evidence of Dr. Lowry, p. 18.

Q127. Does Dr. Lowry's analysis indicate that the current arrangements in Alberta provide about twice as much revenue as required to support the K-factor capital programs?

A127. No. Dr. Lowry's evidence says that "the appropriate compensation is roughly half of the early revenue shortfall if X reflects the long-run MFP trend".[103] However, among other things, Dr. Lowry's analysis measures the net present value of revenues and costs over a period of *50 years*. It would not be reasonable to suggest that a PBR plan be designed to provide less than the authorized rate of return over a period of 10 years, to be compensated by returns above the authorized level in the following 40 years. In any case, Dr. Lowry's analysis does not demonstrate "overcompensation" in the actual situation of the Alberta utilities, nor does it quantify the amount of the supposed "overcompensation". It is a purely hypothetical discussion.

Q128. Have the interveners identified by how much the revenue provided exceeds the level needed for a reasonable opportunity to earn a fair rate of return?

A128. No. As we indicated above, the interveners' concerns are purely hypothetical.

Q129. Do Rule 5 filings quantify an amount of revenue provided by the current PBR plans that exceeds the level needed for a reasonable opportunity to earn a fair rate of return?

A129. No. The Rule 5 filings show recorded costs and recorded revenues and calculate an achieved ROE. These historical numbers are not relevant for assessing, prospectively, whether a PBR plan will provide revenue sufficient for a reasonable opportunity to earn a fair rate of return.

---

[103] Direct evidence of Dr. Lowry, p. 18.

Q130. If the utilities were required to forecast the revenue requirements associated with all of their capital programs, rather than just for the K-factor programs, would it be possible to determine whether the level of revenue to be provided is "too high"?

A130. No. Only if the entire revenue requirement (including O&M expenses) were forecast would it be possible to compare expected PBR revenues with expected utility costs. Requiring the utilities to produce such forecasts would amount to abandoning the TFP-based approach to PBR that has been implemented in Alberta. We anticipate that the regulatory burden associated with producing and testing such forecasts would be greater than that of the existing K-factor mechanism.

Q131. Are you aware of any method for estimating the amount of revenue required to provide a reasonable opportunity to earn the fair rate of return without relying on a forecast?

A131. Yes. The TFP approach relied on by the AUC implicitly assumes that I – X provides revenue sufficient for a reasonable opportunity to earn the fair rate of return. If the TFP approach is not to be relied on, the only alternative we are aware of would be a forecast of the complete revenue requirement.[104]

Q132. Even if the interveners have not quantified an amount by which PBR revenue exceeds that required to provide a reasonable opportunity to earn a fair rate of return, have they demonstrated that the current plans do in fact produce "too much" revenue?

A132. No. Even the interveners' hypothetical concerns rest on an assumption that O&M expenses will grow at I – X (or below). We are not aware of any evidence about likely future rates of O&M cost growth for the Alberta utilities (we note the evidence of Mr. Thygesen that recorded O&M costs have grown faster than I – X in recent years for at least some of the utilities).

[104] This is the approach taken to PBR in some jurisdictions, including Great Britain, California and Australia.

Q133. Is Dr. Lowry's partial factor productivity analysis relevant in this regard?

A133. No. Dr. Lowry's partial factor productivity (PFP) analysis is untested. If it were accepted as robust, it presumably measures the O&M productivity growth of the US electric distribution industry. We are not aware of any evidence that an O&M PFP for the US would be a reasonable proxy for the growth of O&M expenses in Alberta. In fact, the opposite is true: Mr. Thygesen's analysis of historical O&M costs in Alberta shows, at least for one utility, that they have been increasing more rapidly than Dr. Lowry's estimate of O&M PFP growth. [105]

Q134. Are the calculations of historical costs in Mr. Thygesen's evidence relevant to this question?

A134. No. Mr. Thygesen claims to analyze the extent to which total capital-related recorded revenues exceed total capital-related recorded costs, and the extent to which recorded O&M exceeds recorded O&M-related revenues.[106] Since this analysis is purely historical, it is not relevant to assessing future revenues and costs.

Q135. Have the interveners identified any practical approaches that could address the hypothetical problem of "overcompensation" if it in fact manifested during the next generation plans?

A135. No. The interveners have not suggested any prospective analysis. Since the interveners have not proposed (nor are we aware of) any way of quantifying the amount by which the PBR plan will deliver revenues above the level needed to provide a reasonable opportunity to earn a fair return, their proposals amount to arbitrary reductions in revenue.[107] Furthermore, some of the intervener suggestions require testing all of a utility's capital programs rather than just a subset as at present.

---

[105] See Workpaper 5.

[106] Capital-related costs and revenues are identified as part of the K-factor application process. By "O&M-related" revenues we mean total I – X revenues plus K factor revenues less total capital-related costs.

[107] For example, Dr. Lowry had suggested making the accounting test reflect the fact that capital productivity has tended to grow slower than total factor productivity in the U.S. (direct evidence of Dr. Lowry, p. 8). We note that the use of PFP results was rejected in Decision 2012-237.

There are two problems with this: first, more of the utility's total cost would be removed from the strengthened incentives of PBR; and second, the PBR plans would increasingly resemble O&M-only plans, for which there is no tested approach to determining an X-factor on the record.

Q136. Does the discussion above mean that the AUC's approach to PBR is unworkable?

A136. No. Interveners have concerns about "overcompensation". These concerns are purely hypothetical. However, even if such concerns were realized, they would not detract from the benefits of PBR in terms of strengthened incentives to control cost. It remains the case that the benefits of PBR are returned to customers at the time of rebasing.

Q137. How does Dr. Lowry summarize his views?

A137. Dr. Lowry starts by explaining that the K-factor has weaker incentives to control costs than the PBR formula for base rates. We agree. He goes on to state that "The Commission selected its K factor approach as a way to strike a reasonable balance between regulatory cost, performance incentives, utility finances, and overcharging considerations."[108] This seems to us a fair assessment: the design of the K-factor (and the PBR plans as a whole) reflects a number of tradeoffs. However, Dr. Lowry goes on to suggest that outcomes for customers may be worse than under traditional cost-of-service regulation, and to allege that the Alberta situation is "a classic case of 'regulatory capture'".[109]

Q138. Do you agree that the outcomes under PBR are worse than traditional regulation?

A138. No. We have seen no evidence that would allow such a conclusion to be drawn.

---

108 Direct evidence of Dr. Lowry, p. 23.

109 Direct evidence of Dr. Lowry, p. 24.

Q139. What does Dr. Lowry mean when he refers to "regulatory capture"?

A139. Dr. Lowry was asked in an information request to explain what was meant by the term "regulatory capture" in his written evidence. Dr. Lowry explained that the term refers to a situation "when the regulator acts primarily to further the interests of the regulated firm, often at the expense of consumers or other stakeholders." Dr. Lowry also provided examples of behavior and/or outcomes associated with regulatory capture, which included: monetary bribes, hoped-for future employment for commissioners and agency staff, personal relationships, refraining from criticizing publicly the agency's management, and contributions to political campaigns.[110]

Dr. Lowry did not provide examples specific to Alberta.

Q140. What is the nature of intervener concerns over "bunching" or "grouping"?

A140. We believe that in addition to the concerns outlined above, interveners are also alleging that the utilities may adjust their K-factor filings and/or capital expenditure plans in order to maximize the revenue that they will collect. "Bunching" refers to altering the time-pattern of expenditures in order to maximize revenue, and "grouping" refers to altering the definition of projects or programs in order to maximize revenues.

Q141. Are the utilities able to adjust the timing and definition of their capital programs in this way?

A141. No. The utilities' applications for K-factor funding are tested in contested proceedings before the AUC. We note that the filing requirements for the K-factor include "A discussion of any reasonable alternatives, including the rationale for recommending the proposed solution" and "A detailed forecast of costs for the project or project components, in sufficient detail to allow an evaluation of the reasonableness of the forecast."[111]

---

110 Response to Information Request CCA-Utilities-2016APR15-09.

111 Decision 2013-435, paragraph 1092.

4. Specific suggestions relating to "overcompensation"

Q142. What specific suggestions have been made which may be related to intervener concerns of "overcompensation"?

A142. Dr. Lowry has suggested using a different (lower) X-factor in the accounting test than the one used to calculate the escalation of base revenue.[112] This suggestion would have the effect of reducing the return on investment in capital supported by the K-factor below the GCOC-determined level, and would therefore conflict with the AUC's PBR principle 2. The amount of the reduction is also arbitrary and unconnected with any economic logic.

Dr. Lowry has also suggested that "Alternatively, the utility can be denied a share of the temporary revenue shortfall that is forecasted using the accounting test."[113] This suggestion appears similar to the concept of a "deadzone" which was raised in information requests.[114] Dr. Lowry's suggestion has the same undesirable features as the "deadzone": it is arbitrary and would not be consistent with the AUC's PBR principle 2.

Other of Dr. Lowry's suggestions suffer from the disadvantages which he identifies[115] in his evidence.

Q143. What does Dr. Lowry say about re-opening the current plans?

A143. Dr. Lowry has stated "The problems are so serious that mid-term adjustments to the current plan should be considered."[116] In response to an information request, Dr. Lowry clarified that the "problems" to which he referred are "high regulatory cost,

---

[112] Direct evidence of Dr. Lowry, p. 35.

[113] Direct evidence of Dr. Lowry, p. 36.

[114] See response to information request BRATTLE-AUC-2016APR15-019.

[115] Direct evidence of Dr. Lowry, pp. 33-41.

[116] Direct evidence of Dr. Lowry, p. 24.

weak performance incentives, and overcompensation that have resulted from a ratemaking treatment of capital".[117]

Q144. Do you agree with Dr. Lowry's suggestion that the current plans be reopened?

A144. No. Dr. Lowry's concerns about "overcompensation" are unfounded, as we have explained. Recommendations have been put forward to reduce the regulatory cost of the capital mechanism and to strengthen incentives in the next generation PBR plans. Implementing those or different proposals in the current plans is not in the scope of this proceeding, and would be inconsistent with the parameters for plan re-opening that the AUC determined in Decision 2012-237.

Q145. What has Mr. Thygesen said about alternative approaches to funding necessary capital additions?

A145. Mr. Thygesen seems to be suggesting an indexing approach to capital. We believe that his suggestion would be to derive the "quantity" (meaning the number of transformers of a certain type and so on) of capital additions from accounting records of assets due for retirement and the "price" (meaning unit costs) of capital additions from an index such as the Handy–Whitman.[118] It appears that Mr. Thygesen considers that this approach could replace the explicit revenue requirement forecast of the current K-factor.

Q146. Are you aware of any jurisdiction that employs such an approach?

A146. No. We would not expect such an approach to be feasible. We doubt that the "asset continuity schedule" to which Mr. Thygesen refers could provide a reasonable guide to the capital additions actually required to address customer growth, maintain reliability, and otherwise discharge a utility's obligation to provide safe and reliable utility service.

---

117 Response to information request CCA-Utilities-2016APR15-09f.

118 Direct evidence of Mr. Thygesen, p. 67.

Q147. Does Mr. Thygesen present any evidence that his approach would be feasible?

A147. No.

Q148. Do Mr. Thygesen's concerns about the difficulty of predicting capital costs suggest that modifications to the K-factor mechanism are required?

A148. No. Mr. Thygesen discusses various reasons for thinking that it is difficult to accommodate funding for capital expenditures under an I – X PBR plan.[119] He explains that, for example, different utilities having a different age profile of the capital stock at the outset of the PBR plan can have very different capital expenditure requirements. Nevertheless, these concerns should not arise under a K-factor of the type instituted by the AUC (or, for that matter, under the modified K-factor or the F-factor mechanisms that we described in our direct evidence). Under the K-factor, the accounting test requires a forecast of revenue requirements which takes into account the differences of age and depreciation rates that Mr. Thygesen discusses.

5. Purpose of the materiality threshold

Q149. What is your understanding of the purpose of the materiality threshold within the K-factor accounting test?

A149. We understand that the purpose of the materiality threshold is to "filter out" projects or programs for which the size of the project (and associated revenue shortfall) is too small to justify the administrative burden of a K-factor proceeding.

Q150. Are you aware of any reason to adjust the materiality threshold?

A150. No. We are not aware of any reason to change the existing thresholds.

---

[119] Direct evidence of Mr. Thygesen, for example in section 3.1.

B. K-factor recommendations

Q151. What are your K-factor recommendations?

A151. We have recommended that the existing K-factor be modified to include two-year forecasts of additions and incremental funding. This would reduce the regulatory burden associated with the existing K-factor. We have also recommended removing the annual true-up for some of the programs, which would strengthen incentives to control costs.

In addition, we also recommend an optional F-factor mechanism. The F-factor would involve forecasting additions and incremental funding requirements at the start of the PBR plan for the entire plan term. There would be no subsequent true up (until rebasing at the end of the plan). The F-factor would further strengthen incentives to control costs.

Strengthened incentives to control costs are feasible for some capital projects and programs but not others. The determination as to which mechanism might be appropriate for each capital program would include the extent to which the utility is able to make reliable forecasts of additions, and the extent to which the scope and timing of the additions are within the utility's control.

Q152. Does this complete your reply evidence?

A152. Yes.

PEG Reply Evidence

Mark Newton Lowry, PhD

President

David Hovde, MA

Vice President

Revised June 22, 2016

PACIFIC ECONOMICS GROUP RESEARCH LLC
44 East Mifflin, Suite 601
Madison, Wisconsin USA 53703
608.257.1522   608.257.1540 Fax

Table of Contents

1. Introduction

Please state your name and business address.

My name is Mark Newton Lowry. My business address is 44 East Mifflin, Suite 601, Madison Wisconsin USA 53703.

What are your credentials to provide testimony in this proceeding?

I am the President of Pacific Economics Group ("PEG") Research LLC, a consulting firm that is prominent in the field of utility regulation. Performance-based regulation ("PBR"), cost trackers, and other alternatives to the traditional North American approach to rate regulation are company specialties. We are also well known for our statistical research on productivity and other aspects of utility performance. PEG personnel have over 60 person-years of experience in these related fields. Our practice is international in scope and has included projects in Australia, Europe, Japan, and Latin America. We have been fortunate to play a major role in the advance of PBR in Canada.

My duties as company president include expert witness testimony and the supervision of research on PBR plan design and related empirical issues such as the productivity trends of energy utilities. I have supervised dozens of utility productivity studies over the years. In addition to Alberta, venues for my PBR testimony have included British Columbia, California, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maryland, Massachusetts, New Jersey, Oklahoma, Ontario, Oregon, New York, Québec, Texas, and Vermont.

Work for diverse clients has given my practice a reputation for objectivity and dedication to regulatory science. In Canada, for example, my clients have included the Association Québécoise de Consommateurs d'Electricité Industrielles, ATCO Electric, the Canadian Electricity Association, the Commercial Energy Consumers Association of British Columbia ("CEC"), Enbridge Gas Distribution, EPCOR, FortisAlberta, Hydro-Québec, the Ontario Energy Board, and Terasen Gas as well as my client in this proceeding, the Consumers' Coalition of Alberta ("CCA"). I have recently done productivity research and testimony for the CCA and CEC, as well as for Central Maine Power, Oshawa PUC Networks, Pepco, and Unitil.

Before joining PEG I worked for many years at Laurits R. Christensen Associates ("LRCA") in Madison, first as a Senior Economist and later as a Vice President. The key members of the team I led at LRCA have for many years worked for PEG. My career has also included work as an academic economist. I served as an Assistant Professor of Mineral Economics at the Pennsylvania State University and as a visiting professor at l'École des Hautes Études Commerciales in Québec.

My academic research and teaching stressed the use of mathematical theory and statistical methods in industry analysis. I have been a referee for several scholarly journals and have a lengthy record of professional publications and public appearances. I hold a doctorate degree in Applied Economics from the University of Wisconsin-Madison.

Please discuss the credentials of Mr. Hovde.

Dave Hovde is a Vice President of PEG. He undertook most of the productivity calculations in our work for CCA in this and the previous proceeding, along with those in dozens of other projects over two decades. Dave holds a master's degree in Economics from the University of Wisconsin-Madison.

What are the goals of your reply evidence?

My principal goal is to continue to abide by the AUC issues list and doing so to rebut evidence presented, in direct evidence and responses to information requests, by the utility expert witnesses: Dennis Weisman, Mark Meitzen of LRCA, and Paul Carpenter and Toby Brown of the Brattle Group. I find both their X factor research and recommendations problematic, as well as their discussions of other plan design issues. I will also remark on the evidence provided by the distributors.

2. X Factor Issues

2.1 Base Productivity Trend

Let's start with the research and evidence on the base productivity trend. Please provide an overview of the productivity research undertaken by utility witnesses.

Brattle and LRCA have based their X factor recommendations on studies that update the multifactor productivity ("MFP") indexes developed by National Economic Research Associates ("NERA") in Proceeding ID 566.[1] The MFP trend is the difference between the average annual growth rates of output and input quantity indexes. The trend in outputs is an average of trends in the volumes of services provided to four groups of customers. The trend in inputs is an average of the trends in subindexes measuring the use of capital and of labor and material and service ("M&S") inputs used in operation and maintenance ("O&M").

The sample period for the NERA study was 1973-2009. Brattle and LRCA updated the study, adding the five years from 2010 to 2014. Considerable attention is paid to MFP results for these years and whether estimates of long-term MFP trends are good predictors of results for these years.

NERA recommended calibrating the X factor using the MFP trend for the *full* sample period, and the AUC agreed with this recommendation in Decision 2012-237. To defend their research methods, Brattle and LRCA have noted repeatedly in their evidence that the AUC used the NERA results to set the base productivity trend.[2] However, Brattle and LRCA recommend basing X for next-generation PBR on the trends in their MFP indexes in later years of the sample period, when the values of their indexes fall after decades of growth.

Please summarize your concerns

[1] I prefer the term *multifactor* productivity to *total factor* productivity since many costs incurred by the sampled utilities have been excluded from all of the studies filed in this proceeding.

[2] EDTI stated in response to EDTI-AUC-012, for example, that "Because his results are based on the same methodology approved and deemed reliable by the Commission in Decision 2012-237, Dr. Meitzen believes his results are reliable."

The NERA/Utilities methodologies for measuring productivity trends are flawed, and the flaws cause MFP to fall in the later years of the sample period when my own study found the MFP for a larger group of US power distributors to be rising on average. Some of the flaws take the form of obvious methodological and data errors. Others may be better described as substandard practices. Research that provides the basis for Alberta X factors should be free of major errors and use the best available methods. Brattle and LRCA effectively cherry picked results for a favorable sample period without undertaking a thorough review of the NERA methodology and making approximate corrections and upgrades. The NERA/Utilities methodology is a poor basis for setting X in this or future plans.

In what areas have serious errors have been made in your view?

The main problems are in three areas.

- There is an error (as well as substandard practices) in the calculation of the labor quantity trend.
- Some output data are egregiously flawed.
- Errors were made in the benchmark year calculations for the capital quantity index.
- I might also note that corrections were not made for several mergers and a restructuring, and data for two companies were confused.

Let's discuss one by one your concerns about errors, beginning with the labor quantity research.

Until 2002, US electric utilities reported on the FERC Form 1 the total number of their employees. For these years, NERA and the Utilities witnesses estimated the number of power distribution employees by multiplying the total number by the share of power distribution in total salaries and wages.

A means was required to extend these estimates of total labor quantities to the later years of the sample period. NERA endeavored to do this using estimates of labor quantity growth from 2002 onwards obtained using the “residual” approach I discussed on p. 42 of my testimony. The formula for this calculation is

$$trend\ Inputs^{Labor} = trend\ Expenses^{Labor} - trend\ Input\ Prices^{Labor} \qquad [1]$$

In other words, the trend in the quantity of labor equals the trend in "deflated" or "real" labor expenses.

Recollecting that a share of the total labor quantity is, in a second stage of the NERA/Utilities methodology, allocated to distribution, *total* labor O&M expenses should be used in equation [1]. These expenses would shrink after 2001 for the many electric utilities in the sample that sold or spun off generation during this period, as many did in Alberta. Meanwhile, the distribution share of the total would rise. These offsetting trends would cause the estimated number of distribution employees to grow gradually for these companies. Unfortunately, NERA used the growth in *distribution* O&M expenses in equation [1]. This exaggerated labor quantity growth in the later years of the sample period and understated MFP growth.

How did the utility witnesses deal with this error?

Dr. Meitzen noted this error in his testimony and corrected for it. Brattle did not. In response to data request Brattle-AUC-007, however, Brattle acknowledged the error and provided a correction at the AUC’s request. They found that the correction *raised* their estimate of MFP growth by 5 basis points for the full sample period and by a substantial 14 basis points for the more recent 2000-2014 period.

Is this the only serious error NERA made with respect to the trend in the labor quantity?

Remarkably, no. I pointed out in my direct evidence for the CCA in Proceeding ID 566 that, when NERA initially tried to extend its estimates of total employees to the post-2001 period, it escalated the total using the growth in O&M expenses, neglecting to net off labor price growth as required by equation [1].[3] The prices of salaries and wages in the United States grew by around 3% annually on average from 2001 to 2006. Thus, NERA's initial work grossly overstated labor quantity growth in the later years of the sample period by virtue of another error. NERA acknowledged this error and corrected for it in their February 2012 update in Proceeding ID 566.[4]

Turning next to data problems, why do you consider some of the NERA/Utilities output data to be egregiously flawed?

NERA, Brattle, and LRCA employed as their output measure an index of service volume trends. They relied on the Federal Energy Regulatory Commission ("FERC") Form 1 for their volume data. As Dr. Meitzen acknowledged in response to Meitzen-CCA/PEG-010, volumes reported on FERC Form 1 are *sales* volumes, and these do not always equal *delivery* volumes. I disagree with Dr. Meitzen when he says in response to the same question that "the FERC Form 1 data are a reliable measure of output of the study period." These data can produce spurious trends for electric utilities which 1) were restructured to face retail power market competition and 2) thereafter lost substantial sales to competing merchants but did not experience corresponding declines in deliveries.

Restructuring of investor-owned electric utilities in the United States began in the late 1990s. Sales volumes of several distributors declined substantially, as independent merchants made inroads, but delivery volumes did not. The declines in sales volumes were particularly marked for *industrial* customers, and this matters since industrial sales volumes are assigned a sizable weight in the NERA/Utilities output index. Declines in sales volumes due to this problem were large enough to slow the measured output growth of the industry materially and are one reason for the negative MFP growth in the later years of the sample period that Brattle and LRCA highlight in their testimony.

[3] AUC Proceeding 566, Exhibit 0307.01.CCA-566, *PEG Evidence in AUC RRI*, December 18, 2011, pp. 35-36.

[4] AUC Proceeding 566, Exhibit 0391.02.NERA-566, *Second Report of NERA*, February 22, 2012.

Is there a fix for this problem?

Yes. Data on *deliveries* of power by US distributors are readily available on the US Energy Information Administration's Form EIA 861 for years after 1990. PEG routinely uses these data in our studies when delivery volume data are needed. Using these data we found that there were marked differences between sales and delivery volumes for five companies in the NERA/Utilities sample. It would have been straightforward for NERA, Brattle, and LRCA to combine FERC Form 1 data for early years of the sample period with Form EIA 861 data for the later years but they all chose not to.

Have the utility witnesses acknowledged that this is a problem with their work?

No. Brattle conceded in their response to Brattle-AUC-009 (a) that delivery data would be *preferable*.

> Conceptually, the best measure of volume distributed would be the sum of bundled MWh and distribution MWh (since the utility is responsible for distributing bundled MWh and distribution-only MWh). It would be appropriate to refer to the sum of these quantities as the "delivered" MWh.

However, having not been asked by the AUC to provide a run that corrected for the use of sales data, they didn't provide one. Brattle did present sales and delivery data for *3 companies* that were roughly the same for the two sources. Ironically, their acceptance of the slight differences in the FERC Form 1 and Form EIA 861 data undermines an argument against combining these data in a sample for productivity research --- that there may be improper discrepancies between some of these data. In response to EDTI-AUC-13 (a), Dr. Meitzen stated that

> It is Dr. Meitzen's understanding that, for the most part, sales are equal to deliveries in the FERC Form 1 data, but there are some instances where this is not the case. Dr. Meitzen is also aware that NERA found that the EIA-861 data that was [sic] proposed as a "patch" contained some anomalies and that using it in conjunction with the FERC Form 1 data did not materially change the results of the NERA study. Given these factors, Dr. Meitzen believes the FERC Form 1 sales data are a reasonable measure of output. [footnote removed]

Neither NERA, Meitzen nor Brattle made a serious attempt to demonstrate that there were worrisome discontinuities between the FERC Form 1 and Form EIA 861 data that made use of the latter data inadvisable.

Table 1 and Figure 1 illustrate the magnitude of this issue. For most sampled companies, the two data sources are similar, if not identical. It is in the case of outliers that this problem matters. The table and figure show the 5 cases with the most extreme differences between the two data sources. For these five companies, more than half the volume is missing from the Form 1 reporting.

Let's turn now to problems with the *cost* data used in the NERA/Utilities indexes. Please provide an overview.

More than a dozen companies in the NERA/Utilities sample had mergers that were not corrected for. Some utilities transferred sizable costs from transmission to distribution (or vice versa). Some capital cost data for Mississippi Power and Mississippi Power and Light (now Entergy Mississippi) were intermixed. No account was taken of the separation of Gulf States Power into two companies serving Louisiana and Texas and the resultant itemization of their data.

Why do mergers and T&D transfers matter?

In common with PEG, NERA, Brattle, and LRCA used a "perpetual inventory" approach to construct their capital quantity indexes. Under this approach, the quantity of capital held in a given year is a function of the size of real plant additions made in previous years. Absent a cumbersome adjustment, if a merger or acquisition occurs or costs are moved from transmission to distribution, O&M expenses and plant additions will rise abruptly but the older capital quantity will not. Future MFP growth is then underestimated. Brattle implicitly acknowledged the problems mergers can cause when they excluded data for certain companies (e.g., Illinois Power and Central Illinois Public Service) which were involved in mergers during the update years.

Table 1
Form 1 and Form 861 Retail Service Volumes for Selected Companies

	Dayton Power and Light			Central Hudson Gas & Electric			Niagara Mohawk Power		
	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861
2000	27,783,546	27,783,191	100%	9,053,748	9,053,748	100%	60,387,259	60,387,259	100%
2001	27,559,389	27,559,389	100%	9,598,877	9,617,125	100%	59,755,400	66,543,642	90%
2002	28,372,290	28,372,290	100%	9,237,804	10,014,527	92%	56,652,151	67,851,557	83%
2003	27,608,521	29,013,339	95%	8,521,261	10,759,408	79%	52,523,850	68,275,800	77%
2004	28,027,844	29,427,563	95%	8,347,417	10,984,308	76%	49,469,132	68,838,406	72%
2005	28,942,390	30,372,874	95%	8,151,043	11,477,786	71%	46,769,036	70,724,647	66%
2006	28,106,248	29,528,142	95%	7,761,531	10,998,824	71%	43,038,777	58,995,909	73%
2007	29,000,360	30,463,304	95%	9,133,053	11,263,122	81%	41,862,854	59,995,868	70%
2008	28,410,290	29,859,366	95%	7,058,940	10,843,130	65%	39,351,536	58,293,030	68%
2009	25,687,098	27,069,828	95%	6,320,306	10,348,616	61%	36,486,972	57,529,928	63%
2010	27,122,087	28,552,852	95%	6,189,767	10,429,470	59%	37,540,308	59,026,327	64%
2011	24,937,180	28,042,697	89%	5,918,817	10,368,848	57%	35,988,363	59,168,976	61%
2012	11,149,047	27,995,958	40%	5,312,833	10,146,974	52%	35,051,423	59,200,432	59%
2013	8,564,854	27,751,214	31%	5,199,613	10,217,306	51%	31,601,536	67,914,766	47%
2014	7,581,841	28,008,530	27%	4,945,171	10,041,508	49%	26,221,001	68,676,832	38%

	Massachusetts Electric			Narragansett Electric			Total		
	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861	Form 1 (Sales)	Form 861 (Deliveries)	Form 1/ Form 861
2000	36,413,741	36,325,075	100%	13,589,575	12,893,355	105%	147,227,869	146,442,628	101%
2001	38,686,548	41,692,951	93%	13,744,779	14,608,190	94%	149,344,993	160,021,297	93%
2002	33,779,592	43,024,540	79%	13,141,963	14,922,213	88%	141,183,800	164,185,127	86%
2003	34,268,563	43,675,711	78%	13,983,557	15,470,656	90%	136,905,752	167,194,914	82%
2004	31,456,226	43,835,932	72%	13,936,512	15,651,016	89%	131,237,131	168,737,225	78%
2005	33,314,004	44,531,961	75%	14,176,125	15,970,824	89%	131,352,598	173,078,092	76%
2006	26,166,270	43,489,169	60%	13,428,016	15,472,968	87%	118,500,842	158,485,012	75%
2007	25,064,361	44,324,744	57%	13,465,718	15,900,522	85%	118,526,346	161,947,560	73%
2008	24,318,744	42,621,584	57%	13,441,583	15,513,494	87%	112,581,093	157,130,604	72%
2009	21,929,528	41,905,032	52%	11,221,218	15,112,600	74%	101,645,122	151,966,004	67%
2010	22,954,183	45,269,846	51%	10,619,705	15,442,341	69%	104,426,050	158,720,836	66%
2011	22,769,189	42,662,927	53%	10,394,015	15,309,200	68%	100,007,564	155,552,648	64%
2012	21,663,887	42,355,707	51%	9,892,747	15,262,099	65%	83,069,937	154,961,170	54%
2013	21,931,169	42,629,454	51%	10,247,431	15,398,278	67%	77,544,603	163,911,018	47%
2014	21,185,570	41,767,210	51%	10,002,855	15,123,218	66%	69,936,438	163,617,298	43%

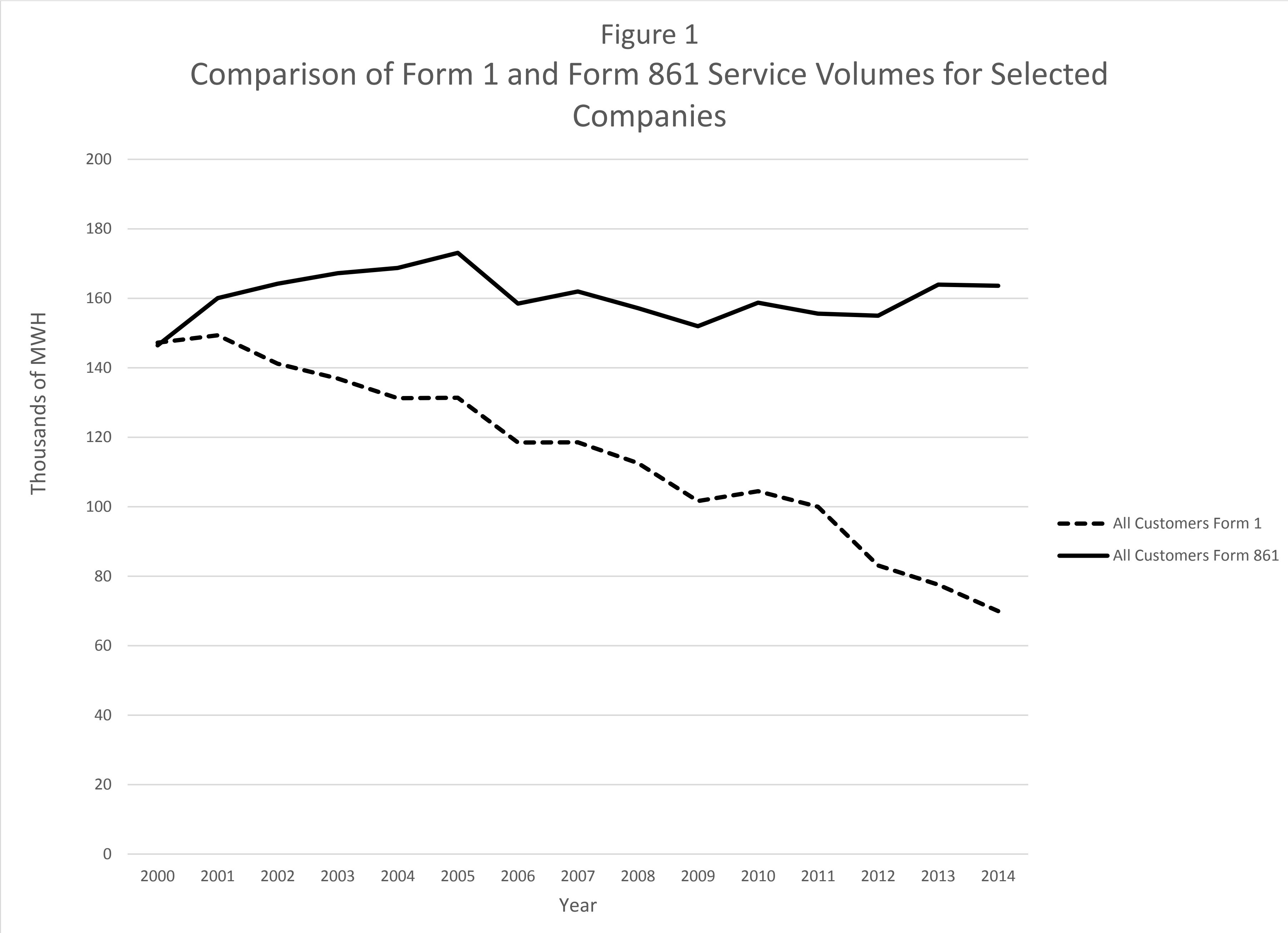


Figure 1
Comparison of Form 1 and Form 861 Service Volumes for Selected Companies
Thousands of MWH
200
180
160
140
120
100
80
60
40
20
0
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
Year
All Customers Form 1
All Customers Form 861

Were appropriate data corrections made for all utilities involved in mergers and restructurings in the NERA/Utilities sample?

No. We examined the data for earlier years of the sample period closely and found that the data had not been corrected for several mergers or for the Gulf States Power separation. We asked LRCA about these problems in Meitzen-CCA/PEG-007. When we (deliberately) asked about a *single* merger between New Jersey Power & Light and Jersey Central Power & Light, EDTI responded that "Dr. Meitzen does not know if the NERA/Brattle study takes into account the assets of New Jersey Power & Light." EDTI further commented that "Dr. Meitzen concluded that NERA did not take measures to account for the separation of Entergy Gulf States" and "did not independently evaluate the data for transfers of assets between transmission and distribution." In response to EDTI-AUC-009, Dr. Meitzen acknowledged that he had included Central Illinois Light, Columbus Southern Power, Central Vermont Public Service, and Illinois Power in his sample even though they ceased filing Form 1s late in the sample period, leading to an unbalanced panel.

As for Brattle, the following responses were made to Brattle-CCA/PEG-010.

Requests:

Please respond to the following questions regarding the continuity of data used in the study.

a) What other years from 1964-2014 did you check besides 2009-2010 for data discontinuities?

b) Can you confirm that the data for other years are free from large discontinuities?

c) Please explain what measures, if any, were taken to adjust the data for Entergy Gulf States to account for the separation of the company into Entergy Gulf States Louisiana and Entergy Texas.

d) For companies included in the analysis, what steps if any were taken to account for transfers of assets between transmission and distribution during the sample period?

e) Attached below is a copy of the 1964 version of the "Statistics of Electric Utilities in the United States" which contains published data for Jersey Central Power and Light and New Jersey Power & Light. These companies merged operations and the assets of New Jersey Power & Light are now part of the current Jersey Central P&L.

i. The working papers provided show a value of 125,883,373 in cell E40 of the Initial Capital Stock worksheet. This matches our records for Jersey Central but does not include the corresponding dollars of plant for New Jersey Power and Light. Does the NERA/Brattle study take into account the assets of New Jersey Power and Light?

ii. Would the exclusion of the assets of acquired companies have an impact on the trend in the capital quantity of Jersey Central using the one-hoss shay method?

iii. Please describe any steps taken to ensure the accuracy of Jersey Central's capital quantity trend in light of merger activity since 1964.

Response:

a) The written evidence of Dr. Brown and Dr. Carpenter contains new results for 2010 through 2014. The TFP recommendation is based on combining the new TFP results with the TFP results for earlier years already put forward by NERA in Proceeding 566 and relied on by the AUC in that proceeding. Dr. Brown and Dr. Carpenter examined the new data for 2010 through 2014 as well as for 2009 (as described in the cited portion of evidence).

b) No. The results for earlier years were taken from NERA's TFP study in Proceeding 566.

c) None. The new data added to the TFP study includes data for Entergy Gulf States Louisiana only.

d) None. The FERC form 1 data was used without adjustment.

e) See response to b).

Did some witnesses acknowledge the importance of the T&D transfer issue?

Yes. Brattle stated in response to Brattle-CCA/PEG-003 (d) that "if there are changes in cost allocation of the type hypothesized in the request, then the measured TFP trend might not be reliable.

Please restate your concerns about the benchmark year calculations.

Let me begin by noting that all of the studies in this proceeding use capital quantity indexes that are, basically, measures of the growth in total plant value adjusted for inflation in the unit cost of construction. The total plant value used in these calculations may, in principle, be gross or net plant value.

NERA and the utilities used the "one-hoss shay" method to calculate the capital cost and quantity. As I discussed on p. 51 of my direct testimony in this proceeding, under this method the quantity of an asset is assumed not to decline gradually due to depreciation but instead to fall abruptly to zero when it is retired and removed from gross plant value. In other words, the capital quantity index is an index of the quantity associated with gross plant value. Dr. W. Erwin Diewert stated in this regard that "we consider the one hoss shay model of depreciation which assumes that the efficiency and hence rental price of each vintage of the capital good is constant over time (until the good is discarded as completely worn out after *N* periods). This model is sometimes known as the *gross capital stock* model."[5] PEG, in contrast, used two approaches to measuring capital cost (geometric decay ["GD"] and cost of service ["COS"]) in its research for this proceeding which attempt to measure the trend in quantity consistent with *net* plant value.

[5] Diewert, W.E., and Lawrence, D.A. (2000), "Progress in Measuring the Price and Quantity of Capital", *Econometrics, Volume 2, Econometrics and the Cost of Capital*, edited by Lawrence J. Lau, 2000, MIT Press, Cambridge, Massachusetts, p. 274-275.

Using any of these methodologies, the capital quantity index starts in a certain "benchmark" year in which the total quantity of plant owned by the utility must be estimated.[6] Total plant value in any year is the sum of assets of different vintages. The quantity of plant in the benchmark year is for this reason estimated by taking the ratio of total plant value to an index of past values of an electric utility construction cost index. NERA and the utilities, like PEG, used the *net* plant value in their benchmark year adjustment.[7] However, the *gross* plant value is consistent with the NERA/Utilities' calculation of capital cost using the one hoss shay specification.

Another problem with the NERA/Utilities benchmark year adjustments is the inconsistency between the 33-year service life assumed for distribution assets before their retirement and the 20-year average of past values of the construction cost index employed in the benchmark year adjustment. A 33-year average would be more consistent.

What are the implications of these problems for the calculated MFP trend?

The use of net plant additions causes the capital quantity to be underestimated in the benchmark year. So does including too few years in the average of construction cost index values used in the benchmark year adjustment, because this increases the denominator of the adjustment. Understatement of the initial capital quantity makes the capital quantity index unduly sensitive to plant additions. Capital quantity growth is *over*stated while MFP growth is *under*stated.

Have Brattle or Meitzen acknowledged problems with the benchmark year adjustment?

No. EDTI stated rather evasively in response to Meitzen-CCA/PEG-011 that "because the benchmark is an approximation, it is reasonable to use net plant with a one hoss shay

---

[6] PEG uses a slightly different method in its alternative COS approach to measuring capital cost.

[7] Note, however, that net plant value had to be imputed because NERA relied on electronic data.

approach." When asked for his *own* views of whether the use of gross or net plant value in the benchmark year adjustment was theoretically consistent with one hoss shay, Dr. Meitzen answered that there was no clear resolution of this issue *in the literature*. In their response to Brattle-AUC-007, Brattle states with respect to the gross vs. net plant value issue that

> these are the sort of technical detail which should not have an important influence on the results of the study if the study is robust. There is unlikely to be a "correct answer" to the determination of a capital quantity index….policy decisions (such as the choice of X-factor) should not be determined by such technical details. As such it would be reasonable to adopt either of the approaches suggested.

At the AUC's request, Brattle nonetheless recalculated the results using gross plant value for the benchmark year adjustment, and reports in their response that MFP growth is 8 basis points more rapid over the full sample period and 8 points more rapid over their featured 1999-2014 period.

What evidence can you present that these problems with the NERA/Utilities study are quantitatively important?

We recalculated the NERA/Brattle index after correcting sequentially for these problems. Results for the full sample of these and other steps we have taken to reconcile results of the PEG and Utilities work are presented in Table 2. Please note the following.

- Our correction for the problem in the labor quantity work which Dr. Meitzen identified raised the MFP growth trends by 5 basis points for the full 1973-2014 sample period, by 12 points for the 1997-2014 period that we featured in our evidence, and by 15 points for the five most recent years of the sample period (2010-2014).[8]

[8] Due to other differences between the Brattle and LRCA studies such as the sample and capital price, our results will differ from those of the final LRCA trends.

Table 2

Summary of Corrections and Modifications to NERA/Brattle/LRCA Productivity Calculations

	MFP Trend (volume weighted averages, Brattle sample)		
	1973-2014	1997-2014	2010-2014
As Reported by Brattle	0.71%	-0.71%	-1.25%
Corrections			
Salary Escalation Correction (Meitzen)	0.76%	-0.59%	-1.10%
Correct Output Quantity Data	0.86%	-0.43%	-0.86%
Use Gross Plant Benchmark with 20 year life	0.99%	-0.28%	-0.71%
Use Gross Plant Benchmark with 33 year life	1.10%	-0.17%	-0.61%
Exclude companies not included in PEG work	1.15%	-0.12%	-0.62%
Methodological Upgrades (Major)			
Use One-Hoss Shay with a 37 year service life and a gross plant benchmark	1.62%	0.49%	0.02%
Use Geometric Decay and a 33 year service life	1.31%	0.14%	0.13%
Use Geometric Decay and a 37 year service life	1.23%	0.09%	0.07%
Correct Data for Mergers and Mismatch	1.28%	0.15%	0.12%
Use total customers	NA	0.18%	0.17%
Variations on the PEG Work (all simple averages)			
PEG using only distribution, 37 year life, GDPPI, and a common sample	NA	0.25%	0.22%
PEG using only distribution, 37 year life and GDPPI	NA	0.21%	0.13%
PEG with 37 year life and GDPPI	NA	0.37%	0.32%
PEG with 37 year Service Life [Revised Testimony]	NA	0.43%	0.31%
PEG Testimony [Original]	NA	0.48%	0.39%

Correcting for the problems caused by using FERC Form 1 volume data raised the MFP trend by another 10 basis points for the full sample period, 16 points for the 1997-2014 period, and by 24 points for the five most recent years.

- Using gross rather than net plant in the benchmark year calculation raised the MFP trend by another 13 to 15 basis points.

- Using a 33-year average of past construction cost index values in the benchmark year calculation raised MFP growth by another 10-11 basis points. Excluding companies not included in the PEG sample due to T&D transfers and other problems raised the MFP trend by 5 basis points for the full sample period and 1997-2014 period but decreased it by one point for the five most recent years.

When all of these errors are corrected, please note that the MFP trend for the 1997-2014 period is -0.12%, still negative but much closer to zero than the trend Brattle reported for a similar sample period.

Let's turn now to your concerns about aspects of the NERA/utilities methodology that are not in your view clearly erroneous but are instead "suboptimal". What are your main concerns?

The most notable areas of substandard practice are as follows:

- The one hoss shay approach to calculating capital cost is very sensitive to the assumption made concerning the average service life of capital. This matters because the 33-year average service life assumed in the NERA/Utilities methodology is too low.

- The geometric decay and COS approaches to capital costing are more appropriate.

- The number of customers is a better output measure than the volumetric index that the utilities use.

- The NERA/Utilities methodology excludes meter reading and administrative and general expenses.

- GDPPI is not an ideal measure of M&S input price inflation.

Let's discuss these issues one by one, starting with the service life issue.

The NERA study assumes a 33-year service life for power distributor assets. Based on our extensive experience in the field of energy utility productivity measurement, we believe that this is lower than the norm for US power distribution assets and is likely also lower than the norm in Alberta. Lacking evidence on average service lives in Alberta, the MFP index we used to prepare our direct evidence for CCA in this proceeding assumed a 44-average service life based on an estimate we obtained from a recent client, Central Maine Power.

We asked Brattle and LRCA in information requests to provide data that would permit us to calculate average service lives for Alberta power distributors. Both refused, arguing in part that they didn't know the answer. However, in response to information request EDTI-UCA-014, EDTI submitted data that permit us to calculate a *37*-year average service life for the distribution assets of this company.[9] We believe that, absent better data, this the most reasonable number available in this proceeding for use in productivity research to calibrate X factors for Alberta energy distributors.

What is your concern about the one hoss shay methodology for calculating the capital cost and quantity?

The one hoss shay methodology involves an assumption about asset decay that is very different from the assumption (typically straight-line depreciation) used in North American regulatory accounting. The geometric decay approach that PEG has featured in its testimony for the CCA is much more similar, yet mathematically elegant and easy for other parties to the proceeding to review. Another advantage of the GD approach is that it is more robust than one hoss shay with respect to the choice of an average service life for the capital quantity index.

[9] See Attachment G-1, EDTI Service Life Review.

The GD approach is also much more widely used than the one hoss shay approach. GD would thus facilitate involvement of expert witnesses in future proceedings on distributor productivity trends in Alberta. For example, EDTI noted in response to Meitzen-CCA/PEG-011 that "Dr. Meitzen has used geometric depreciation in each of the studies he has co-authored and has not used the one hoss shay method." In recent work for the Ontario Energy Board, PEG used the geometric decay approach to measure the productivity trends of Ontario power distributors. This research was used to set the X factors currently used in the PBR plans of most Ontario distributors.

What about the output specification?

I have a number of additional concerns about the NERA/Utilities treatment of power distributor output. Consider first that, as Dr. Meitzen acknowledged in response to question Meitzen-CCA/PEG-010 and Brattle acknowledged in response to Brattle-CCA/PEG-008, the NERA/Utilities methodology assigns a weight to the sales volume of each customer class based on its share of the revenue for *all* services provided and not just *distribution* services. This often includes a sizable charge for energy supplied. NERA reported that this approach produced a 20.5% weight for industrial sales volumes on average during their 1972-2009 sample period. A 20.5% share for the industrial volume is far above the typical share of industrial customers in power distribution *base* rate revenues because these customers tend to have high load factors and, as Brattle acknowledged in response to Brattle-CCA/PEG-008, some take delivery of power directly from the transmission grid, as they do in Alberta.[10]

Most of my concerns about the NERA/Utilities output treatment, however, involve the fact that it is an index of *volume* trends. Utility sales (and delivery) volumes tend to be volatile. Business cycle and weather conditions are important causes of this volatility. It is generally considered desirable to include the most recently available data in productivity research to

[10] Dr. Meitzen stated in response to Meitzen-CCA/PEG-010 that "Dr. Meitzen is not aware of how often bypass occurs for large industrial customers in the United States."

calibrate X factors. With a volume-based output index, however, the trend for the entire sample period is then sensitive to unusual business conditions in the most recent year. This was a problem with NERA's study in Proceeding ID 566, which ended in 2009 at the bottom of the Great Recession, and was probably one reason why NERA used such a long sample period.[11] Volumetric output indexes can be smoothed by various means, but this adds a new level of complexity to the study and is sometimes opposed by parties to the proceeding.

The relevance of recent US volume trends is, in any event, questionable in the calibration of X factors for Alberta energy distributors.

- I explain on pp. 47-50 of my direct testimony that the output index in productivity research to calibrate the X factor for a *revenue* cap index should be consistent with the scale variable in the revenue cap formula. The AUC acknowledged this logic in Proceeding ID 566.[12] Alberta *gas* distributors operate under revenue caps escalated by customer growth. Accordingly, numbers of customers served are the appropriate output metrics for productivity research to calibrate their X factors.
- One reason that the number of customers is typically used as the scale escalator in revenue cap indexes is that it is a good measure of the trends in demand that drive up the cost of base rate inputs. The number of customers is an important cost driver in its own right and is also highly correlated with peak demand. Extensive econometric cost research by PEG over the years has revealed that the number of customers served is the single most important scale-related driver of the costs of energy distributors. Our econometric research on this topic is detailed in our response to CCA-Utilities-073.

---

[11] 2015 would, similarly, be an inconvenient year to end a study of Alberta productivity trends were a volumetric index used.

[12] AUC Proceeding 566, Decision 2012-237, p. 82.

- The number of customers has the added advantage of being much more stable than volumes. This reduces the need to have a long sample period in productivity studies.

- Since I left LRCA with my research team, LRCA has prepared just one stand-alone study of power distributor productivity trends to my knowledge. In that study, for Kansas City Power and Light, the trend in output was measured as an average of customer and peak demand trends. There was no volume variable.[13]

- I explain on pp. 46-47 of my direct testimony that productivity research to calibrate the X factor for a *price* cap index should consider by some means a revenue-weighted average of the trends in billing determinants. The structure (aka design) of rates is thus an important consideration in designing a research plan for X factor calibration. I have used revenue-weighted output indexes several times in productivity research and in testimony for clients proposing price cap indexes.[14]

- In the United States, base (non-energy) revenue from residential and small business customers is typically collected chiefly through volumetric charges, while the rest of the revenue from these customers is gathered through fixed charges. Revenue from customers with larger loads is drawn chiefly from demand charges. In designing a price cap index for a *US* power distributor, volume trends therefore matter greatly, but so can trends in the number of customers and peak demand. The trends in delivery volumes and peak demand matter less to the extent that a high percentage

[13] Meitzen states otherwise in response to a data request but is referencing the measure of TFP for *integrated* services in the KCP&L study. LRCA's *distribution* TFP output measure was constructed from peak MW and the number of customers. Please see AUC Proceeding 566, Exhibit 0244.06.AUI-566, CCA-AUI-AUI-CA Energy Consulting 1b, Technical Discussion Paper, p. 1.

[14] Please see Dr. Lowry's testimonies for Gaz Metro in 2011 and 2012, OEB in 2007, and Direct Testimony for Central Maine Power in 2013.

of base rate revenue is drawn from fixed charges and large industrial customers make little use of distribution services.

- The choice between revenue-weighted and customer-based output indexes matters little in productivity research for X factor calibration if their trends are similar. Since residential and commercial ("R&C") *volumes* typically have heavy weights in *revenue*-weighted output indexes, the trends in revenue-weighted and customer-based indexes differ chiefly to the extent that trends in R&C customers and volumes differ. The difference between the volume and customer trends is sometimes referred to as the trend in "average use."

- Table 3 presents data on trends in the average use of power by R&C customers of US electric utilities. It can be seen that these trends have slowed substantially since the Great Recession and are now zero or negative. This is one reason for the slowdown in MFP growth that occurs over the lengthy NERA sample period. The MFP numbers before 2008 were accelerated by growth in R&C average use.

What are the implications of your analysis for Alberta?

Alberta power distributors currently operate under price caps, but some have fixed charges that are high by US standards. This is shown in Table 4, where we compare the residential fixed charges of the Alberta power distributors to those of a sample of US utilities. It can be seen that those of ENMAX and EDTI are fairly similar to those of US utilities whereas those of Fortis and (particularly) ATCO Electric are considerably higher.

Table 3

AVERAGE ANNUAL ELECTRICITY USE PER RESIDENTIAL & COMMERCIAL CUSTOMER 1927-2014

	Residential		Commercial	
	U.S.		U.S.	
	Level	Growth Rate	Level	Growth Rate
Multiyear Averages				
1927-1930	478	7.06%	3,659	6.67%
1931-1940	723	5.45%	4,048	2.00%
1941-1950	1,304	6.48%	6,485	5.08%
1951-1960	2,836	7.53%	12,062	6.29%
1961-1970	5,235	6.13%	28,893	9.51%
1971-1980	8,205	2.45%	49,045	3.07%
1981-1990	9,062	0.63%	56,571	1.40%
1991-2000	10,061	1.15%	67,006	1.68%
2001-2007	10,941	0.73%	74,224	0.64%
2008-2014	11,059	-0.38%	75,311	-0.22%

Sources: U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

Table 4

Comparison of Residential Fixed Charges Between Alberta and US Electric Utilities

	Number of Utilities	Average Monthly Fixed Charge (CAD)	Median Monthly Fixed Charge (CAD)
Alberta			
ATCO Electric	1	$36.50	$36.50
FortisAlberta	1	$21.25	$21.25
EDTI	1	$17.18	$17.18
ENMAX	1	$13.01	$13.01
Total	**4**	**$21.99**	**$19.22**
United States			
IOUs	70	$13.66	$13.11
Non-IOUs	20	$18.33	$14.94
Total	**90**	**$14.70**	**$13.29**

Data for the Alberta utilities were obtained from their current tariff sheets.

The U.S. data were obtained from three recent reports: A) Caught in a Fix: The Problem with Fixed Charges for Electricity (Synapse Energy Economics, February 2016, pp. 43-45); B) The 50 States of Solar: 2015 Policy Review and Q4 Quarterly Report (NC Clean Energy Technology Center, February 2016, pp. 57-73); and C) The 50 States of Solar: Q1 2016 Quarterly Report, April 2016, pp. 33-38). Where the information from these three reports differed, data from the more recent report were used. Data were thus included in the following order of preference: the "approved" charge listed in (C), the "existing" charge listed in (C), the "approved" charge listed in (B), the "approved" charge listed in (A), and the "existing" charge listed in (A) (the table in [C] includes a footnote stating "Research as of December 1, 2015"; since [B] extends through the end of 2015, its data were considered more recent than the data from [C]). No verification was performed that cases listed as "pending" are still pending at this time.

Tables 5a-5d present trends in the average use of power by R&C customers of the four Alberta power distributors in this proceeding. Over the 2005-2014 (non-recession) years for which data are available for all four companies, the average use of residential customers averaged 0.35% growth while the average use of commercial customers averaged 1.12% growth.

None of the average use data I have presented have been normalized for weather or the business cycle. However, they nonetheless seem to suggest that the average use trends of R&C customers of power distributors in the United States and Alberta have since 2007 been quite

Table 5a

Demand Trends of Alberta Energy Distributors: ATCO Electric

Year	Demand Drivers		Residential						Commercial						Total	
	Edmonton Cooling Degree Days[1]	Alberta Population Growth Rate[2]	Customers[3]		MWh		MWh/ Customer		Customers[3]		MWh		MWh/ Customer		Customers[3,4]	
			Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2002[5]	76.5		110,376		797,536		7.23		23,096		1,480,759		64.11		172,720	
2003[5]	73.6	1.73%	113,606	2.88%	806,369	1.10%	7.10	-1.78%	23,317	0.95%	1,489,756	0.61%	63.89	-0.35%	177,070	2.49%
2004	37.0	1.73%	118,020	3.81%	826,614	2.48%	7.00	-1.33%	23,954	2.70%	1,531,276	2.75%	63.93	0.05%	182,068	2.78%
2005	16.5	2.54%	121,325	2.76%	850,612	2.86%	7.01	0.10%	24,492	2.22%	1,567,342	2.33%	63.99	0.11%	186,134	2.21%
2006	65.5	2.96%	125,562	3.43%	900,244	5.67%	7.17	2.24%	25,040	2.21%	1,667,735	6.21%	66.60	4.00%	191,132	2.65%
2007	68.8	2.67%	130,885	4.15%	966,966	7.15%	7.39	3.00%	25,570	2.09%	1,749,215	4.77%	68.41	2.68%	197,354	3.20%
2008	52.2	2.30%	135,377	3.37%	997,982	3.16%	7.37	-0.22%	26,118	2.12%	1,808,790	3.35%	69.25	1.23%	202,824	2.73%
2009	56.5	2.29%	138,838	2.52%	1,037,896	3.92%	7.48	1.40%	26,579	1.75%	1,865,909	3.11%	70.20	1.36%	206,980	2.03%
2010	25.8	1.44%	141,967	2.23%	1,040,448	0.25%	7.33	-1.98%	26,873	1.10%	1,885,712	1.06%	70.17	-0.04%	210,630	1.75%
2011	37.6	1.53%	143,957	1.39%	1,072,984	3.08%	7.45	1.69%	27,089	0.80%	1,958,721	3.80%	72.31	3.00%	213,022	1.13%
2012	63.6	2.56%	146,242	1.57%	1,069,358	-0.34%	7.31	-1.91%	27,482	1.44%	2,069,234	5.49%	75.29	4.05%	215,964	1.37%
2013	53.7	3.00%	149,409	2.14%	1,120,871	4.70%	7.50	2.56%	28,021	1.94%	2,113,725	2.13%	75.43	0.19%	219,951	1.83%
2014	69.8	2.82%	152,243	1.88%	1,160,263	3.45%	7.62	1.58%	28,535	1.82%	2,217,404	4.79%	77.71	2.97%	223,259	1.49%
2015	94.6	1.94%	155,418	2.06%	1,126,254	-2.97%	7.25	-5.04%	29,076	1.88%	2,186,342	-1.41%	75.19	-3.29%	226,886	1.61%
2016		1.64%	158,566	2.01%					29,410	1.14%					230,248	1.47%
2017		1.64%	161,778	2.01%					29,749	1.14%					233,661	1.47%
2018		1.80%	165,313	2.16%					30,138	1.30%					237,494	1.63%
2019		1.88%	169,057	2.24%					30,557	1.38%					241,580	1.71%
2020		1.83%	172,809	2.19%					30,967	1.33%					245,625	1.66%
2021		1.74%	176,472	2.10%					31,352	1.24%					249,495	1.56%
2022		1.67%	180,094	2.03%					31,721	1.17%					253,259	1.50%
2023		1.65%	183,751	2.01%					32,088	1.15%					257,025	1.48%
Average Annual Growth Rates:																
2003-2015		**2.27%**		**2.63%**		**2.65%**		**0.02%**		**1.77%**		**3.00%**		**1.23%**		**2.10%**
2005-2014		**2.41%**		**2.55%**		**3.39%**		**0.84%**		**1.75%**		**3.70%**		**1.95%**		**2.04%**
2006-2015		**2.35%**		**2.48%**		**2.81%**		**0.33%**		**1.72%**		**3.33%**		**1.61%**		**1.98%**
2018-2023		**1.76%**		**2.12%**		**N/A**		**N/A**		**1.26%**		**N/A**		**N/A**		**1.59%**

[1] Data are from http://edmonton.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for Alberta, released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2016-2023 customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Alberta population is calculated for 2003-2015. Second, the projected Alberta population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecast number of customers for each year.

[4] Total customers includes all of the utility's customers except for lighting customers (which are not reported on the company's Rule 005 filings).

[5] 2002 and 2003 values from CCA AE 1(a) Attachment 1, from 2013 PBR capital tracker applications (proceeding ID 2131).

Table 5b

Demand Trends of Alberta Energy Distributors: FortisAlberta

Year	Demand Drivers: Calgary Cooling Degree Days[1]	Demand Drivers: Alberta Population Growth Rate[2]	Residential: Customers[3] Level	Residential: Customers[3] Growth Rate	Residential: MWh Level	Residential: MWh Growth Rate	Residential: MWh/ Customer Level	Residential: MWh/ Customer Growth Rate	General Service: Customers[3] Level	General Service: Customers[3] Growth Rate	General Service: MWh Level	General Service: MWh Growth Rate	General Service: MWh/ Customer Level	General Service: MWh/ Customer Growth Rate	Total: Customers[3,4] Level	Total: Customers[3,4] Growth Rate
2004	37.0		284,308		2,111,485		7.43		48,972		6,679,529		136.39		396,780	
2005	16.5	2.54%	295,230	3.77%	2,190,968	3.70%	7.42	-0.07%	49,776	1.63%	6,941,360	3.85%	139.45	2.22%	433,734	8.90%
2006	65.5	2.96%	306,631	3.79%	2,322,664	5.84%	7.57	2.05%	51,025	2.48%	7,300,516	5.04%	143.08	2.57%	446,969	3.01%
2007	68.8	2.67%	320,641	4.47%	2,485,272	6.77%	7.75	2.30%	52,863	3.54%	7,557,021	3.45%	142.95	-0.09%	463,914	3.72%
2008	52.2	2.30%	333,633	3.97%	2,586,733	4.00%	7.75	0.03%	54,687	3.39%	7,760,476	2.66%	141.91	-0.74%	480,100	3.43%
2009	56.5	2.29%	343,006	2.77%	2,691,700	3.98%	7.85	1.21%	55,995	2.36%	7,805,224	0.57%	139.39	-1.79%	500,832	4.23%
2010	25.8	1.44%	351,395	2.42%	2,732,204	1.49%	7.78	-0.92%	57,110	1.97%	7,897,864	1.18%	138.29	-0.79%	511,608	2.13%
2011	37.6	1.53%	359,075	2.16%	2,777,057	1.63%	7.73	-0.53%	58,098	1.72%	8,071,356	2.17%	138.93	0.46%	521,032	1.83%
2012	63.6	2.56%	366,422	2.03%	2,799,511	0.81%	7.64	-1.22%	59,226	1.92%	8,313,449	2.96%	140.37	1.03%	529,721	1.65%
2013	53.7	3.00%	374,579	2.20%	2,872,740	2.58%	7.67	0.38%	60,467	2.07%	8,393,967	0.96%	138.82	-1.11%	539,703	1.87%
2014	69.8	2.82%	383,792	2.43%	2,979,104	3.64%	7.76	1.21%	61,722	2.05%	8,383,229	-0.13%	135.82	-2.18%	550,857	2.05%
2015	94.6	1.94%	393,709	2.55%	2,989,285	0.34%	7.59	-2.21%	62,999	2.05%	8,108,212	-3.34%	128.70	-5.38%	562,135	2.03%
2016		1.64%	402,596	2.23%					63,980	1.55%					576,438	2.51%
2017		1.64%	411,685	2.23%					64,977	1.55%					591,108	2.51%
2018		1.80%	421,635	2.39%					66,092	1.70%					607,095	2.67%
2019		1.88%	432,165	2.47%					67,279	1.78%					624,005	2.75%
2020		1.83%	442,759	2.42%					68,457	1.74%					641,097	2.70%
2021		1.74%	453,172	2.32%					69,588	1.64%					658,018	2.61%
2022		1.67%	463,522	2.26%					70,690	1.57%					674,937	2.54%
2023		1.65%	474,008	2.24%					71,795	1.55%					692,145	2.52%
Average Annual Growth Rates:																
2005-2014		**2.41%**		**3.00%**		**3.44%**		**0.44%**		**2.31%**		**2.27%**		**-0.04%**		**3.28%**
2006-2015		**2.35%**		**2.88%**		**3.11%**		**0.23%**		**2.36%**		**1.55%**		**-0.80%**		**2.59%**
2018-2023		**1.76%**		**2.35%**		**N/A**		**N/A**		**1.66%**		**N/A**		**N/A**		**2.63%**

[1] Data are from http://calgary.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for Alberta, released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2016-2023 residential and general service customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Alberta population is calculated for 2005-2015. Second, the projected Alberta population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecast number of customers for each year.

[4] Total includes all of the utility's customers.

Table 5c

Demand Trends of Alberta Energy Distributors: EDTI

Year	Demand Drivers		Residential					
	Edmonton Cooling Degree Days[1]	Edmonton Population Growth Rate[2]	Customers[3]		MWh		MWh/ Customer	
			Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2004	67.0		264,739		1,633,388		6.17	
2005	45.5	2.38%	272,092	2.74%	1,653,030	1.20%	6.08	-1.54%
2006	143.4	3.03%	280,795	3.15%	1,730,470	4.58%	6.16	1.43%
2007	139.4	2.71%	288,803	2.81%	1,812,794	4.65%	6.28	1.84%
2008	115.0	2.42%	294,627	2.00%	1,848,929	1.97%	6.28	-0.02%
2009	111.5	2.60%	298,533	1.32%	1,890,054	2.20%	6.33	0.88%
2010	61.2	1.75%	303,447	1.63%	1,905,023	0.79%	6.28	-0.84%
2011	55.8	1.84%	308,689	1.71%	1,925,708	1.08%	6.24	-0.63%
2012	120.8	2.73%	315,210	2.09%	1,960,505	1.79%	6.22	-0.30%
2013	83.0	3.36%	323,613	2.63%	2,014,497	2.72%	6.23	0.09%
2014	126.4	3.13%	332,484	2.70%	2,076,522	3.03%	6.25	0.33%
2015	151.8	2.09%	342,910	3.09%	2,084,920	0.40%	6.08	-2.68%
2016		1.81%	348,088	1.50%				
2017		1.83%	353,383	1.51%				
2018		1.99%	359,336	1.67%				
2019		2.03%	365,548	1.71%				
2020		2.01%	371,795	1.69%				
2021		1.91%	377,784	1.60%				
2022		1.85%	383,615	1.53%				
2023		1.83%	389,450	1.51%				
Average Annual Growth Rates:								
2005-2014		**2.59%**		**2.28%**		**2.40%**		**0.12%**
2006-2015		**2.57%**		**2.31%**		**2.32%**		**0.01%**
2018-2023		**1.94%**		**1.62%**		**N/A**		**N/A**

Year	Small Commercial						Medium Commercial					
	Customers[3]		MWh		MWh/ Customer		Customers[3]		MWh		MWh/ Customer	
	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2004	26,095		704,896		27.01		2,369		561,189		236.89	
2005	26,185	0.34%	718,107	1.86%	27.42	1.5%	2,442	3.03%	580,733	3.42%	237.81	0.39%
2006	26,464	1.06%	732,225	1.95%	27.67	0.9%	2,620	7.04%	643,846	10.32%	245.74	3.28%
2007	26,649	0.70%	748,287	2.17%	28.08	1.5%	2,769	5.53%	659,934	2.47%	238.33	-3.06%
2008	26,833	0.69%	753,028	0.63%	28.06	-0.1%	3,098	11.23%	691,049	4.61%	223.06	-6.62%
2009	27,024	0.71%	742,889	-1.36%	27.49	-2.1%	3,348	7.76%	689,473	-0.23%	205.94	-7.99%
2010	27,251	0.84%	740,439	-0.33%	27.17	-1.2%	3,510	4.73%	709,849	2.91%	202.24	-1.81%
2011	27,390	0.51%	745,899	0.73%	27.23	0.2%	3,672	4.51%	736,882	3.74%	200.68	-0.77%
2012	27,621	0.84%	755,211	1.24%	27.34	0.4%	3,928	6.74%	769,605	4.34%	195.93	-2.39%
2013	27,828	0.75%	753,886	-0.18%	27.09	-0.9%	4,280	8.58%	818,231	6.13%	191.18	-2.46%
2014	27,973	0.52%	756,936	0.40%	27.06	-0.1%	4,532	5.72%	853,729	4.25%	188.38	-1.47%
2015	28,096	0.44%	734,195	-3.05%	26.13	-3.5%	4,833	6.43%	870,253	1.92%	180.06	-4.51%
2016	28,072	-0.08%					5,117	5.71%				
2017	28,052	-0.07%					5,418	5.72%				
2018	28,076	0.09%					5,746	5.88%				
2019	28,113	0.13%					6,097	5.92%				
2020	28,144	0.11%					6,467	5.90%				
2021	28,148	0.01%					6,854	5.81%				
2022	28,133	-0.05%					7,259	5.74%				
2023	28,112	-0.07%					7,686	5.72%				
Average Annual Growth Rates:												
2005-2014		**0.69%**		**0.71%**		**0.02%**		**6.49%**		**4.20%**		**-2.29%**
2006-2015		**0.70%**		**0.22%**		**-0.48%**		**6.83%**		**4.04%**		**-2.78%**
2018-2023		**0.04%**		**N/A**		**N/A**		**5.83%**		**N/A**		**N/A**

Year	Small + Medium Commercial						Total	
	Customers[3]		MWh		MWh/ Customer		Customers[3,4]	
	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2004	28,464		1,266,085		44.48		296,961	
2005	28,627	0.57%	1,298,840	2.55%	45.37	1.98%	304,454	2.49%
2006	29,084	1.58%	1,376,071	5.78%	47.31	4.19%	313,502	2.93%
2007	29,418	1.14%	1,408,221	2.31%	47.87	1.17%	321,830	2.62%
2008	29,931	1.73%	1,444,077	2.51%	48.25	0.79%	328,168	1.95%
2009	30,372	1.46%	1,432,362	-0.81%	47.16	-2.28%	332,566	1.33%
2010	30,761	1.27%	1,450,288	1.24%	47.15	-0.03%	337,861	1.58%
2011	31,062	0.97%	1,482,781	2.22%	47.74	1.24%	343,396	1.62%
2012	31,549	1.56%	1,524,816	2.80%	48.33	1.24%	350,349	2.00%
2013	32,108	1.76%	1,572,117	3.05%	48.96	1.30%	359,192	2.49%
2014	32,505	1.23%	1,610,665	2.42%	49.55	1.19%	368,446	2.54%
2015	32,929	1.30%	1,604,448	-0.39%	48.72	-1.68%	379,294	2.90%
2016	33,189	0.79%					384,553	1.38%
2017	33,469	0.84%					389,930	1.39%
2018	33,822	1.05%					396,017	1.55%
2019	34,209	1.14%					402,373	1.59%
2020	34,611	1.17%					408,752	1.57%
2021	35,002	1.12%					414,832	1.48%
2022	35,392	1.11%					420,723	1.41%
2023	35,799	1.14%					426,604	1.39%
Average Annual Growth Rates:								
2005-2014		**1.33%**		**2.41%**		**1.08%**		**2.16%**
2006-2015		**1.40%**		**2.11%**		**0.71%**		**2.20%**
2018-2023		**1.12%**		**N/A**		**N/A**		**1.50%**

[1] Data are from http://edmonton.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for census division 11 (Edmonton), released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2016-2023 customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Edmonton population is calculated for 2005-2015. Second, the projected Edmonton population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecasted number of customers for each year.

[4] For the small + medium commercial customer category, customer number forecasts are the sum of the rate class-specific customer forecasts.

[5] Total includes all of the utility's customers.

Table 5d

Demand Trends of Alberta Energy Distributors: ENMAX

	Demand Drivers		Residential (& Farm)						Commercial (& Industrial)						Total	
Year	Calgary Cooling Degree Days[1]	Calgary Population Growth Rate[2]	Customers[3]		MWh		MWh/ Customer		Customers[3]		MWh		MWh/ Customer		Customers[3,4]	
			Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2004	37.0		343,600		2,359,053		6.87		35,024		5,596,132		159.78		378,624	
2005	16.5	3.28%	352,385	2.52%	2,406,165	1.98%	6.83	-0.55%	35,506	1.37%	5,787,254	3.36%	162.99	1.99%	387,891	2.42%
2006	65.5	3.32%	363,856	3.20%	2,490,381	3.44%	6.84	0.24%	35,319	-0.53%	6,014,019	3.84%	170.28	4.37%	399,175	2.87%
2007	68.8	2.73%	376,767	3.49%	2,634,137	5.61%	6.99	2.13%	31,082	-12.78%	6,105,847	1.52%	196.44	14.29%	407,849	2.15%
2008	52.2	2.77%	385,031	2.17%	2,691,101	2.14%	6.99	-0.03%	32,282	3.79%	6,209,525	1.68%	192.35	-2.10%	417,313	2.29%
2009	56.5	2.84%	390,774	1.48%	2,745,805	2.01%	7.03	0.53%	32,814	1.63%	6,164,116	-0.73%	187.85	-2.37%	423,588	1.49%
2010	25.8	1.82%	397,761	1.77%	2,756,791	0.40%	6.93	-1.37%	33,370	1.68%	6,256,824	1.49%	187.50	-0.19%	431,131	1.77%
2011	37.6	1.89%	403,199	1.36%	2,821,254	2.31%	7.00	0.95%	33,936	1.68%	6,385,752	2.04%	188.17	0.36%	437,135	1.38%
2012	63.6	3.26%	410,179	1.72%	2,830,473	0.33%	6.90	-1.39%	34,437	1.47%	6,506,354	1.87%	188.93	0.41%	444,616	1.70%
2013	53.7	3.63%	419,199	2.18%	2,903,992	2.56%	6.93	0.39%	34,937	1.44%	6,466,483	-0.61%	185.09	-2.06%	454,136	2.12%
2014	69.8	3.43%	428,326	2.15%	2,936,869	1.13%	6.86	-1.03%	35,343	1.16%	6,561,393	1.46%	185.65	0.30%	463,669	2.08%
2015	94.6	2.39%	435,644	1.69%					35,195	-0.42%					470,753	1.52%
2016		2.06%	441,650	1.37%					34,934	-0.74%					476,395	1.19%
2017		2.00%	447,464	1.31%					34,654	-0.81%					481,809	1.13%
2018		2.16%	454,099	1.47%					34,432	-0.64%					488,085	1.29%
2019		2.24%	461,157	1.54%					34,236	-0.57%					494,791	1.36%
2020		2.13%	467,828	1.44%					34,005	-0.68%					501,057	1.26%
2021		2.00%	473,965	1.30%					33,731	-0.81%					506,729	1.13%
2022		1.92%	479,822	1.23%					33,433	-0.89%					512,078	1.05%
2023		1.89%	485,591	1.20%					33,128	-0.92%					517,315	1.02%
Average Annual Growth Rates:																
2005-2014		**2.90%**		**2.20%**		**2.19%**		**-0.01%**		**0.09%**		**1.59%**		**1.50%**		**2.03%**
2006-2015		**2.81%**		**2.12%**		**N/A**		**N/A**		**-0.09%**		**N/A**		**N/A**		**1.94%**
2018-2023		**2.06%**		**1.36%**		**N/A**		**N/A**		**-0.75%**		**N/A**		**N/A**		**1.19%**

[1] Data are from http://calgary.weatherstats.ca (retrieved March 2016). Cooling degree days are relative to 18C.

[2] Historical and forecasted population growth rates are based on the medium-growth scenario for census division 6 (Calgary), released by the Alberta Treasury Board and Finance in July 2015 (retrieved in March 2016 from: http://finance.alberta.ca/aboutalberta/population-projections/index.html).

[3] The 2015-2023 customer forecasts are estimated as follows. First, the average difference in growth rates between customers and the Calgary population is calculated for 2005-2014. Second, the projected Calgary population growth rates are adjusted by the amount of this difference to yield forecasted customer growth rates for each year. Finally, these growth rates are used to calculate the forecasted number of customers for each year.

[4] Total customers includes all of the utility's customers except for lighting customers (which are not reported on the company's Rule 005 filings).

different. Brattle and LRCA are therefore advocating basing the X factor for Alberta power distributors on the recent trend in an MFP index that is particularly sensitive to declining R&C average use trends in the US. Meanwhile, R&C average use trends in Alberta may very well rise prospectively.

How might considerations of volume trends be included in the X factor calibration procedure?

I showed on pp. 45-46 of my direct testimony that the trend in an MFP index constructed using a revenue-weighted output index can be decomposed into the trend in a cost efficiency index (i.e., a productivity index using the number of customers to measure output) and an output differential. It is then possible to base X factors for Alberta power distributors on the trends in MFP of US power distributors that use the number of customers to measure output and an Alberta-specific output differential. I have used this methodology in work for several clients, including several utilities. Our evidence suggests that if such an adjustment were undertaken for the Alberta utilities it would, if anything, *raise* the X factors by a modest amount.

Consideration of volume trends can be sidestepped by using *revenue* cap indexes for the power distributors in Alberta, as is done for the gas distributors. This facilitates the additional step of instituting revenue decoupling sometime during next generation PBR or in later years. The combination of revenue caps and revenue decoupling is used for electric utilities in a number of American states, including California, Idaho, Massachusetts, Maryland, Minnesota, New York, and Washington. A central appeal of this combination is its ability to remove the disincentive utilities have to aggressively promote demand-side management.

What is your concern about administrative, general, and meter reading costs?

Administrative, general, and meter reading expenses are an important part of the O&M expenses addressed by the I-X escalator in Alberta. These expenses should, accordingly, be included in the study if a sensible means can be found to allocate the A&G expenses. PEG has developed a sensible allocation method that is based on the share of distribution services in the sum of O&M expenses allocated to the various utility functions. The sensitivity of results to the method for allocating costs diminishes as the era of restructuring recedes in the rear view mirror. It is therefore preferable to include these additional expenses in the MFP study.

What is your concern about the use of the GDPPI as an inflation measure for M&S inputs?

NERA, Brattle, LRCA, and PEG all use the residual approach to measure trends in M&S inputs. The general formula used is

$$\textit{trend Inputs}^{M\&S} = \textit{trend Expenses}^{M\&S} - \textit{trend Price Index.} \quad [2]$$

The accuracy of the approach depends on the accuracy of the price index employed as a measure of M&S input price trends. In its gas productivity study for the CCA in ID 566, PEG used a sophisticated M&S price index constructed from detailed price indexes for utility M&S inputs purchased (or, more accurately rented) from the *Power Planner* service of Global Insight. However, the AUC indicated a preference in Decision 2012-237 for the use of publicly available data in productivity studies. In this proceeding, PEG has therefore used a custom M&S price index it constructed from producer price indexes. The design is similar to that of the Global Insight price indexes we previously used.

NERA, Brattle, and LRCA have instead used the GDPPI to deflate M&S expenses. This is the federal government's featured measure of inflation in the prices of the economy's final goods and services. Its use is problematic in this application for several reasons.

- The GDPPI places much larger weights on products like food, gasoline, and capital goods than are appropriate for the M&S product basket.
- As a measure of output prices, the GDPPI also reflects the oftentimes substantial growth in the MFP of the US economy. It therefore tends to underestimate the trend in the economy's *input* prices.
- Over PEG's full 1997-2014 sample period, the average annual growth rate of our custom M&S input price index exceeded that of the GDPPI by 23 basis points. Thus, the use of the GDPPI as the deflator for M&S expenses would tend to *over*state M&S quantity growth and *under*state MFP growth.

What evidence can you present that the methodological upgrades you propose are quantitatively important?

We started with the corrected NERA/Utilities methodology and then added methodological upgrades in the areas I have discussed. These results are also presented in Table 2. Please note the following.

- Raising the average service life to 37 years raised MFP growth by a remarkable 47 basis points for the full sample period, 61 basis points for the 1997-2014 period, and 64 basis points for the five most recent years. Even if the AUC for some reason prefers a 33-year service life, it should be concerned about how sensitive the results from the one hoss shay approach are to the service life assumption.

- Switching next to geometric decay with a 37-year service life *slowed* MFP growth modestly. Growth was down 39 basis points for the full sample period and 40 basis points for the 1997-2014 sample period but was up 5 basis points for the last five years. It is also important to note that when GD is assigned a 33-year service life, the MFP trends change little and are far above the results obtained using one hoss shay and a 33-year service life. Thus, a decision to EITHER adopt the geometric decay approach that Dr. Meitzen routinely uses OR extend the average service life (or do BOTH) has a major impact on the estimated MFP trend and produces a trend for recent years that is positive (though close to zero) in recent years.

- At this point in our sequence it is possible to correct for the mergers and the "Mississippi mismatch" I discussed above. Correcting for these data problems had a small 5 to 6 basis point effect on the MFP trends.

- For NERA's lengthy full sample period, we unfortunately do not know the impact of replacing the volumetric index (with corrected volume data) with the total number of customers as the output index, since customer data have not been gathered (apparently by any consultant) for the earlier years of NERA sample period. We would expect the MFP trend to fall, since R&C average use rose between 1974 and 1996. For the 1997-

2014 period, using the total number of customers accelerates MFP growth by only 3 basis points. For the five most recent years, however, it accelerates MFP growth by 5 basis points. Thus, for the most recent years a switch from the uncorrected volume index used by NERA and the Utilities to the number of customers raises the MFP trend by a substantial 29 basis points. (24 + 5 = 29)

Since use of the number of customers rather than the corrected volumetric index has little impact over the 1997-2014 sample period, why is its use nonetheless preferable?

In a nutshell, modestly *positive* growth in R&C average use before 2008 was offset by modestly *negative* growth after 2008. For this reason the number of customers and corrected volumetric index yield similar results and there is no real harm in using the number of customers for this sample period. However, when a corrected volumetric index is used, it will reflect modest *growth* in R&C average use before 2008 and a modest *decline* in average use going forward. This will incentivize utility witnesses in future proceedings to focus on the latest MFP results, and discourage a focus on results for earlier years. Note also that results for the full sample period reflect the many years of modest growth in average use that occurred before 2008. Due to their use of revenue per customer caps, this is irrelevant to the calculation of gas distributor X factors.

When all of these data corrections and upgrades are made, how do the results compare with those from your own research?

To make this comparison, I first calculated results using PEG's code and the sample of common companies with good data. To enhance comparability, I also chose a 37-year service life for distribution plant, excluded general costs and meter reading expenses, and used GDPPI as the M&S price index rather than our own custom index. With these changes, MFP growth averages 25 basis points for the 1997-2014 period and 22 basis points for the last five years of the sample. This is similar to the 18 basis points for the 1997-2014 period and the 17 basis point average for the final five years using the corrected and upgraded NERA/Utilities methodology. Results still differ due to the combined effect of several additional small upgrades in our methodology.

What is the impact of adding general costs and meter reading expenses, expanding the sample, and using the custom M&S price index?

The MFP growth trend for the full sample rises by 18 basis points for the 1997-2014 sample period to 0.43%. The MFP growth trend for the final five years rises from 22 basis points to 0.31%. Note there is no slowdown in the final five years.

The Commission could use the results you have provided for the upgraded NERA/Utilities methodology rather than the results from your own research. What are the advantages of PEG's research as the basis for X factors in next-generation Alberta PBR?

There are, first of all, the advantages to using our considerably larger sample, the custom M&S price index, and general cost and meter reading expenses. There are a number of small additional advantages.

- Regionalized labor price indexes are used to calculate labor quantity trends.
- The residual approach is used to calculate the labor quantity trend throughout the sample period.
- Since the four Alberta power distributors are small by US standards, a simple average of the productivity trends of sampled US power distributors is more relevant than a size-weighted average.

The combined effect of all of these upgrades on the MFP growth trend is appreciable. Using our approach will also liberate the Commission from continuing to base X factors on a methodology with many flaws.

You mentioned above that the NERA/Utilities method for calculating the labor quantity index is substandard even when corrected. Please explain.

It is suboptimal to calculate the *distribution* labor quantity in the early years of the full sample period as a share of the *total* labor quantity, for several reasons.

- The NERA/Utilities method essentially estimates the trend in the *total* number of employees rather than the trend in distribution *O&M* employees, which is what we care about. The total number of employees includes construction employees, which are counted implicitly in the capital quantity index.

- The trend in the *total* number of employees does not take account of changes in the *composition* of employees over time.

- The NERA/Utilities method uses the share of distribution salaries and wages in *total* salaries and wages.[15] Total salaries and wages includes an allocation to clearing accounts. In other words, the denominator includes expenses that have not been allocated to a utility function (generation, transmission, etc.). The distribution share is thus understated.

All of these problems can be sidestepped by using the residual approach set forth in equation [1] in *all* years of the sample period, as PEG did in its research for the CCA. I should also note that in our application of the residual method we regionalize the labor price trend.

Some of the productivity research methods you propose for X factor calibration seem tailored to the circumstances of Alberta utilities. Do you often customize your productivity research methods to be relevant to the utilities to which they apply?

Yes. For example, I tend to consider *revenue*-weighted output indexes that include volumes by *some* means when utilities will likely be subject to *price* caps, and the number of customers when they are likely to be subject to *revenue* caps. In work for utilities in the northeast United States, I have throughout my career tended to use northeast utility peer groups.

[15] They could instead have used the share of distribution salaries and wages in the sum of all salaries and wages *assigned directly to utility functions*.

I have in recent years featured the COS approach to measuring capital cost in my US research and testimony. This reflects the fact that US utilities often propose *macroeconomic* inflation measures such as the GDPPI in the rate (or revenue) cap escalator. This raises the issue of how well these measures track input price trends of utilities. The COS approach to measuring capital cost sheds more light on this issue than the GD or one hoss shay approaches. In this proceeding, I have instead featured the GD approach because a more customized measure is more likely to be used for inflation in next generation PBR, and the GD approach is simpler and easier for other parties to review. In future proceedings, MFP calculations using GD can be presented on a spreadsheet if parties so desire.[16]

Are there other reasons why your methodology may change from time to time?

Yes. My opinions concerning best practices in X factor calibration have naturally evolved over the years. For example, I now use a custom M&S price index rather than the GDPPI when calculating the M&S quantity trend. I have greater appreciation for the usefulness of the GD approach to capital costing in Canadian proceedings.

This Commission ruled in paragraph 337 of Decision 2012-237 that "the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta." Why then have you tried to customize your approach to X factor calibration in this proceeding?

My reading of this paragraph is that the Commission felt that business conditions that were different in Alberta but affected the *level* of costs rather than their *trends* were not grounds for X factor customization, and I generally agree. However, some business conditions may be unusual in Alberta that affect productivity *trends*. Or, as in the case of the

[16] We did not do this in this proceeding because the COS approach to capital costing is also used and is more difficult to place on a spreadsheet.

NERA/Utilities assumption of a 33-year service life, a methodology may for some reason fail to account for the fact that Alberta business conditions are *normal.* In that event, customization is appropriate if it is not unduly complicated.

The Commission stated in the very next paragraph of D. 2012-237 that "The relevant question to ask is not whether the companies in the sample are similar to the Alberta utilities but ... whether the US industry TFP trend represents a reasonable productivity trend estimate for the Alberta companies." The Commission goes on to say in paragraph 342 that the productivity trend of the US power distribution industry is a reasonable "*starting point*" for setting an Alberta X factor [italics added]. I should also note that Principle 4 on the Commission's list for PBR plan design is "A PBR plan should recognize the unique circumstances of each regulated Company that are relevant to a PBR design."

What positions have the other expert witnesses in this proceeding taken on the customization issue?

Their positions have varied considerably. Dr. Meitzen has strongly asserted that the X factor should reflect the *industry* productivity trend. He stated in response to Meitzen-CCA/PEG-004, for example, that "The X factor should represent industry trends, irrespective of particular company circumstances." On the other hand, Brattle stated in response to question Brattle-CCA/PEG 3 (c) that, "If the industry itself is changing in the US in a way that it is not changing in Alberta, then a trend measured in the US may be irrelevant to Alberta." Brattle stated in response to Brattle-CCA/PEG-006 that "the X factor should reflect the utility's prospects for the plan term so that the revenues delivered by the plan are consistent with the utility's expected costs."

Dr. Weisman also argued in favor of a customized X factor. He stated in response to Weisman-CCA/PEG-015 (b) that "the X factor applied to a regulated firm should be based on a representative peer group of firms. To the extent that the unique circumstances of the regulated firm are expected to lead to changes in productivity growth it would be necessary to take these into account." He stated in response to Weisman-CCA/PEG-016 that "The X factor for Alberta utilities should be based on a representative peer group. If it is not, then the X factor would not provide the proper 'competitive benchmark' called for in AUC PBR Principle 1."

Are there other arguments in favor of customized X factors?

Yes. One is that customization has been quite common in PBR. X factors based on productivity trends in the Northeast United States have been favored by utilities and regulators alike in that region. The X factor for power distributors in Ontario currently reflects the productivity trends of Ontario distributors. In Alberta, Dr. Makholm of NERA proposed a western peer group in his productivity study to calibrate the X factor in an early PBR proposal for Utilicorp Networks Canada.[17] Data are still available for a sizable western peer group and I include one in the results I present below.

Please provide your final recommendations concerning the base productivity trend.

Our final MFP index results for the full sample feature a 37-year service life for distribution assets and are detailed in Table 6a. It can be seen that MFP growth averaged 0.43% over the full sample period. Capital productivity growth averaged 0.26% whereas O&M productivity growth averaged 0.76%.

Analogous results using the alternative COS approach to measuring capital cost are detailed in Table 6b. It can be seen that MFP growth averaged 0.56% over the full sample period. Capital productivity growth averaged 0.51% whereas O&M productivity growth averaged 0.76%. In contrast to the utility witnesses, we thus provide some assurance that the results using our featured method of measuring capital cost are robust.

The analogous results using GD for the *rapid growth* sample outlined in our direct testimony are detailed in Table 6c. It can be seen that MFP growth averaged 0.78% over the

[17] The testimony itself was provided in response to EDTI-NERA-1 (Exhibit 198.01) in Proceeding 566.

Table 6a

US Power Distribution Productivity Trends: Full Sample with Geometric Decay Depreciation

Year	Output	Input	Productivity		
			O&M	**Capital**	**Mult-Factor**
	[A]	[B]			[C=A-B]
1997	1.44%	-0.11%	3.84%	0.60%	1.54%
1998	1.56%	2.71%	-5.64%	0.59%	-1.15%
1999	0.83%	0.08%	1.54%	0.39%	0.75%
2000	1.55%	0.61%	1.77%	0.57%	0.94%
2001	1.79%	0.86%	1.11%	0.84%	0.93%
2002	1.28%	-0.40%	4.52%	0.36%	1.68%
2003	0.75%	2.25%	-5.29%	0.01%	-1.50%
2004	1.11%	-0.26%	3.65%	0.40%	1.38%
2005	1.27%	0.12%	2.62%	0.42%	1.15%
2006	0.50%	0.53%	-0.03%	-0.05%	-0.04%
2007	1.06%	1.10%	-0.16%	0.21%	-0.04%
2008	0.56%	0.86%	-0.43%	0.04%	-0.31%
2009	0.25%	-0.51%	3.26%	-0.32%	0.76%
2010	0.41%	0.09%	0.29%	-0.04%	0.32%
2011	0.29%	-0.18%	0.73%	0.11%	0.47%
2012	0.57%	-0.50%	2.24%	0.61%	1.07%
2013	0.30%	0.41%	1.11%	-0.48%	-0.11%
2014	0.65%	0.83%	-1.52%	0.42%	-0.18%
Average Annual Growth Rates					
1997-2014	**0.90%**	**0.47%**	**0.76%**	**0.26%**	**0.43%**
1997-2007	**1.19%**	**0.68%**	**0.72%**	**0.39%**	**0.51%**
2008-2014	**0.43%**	**0.14%**	**0.81%**	**0.05%**	**0.29%**

[1]Annual growth rates are calculated logarithmically.

Table 6b-Revised

US Power Distribution Productivity Trends: Full Sample with Cost-of-Service Depreciation

Year	Output	Input	Productivity		
			O&M	Capital	Mult-Factor
	[A]	[B]			[C=A-B]
1997	1.44%	-0.43%	3.84%	0.91%	1.87%
1998	1.56%	2.41%	-5.64%	1.45%	-0.85%
1999	0.83%	0.03%	1.54%	0.35%	0.80%
2000	1.55%	0.46%	1.77%	0.74%	1.09%
2001	1.79%	0.71%	1.11%	1.20%	1.08%
2002	1.28%	-0.84%	4.52%	0.86%	2.12%
2003	0.75%	2.23%	-5.29%	0.29%	-1.47%
2004	1.11%	-0.49%	3.65%	0.50%	1.60%
2005	1.27%	-0.16%	2.62%	0.91%	1.43%
2006	0.50%	0.71%	-0.03%	-0.24%	-0.21%
2007	1.06%	0.65%	-0.16%	0.64%	0.41%
2008	0.56%	0.79%	-0.43%	-0.05%	-0.24%
2009	0.25%	-0.42%	3.26%	0.05%	0.67%
2010	0.41%	-0.31%	0.29%	0.93%	0.72%
2011	0.29%	-0.12%	0.73%	0.38%	0.41%
2012	0.57%	-0.05%	2.24%	-0.19%	0.62%
2013	0.30%	0.04%	1.11%	0.06%	0.26%
2014	0.65%	0.90%	-1.52%	0.43%	-0.26%
Average Annual Growth Rates					
1997-2014	**0.90%**	**0.34%**	**0.76%**	**0.51%**	**0.56%**
1997-2007	**1.19%**	**0.48%**	**0.72%**	**0.69%**	**0.71%**
2008-2014	**0.43%**	**0.12%**	**0.81%**	**0.23%**	**0.31%**

[1]Annual growth rates are calculated logarithmically.

Table 6c

US Power Distribution Productivity Trends: Rapid Growth Sample with Geometric Decay Depreciation

Year	Output	Input	Productivity		
			O&M	**Capital**	**Mult-Factor**
	[A]	[B]			[C=A-B]
1997	2.63%	0.15%	7.25%	0.73%	2.48%
1998	2.78%	3.58%	-4.53%	0.12%	-0.80%
1999	2.44%	1.66%	1.73%	0.46%	0.78%
2000	2.33%	1.46%	2.06%	0.52%	0.87%
2001	2.04%	0.54%	4.35%	0.17%	1.50%
2002	2.10%	0.12%	6.92%	-0.24%	1.98%
2003	2.12%	5.06%	-11.24%	0.22%	-2.94%
2004	2.10%	0.96%	3.13%	0.09%	1.14%
2005	2.73%	2.24%	0.30%	0.62%	0.49%
2006	1.81%	1.42%	0.69%	0.26%	0.39%
2007	2.00%	0.79%	2.25%	0.60%	1.21%
2008	1.10%	-0.88%	4.66%	0.11%	1.98%
2009	0.53%	-1.42%	4.88%	-0.18%	1.96%
2010	0.49%	0.86%	-1.09%	-0.05%	-0.37%
2011	0.51%	-0.23%	1.61%	0.64%	0.74%
2012	0.73%	-0.78%	4.88%	0.58%	1.51%
2013	1.01%	0.29%	-1.47%	1.21%	0.72%
2014	1.19%	0.73%	-1.47%	1.23%	0.46%
Average Annual Growth Rates					
1997-2014	**1.70%**	**0.92%**	**1.38%**	**0.39%**	**0.78%**
1997-2007	**2.28%**	**1.64%**	**1.17%**	**0.32%**	**0.65%**
2008-2014	**0.79%**	**-0.21%**	**1.71%**	**0.51%**	**1.00%**

[1]Annual growth rates are calculated logarithmically.

full sample period. Capital productivity growth averaged 0.39% whereas O&M productivity growth averaged 1.38%.

The analogous results using GD for the *Mountain West* sample identified in our direct testimony are detailed in Table 6d. It can be seen that MFP growth averaged 0.86% over the full sample period. Capital productivity growth averaged 0.36% whereas O&M productivity growth averaged 1.57%.

We recommend basing the X factor for the Alberta distributors on our GD results for the rapid growth sample over the full 1997-2014 sample period for which we have gathered data. There are strong arguments for considering scale economies, and we are not considering the rising R&C average use trends of Alberta power distributors. The Commission may also wish to consider the 1.28% trend in the corrected and upgraded NERA/Utilities MFP indexes for the *full* 1973-2014 sample period, which we report in Table 2 using the common sample, data corrected for mergers, a volumetric index, a 37-year service life, and geometric decay.

Have other witnesses in this proceeding acknowledged that opportunities to realize scale economies are an important driver of productivity growth?

Yes. Dr. Meitzen, for example, stated in response to Meitzen-CCA/PEG-005 that

> Economies of scale are one determinant of a utility's TFP growth. In addition, as other research has shown, economies of density and capacity utilization are important sources of TFP growth in network industries.

2.2 Stretch Factor

Let's turn now to your concerns about the stretch factor recommendations of the utilities and their witnesses.

All of the utilities and Brattle proposed in their direct testimony to eliminate stretch factors. Brattle stated in response to question 70 in their testimony that "it would not be reasonable to anticipate additional cost savings over and above those implicitly assumed in the X factor because the distribution utilities in Alberta have been operating under PBR for some

Table 6d

US Power Distribution Productivity Trends:
Mountain West Sample with Geometric Decay Depreciation

Year	Output	Input	Productivity		
			O&M	**Capital**	**Mult-Factor**
	[A]	[B]			[C=A-B]
1997	2.84%	1.02%	6.31%	0.00%	1.82%
1998	2.58%	3.38%	-0.25%	-0.98%	-0.81%
1999	2.57%	1.69%	3.83%	-0.05%	0.87%
2000	2.54%	0.93%	3.53%	1.04%	1.61%
2001	2.29%	0.24%	3.78%	0.33%	2.05%
2002	2.07%	-1.28%	13.27%	-1.20%	3.36%
2003	2.49%	5.50%	-13.79%	0.76%	-3.01%
2004	2.17%	3.36%	-4.77%	0.07%	-1.19%
2005	3.47%	1.38%	4.25%	1.00%	2.09%
2006	1.58%	1.06%	1.10%	0.52%	0.51%
2007	2.25%	0.39%	2.35%	1.43%	1.86%
2008	1.27%	0.35%	2.29%	-0.17%	0.92%
2009	0.77%	-0.99%	4.55%	-0.55%	1.76%
2010	0.67%	0.11%	1.86%	-0.04%	0.56%
2011	0.55%	-0.11%	1.24%	0.76%	0.66%
2012	0.82%	0.49%	1.35%	0.43%	0.33%
2013	1.12%	0.82%	-5.35%	1.62%	0.30%
2014	1.27%	-0.54%	2.80%	1.54%	1.82%
Average Annual Growth Rates					
1997-2014	**1.85%**	**0.99%**	**1.57%**	**0.36%**	**0.86%**
1997-2007	**2.44%**	**1.61%**	**1.78%**	**0.27%**	**0.83%**
2008-2014	**0.92%**	**0.02%**	**1.25%**	**0.51%**	**0.91%**

[1]Annual growth rates are calculated logarithmically.

time." [footnote removed] When asked in Brattle-CCA/PEG-017 if there are precedents for stretch factors in next generation PBR, they answered that "Dr. Brown and Dr. Carpenter are aware of few if any precedents that are directly relevant, given the unique nature of Alberta PBR plans and the circumstances of the Alberta utilities."

Drs. Meitzen and Weisman noted in their testimony that there are arguments for lowering the stretch factor in second-generation PBR. In response to CCA information requests, however, both endorsed zero stretch factors. Dr. Weisman stated in response to EDTI-AUC-014 that "It was perhaps most common in incentive regulation plans in the telecommunications industry to eliminate the stretch factor in second- and subsequent-generation incentive regulation plans."

How do you respond?

Convincing evidence has not been presented that Alberta utilities are superior cost performers. However, the large supplemental revenue requested for capital suggests a serious decline in capital productivity. Hence, the continuation of positive stretch factors appears to be a "no brainer." I made several arguments in favor of continued stretch factors in my direct testimony and venture some additional arguments here.

I stated in my 2011 direct testimony in AUC ID 566 that the stretch factor for Alberta power distributors should lie in the interval [0.13, 0.50].[18] The upper bound of this interval was the average of the itemized stretch factors in the PBR plans of North American energy utilities which had been approved up to that time. The lower bound was drawn from PEG's incentive power research.

Please elaborate on your incentive power research.

---

[18] AUC Proceeding 566, Exhibit 307.01, p. 64.

PEG has developed an incentive power model that estimates the typical cost performance improvements that will be achieved by utilities under alternative, stylized regulatory systems. Results can be obtained for companies at various levels of initial operating efficiency. Clients who have supported the development of this model include the Ontario Energy Board and US and Canadian gas distributors. I provided working papers on our research to the Brattle group in response to a data request in Proceeding ID 566.

The model sheds light on how cost performance is likely to improve in Alberta under PBR. At the onset of PBR, Alberta energy distributors had been operating for many years under a two-year rate case cycle. There were no earnings sharing mechanisms. I assumed that this regulatory system would be replaced with one with a five-year rate case cycle and an earnings sharing mechanism.

Based on my experience, I believe that US energy distributors typically hold rate cases about every three years. Earnings sharing mechanisms are uncommon. Assuming a normal level of operating efficiency, the incentive power model indicated that the stronger performance incentives of a three-year rate case cycle would generate 24 basis points of average annual performance gains in the long run. Thus, customers would benefit from more rapid productivity growth just by basing X on the peer group productivity trend. The model also indicated that the long run annual average performance gain under Alberta PBR would be 27 basis points higher than the norm under American regulation. Half of 27 basis points is about 13 basis points, the lower bound of my range of reasonableness.

How might this analysis be adopted to evaluate the need for stretch factors in second generation PBR?

Note first that the average itemized stretch factor in approved PBR plans for North American energy utilities has fallen modestly since my 2011 survey to 0.42%, as shown on Table 6 of my direct evidence. As for the incentive power research, the AUC ultimately chose a system with a five-year term that *excludes* earnings sharing but *includes* an efficiency carryover mechanism ("ECM") and a capital tracker. The incentive power result for a five-year plan with earnings sharing should be a reasonable proxy for the result under the current system.

Utility witnesses have argued that one round of PBR is likely to have eliminated the "low-hanging fruit" of inefficiencies. The incentive power model sheds light on this issue. Note first that the model indicated a 27 basis point acceleration in the average annual performance gain under PBR in the *long* run relative to the norm for the productivity peer group, not in the first plan period. For the first two PBR plan periods, the model indicated that the average annual performance gain would rise by 39 basis points.

What are the precedents for second-generation stretch factors?

Stretch factors have been included in a number of second generation or later PBR plans for energy utilities, including those of Boston Gas, the FortisBC utilities, and Ontario power distributors. Three generations of PBR plans for Ontario have included a stretch factor, including the current plan. The OEB explained why it continues to include stretch factors in PBR plans in a decision on fourth-generation PBR, stating that:

> The Board believes that stretch factors continue to be required and is not persuaded by arguments that stretch factors are only warranted immediately after distributors switch from years of cost of service regulation to IR. Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend. Consequently, stretch factors continue to have an important role in IR plans after distributors move from cost of service regulation.[19]

Stretch factor assignments in the 3rd and 4th generation Ontario power distribution PBR plans have been updated annually to reflect company performance in cost benchmarking studies. These benchmarking studies began as assessments of *O&M* cost performance in the Ontario 3rd generation PBR plan and were expanded to assess *total* cost performance in the Ontario 4th generation PBR plan.

---

[19] Ontario Energy Board (2013), EB-2010-0379, *Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,* issued on November 21, 2013 and as corrected on December 4, 2013, p. 18-19.

Similarly, after several generations of PBR plans, the British Columbia Utilities Commission approved stretch factors of 0.2% for FortisBC Energy Inc. (formerly Terasen Gas) and 0.1% for FortisBC (formerly West Kootenay Power) for their current plans. The Commission also endorsed the possibility of including stretch factors in future generations of PBR plans that are based on benchmarking evidence. The Commission believed that there was

> a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.** [20] [Emphasis in original]

In contrast to the opposition to stretch factors by all utility witnesses in this proceeding, I have advocated the inclusion of stretch factors in second generation or later PBR plans in testimony for several utility clients.[21] Dr. Meitzen's colleague Dr. Philip Schoech has also advocated a positive stretch factor for a utility client. The following exchange occurred in oral testimony when he was a witness for Union Gas, a large Ontario gas utility.

> MR. THOMPSON You came up with a stretch factor of 0.4%. That's your recommendation. Is that right?
>
> MR. SCHOECH Yes, we determined that that was a reasonable stretch factor.
>
> MR. THOMPSON And what did you consider in coming up with that number?
>
> MR. SCHOECH Well, as my colleague indicated, it is a subjective number. I guess what we did was we looked at the way the stretch factor had been addressed in other jurisdictions. It seemed that a range of 0.25 to, say, 0.75 was reasonable. And the discussions with Union led us

---

[20] British Columbia Utilities Commission (2014), *Decision,* In the Matter of FortisBC Energy Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, p. 96.

[21] See, for example, my X factor recommendations for Central Maine Power in 2007 and Gaz Metro in 2012. These recommendations were detailed in CCA-EDTI Attachment 1b.

> to the position where we found 0.4% an acceptable stretch factor — a recommended stretch factor, I might add.[22]

Telecommunications precedents are also of interest given the opposition of Drs. Weisman and Meitzen, who are experts in the field of telecom PBR, to the imposition of a stretch factor for their client, EDTI. While we have never done a full survey of telecom PBR precedents, several examples of second-generation stretch factors were identified with very little work.

- The US Federal Communications Commission approved stretch factors in second-generation PBR plans for AT&T and the interstate services of incumbent local exchange carriers.[23]
- The Illinois Commerce Commission approved a second-generation stretch factor in 2002 for Ameritech Illinois (formerly Illinois Bell), a large local exchange carrier. The proceeding apparently involved Dr. Meitzen. The Commission stated in its decision that

> AI in its Briefs seems to suggest that under the Plan, ratepayers were only to receive a consumer dividend for the first term of the plan. The implication therefore is that once the original term of the plan expired, so to would the consumer dividend. We reject this implication. Ratepayers are to receive the first cut from any improvements which arise from technological and regulatory change under the original term of the Plan and just as importantly any modification or extension thereof.[24]

It should also be noted that the lack of an explicit stretch factor in many second generation PBR plans does not necessarily indicate commission disapproval of the notion since

---

[22] Hearing Volume 6, Ontario Energy Board Docket RP-1999-0017, June 2000.

[23] Federal Communications Commission, FCC 93-326, Report Adopted June 24, 1993 in CC Docket 92-134. Federal Communications Commission, FCC 97-159, Fourth Report and Order Adopted May 7, 1997, in CC Dockets, 94-1 and 96-262. The latter decision was subsequently overturned by the US Court of Appeals for the District of Columbia Circuit in 1999.

[24] December 30, 2002 order in Illinois Commerce Commission case 00-0764, p. 100.

X factors in many second generation plans were the outcomes of settlements. For example, the three approved price cap plans of Central Maine Power ("CMP") were all resolved with Commission-approved settlements. These settlements set an explicit value for the overall X factor, referred to in Maine as a productivity offset, without identifying specific values for a productivity differential, input price differential, stretch factor, output differential, or any other possible components of an X factor. Nevertheless, stretch factors were frequently discussed in these proceedings. In the proceeding leading to the most recently approved price cap plan, Dr. Lowry, as a witness for CMP, recommended a stretch factor of 0.4%.

Based on this evidence, we believe that continuation of the current 0.20% stretch factor is prudent. Statistical benchmarking can yield stretch factors that are specific to each company's level of operating efficiency. A 0% stretch factor should be reserved for companies that score well in credible independent benchmarking studies.

Has Dr. Weisman commented on the potential role of statistical benchmarking in utility regulation?

Yes. He was a witness in a PBR proceeding in which I provided statistical benchmarking evidence on behalf of the same client, AmerenUE, in 2002. In an article coauthored with Dr. Sappington, he commented in 1994 that

> Basing the firm's compensation on performance measures that are relative to those of similar firms can serve an analogous role. The performance of other firms that operate in similar environments can sometimes serve as a benchmark against which to assess the regulated firm's performance. (Recall also that yardstick competition of this type has been proposed for natural gas pipelines.) When the regulated firm in question is shown to perform better than other firms in comparable settings, evidence of greater diligence or ingenuity on the part of the regulated firm is provided. Such evidence can help to justify enhanced compensation for the firm. Of course, it is critical that the comparison group of firms be carefully selected. Observed differences in performance must be due to differences in diligence or ingenuity, not to exogenous environmental differences, if

they are to motivate the regulated firm and enhance perceptions of fairness. [25]

The incentives yielded by the current regulatory system are one issue in deciding whether the stretch factor should be continued. What then of Dr. Weisman's comment in response to EDTI-AUC-014 that "the Commission's scrutiny of these capital tracker applications is the antithesis of the proverbial 'rubber stamp' that the intervenors seem to think is the *modus operandi* underlying the Commission's analysis, deliberations and decisions?"

This is one of several complaisant remarks Dr. Weisman has made in his evidence to avoid hard truths that inconvenience his client. In reality, it is very difficult for any Commission to render decisions concerning optimal distribution investment policies. Decisions concerning deferrable capex are especially difficult. The supplemental revenue obtained from trackers has been enormous. If capital trackers with substantially full true ups to actuals don't seriously weaken utility performance incentives, why was there any need for the AUC to abandon biennial rate cases in the first place?

3. Capital Trackers

Turning next to the issue of capital trackers, all of the utilities have argued for their continued need in next generation PBR. What are your views?

We believe that a system of PBR that features I-X attrition relief mechanisms based on industry cost trends may occasionally require supplemental revenue to compensate utilities for needed capex surges. Capital trackers can provide this revenue, thereby reducing utility operating risk and facilitating their operation under PBR.

Trackers also have notable disadvantages and implementation challenges.

- Trackers raise regulatory cost and weaken capex containment incentives.

[25] Sappington, David, and Weisman, Dennis, "Designing Superior Incentive Regulation; Modifying Plans to Preclude Recontracting and Promote Performance," *Public Utilities Fortnightly*, Vol. 132, No. 5, March 1, 1994, p. 27.

- As Weisman and Sappington observed in their white paper last year for EDTI, utilities are incentivized to game the tracker system. Substantial extra revenue can, after all, potentially be produced at the modest cost of a regulatory initiative.
- I-X+G (where G stands for growth in customers or all billing determinants) escalation between rate cases is usually insensitive to capex surges. However, it also bolsters utility margins between rate cases since the revenue associated with each plant addition made before the current plan rises while the cost of these assets tends to fall due to mechanistic depreciation of the rate base. The X factor is based in part on the productivity growth of a peer group, which was slowed by capex surges like those for which utilities seek compensation. I-X+G thus provides a "budget" for capex surges paid out in regular installments rather than when it is most needed.

Have utilities acknowledged the reality of these capital revenue surpluses?

Yes. EDTI acknowledged that I-X+G can generate capital revenue surpluses in the 2013 capital tracker proceeding 2131 when it stated that

> [F]or certain [proposed] Trackers, EDTI will recover a higher amount of return and depreciation under the PBR Formula than it will incur. As such, these Trackers result in K factor adjustments that are negative (i.e., they reduce EDTI's PBR rates rather than increase them). The negative K factor adjustment occurs in relation to these Trackers because they are previously completed one-off projects that were outside of the ordinary course of EDTI's business operations. The negative K factor adjustment arises from the fact that the net book value associated with the original rate base addition for the project in question is declining on EDTI's books every year due to the effects of depreciation (i.e., the return of capital).[26]

What does the existence of these capital revenue surpluses say about the need for trackers?

[26] AUC Proceeding 2131, Exhibit 38.01, paragraph 296.

Capital revenue surpluses produced by this feature of PBR can mitigate the short-term revenue shortfalls on plant additions, if not in the year of the surge then over time. There is thus a material risk of *over*compensation if trackers provide utilities with full compensation for their short-term revenue losses due to capex surges. This weakens utility incentives to contain capex and can deny customers a fair share of the benefits of PBR. Utilities can pocket "prepayments" for surges and then request full compensation for the surges.

The need for supplemental revenue for capex thus depends on the extent to which the following conditions hold:

- Capex requirements are unusually high (e.g., for example, due to an exogenous event, unusual uses of capex (e.g., a major undergrounding program) or unusually large need to replace aging assets).
- The regulatory system before PBR featured frequent rate cases that promptly passed the benefits of depreciation on to customers.
- Required capex surges are concentrated in the early years after a switch from traditional rate regulation to PBR.
- Required capex surges occur in the *middle* of plan periods and not around the time of the rate case, when they are easier to self-finance.
- Capex was low in recent years, since this reduces the rate base that makes surpluses possible between rate cases.

When high capex is fully compensated by trackers the following outcomes can therefore be envisioned.

1. If the need for capex surges is unusually low, I-X+G (where G is the extra revenue from demand growth) may substantially overcompensate utilities for needed surges that do occur.
2. If the utility experiences normal capex surges, revenue from I-X+G may roughly compensate the utility in the long run but not in the short run.

3. The utility experiences abnormally large capex surges, I-X+G may provide inadequate compensation in the long run as well as the short run.

Under outcome 2 (and even under outcome 1) short-term revenue shortfalls may be deemed intolerable even though I-X+G provides adequate compensation in the long run. For example, utilities may oppose PBR at the outset or off-ramp provisions will be triggered that cause a suspension of PBR.

What conclusions should the Commission draw from your analysis?

Based on this analysis, and the following facts, we acknowledge that there are some grounds for providing Alberta distributors with more compensation than I-X+G can provide, at least in the early years of PBR.

- Alberta has traditionally had a resource-based economy that occasionally experiences rapid growth. This can trigger surges in energy distributors' capex to expand service and adapt to the expansion of other kinds of infrastructure.
- Alberta distributors operated for many years under frequent rate cases that passed through to customers the full benefits of depreciation on older assets.
- Distributors have recently had some reasons for high capex. These include rapid economic growth in the province and the "echo effect" occasioned by the need to replace plant added during the growth surge that occurred from the middle of the 1970s to the early eighties.

Notwithstanding these realities, the need for supplemental capital revenue should diminish in Alberta going forward, for several reasons.

- Energy distributors generally have less need for capex surges than vertically integrated electric utilities because their systems grow gradually as the economies of their service territories expand. That is why North American-style I-X regulation has been applied chiefly to energy distributors, and extra revenue for capex has often been addressed chiefly by Z factors.

- Economic growth has slowed markedly in Alberta from the pace of recent years. Growth will resume to varying degrees in the service territories of distributors after the recession. The pace may be brisk in some service territories but will likely be slower than in the recent boom. Remarks by FortisAlberta in paragraph 13 of its direct evidence are consistent with this view.

> When the first generation of PBR was implemented, Alberta was in a period of high economic activity primarily driven by the oil and gas sector. This high growth began to slow in 2015 following the rapid drop in oil prices and subsequent slowdown in related developments. Despite the current economic climate, FortisAlberta continues to experience modest, albeit much slower, growth.[27]

- Under circumstances like these, unusually large opportunities should be available to realize economies of scale and density. There should be less need for prebuilds of growth-related capacity and for projects triggered by infrastructure construction in other sectors of the economy. Opportunities should abound to grow into recently constructed facilities that were sized to accommodate future growth.
- Depreciation of the large plant additions that occurred in the rapid-growth years immediately prior to PBR will slow cost growth.
- The substantial capital cost being tracked in current PBR plans will be addressed by I-X in the next plan, adding a sizable new flow of capital revenue surpluses.
- The percentage increase in revenue needed to finance "echo effect" replacement capex is diminished by the fact that Alberta distribution systems have grown substantially since the era when the plant requiring replacement was added.
- High replacement capex due to the echo effect will eventually tail off. For FortisAlberta, this kind of capex never posed an outsized financing problem. Growth-related capex was advanced as the company’s biggest challenge and growth has now stalled.

[27] Exhibit 20414-X0073, p. 5.

- The power distribution industry is experiencing technical change that may slow future cost growth. For example, time-sensitive pricing using AMI can slow peak demand growth, and there are many other potential "smart grid" innovations.
- Reforms to PBR such as more incentivized capital trackers with diminished overcompensation and scope can strengthen capex containment incentives.

For all of these reasons, the capital productivity growth of Alberta distributors has the potential to rise abruptly in the future, slowing cost growth abruptly, if not for all utilities in the next plan then very probably in subsequent plans. Alberta distributors should be able to achieve the MFP growth of their American peers in the longer run. That would require productivity growth well *in excess of* the peer group norm in many future years and not just a return to the peer group norm.

EDTI stated in paragraph 119 of its March 23 submission that

> **the shortfall identified above primarily stems from the fact that EDTI's rate base reflects blended (or average) (i) life-cycle asset replacement rates and (ii) asset installation costs that [are] each substantially lower than the rates and costs that EDTI is currently experiencing and will continue to face over the second PBR term. As a result, applying I-X to the capital costs (ie., return and depreciation) reflected in EDTIs base rates will fail to come anywhere close to funding EDTI's required capital investment over the next generation PBR Term without a capital funding mechanism, just as it would have during the first generation PBR Plan.[28]**

How do you respond?

It is an absolutely normal part of utility operation for replacement assets to cost far more than the original assets. This is therefore a necessary but by no means sufficient reason why a tracker might be needed. Many utilities subject to PBR have funded replacement investments over the years from I-X revenue. A tracker should be used for situations when other factors also come into play and are material, such as a surge in the required *quantity* of capital.

[28] Exhibit 20414-X0074, p. 57.

Please summarize the capital tracker proposals of the distributors.

We begin with EDTI because it has shown some intellectual leadership in Alberta PBR to date and has proposed options for next generation PBR that are also mentioned by the other utilities. In paragraph 121 of its evidence, EDTI divides its capex into two broad categories. One is "recurring (i.e., non-idiosyncratic) capital projects and programs".[29] EDTI states in paragraph 124 that these are projects or programs that are "ongoing or foreseeable, and that are partially but not fully funded through the I-X component of the PBR Plan."[30,31] In paragraph 126, EDTI states that this category would include the "vast majority" of its capital projects.[32]

EDTI describes the other class in paragraph 121 as "truly idiosyncratic capital projects, projects that are not funded under the I-X component of the PBR plan to any extent and projects driven by third parties (other than growth projects)."[33,34] Examples offered in paragraph 125 are "the Work Centre Redevelopment project, the Advanced Metering Infrastructure project, and third party driven relocation-related projects as well as contributions for AESO required projects and contributions to Transmission projects for Distribution."[35]

Under EDTI's proposal, projects of the latter kind would continue to be addressed by the current tracker mechanism. Two options are proposed for recurring, ongoing, and foreseeable projects.

1. EDTI calls Option 1, its preferred approach, the "F Factor" (aka "K-bar") approach. Supplemental revenue would compensate the utility for any positive difference between

[29] Exhibit 20414-X0074, p. 57.

[30] Exhibit 20414-X0074, p. 58.

[31] These were described by EDTI in previous documents as "Category 2" projects.

[32] Exhibit 20414-X0074, p. 59.

[33] Exhibit 20414-X0074, p. 57.

[34] These were described by EDTI in previous submissions as Category 1 and 3 projects.

[35] Exhibit 20414-X0074, p. 58.

its forecasted capital cost and the capital revenue generated by I-X+G over the years of the PBR plan.

2. Option 2 is a more incentivized version of the current capital tracker approach in which there are "limited, prospective only true ups" of revenue to actual capital costs.[36] In other words, retrospective true ups of tracker revenue to actual costs would be eliminated.

EDTI recommends a continuation of the current tracker system should the Commission reject both of these options.

Please summarize the proposals of the other utilities.

ATCO

The current tracker system would continue for unstable and/or unpredictable projects. For all other projects, ATCO recommends a "modified K factor" approach that is similar to EDTI's Option 2. Under this approach, true ups to actuals would be limited. Other aspects of the current tracker system would continue. Only revenue shortfalls would apparently be considered for tracker treatment. The current criteria (including the accounting test), materiality thresholds, and Capital Tracker MFR would be maintained.

AUI

AUI prefers to operate under a continuation of the current tracker system. However, it is open to reducing the frequency of true ups.

ENMAX

EPC will employ the existing K factor mechanism in its 2015-2017 Capital Tracker application. It is open to the "modified" K factor" proposed by Brattle in next-generation PBR.

[36] Exhibit 20414-X0074, p. 66.

EPC notes in paragraph 53 of its evidence that "the modified K factor mechanism would rely on the same accounting test and materiality thresholds used in the existing K factor mechanism."[37]

Fortis

Fortis groups its capex programs into two categories. Category 1 includes Customer Growth as well as Externally Driven projects. Externally Driven projects include those for distribution line moves, substation associated upgrades, and AESO contributions. Category 2 is essentially "Sustainment" capital and includes the Company's programs for Cable Replacement and Compliance, Safety, Aging Systems and Reliability, Transportation Equipment, and Information Technology.

The current tracker approach is envisioned in next generation PBR for Category 1 projects. However, Fortis notes that it "has considered" several new ratemaking treatments for Category 2 projects.[38] A Modified K Factor seems to have the greatest appeal for Fortis. It would limit true-ups and extend the period between applications.

An F factor approach has also been considered by Fortis that involves multiyear forecasts of Category 2 capital costs and associated I-X+G revenue. F would be updated for debt costs and I and Q factors but would not be trued up for actual plant additions. Accounting tests would apparently be applied to *individual* projects. Fortis states in paragraphs 104-5, for instance, that

> FortisAlberta's Sustainment capital expenditures would be forecast at the start of the PBR term for each year of the term. These forecasts would be included in the accounting test to determine the qualifying Type 2 capital trackers....Those that meet the criteria for capital trackers, including the materiality thresholds, would form the basis for the F factor....Actual expenditure profiles between the projects could be different, and these differences might not be considered in the

[37] Exhibit 20414-X0069, p. 23.

[38] Exhibit 20414-X0073, p. 28.

> accounting test over the PBR term. This could result in some programs no longer requiring funding or, alternatively, requiring funding not provided by the F Factor.[39]

A K-Bar approach has also been considered in which forecasts of plant additions would be replaced with historical average plant additions adjusted for inflation.

Important aspects of the current capital tracker approach would continue. Fortis states in paragraph 111 that

> The capital tracker criteria, including the accounting test, should continue to determine what projects and programs qualify for tracker treatment. The second tier materiality thresholds should continue to apply to all qualifying capital projects in the aggregate.[40]

What summary comments do you have about the utility submissions?

I have several.

- The companies wish to continue key aspects of the current tracker system, such as the current accounting tests and materiality thresholds. They tout benefits of continuing the system, such as the fact that these provisions are well developed and understood by the utilities, customer groups, and the Commissions. This may indicate that these provisions are quite favorable to their interests.
- All of the utility submissions narrowly address the Commission's questions about how capital trackers can be upgraded to *strengthen incentives* and *reduce regulatory cost*. Little or no consideration is paid to how to improve the balance of PBR plan benefits between utilities and customers.

[39] Exhibit 20414-X0073, pp. 30-31.

[40] Exhibit 20414-X0073, p. 33.

- The utilities have, to a first approximation, proposed in their evidence ways to enhance their earnings opportunities (including new opportunities to game the system) and reduce regulatory cost without increasing the share of benefits enjoyed by customers or materially jeopardizing the recovery of capital cost.

This should cause the Commission concern, for several reasons.

  - Ensuring that customers receive a fair share of benefits is one of the AUC's five PBR principles, and is generally held as a requirement for regulation to be just and reasonable.
  - Ways of strengthening performance incentives and reducing regulatory cost that also improve the customer share and/or reduce the assurance of cost recovery were largely ignored. For example, Dr. Weisman, Brattle, and the utilities did not propose to raise materiality thresholds or exclude some kinds of capex from tracker eligibility.

What are your views about the continuation of the ratemaking treatment of capital under the current PBR plan?

The general pros and cons of capital trackers were discussed above. We believe that the particular approach chosen in Alberta has been especially problematic. There are problems with respect to most of the AUC's five principles for PBR plan design.

- Regulatory cost is high because a high proportion of capex has been eligible for supplemental revenue and reviews are annual.
- It is difficult for any commission or intervenor to review the need for capex surges. As Dr. Weisman notes in paragraph 93 of his direct evidence, "the regulator is required to second guess the company's operating practices, a task that is fraught with difficulty."[41]

[41] Exhibit 20414-X0074, Appendix A, p. 33.

- Capex containment incentives are unusually weak, since a high percentage of capex has in many cases been eligible for tracker treatment and there are substantially full true ups of tracker revenue to actual cost. As Dr. Weisman noted in paragraph 92, "ongoing adjustments for unusual capital projects might limit incentives to minimize overall production costs (AUC PBR Principal 1). Incentives can be diluted particularly severely by a full true-up of actual CAPEX associated with the capital tracker and forecast CAPEX."[42]
- Review of the need for supplemental funding is also difficult. As Dr. Weisman notes in paragraph 91, "it can be difficult to distinguish between projects that are outside the normal course of a company's operations and those that are not."[43] Further, "the plan may provide the company with an incentive to identify (and possibly exaggerate) 'positive' capital trackers, but overlook (or understate the impact of) 'negative' capital trackers."[44]
- Customers are denied a fair share of the benefits of PBR because they are overcompensating utilities for their short-term revenue shortfalls and will be denied the full benefits of industry productivity growth in both the short and long run.
- Customers are experiencing rate increases commensurate with the negative capital productivity growth that US power distributors have experienced only under extreme circumstances such as a hurricane.[45] This is likely due to a combination of legitimate need for high capex, strategic timing of capex, weak capex containment incentives, and artful tracker applications.

The principle most fully embraced in the current system is that distributors have a reasonable opportunity to recover their cost of service. Remarkably, distributors are afforded a

[42] Exhibit 20414-X0074, Appendix A, p. 33.

[43] Exhibit 20414-X0074, Appendix A, p. 32.

[44] Exhibit 20414-X0074, Appendix A, p. 33.

[45] See our response to CCA-Utilities-10 for elaboration on this disturbing statement.

good chance of recovering their capital costs *each and every year*. This is a "bumper bowling" approach to PBR in which the lower bound of expected outcomes is that distributors earn their allowed ROE. This approach to PBR may prove worse for customers than a return to traditional regulation.

What in your view are the underlying causes of these poor outcomes?

We believe that the problems experienced in Alberta can be traced to certain decisions the AUC made in the implementation of the current PBR system, and importantly the utilities' response to these decisions.

- Capital trackers give utilities a good chance of recovering their capital costs every year.[46]
- The seemingly strict general guidelines for capital tracker eligibility approved in Decision 2012-237 were replaced in Decision 2013-435 with a much more permissive financial accounting test.
- No consideration is paid to capital revenue surpluses. For example, negative K factors were prohibited and no remedy was approved for *intertemporal* double counting even though its existence is undeniable.
- Distributors have artfully prepared their capital tracker applications so that a high percentage of the annual cost of their capex has often been approved for tracker treatment.[47] A common strategy is to choose a very small base revenue for the test that results in a high proportion of capex cost being deemed eligible for supplemental revenue. For example, ATCO Gas compares the cost of replacement capex to the highly depreciated annual cost (as escalated by I-X+G) of assets nearing replacement. AltaGas compares the cost of replacement capex to the escalated annual cost of similar capex at

[46] It should be noted that no analogous decision was made with respect to O&M expenses. These will typically be higher than the O&M revenue in some years and lower in others.

[47] See for example, our response to CCA-Utilities-008 for further discussion of this problem.

an early stage in the same replacement program. Approved accounting tests have accorded tracker treatment for what appears in some cases to be routine capex.

- There are substantially full true ups of capital tracker revenues to actuals.
- Rationales for raising the X factor (e.g., to reflect the outsized opportunities to realize scale economies in Alberta) to strike a better balance between utility and customer interests were not considered and the opportunity for added balance was thus rejected.

The Commission has been wary of considering capital revenue surpluses because this can weaken performance incentives and raise regulatory cost. How do you respond?

These considerations are legitimate but must be balanced against others.

- Ignoring capital revenue surpluses can deny customers a fair share of plan benefits, and this is also a stated goal of PBR in Alberta.
- Consideration of revenue surpluses by some means can strengthen incentives for tracked capex by narrowing the scope of eligible capex or reducing overpayment.
- Much of the capital revenue surplus that occurs between rate cases due to I-X+G results from the *mechanistic* decline in rate base due to depreciation. Incentives are not weakened by taking account of the resultant surpluses until assets approach the end of their service lives.

What are Dr. Weisman's views on the need to ensure that a utility has a fair chance to recover its expected capital costs each and every year?

In response to information request Weisman-CCA/PEG-037 EDTI stated that

> Dr. Weisman does not believe that a utility earning below (or, for that matter, above) its target rate of return in any one given year under PBR is dispositive of rates that are not just and reasonable... Dr. Weisman does not believe that the Commission should seek to increase the earnings variability of the regulated firm by design as part of the PBR plan. That said, it is generally true that under PBR the regulated firm agrees to bear greater risk in exchange for the prospect of greater reward. This greater degree of risk bearing may translate into a greater degree of earnings variability, ceteris paribus.

Let's turn now to the utilities' proposals for new ratemaking treatments. Please comment first on the proposed F factor approach.

Given the unhappy experience with capital trackers thus far in Alberta, we believe that some thought should be paid to setting revenue for most kinds of capital cost using multiyear cost forecasts. This approach, sometimes called the “building block” approach, is applied to *all* costs in Australian and British PBR and is available in Ontario under the "Custom IR" option.

Potential advantages of this approach include the following.

- Capex containment incentives would likely be considerably stronger than under the current system since, once budgets are set, utilities pocket all underspends.
- Surpluses from costs that are growing more slowly than the corresponding I-X+G revenue can be available to fund capex surges. Overcompensation of revenue shortfalls might then be reduced.
- Annual tracker proceedings can be much more limited.

Disadvantages to this approach are also considerable, and many have already been recognized by this Commission.

- Regulatory cost is still fairly high, since business plans must be approved in advance for a wider range of projects than under the current system. In Britain, a PBR proceeding for a utility that makes controversial cost forecasts can take three years.
- Utilities can seek and receive advanced blessing for ill-advised business plans, to that extent weakening their cost containment incentives. Were the regulator to rule at a later date that the plan was imprudent in retrospect, utilities and their expert witnesses would argue that such reconsideration amounted to “recontracting” or an attempt to “claw back” plan benefits.
- As Dr. Weisman comments in paragraphs 84-85 of his direct evidence, "the forward looking approach the plan entails may provide the companies with incentives to exaggerate actual capital investment needs." Further, "the companies may have an

incentive to identify (and possibly exaggerate) ‘positive’ capital trackers, but overlook (or understate the impact of) ‘negative’ capital trackers."[48]

- Due to information and resource asymmetries, it is difficult for regulators and stakeholders to assess the prudence of multiyear total cost forecasts.
- Customers are not ensured the benefits of industry productivity growth.
- The AUC may be less inclined to incur the large expenditures made by their Australian and British counterparts on independent engineering and benchmarking expertise in order to sharpen their views of utility cost escalation requirements. Competent independent experts are sometimes difficult to source and deploy.
- There is a danger to customers in permitting the utility to alternate between a building block approach and simpler indexing from one plan period to the next. As we have seen, Alberta utilities are experiencing a temporary capex surge that has already ended for FortisAlberta. As it winds down for the other distributors, productivity growth should accelerate greatly. There is no reason to believe that the productivity growth of Alberta distributors cannot match or exceed that of a proper US peer group in the longer run. In principle, distributors could therefore use an F factor for one plan period, then operate for one or multiple plans without one, and then request a return to an F factor for some catch up capex. Dr. Weisman discussed the problem of strategic cost shifting in his response to Weisman-CCA/PEG-26&27.

Are there precedents for a PBR approach that combines indexation of revenues (or rates) for O&M expenses with a forecast-based approach to revenues (or rates) for capital?

Yes. An approach similar to this is currently used by Toronto Hydro-Electric. A "hybrid" approach has also been used periodically in multiyear rate plans of California energy utilities since the 1980s. Revenue for O&M expenses is indexed for inflation. Revenue for capital has a

[48] Exhibit 20414-X0074, Appendix A, pp. 30-31.

predetermined "stairstep trajectory that reflects expected growth in capital cost. The extra step of calculating an F factor is sidestepped.

A similar approach was proposed by our client Central Maine Power in a 2013 PBR initiative in Maine. The Maine Public Utilities Commission was so opposed to the idea that it rejected it at an early stage in the proceeding, stating that

> We are also not persuaded by CMP's arguments that its 6-year capital distribution plan should be fully vetted and blessed by the Commission in this proceeding. Detailed long-term capital planning is an activity that, at least in detail, should be left to management subject to prudency review. In addition, as a practical matter, by requiring that the parties and the Commission pre-approved specific capital programs years in advance, whenever CMP acknowledges that there is uncertainty relating to the timing, cost and even the ultimate need for the projects, the CRM [Capital Expenditure Recovery Mechanism] introduces a level of predictive uncertainty into the ratemaking process that we find to be unacceptable.[49]

Do you have any concerns about the particular approach to F Factor design proposed by the utilities in this proceeding?

Yes. Some parties (e.g., ATCO) seem to be proposing a fragmented approach to the development of F Factors in which only revenue *shortfalls* are considered. Dr. Weisman states in paragraph 97 of his direct evidence that "Under Alternative B, EPCOR's ability to true-up its Category 2 Trackers during the PBR term would be limited to the share of the company's annual forecast capital cost for *each Category 2 tracker* that is funded by the approved Capital Tracker K factor adjustment."[50] Yet EDTI provides a spreadsheet illustrating the operation of its proposed F factor that seems to include capital revenue surpluses.

Even where the F factor does reflect an aggregate cost forecast, negative values may not be allowed. Dr. Weisman, for example, states in paragraph 78 that "The company identifies at

[49] Maine PUC, Order of Partial Dismissal, Docket No. 2013-00168, August 2013, p. 7.

[50] Exhibit 20414-X0074, Appendix A, p. 34 [emphasis added].

the start of the PBR regime any additional F (forward-looking) factor adjustment that is required for (expected) revenue sufficiency."[51] EDTI notes in paragraph 124 that "The F Factor is a capital funding mechanism that will be used to address EDTI's capital funding *shortfall* for projects or programs that are ongoing or foreseeable."[52] [italics added]

Note, finally, that the utilities have not commented on the freedom they might have to revert to a more conventional I-X plus tracker system at a later date.

Is it realistic to think that capital cost growth could occasionally be less than I-X+G?

Certainly. Otherwise, companies would never be able to achieve the capital productivity growth of the peer group in the longer run. The growth in capital cost can slow abruptly when surges in replacement capex end and no capex is needed due to exogenous shocks. Capex is lower and the annual cost of recent surges declines due to depreciation.

Do you have any suggestions for improving the F Factor approach?

Yes. Revenue surpluses should be included in the calculations. Negative F factors should be permitted and not be optional.

- Capital cost forecasts can be informed by indexing and benchmarking studies. It can make sense to set budgets for some kinds of capex based on an average of past values (as in California), subject to escalation for construction cost inflation.
- Budgets for some kinds of capex can be established formulaically. For example, two formulas are used to set capex budgets in the current PBR plan of Fortis BC Energy. One is for growth capital and the other for sustainment and other capital.

[51] Exhibit 20414-X0074, Appendix A, p. 29.

[52] Exhibit 20414-X0074, p. 58.

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: *GC = Growth Capital*
SLA = Service Line Additions
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

$$RC_t = RC_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *RC=Remaining Capital: Total of Sustainment & Other Capital*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

- Treatment of overspends can be treated differently from the treatment of underspends. For example, no compensation might be offered for overspends on F factor budgets while underspends are shared 50/50.

Please discuss the Ontario Energy Board's directives in the use of benchmarking in Custom IR plans.

In its decision on a Renewed Regulatory Framework for Electricity that sanctioned Custom IR plans, the OEB explained that

> The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast....
>
> The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);
- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of distributor forecasts.

Expected inflation and productivity gains will be built into the rate adjustment over the term.[53]

Later in its decision the Board issued the following clarification.

The Board concludes that benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including: total cost benchmarking; an Ontario TFP study; and input price trend research. The Board will engage stakeholders in this effort.

The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under 4th Generation IR and the Annual IR Index, and will inform the Board's review and approval of applications under the Custom IR method. Consequently, regardless of the rate-setting plan under which a distributor's rates are set, the distributor will continue to be included in the Board's benchmarking analyses.

Benchmarking will also continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans. The publication of benchmark results will also continue to inform the public about distributor performance and facilitate comparisons among distributors.[54]

In light of your concerns about the F Factor approach, is there something to be said for sticking

---

[53] Ontario Energy Board (2012), *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* issued on October 18, 2012, p. 19-20.

[54] Ontario Energy Board (2012), *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* issued on October 18, 2012, p. 60.

with a system of I-X regulation and capital trackers?

Yes. The I-X approach to PBR is a reasonable alternative to the all-forecast approach if done correctly. It was widely used in North American telecom regulation for many years, usually without capital trackers. The I-X approach has also been used with some success for energy utilities in the United States, Canada, and New Zealand. ENMAX just completed a term of I-X PBR for its distribution services, with satisfactory results. I-X has applied to most power distributors in Ontario for many years, and capital trackers have been used sparingly there. Central Maine Power operated under I-X for nearly two decades, from 1995 to 2013, with very limited use of capital trackers. During this period the company achieved productivity growth well above that of regional peers, with noteworthy capex economies.

What are your views of the modified K factor approach?

We believe an argument can be made for strengthening capital tracker incentives by limiting in some fashion the true-up of tracker revenue to actuals. The utilities are generally proposing that there be no true-up, but other options are available.

- Variances between forecasted and actual cost can be shared in a predetermined way (e.g., 50/50).
- Treatment of overspends can be treated differently from the treatment of underspends. For example, no compensation might be offered for overspends while underspends are shared 50/50.

These approaches provide customers with some protection against exaggerated cost forecasts.

Dr. Weisman reviews the EDTI proposal in his evidence and gives it high marks. For example, he states in paragraph 104 that

> **EDTI's PBR proposal seeks to fine tune the incentive properties of the first-generation PBR. Specifically, the proposal seeks to (1) identify elements of the current PBR regime that can be improved upon by providing more high-powered incentives for**

firm efficiency; and (2) identify opportunities to improve regulatory efficiency by reducing the degree of regulatory intervention required over the PBR term.[55]

How do you respond?

We note first that this commentary displays the bias that has pervaded both Dr. Weisman's analysis for EDTI and the proposals of EDTI and the other utilities. The goal of their participation in the regulatory reform initiative is to selectively strengthen the performance incentives and improves the regulatory efficiency of a system that provides a high likelihood of capital cost recovery and denies customers a fair share of plan benefits.

What of Dr. Weisman's concluding statement in paragraph 110 that "EDTI's proposal for the second-generation PBR is fully aligned with the AUC's five PBR principles and the relevant economics literature. The proposal seeks to improve upon the first-generation PBR plan with respect to important dimensions of performance (including firm efficiency and regulatory efficiency) and therefore represents a best practices PBR regime for the 21st century"?[56]

It will take us several paragraphs to detail all the falsehoods in this statement.

- The proposal is not *fully* aligned with the AUC's five PBR principles because it puts an unusually high emphasis on the Company's cost recovery and very little emphasis on customers' share of benefits.
- The statement that the proposal is fully aligned with the relevant economics literature is also off base. He likely means by this that the regulatory literature suggests that stronger incentives and lower regulatory cost are good, and his proposal would accomplish this. But there is not an extensive (much less an applauding) literature supporting *either* the combination of I-X regulation and the peculiarly permissive cost

[55] Exhibit 20414-X0074, Appendix A, pp. 36-37.

[56] Exhibit 20414-X0074, Appendix A, p. 38.

trackers in Alberta *or* a forecast-based approach to setting revenue requirements. Further, the literature largely ignores how to equitably share the benefits of PBR between utilities and their customers.

- A proposal does not constitute "best practices" PBR simply because it makes improvements on the current system in a couple of areas. Neither is it best practices because it was, in Dr. Weisman's opinion, the best of the limited options that Dr. Weisman and Dr. Sappington considered in their white paper.

Dr. Weisman notes in paragraph 11 that "The regulatory economics literature recognizes that a primary objective of economic regulation is to emulate a competitive market standard."[57] He further notes in paragraph 13 that "the focus of PCR [price cap regulation] is placed on fostering the process of innovation and discovery."[58] Do you agree?

We of course agree with these statements as regulatory economists but note that what Dr. Weisman is endorsing in this proceeding is an approach to PBR in which capital revenue never falls below the utility's forecasted capital cost. This does not remotely resemble a competitive market standard. A plan that does not guarantee full compensation to utilities for their expected short term capital revenue shortfalls better emulates competition and is a better way to launch them on a voyage of innovation and discovery.

Dr. Weisman states in paragraph 14 that "the Commission should be willing to accept some transitory distortions in static efficiency (prices that diverge from competitive levels) in order to encourage dynamic efficiency (optimal investment in innovation over time)."[59] Your response?

---

[57] Exhibit 20414-X0074, Appendix A, p. 5.

[58] Exhibit 20414-X0074, Appendix A, p. 6.

[59] Exhibit 20414-X0074, Appendix A, p. 7.

By this he apparently means that the Commission should make sure that capital revenue equals forecasted cost and then not worry if it is *higher*. But this argument cuts both ways. Dynamic efficiency is also encouraged by exposing utilities to the risk of capital revenue shortfalls. He nonetheless endorses capital proposals that will ensure that companies will be unlikely to experience such shortfalls.

What of Dr. Weisman's statement in paragraph 85 that "this first-best approach to capital additions preserves to the greatest extent possible the high powered incentive properties of [price cap regulation] and is therefore fully aligned with AUC PBR Principle 1."[60]

The F Factor is clearly not a "first-best" approach to the problem since many alternatives potentially dominate it and many were not considered. To cite but one example, there is a well-developed approach in Britain that merits consideration. In response to a data request, Dr. Weisman indicated that he is not an expert on British PBR.[61]

Dr. Weisman states in paragraph 82 of his direct evidence that the F Factor approach "leverages familiarity with telecommunications style price-cap regulation while explicitly accounting for the unique characteristics of the energy sector."[62] Do you agree?

No. A plan in which most capital revenue is based on a forecast of capital cost is very different from telecommunications-style price caps. In the telecom sector, utilities operated under I-X mechanisms that often reflected estimates of industry productivity trends. Capital trackers were rare. Utilities did not assert an entitlement to supplemental revenue to compensate them for capex surges.

The very different flavor of telecom PBR is underlined in several of Dr. Weisman's own

[60] Exhibit 20414-X0074, Appendix A, p. 31.

[61] Weisman-CCA/PEG-034(d)

[62] Exhibit 20414-X0074, Appendix A, p. 30.

publications. For example, he states on p. 357 of an *Information Economics and Policy* paper that

> A key tenet of PCR is that the firm agrees to bear greater risk in return for the prospect of greater reward. This observation suggests that deficient earnings alone would not be sufficient to qualify the price-regulated firm for an appeal to [the US Supreme Court's] *Hope* [decision] for relief from financial distress.[63]

On p. 367 of the same paper he states that

> The basic premise underlying the discussion in this article is that PCR represents a fundamental change in the nature of the regulatory contract and a wholesale shift in risk bearing from consumers to the regulated firm.[64]

He states on p. 344 of a *Review of Industrial Organization* paper that

> For the incumbent firms, price cap regulation had significant appeal on two fronts. First, it severs the link between a firm's costs and its earnings.[65]

and on p. 352 that

> The traditional regulatory compact under which most utilities operate does not guarantee full cost recovery, but it does provide for a 'reasonable opportunity' to recover prudently-incurred costs. In the transition from ROR regulation to price cap regulation, the firm foregoes virtually all downside financial protections."[66] [footnote removed]

Sappington and Weisman state on p. 12 of a *Public Utilities Fortnightly* paper that

> Under pure PCR, the earnings of a regulated company are divorced entirely from

[63] Weisman, Dennis, "Is There *'Hope'* for Price Cap Regulation?" *Information Economics and Policy*, Vol. 14, 2002, pp. 349-370.

[64] Weisman, Dennis, "Is There *'Hope'* for Price Cap Regulation?" *Information Economics and Policy*, Vol. 14, 2002, pp. 349-370.

[65] Lehman, Dale and Weisman, Dennis, "The Political Economy of Price Cap Regulation," *Review of Industrial Organization*, Vol. 16, 2000, pp. 343-356.

[66] Lehman, Dale and Weisman, Dennis, "The Political Economy of Price Cap Regulation," *Review of Industrial Organization*, Vol. 16, 2000, 343-356.

both its realized production costs and its investment decisions. Maximum average price levels (price caps) are specified in advance and remain unaltered as the magnitude of the company's realized production costs change or its investment patterns and performance vary. In this respect, the company bears the full financial implications of its actions.[67]

Dr. Weisman states in paragraph 61 of his testimony that

At the time when PCR adoption was increasing most rapidly in the U.S. telecommunications sector, sustained or increasing productivity growth rates often were feasible for two primary reasons. First, the demand for communications services was increasing. Second, information processing costs (which are a key component of the costs of supplying switched telecommunications services) were declining. Increasing output levels and declining input costs both promote increasing productivity growth rates.[68]

He states in paragraph 69 that it is generally recognized that

Moore's Law has operated to dramatically reduce the cost of providing telecommunications services over time. Moore's Law operates to a lesser degree in electric power than it does in telecommunications. Hence, one possibility is that X factors based on historical, industry productivity growth trends understate forward-looking productivity growth in the telecommunications industry at the same time that they overstate forward-looking productivity growth in the electric power industry. This may also help to explain why PCR has been widely deployed in the telecommunications sector, but its adoption in the electricity sector has been far less ubiquitous."[69]

How do you respond?

Dr. Weisman stated in response to Weisman-CCA/PEG-001 that "Dr. Weisman is an expert on incentive regulation and regulatory economics, but does not consider himself an

[67] Sappington, David, and Weisman, Dennis, "Designing Superior Incentive Regulation," *Public Utilities Fortnightly*, Vol. 132, No. 4, February 15, 1994, 12-15.

[68] Exhibit 20414-X0074, Appendix A, p. 23.

[69] Exhibit 20414-X0074, Appendix A, pp. 25-26.

expert on empirical productivity measurement." This theory on why capital trackers weren't adopted in telecom PBR should be taken with a sizable grain of salt for this reason alone. There are many other reasons to think that the relevance of telecom experience should not be readily dismissed.

- Despite rapid productivity growth, telecom utilities were subject to financial stresses during their PBR years. Utilities were subject to high X factors or rate freezes. Kridel, Sappington, and Weisman note on p. 289 of their *Journal of Regulatory Economics* article that "it is important to recall that investment in network modernization was a frequent prerequisite for the adoption of incentive regulation at the state level."[70]   Abel (2000, pp. 66-68) concludes that:

> Under price-cap regulation, telephone prices have either fallen or remained the same, productivity has generally increased, *modern infrastructure has been deployed at a more rapid pace*, and firms have performed at least as well financially relative to the other methods of regulation available. … In addition, the evidence so far suggests that the response has been more pronounced under pure price-cap regulation compared to hybrid plans having an earnings sharing component. This result is particularly true along the productivity and *network modernization* dimensions.[71] [italics added]

This corresponds with Dr. Weisman's response to WEISMAN-CCA/PEG-025 where he stated that "In fact, Dr. Weisman's recollection is that in the immediate aftermath of implementing price cap regulation, productivity growth rates did not show dramatic improvement—likely because of the transitory 'adjustment costs' these firms would have had to bear."

[70] Kridel, Donald, Sappington, David, and Weisman, Dennis, "The Effects of Incentive Regulation in the Telecommunications Industry: A Survey," *Journal of Regulatory Economics*, Vol. 9, 1996, 269-306.

[71] Abel, Jaison, "The Performance of the State Telecommunications Industry Under Price-Cap Regulation: An Assessment of the Empirical Evidence," NRRI Report 00-14, Columbus, OH: The National Regulatory Research Institute, September 2000.

Sappington and Weisman state on p. 136 of their *Information Economics and Policy* paper that

> often, incentive regulation plans that provide long-term earnings potential for the regulated firm will foster increased investment by the firm in the short run. The investment (which may take the form of more modern operating equipment, for example) will be designed to reduce operating costs in the long run.[72]

Competition mounted, slowing demand growth, and utilities were not protected from this under the price cap system of regulation.

- The notion that productivity growth accelerated under price caps has been challenged by some experts. For example, LRCA, working for the US Telecom Association, reached a different conclusion.

> [W]e believe there is no basis for increasing the X-Factor as competition in LEC [Local Exchange Carrier] markets intensifies. In fact, the evidence indicates that the X-Factor should be reduced... Loss of demand growth to competitors could reduce measured TFP growth by 0.6% to 2.0% per year. [73]

In a later project, Christensen Associates' showed that there not a sustained jump in TFP growth for the ILECs ("Incumbent Local Exchange Carriers") during the 1990s. TFP growth from 1988 to 1998 was 3.2%, while TFP growth in the subperiods of 1988-1993 and 1993-1998 were not noticeably different.[74]

---

[72] Sappington, David and Weisman, Dennis, "Potential Pitfalls in Empirical Investigations of the Effects of Incentive Regulation Plans in the Telecommunications Industry," *Information Economics and Policy*, Vol. 8, 1996, 125-140.

[73] Meitzen-CCA/PEG-2016APR15-001, Attachment 6, p. 14-15.

[74] Meitzen-CCA/PEG-2016APR15-001, Attachment 1, Table 17.

- An X factor that is 100 basis points below actual MFP growth would not, in any event, necessarily have ensured that ILECs did not incur short term revenue shortfalls during capex surges.
- Operation under "pure PCR" gave utilities strong incentives to contain capex without declines in service.

Dr. Weisman states in paragraph 74 that "capital trackers are now commonplace in the electric power and natural gas industries. In fact, the use of capital trackers is arguably more the rule than the exception."[75] He cites a recent survey you prepared for the Edison Electric Institute to substantiate this claim. How do you respond?

Our extensive survey work on capital trackers in US utility regulation reveals that they are in use today for at least one gas or electric utility in most US jurisdictions. This is not to say that most US energy utilities operate under capital cost trackers, however. Furthermore, the conditions under which these trackers are approved are commonly quite different from those in Alberta. Multiyear rate plans are rare, and fully forecasted test years are not used in most rate cases. Notwithstanding the lack of these financial benefits, the scope of capital trackers in the US is typically much more limited than in Alberta.

What are your views about offering utilities a menu of alternative PBR approaches, like regulators do in Ontario?

Our many reservations about a building block treatment of capital cost have already been noted. Most of the larger power distributors in Ontario have opted for the Custom IR approach. This may reflect a widespread need in Ontario for catchup capex after years of operating under I-X regulation with limitations on the use trackers. However, their choices may also reflect their view that this approach is more utility-friendly.

[75] Exhibit 20414-X0074, Appendix A, p. 27.

Notwithstanding these disadvantages of an Ontario-style menu, we believe that there may be merit in permitting one utility to operate under a building block treatment of capital revenue in the next plan period to learn more about the pros and cons of this alternative system. However, this would involve large regulatory startup costs and a risk of unforeseen outcomes comparable to that which the AUC has encountered with its current system of I-X and trackers.

Are other kinds of menus worth considering?

Yes. We encouraged the Commission to consider a menu approach to PBR on p. 73 of our direct evidence.[76] One promising use of menus is to incentivize utilities to reveal, through their choice between options, their cost containment potential and to share benefits with customers. Britain's energy utility regulator Ofgem is now in its third generation of information quality incentive ("IQI") mechanisms that feature menus in PBR plans for jurisdictional utilities in Britain. This approach requires Ofgem to develop an independent view, informed by engineering and benchmarking work, of each utility's future efficient cost for up to an 8-year period. The revenue requirement for each utility is based primarily on Ofgem's cost forecasts. However, the IQI offers utilities a schedule of financial rewards that vary with the extent to which their cost forecasts are similar to Ofgem's and to the costs that they ultimately incur.

Alternative menus can be designed for use in the context of a PBR plan in which there is an I-X mechanism that reflects industry input price and productivity trends.[77] As one example, PEG has developed stylized "revenue option" approaches and considered them with our incentive power model, as discussed further in the attachment to our supplemental response to CCA-AUC-011. In the Alberta context, a company might be given the option at the end of the next PBR plan of forgoing a rebasing provided that it did not request supplemental revenue during this plan for reasons other than exogenous shocks.

[76] Exhibit 20414-X0082, p. 73.

[77] The American economists Crew and Kleindorfer wrote several articles on menus that can be used in I-X regulation.

CCA noted in response to CCA-AUC-017 (c) that "[Dr. Lowry's] thoughts on this complicated issue continue to evolve." Please provide your latest views on needed reforms in the regulatory treatment of capital in Alberta PBR.

We have outlined in our direct evidence and our responses to AUC information requests various reforms to the current PBR system in Alberta so that it can do a better job of fulfilling the Commission's five principles for PBR. These reforms can be grouped into the following categories.

1. Continue cautiously with relatively liberal use of capital trackers (trackers will continue then to be a prominent feature of regulation) but make more benefits of negative trackers available to customers in ways that don't unduly raise regulatory cost or weaken performance incentives.
    - Continue tracking capital costs of assets once tracking is initiated (as in the PBR plans for the Fortis companies in British Columbia) so that customers get the full benefit of the subsequent mechanistic depreciation on taxes and the return on rate base. If, for example, a certain portion of the annual cost of an asset qualifies for supplemental revenue during one plan term, that portion of the cost of that asset can be Y factored in future plans. To strengthen incentives, the last years of an asset's service life could be exempted from tracking.
    - Raise the X factor the higher are K factor revenues in order to increase the likelihood that customers receive the benefits of industry productivity growth in the long run. This approach would make X factors company-specific. Equivalently, let utilities borrow revenue escalation rights between plan years and plans.
2. Let utilities keep the benefits of potential "negative trackers" between rate cases. However, acknowledge this benefit and the potential for overcompensation and use it to scale back the role of trackers. In other words, make utilities self-finance a growing portion of their short-term revenue shortfalls from the benefits of I-X+G that they are sure to experience between rate cases.
    - Restrict the kinds of capex eligible for tracking.

- Raise materiality thresholds.
- Don't compensate the utility for a "dead zone" in estimated revenue shortfalls that is defined by the materiality thresholds.
- Reduce compensation for capex surges by the benefits of potential negative trackers that utilities previously received between rate cases, with appropriate interest.
- Compensate a set fraction of the short term revenue shortfalls.
- Use an historical review window for computing tracker revenue, with no compensation for the resultant regulatory lag. For example, the extra revenue in 2019 for a given class of capital could be the revenue shortfall demonstrated for 2018 using an accounting test. The Commission could thereby sidestep an advance review of the reasonableness of capex plans if it wished.
- Revise tracking procedures (e.g., accounting test and grouping rules) to avoid unnecessary tracking.
- Deny trackers for capex surges in the last year of the plan period that result from exogenous events.

3. The following miscellaneous reforms in the ratemaking treatment of capital also merit consideration.
    - Incentivize trackers by having utilities absorb some of the variances between actual and predicted capex.
    - Spend more money on independent engineering and statistical cost research so that regulators and stakeholders can develop better views on capex requirements. The extra work could be undertaken by in-house experts of the AUC or intervenors or outsourced by either party to consultants.
    - Develop improved reporting for increased transparency and ease of understanding the trackers and their financing including better minimum filing requirements for tracker applications and more relevant and detailed annual Rule 005 reporting

which accounts for PBR and trackers. We understand that this area is further discussed by CCA witness Jan Thygesen.

Please note the following about these varied reform options.

- The reform package that the Commission prefers will depend on which of its current policies it is willing to compromise on or reverse.
- Some reforms are complementary. For example, there is no reason not to combine a more incentivized ratemaking treatment of the variances between actual and forecasted capex with one of the various remedies for overcompensation.
- Different approaches can be used for different kinds of assets. Suppose, for example, that trackers providing *full* compensation for short-run revenue shortfalls for capex surges triggered by external events such as storms, floods, or forest fires are "here to stay" using a K factor (or Z factor), even though I-X usually provides an adequate budget for such events over many years. Then costs of such assets that are approved for tracker treatment can be subject to ongoing Y factor treatment in future plans even as distributors are permitted to keep revenue surpluses for other asset classes but supplemental revenue for capex surges in these classes is greatly restricted.
- If utilities are allowed to keep capital revenue surpluses between rate cases, the rationale for restricting recourse to trackers *increases* over time because utilities will have accumulated more years of benefits. These "up-front payments" loom especially large given the time value of money. Trackers for assets with short replacement cycles could be eliminated as early as the next plan period.
- Several of the reforms I have mentioned address several problems simultaneously. For example, an historical review window reduces regulatory cost and strengthens performance incentives, in addition to reducing overcompensation for short-term revenue shortfalls. In contrast, a higher X to reflect outsized opportunities for scale economies gives more benefits of PBR to customers at negligible regulatory cost but doesn't make headway on the other problems.

- It is difficult to base changes in the ratemaking treatment of capital on a detailed quantitative exercise without being drawn into the chore of appraising specific capex programs. Rough judgments of pros and cons of reforms may ultimately be required by the Commission to arrive at a suitable reform package.
- There are solid grounds for instituting some capital tracker reforms BEFORE the end of the term of the current PBR plans.
    - Serious problems have been identified.
    - The reforms we have discussed generally will NOT weaken performance incentives or claw back the benefits of performance gains already achieved. Indeed, if they are implemented now rather than later they are less likely to be interpreted by utilities as part of a clawback strategy.

What is your current thinking about the best reform package?

We have tried to equip the AUC with a large menu of potential reforms that gives the Commission some flexibility depending on which of its current policies it is willing to change. Here is our current thinking on a package of reforms for next generation PBR.

- Given the many problems capital trackers have given rise to, we are drawn to remedies that scale back the role of trackers. These remedies generally reduce overcompensation and have additional advantages.
    - An historical review window strengthens performance incentives and can reduce regulatory cost considerably insofar as the regulator can sidestep approval of capex forecasts. However, this approach will typically not by itself reduce the scope of capex eligible for filing.
    - Tracking only a set fraction of capital revenue shortfalls that exceeds the materiality threshold strengthens performance incentives but does not reduce regulatory cost. The scope of capex eligible for tracker treatment will not change.
    - Raising materiality thresholds and excluding certain kinds of capex from

eligibility for tracking are both remedies that strengthen performance incentives and can materially reduce regulatory cost by reducing the scope of capex eligible for tracking.

This approach will expose the utilities to greater risk but also encourage discovery and innovation.

- Tracking of capex surges required by external events can continue. This could in principle be addressed through Z factors rather than the K factor. In either event, overcompensation can be reduced and incentives strengthened by such means as selectively passing the benefits of depreciation of these projects through to customers via Y factors.
- To give the utilities more flexibility, they may be permitted to "borrow" allowed revenue escalation from other years and other plans.
- More money should be spent on independent engineering and statistical cost research expertise so that regulators and stakeholders can develop better views on capex requirements.
- Reporting and filing requirements should be improved.
- Remaining trackers should be further incentivized by limiting the true up of tracker revenue to actuals.
- If the AUC agrees to base X on Dr. Lowry's productivity research, accounting tests can use a somewhat lower X factor that reflects the slower productivity growth trend of capital rather than the multifactor productivity trend. This would slightly reduce the scope of capex eligible for tracking with resultant improvements in incentives and regulatory cost.

Several utilities have proposed a continuation of the current materiality thresholds. Why do you believe that they should be raised?

Higher materiality thresholds strengthen capex containment incentives at the same time that they address overcompensation for short-term revenue shortfalls and reduce regulatory costs. With higher thresholds on *individual* projects, utilities will recognize that they are "on their own" between rate cases when it comes to many smaller projects. A higher *aggregate* threshold will meanwhile signal to the utility that it can hope for supplemental revenue only in years when a capex surge is unusually large. Of course, higher materiality thresholds also strengthen utility incentives to bunch capex and to artfully combine capex categories so that they clear thresholds. Regulatory vigilance would be needed to prevent this outcome.

Are materiality thresholds higher in other jurisdictions?

Yes. Our research suggests that materiality thresholds in Ontario are substantially higher. One problem with the Alberta approach is that the mid-term convention for valuing plant makes it possible for utilities to qualify for tracker treatment in the latter years of a PBR plan just because they made large plant additions in the first year of the PBR plan or in the year prior to the plan's start. Even if the mid-term convention were suspended, however, we believe that materiality thresholds in Ontario would still be considerably higher.

What are your thoughts concerning a change in the kinds of capex that are eligible for tracker treatment?

In Decision 2012-237, Criterion 2 for capital tracker eligibility was that "ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party".[78] It further explained that

> the second criterion generally limits the scope of eligible capital projects to those required for replacement of aging infrastructure that has come to the end of its useful life and those that are required by third parties, such as projects ordered by government agencies. It excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources

[78] Decision 2012-237, paragraph 592, p. 126.

of revenue that offsets the cost of new capital. The new sources of revenue can come in the form of increased customers and load growth and also through contributions in aid of construction.[79]

We strongly encourage the Commission to return to this sensible approach and to make required echo effect capex surges one of few that are eligible for tracker treatment. In the alternative, the Commission should at least search for reasonable ways to narrow the kinds of capex eligible for tracker treatment. Growth-related capex is certainly one category that should be considered for exclusion. In addition to all of the reasons for exclusion of this category that the Commission has already acknowledged, we note the following.

- It is sometimes rational to "prebuild" growth related capex. It might, for example, be more cost effective to build a substation that temporarily exceeds the needs of a growing suburban area than to add to the substation's capacity at a later date. It should be noted, however, that if the growth actually materializes productivity growth should thereafter surge. The utility may capture the lion's share of the benefit under the current system.
- The slowdown in Alberta economic growth should reduce the need for prebuilds of growth-related projects for some time to come.
- Brisk system growth that might occasion growth-related capex also gives rise to outsized scale economies.
- In an accounting test for growth-related capex, it is reasonable to ascribe to these assets ALL of the revenue that results from growth in billing determinants (or, in the case of revenue caps, from customers).

Other capex categories can also be reasonably considered for tracker ineligibility. For example, assets with short replacement cycles (e.g., tools, vehicles, and software) may be

[79] Decision 2012-237, paragraph 595, p. 127.

excluded because they are more easily self-funded by the surplus revenue that I-X produces between rate cases.

When considering the exclusion of asset categories, it must be remembered that only so many remedies for overcompensation of short-term revenue shortfalls can be implemented simultaneously. For example, if growth-related assets are not eligible for tracking, this weakens the argument for using the full I-X+G formula in accounting tests for assets that are eligible.

Are there precedents for limiting the scope of capex eligible for tracking in PBR plans?

Yes. We have already noted that eligibility for capital trackers in the United States is generally quite limited. Many PBR plans have not Y factored any kind of capex. However, capex due to exogenous events is usually addressed by Z factor provisions.

4. Efficiency Carryover Mechanism

The utilities and their witnesses generally favor a continuation of the current efficiency carryover mechanism. How do you respond?

The rationale for ECMs is to counteract some of the adverse incentives that result under PBR plans from a periodic rebasing of revenue to cost. The following adverse incentives are notable.

- Due to the compression of the payback period, utilities have less incentive in the later years of a plan to incur the upfront costs that may be needed to achieve long term performance gains.
- There is also less incentive for utilities to contain cost in a historical reference year that provides the foundation for the forward test year. For example, there would be less incentive to strike a hard bargain with labor unions and other input vendors.
- Utilities are incentivized to defer certain expenditures in the later years of a PBR plan and then ask for supplemental revenue to finance them in subsequent plans. In the absence of an earnings sharing mechanism, customers may then "pay twice" for some of the

same costs. Dr. Weisman agrees with this rationale for ECMs in his response to Weisman-CCA/PEG-013.

To counteract such incentives, ECMs can reward utilities for offering customers good value in later PBR plans, and can penalize them for offering customers poor value. I discussed in my direct testimony ECMs that involve a comparison of the revenue requirement ("RR") (or underlying cost) in the next plan period to some kind of a benchmark. The ECM could take the form of a targeted incentive mechanism. The revenue requirement in the forward test year could, for example, correspond to the following formula.

$$RR_{t+1} = Cost_{t+1} + \alpha(Benchmark_{j,\, t+} \text{-}\ Cost_{j,\, t+1})$$

where α is a share of the value implied by benchmarking. Note that the formula allows for the possibility that only a subset *j* of the total cost is benchmarked. This could be the subset that is easier to benchmark. The variance between the cost benchmark and actual cost can alternatively be used to adjust the X factor. This would typically take the form of a stretch factor adjustment.

This kind of ECM clearly strengthens the utility's incentive to contain the cost of service in the forward test year. Moreover, by making the *test* year the focus of the appraisal rather than the years of the prior plan period, this ECM also guards against strategic deferrals and promotes a fair share of plan benefits for customers.

The choice of a benchmark is an important consideration in the design of this kind of ECM. We discussed two methods for calculating a benchmark in our direct evidence. One was to escalate the cost established in the last forward test year by a suitable escalation index. This could be the I-X+G formula used in the prior plan.

Many variations on this theme are possible. For example, instead of benchmarking *cost*, the *productivity* growth that is implicit in the test year cost since the level approved in the last rate case can be compared to the productivity growth of the peer group. This guards against any failure of the inflation measure in the I-X+G mechanism to accurately track input price inflation.

Cost (or the revenue requirement) may, alternatively, be compared to a benchmark based on statistical cost research that is completely independent of the Company's cost. We have noted that statistical benchmarking is used by the Ontario Energy Board to update stretch factors annually. Benchmarking is also used extensively in PBR by the Australian Energy Regulator and by Ofgem in Britain. Benchmarking studies have occasionally been filed by US utilities in support of stretch factors or forward test year cost proposals. Public Service of Colorado, for example, has filed benchmarking studies of its forward test year proposals for the cost of its gas utility and its vertically integrated electric utility.

Please note the following with respect to both of these options.

- The ECM should ideally apply to *total* cost, including capital cost that has been tracked. The O&M expenses of Alberta energy distributors are fairly inconsequential because they provide few customer services. However, the Commission may wish to apply such an ECM only to O&M expenses. In that event, it may be desirable to base any benchmark index on the *O&M* productivity trend of the peer group if this differs from the multifactor productivity trend.
- When costs of deferred capex can be recovered through a tracker, the utility may be incentivized to request recovery of deferred capex after the rebasing. This is an argument for not basing the ECM on cost in the previous plan. Strategic deferrals have complicated the administration of ECMs in Australia.
- Both of these options have been considered in our incentive power research. This research is discussed in considerable detail in the attachment to our supplemental response to CCA-AUC-011. Assuming an *historical* test year, PEG examined the revenue requirement at the start of a new plan that is based $\alpha\%$ on the actual cost in the last year of the previous plan and $(1-\alpha)\%$ on the revenue requirement in that year. This effectively permits the company to share $(1-\alpha)\%$ of any deviation between its cost and the revenue requirement. We also considered a plan in which revenue at the start of the next plan period is based partly on an external benchmark. The greater incentive power of this alternative results from the fact the benchmark is completely external.

Thus, the utility will not consider that lower cost in the upcoming test year will produce a tougher benchmark in future plan updates.

Does this conclude your testimony?

Yes it does.

MRI Design for

Hydro-Québec Distribution

Mark Newton Lowry, PhD

President

Matt Makos

Consultant

5 January 2018

Errata 11 January 2018

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin, Suite 601

Madison, Wisconsin USA 53703

608.257.1522 608.257.1540 Fax

Table of Contents

1. Introduction

The Régie de l'Energie ("Régie") has been engaged for several years in a proceeding (R-3897-2014) to develop *méchanismes de reglementation incitative* ("MRIs") for transmission and distribution services of Hydro-Québec. In April 2017, the Régie's Decision D-2017-043 established some key provisions of the first MRI for Hydro-Québec Distribution ("HQD" or "the Company"). The MRI will take the form of a multiyear rate plan with a revenue cap (*plafonnement des revenus*). Growth in HQD's revenue requirement (*revenu requis*) will be escalated each year by a revenue cap index similar to that which the Régie currently uses in rate cases (*dossiers tarifaires*) to limit growth in the *revenu requis* for operation and maintenance expenses (*charges d'exploitation*). The index formula (*formule d'indexation*) includes a *facteur d'inflation* (measured inflation), a *facteur de productivité* (*X*), a *dividende client* ("stretch factor" or s), and 0.75 x growth in the number of HQD's *abonnements* (customer accounts).

The X factor in the revenue cap escalation formula is a key issue in the proceeding. It will be decided by the Régie without the benefit of new, custom productivity studies. Instead,

> **La Régie retient la méthode basée sur le jugement préconisée par le Distributeur pour déterminer la valeur du Facteur X à inclure dans la Formule d'indexation. À cette fin, le Distributeur devra mettre à la disposition des intervenants les études, analyses et rapports susceptibles d'éclairer la Régie quant à la détermination du Facteur X en phase 3.[1]**

The Régie, paraphrasing remarks by HQD, explained what it meant by a process of *jugement.*

> **Le jugement exercé par la Régie serait basé sur l'étude des valeurs du Facteur X utilisées dans d'autres juridictions, de même que sur l'analyse des gains d'efficience réalisés par le Distributeur à ce jour et du potentiel de réalisation de gains d'efficience supplémentaires dans les années à venir.[2]**

Resolution this and of some other MRI implementation details will occur in Phase III of this proceeding.

---

[1] Régie de l'Energie, D-2017-043, R-3897-2014 Phase 1, April 2017, p. 43.

[2] Ibid., p. 37.

HQD submitted the requested X factor evidence in June 30 2017.[3] The Company discussed its own cost performance and submitted commentary on productivity evidence and X factor decisions in North American regulation from its consultant, Concentric Energy Advisors ("CEA").[4] HQD may file further X factor evidence on this topic during the Phase 3 proceeding.

> Dans le cadre de la phase 3B de l'établissement de son MRI, le Distributeur procédera à la mise à jour des études, analyses et rapports existants, le cas échéant, et présentera son positionnement quant à la détermination du Facteur X à utiliser pour son MRI.[5]

The Company filed a *dossier tarifaire* for an increase in rates for the 2018-19 tariff year on 31 July 2017.[6] This filing included a section on Phase 3 MRI issues. Only the Y and Z factor issues were discussed at length. HQD may provide further evidence on unresolved MRI design issues in January 2018.

Pacific Economics Group Research LLC has for many years been the leading North American consultancy on MRIs for gas and electric utilities. Work for a diverse client mix that includes regulators, utilities, and consumer groups has given our practice a reputation for objectivity and dedication to good regulation. In Canada, we have played a prominent role in MRI proceedings in Alberta, British Columbia, and Ontario, as well as in Québec. Research and testimony on productivity trends of power distributors and other energy utilities is a company specialty. AQCIE-CIFQ has retained us and the Régie has authorized us to provide Phase 3 comments on the appropriate X factor and other unresolved provisions of the MRI of HQD.

Section 2 of our report provides a brief review of the Régie's Phase 1 decision. There follows in Section 3 a discussion of principles and methods for selecting the X factor and stretch factor.[7] Section 4

---

[3] HQD, *Etudes, Analyses et Rapports pour la Determination du Facteur X Deposes dans le Cadre de l'Etablissement du Mechanisme de Reglementation Incitative du Distributeur.* June 2017.

[4] CEA, *Performance-Based Regulation: Productivity Factor for HQD*, 30 June 2017.

[5] HQD, op. cit., p. 12.

[6] HQD, *Implantation d'un Mechanisme de Reglementation Incitative* (MRI) – *Phase 3*, 31 July 2017.

[7] This discussion reorganizes and elaborates on material presented in Section 4 of our report in Phase 1 of this proceeding.

of this report adds to CEA's evidence by providing an independent review of energy utility productivity studies and commission decisions in MRI proceedings. We hope that this review can help the Régie make informed decisions on X and s. Our recommendations concerning the inflation measure, X factor, and stretch factor for HQD follow in Section 5. Section 6 discusses other plan design issues.

2. Background

The Régie made the following additional decisions concerning the design of the MRI for HQD in D-2017-043.

- The basic form of the MRI is a multiyear rate plan. The plan will begin in April 2018 and have a four-year term.
- The initial *revenu requis* will be established in a *dossier tarifaire* that is currently under way.
- The *revenu requis* for most of the cost of HQD's base rate inputs will then be escalated for three years by a revenue cap index. Costs addressed by the index will include *charges d'exploitation* that the Company can control, including fuel expenses (*couts de combustible*) administrative and general expenses (*frais corporatifs*), amortization and depreciation expenses (*amortissement*), the return on rate base (*rendement sur la base de tarification*), and taxes.
- Costs of the Company's autonomous networks will be an integral part of the MRI.
- A study of *productivité multifactorielle* ("PMF") [multifactor productivity] will be undertaken, after the MRI begins, for possible application in the last year of the plan. With respect to this study, "la Régie demande au Distributeur de présenter en phase 3, la méthodologie et l'échéancier rattachés a la realisation d'une etude PMF."[8] Appropriate methods for measuring productivity are thus a key issue in this proceeding.
- The plan will not include revenue decoupling. However, *nivellements pour les aléas climatiques* (weather normalization of revenue) will continue.

[8] Régie, op. cit., p. 44

- A *clause de sortie* ("off ramp" mechanism) will be included.
- There will be no formal *clause de* succession (plan termination provisions). Instead,

  > **La Régie se prononcera au moment opportun, après consultation des participants, quant à la forme du recalibrage, la date et les modalités d'un retour éventuel au coût de service, qu'il soit complet ou partiel.[9]**

- A *méchanisme de traitement des ecarts de rendement* ("MTER", or earning sharing mechanism) will be included.[10] This will likely be the same as that currently used.
- There will be no *méchanisme de report des gains d'efficience* (efficiency carryover mechanism) in this plan.[11]
- No additional marketing flexibility will be granted to HQD.
- Metrics for reliability, customer service quality, and safety will be established and linked to the MTER. HQD should develop during the first-generation MRI a metric addressing short-term energy and demand purchases and underutilization of the patrimonial block of power.

The Régie's decision left for Phase 3 the final resolution of the following MRI provisions:

- Inflation measure formula
- X Factor
- Stretch Factor
- Final list of costs eligible for Y factor and Z factor treatment
- Method for Y factoring the rate of return on capital
- Materiality thresholds for Y and Z
- Specific safety, reliability, and customer service metrics

Determination of some additional details of the MRI will be delayed until the fall of 2018.

---

[9] Ibid., p. 103.

[10] Ibid., p. 106.

[11] Ibid., p. 109.

3. Methods and Principles for Revenue Cap Index Design

In this section of the report we discuss methods and principles for the design of revenue cap indexes. We begin by discussing basic indexing concepts. There follow discussions of the use of indexing research in MRI design, capital cost specifications, Kahn X factors, other methodological issues, and the choice of a stretch factor.

3.1 Basic Indexing Concepts

The logic of economic indexes provides the rationale for using price and productivity research to design attrition relief mechanisms. To review this logic, it may be helpful to make sure that the reader has a high-level understanding of basic tools of index research.

Input Price and Quantity Indexes

The growth (rate) of a company's cost can be shown to be the sum of the growth of an input (*intrant*) price index ("Input Prices") and input quantity index ("Inputs").

growth Cost = growth Input Prices + growth Inputs.[12] [1]

These indexes are typically multidimensional in the sense that they summarize trends in subindexes that are appropriate for particular subsets of cost. This is accomplished by taking a cost-share weighted average of the subindex growth. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by electric power distributors. The technology for providing distributor services is capital intensive, so the heaviest weights in these indexes are placed on the capital subindexes.

Calculation of input quantity indexes is complicated by the fact that firms typically use numerous inputs in service provision. This complication is contained when summary input price indexes are readily available for a group of inputs such as labor. Rearranging the terms of [1] we can calculate input quantity growth using the formula

---

[12] Cost-weighted input price and quantity indexes are attributable to the French economist Francois Divisia.

$$\text{growth Inputs} = \text{growth Cost} - \text{growth Input Prices}. \quad [2]$$

This residual approach to input quantity growth calculation is widely used in productivity research. One can, for example, calculate growth in the quantity of labor by taking the difference between salary and wage expenses and a salary and wage price index.

Productivity Indexes

The Basic Idea A productivity index is the ratio of a scale (aka "output") index ("Scale") to an input quantity index.

$$\text{Productivity} = \frac{\text{Scale}}{\text{Inputs}}. \quad [3]$$

It can be used to measure the efficiency with which firms use inputs to achieve their scale of operation.

Some productivity indexes are designed to measure productivity *trends*. The growth of such a productivity index is the *difference* between the growth in the scale and input quantity indexes.

$$\text{growth Productivity} = \text{growth Scale} - \text{growth Inputs}. \quad [4]$$

Productivity grows when the scale index rises more rapidly (or falls less rapidly) than the input index. The productivity growth of utilities can be volatile but has historically tended to grow over time. The volatility is typically due to demand-driven fluctuations in operating scale and/or the uneven timing of certain expenditures. The volatility of productivity growth tends to be much greater for individual companies than the average for a group of companies.

Relations [1] and [4] imply that

$$\text{growth Productivity} = \text{growth Scale} - (\text{growth Cost} - \text{growth Input Prices})$$

$$= \text{growth Input Prices} - \text{growth (Cost/Scale)}$$

Productivity growth is thus the amount by which a firm's unit cost grows more slowly than its input prices.

Some indexes are designed to measure only productivity *trends*. "Bilateral" productivity indexes are designed to compare only productivity *levels*. For example, the productivity level of HQD in 2016 can be compared to the average for U.S. power distributors in the same year. "Multilateral" productivity indexes are designed to measure *both* trends and levels.

The scope of a productivity index depends on the array of inputs which are considered in the input quantity index. Some indexes measure productivity in the use of a single input group such as labor. A *multifactor* productivity index measures productivity in the use of multiple inputs. PMF indexes are sometimes called *total* factor productivity indexes, a term that is usually a misnomer since in practice some inputs are excluded from the index calculations.

Scale Indexes A scale index of a firm or industry summarizes trends in the scale of operation. These indexes may also be multidimensional. Growth in each dimension of scale that is itemized is then measured by a subindex. The scale index then summarizes growth in the subindexes by taking a weighted average of them.

In designing a scale index, choices concerning scale variables (and weights, if the index is multidimensional) should depend on the manner in which the index is used. One possible objective is to measure the impact of growth in scale on *revenue*. In that event, the scale variables should measure growth in *billing determinants* and the weight for each itemized class of determinants should be its share of a utility's base rate revenue.[13] In this report we denote by $Scale^R$ a scale index that is "revenue-based" in the sense that it is designed to measure the impact of growth in scale on revenue. A productivity index that is calculated using $Scale^R$ will be denoted as $Productivity^R$.

$$\text{growth Productivity}^R = \text{growth Scale}^R - \text{growth Inputs.} \qquad [5a]$$

Another possible objective of scale indexing is to measure growth in dimensions of scale that affect *cost.* In that event, the scale variable(s) should measure dimensions of the "workload" that drive cost.[14] A multidimensional scale index with elasticity weights is unnecessary if econometric research reveals that there is one dominant cost driver. A productivity index calculated using a cost-based scale index (which may be unidimensional) will be denoted as $Productivity^C$.

---

[13] Revenue-weighted scale indexes are attributable to the French economist Francois Divisia.

[14] If there is more than one scale variable in the index, the weights for each variable should reflect its relative cost impact. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities of utilities can be estimated econometrically using data on the costs and operating scale of a group of utilities.

$$\textit{growth Productivity}^{C} = \textit{growth Scale}^{C} - \textit{growth Inputs}. \qquad [5b]$$

This may fairly be described as a "cost efficiency index."

In measuring the productivity growth of U.S. energy distributors the choice of a scale index can have a major effect on results. To understand why, consider first that under legacy rate designs, the volume of deliveries to residential and commercial ("R&C") customers is the major driver of distributor revenue. Meanwhile, econometric research has repeatedly shown that the number of customers served is by far the most important scale-related driver of energy distributor cost. Customer growth affects cost directly, and is highly correlated with the growth of other demand drivers such as peak load. The difference between the growth trends of revenue- and cost-based scale indexes thus depends on the trend in R&C average use.

A second reason why the scale index matters is that growth in the R&C average use of electric utilities has slowed substantially in recent years due to sluggish economic growth and growth in energy efficiency programs. Table 1 is drawn from a recent white paper on multiyear rate plans which PEG prepared for Lawrence Berkeley National Laboratory, a unit of the U.S. Department of Energy.[15] The table shows that growth in average use of power by R&C customers of U.S. electric utilities was in the neighborhood of 1.5% annually over the 1973-2000 period but is now negative.

A third reason why choice of a scale index matters is that the growth of power delivery volumes is much more volatile than customer growth. This makes results using delivery volumes much more sensitive to the choice of a sample period.

[15] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

Table 1

Average Use Trends of U.S. Electric Utilities

	Residential[1]		Commercial[1]		Average
	Level	Growth Rate	Level	Growth Rate	Growth Rate
Multiyear Averages					
1927-1930	478	7.06%	3,659	6.67%	6.86%
1931-1940	723	5.45%	4,048	2.00%	3.73%
1941-1950	1,304	6.48%	6,485	5.08%	5.78%
1951-1960	2,836	7.53%	12,062	6.29%	6.91%
1961-1972	5,603	5.79%	31,230	8.79%	7.29%
1973-1980	8,394	2.03%	50,576	2.53%	2.28%
1981-1986	8,820	0.12%	54,144	0.81%	0.46%
1987-1990	9,424	1.39%	60,211	2.29%	1.84%
1991-2000	10,061	1.15%	67,006	1.68%	1.41%
2001-2007	10,941	0.73%	74,224	0.64%	0.68%
2008-2014	11,059	-0.38%	75,311	-0.22%	-0.30%

[1] U.S. Department of Energy, Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," Form EIA-826, "Monthly Electric Utility Sales and Revenues Report with State Distributions," and EIA-0035, "Monthly Energy Review."

3.2 Use of Index Research in MRI Design

Productivity studies have many uses, and the best methodology for one use may not be best for another. One use of productivity research is to measure the trend in a utility's operating efficiency. Another is to calibrate the X factor in a rate-cap or revenue-cap index. A method that is best for measuring efficiency may not be the best for X factor calibration. In this section, we consider the rationale for using productivity research in rate and revenue cap index design.

Price Cap Indexes

An early use of index research in regulation was to design *price* cap indexes. We begin our explanation of the supportive index logic by considering the growth in the prices charged by an industry that earns, in the long run, a competitive rate of return.[16] In such an industry, the long-run trend in revenue equals the long-run trend in cost.

$$\text{trend Revenue} = \text{trend Cost}. \qquad [6]$$

The growth in the revenue of any firm or industry can be shown to be the sum of the growth in revenue-weighted indexes of its output prices ("*Output Prices^R*") and billing determinants ("*Scale^R*").

$$\text{growth Revenue} = \text{growth Scale}^R + \text{growth Output Prices}^R. \qquad [7]$$

Recollecting from [1] that cost growth is the sum of the growth in cost-weighted input price and quantity indexes, it follows that the trend in output prices which permits revenue to track cost in the longer run is the difference between the trends in an input price index and a multifactor productivity index constructed with a revenue-weighted scale index.

$$\begin{aligned}\text{trend Output Prices}^R &= \text{trend Input Prices} - (\text{trend Scale}^R - \text{trend Inputs}) \\ &= \text{trend Input Prices} - \text{trend PMF}^R. \qquad [8]\end{aligned}$$

This result provides a conceptual framework for the design of price cap indexes of general form

$$\text{trend Rates} = \text{trend Input Prices} - X. \qquad [9a]$$

where

$$X = \overline{PMF^R} + S \qquad [9b]$$

Here X, the "X factor", is calibrated to reflect a base PMF^R growth target ("$\overline{PMF^R}$"). This has been commonly established by calculating the PMF^R trend of a group of utilities. A stretch factor ("S"),

[16] The assumption of a competitive rate of return applies to unregulated, competitively structured markets. It is also applicable to utility industries and even to individual utilities.

established in advance of plan operation, is often added to the formula which, if positive, benefits customers.

Notice that a *revenue*-based scale index is appropriate for the supportive productivity research for price caps. This helps to explain why some productivity indexes used in X factor calibration over the years featured a *volumetric* scale index.

Revenue Cap Indexes

General Result Index logic also supports the design of *revenue* cap indexes. Consider first the following basic result of cost theory:

$$\text{growth Cost} = \text{growth Input Prices} - \text{growth Productivity}^{C} + \text{growth Scale}^{C}. \qquad [10a]$$

The growth in the cost of a company is the difference between the growth in input price and cost efficiency indexes plus the trend in a consistent cost-based scale index. This result provides the basis for a revenue cap escalator of general form

$$\text{growth Revenue} = \text{growth Input Prices} - X + \text{growth Scale}^{C} \qquad [10b]$$

where

$$X = \overline{\text{PMF}^{C}} + \text{S}. \qquad [10c]$$

Notice that a *cost*-based scale index should be used in the supportive productivity research for a *revenue* cap X factor.

Application to Energy Distributors For gas and electric power distributors, the number of customers served was noted above to be a sensible scale variable when calculating PMF^{C}. For an energy distributor, $Outputs^{C}$ can thus be reasonably approximated by growth in the number of customers served and there is no need for the complication of a multidimensional output index with cost elasticity weights. It is then approximately true that

$$\begin{aligned}&\text{growth Cost}\\&\quad = \text{growth Input Prices} - (\text{growth Customers} - \text{growth Inputs}) + \text{growth Customers}\\&\quad = \text{growth Input Prices} - \text{growth PMF}^{N} + \text{growth Customers}\end{aligned}$$

where PMF^N is an PMF index that uses the number of customers to measure output.

This result provides the rationale for the revenue cap index formula

growth Revenue = growth Input Prices – X + growth Customers [11a]

where

$X = \overline{PMF^N} + \text{Stretch}.$ [11b]

An equivalent formula is

trend Revenue – trend Customers

= trend (Revenue/Customer) = trend Input Prices – X. [11c]

This is sometimes called a "revenue per customer" index, and we will for convenience use this expression below to refer to revenue cap indexes which conform to either [11a or 11c].

Revenue caps using formulas like [11a] and [11c] are currently used in the MRIs of ATCO Gas and AltaGas in Canada. The Régie de l'Energie in Québec has directed Gaz Métro to develop a plan featuring a revenue per customer index. Revenue cap indexes like these were previously used by Southern California Gas and Enbridge Gas Distribution ("EGD"), the largest gas distributors in the U.S. and Canada, respectively.

Consider, finally, that whether or not the PMF^N is a fully satisfactory approximation for PMF^C, when a revenue per customer index is chosen to regulate a utility the following result must hold if revenue is to track cost.

trend Revenue = growth Input Prices - X + growth Customers

= growth Cost

= growth Input Prices + growth Inputs.

The X factor that causes revenue to track cost must then use the number of customers as the output index.

X = trend Customers - trend Inputs.

This means that the decline in R&C use per customer that has occurred in the United States since 2000 is irrelevant in the calculation of the revenue cap index.

Inflation Measure Issues

Our discussion has thus far assumed that any rate or revenue cap index under consideration would use an *input price* index as the inflation measure. Suppose, however, that a *macroeconomic* price index is instead used as the inflation measure. This has been common practice in approved U.S. MRIs. The gross domestic product price index ("GDPPI") has been commonly used for this purpose. This the U.S. government's featured measure of inflation in prices of the economy's final goods and services. Final goods and services consist chiefly of consumer products but also include capital equipment and exports.

When a macroeconomic inflation measure is used in a rate or revenue cap index, the X factor must be calibrated in a special way if it is to reflect industry cost trends. Suppose, for example, that the inflation measure is the GDPPI. In that event we can restate the revenue per customer index in [11c], for example, as

$$\text{growth Revenue/Customer}$$
$$= \text{growth GDPPI} - [\text{trend PMF}^{\text{Industry}} + (\text{trend GDPPI} - \text{trend Input Prices}^{\text{Industry}}) + \text{Stretch}] \qquad [12]$$

It follows that a revenue cap index that features GDPPI as the inflation measure can still conform to index logic provided that the X factor effectively corrects for any tendency of GDPPI growth to differ from industry input price growth in addition to reflecting the industry PMF^{N} trend. The term in parentheses in relation [12] is sometimes called the "inflation differential."

Consider now that the GDPPI is a measure of *output* price inflation. Due to the broadly competitive structure of the U.S. economy, we can use relation [8] to reason that the long-run trend in the GDPPI is the difference between the trends in input price and PMF indexes for the economy.

$$\text{trend GDPPI} = \text{trend Input Prices}^{\text{Economy}} - \text{trend PMF}^{\text{Economy}} \qquad [13]$$

Relations [12] and [13] can be combined to produce the following formula for a revenue cap index:

$$\text{growth Revenue/Customer}$$
$$= \text{growth GDPPI} - [(\text{trend PMF}^{\text{Industry}} - \text{trend PMF}^{\text{Economy}})$$
$$+ (\text{trend Input Prices}^{\text{Economy}} - \text{trend Input Prices}^{\text{Industry}}) + \text{Stretch}] \qquad [14]$$

This formula suggests that when the GDPPI is the inflation measure, the revenue cap index can be calibrated to track industry cost trends when the X factor has two calibration terms: a "productivity differential" and an "input price differential". The productivity differential is the difference between the PMF trends of the industry and the economy. X will be larger, slowing revenue growth, to the extent that the industry PMF trend exceeds the economy-wide PMF trend.

The trend in the GDPPI reflects the PMF trend of the economy provided that the input price trends of the industry and the economy are fairly similar. The growth trend of the GDPPI is then slower than that of the industry-specific input price index by the trend in the economy's PMF growth. In an economy with rapid PMF growth this difference can be substantial. X factor calibration is warranted only to the extent that the input price and productivity trends of the utility industry differ from those of the economy.

PMF trends of the U.S. and Canadian economies are detailed in Table 2. It can be seen that the PMF trend of the U.S. economy was fairly brisk, averaging 1.06% annual growth annually from 1998-2015. A sizable adjustment to the X factor is thus warranted in a U.S. *formule d'indexation* when the GDPPI is used as the inflation measure. The PMF trends of the Canadian and Québec economies have, meanwhile, been much closer to zero.[17] This reality complicates comparisons of X factors in the United States and Canada. It is more useful in the contemplated process of *jugement* to compare U.S. and Canadian commission rulings on industry productivity trends and stretch factors than it is to compare X factors.

The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.[18] In American MRI proceedings, regulators have typically ruled that the input price differential is small (e.g., twenty basis points) or zero.

[17] PMF trends in the two countries have been closer in recent years.

[18] The input price trends of a utility industry and the economy can differ for several reasons. One possibility is that prices in the industry grow at different rates than prices for the same inputs in the economy as a whole. For example, labor prices may grow more rapidly to the extent that utility workers have health care benefits that are better than the norm. Another possibility is that the prices of certain inputs grow at a different rate in some regions than they do on average throughout the economy. It is also noteworthy that the energy distribution industry has a different and more capital-intensive mix of inputs than the economy.

Table 2
PMF Trends of U.S. and Canadian Economies

	United States[1]		Canada[2]		Québec[3]	
	Level	**Growth Rate**	**Level**	**Growth Rate**	**Level**	**Growth Rate**
1997	100		100		100	
1998	101	1.42%	101	0.63%	100	0.28%
1999	103	1.86%	103	2.35%	103	3.00%
2000	105	1.70%	105	2.10%	105	1.79%
2001	106	0.54%	105	0.06%	105	0.16%
2002	108	2.16%	107	1.28%	105	-0.53%
2003	111	2.48%	106	-0.74%	105	0.22%
2004	114	2.61%	106	-0.32%	105	-0.26%
2005	115	1.52%	106	0.04%	104	-0.55%
2006	116	0.40%	105	-0.82%	104	0.24%
2007	116	0.41%	103	-1.15%	104	-0.39%
2008	115	-1.18%	101	-2.33%	103	-1.25%
2009	115	-0.23%	99	-2.60%	102	-0.29%
2010	118	2.85%	100	1.77%	102	-0.17%
2011	118	0.20%	102	1.48%	103	0.98%
2012	119	0.64%	101	-0.61%	103	-0.21%
2013	120	0.52%	102	0.90%	103	-0.29%
2014	120	0.61%	103	1.33%	104	1.04%
2015	121	0.54%	102	-1.00%	104	-0.23%
2016	121	-0.07%	NA	NA	NA	NA
Average Growth Rates:						
1998-2015		**1.06%**		**0.13%**		**0.20%**
2001-2015		**0.94%**		**-0.18%**		**-0.10%**
2006-2015		**0.48%**		**-0.30%**		**-0.06%**

[1] Bureau of Labor Statistics, MFP for Private Business Sector (NAICS 11-81), Series MPU4900012.
[2] Statistics Canada, MFP for Aggregate Business Sector: Canada, Table 383-0021.
[3] Statistics Canada, MFP for Aggregate Business Sector: Québec, Table 383-0026.

Whether or not the X factor properly reflects *long-term* inflation trends, macroeconomic inflation measures vary in their ability to track the input price inflation of utilities from year to year. Some are more volatile than others, and volatility typically results from fluctuation in the prices of commodities, such as food and fuel, which have little relevance to the cost of most energy distributors. Inflation measures with irrelevant volatility needlessly increase utility risk.

Long Run Productivity Trends

Another important issue in the design of a rate or revenue cap index is whether it should be designed to track short-run or long-run industry cost trends. Indexes designed to track short-run growth will also track the long run growth trend if this approach is used repeatedly over many years. An alternative approach is to design the index to track *only* long-run trends. Different approaches can, in principle, be taken for the input price and productivity components of the ARM.

Different treatments of input price and productivity growth are in most cases warranted. The inflation measure should track *short-term* input price growth. Meanwhile, productivity research for X factor calibration commonly focuses on discerning the current *long-run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in outputs and/or inputs. The long run productivity trend is faster than the trend during a short-lived surge in input growth or lull in output growth but slower than the trend during a short-lived lull in input growth or surge in output growth.

This general approach to PCI design has important advantages. The inflation measure exploits the greater availability of inflation data. Making the PCI responsive to short term input price growth reduces utility operating risk without weakening performance incentives. Having X reflect the long run industry PMF trend, meanwhile, sidesteps the need for more timely cost data and avoids the chore of annual PMF calculations.

To calculate the long-run productivity trend using indexes it is common to use a lengthy sample period. However, a period of more than twenty years may be unreflective of current business conditions. Quality data are often unavailable for sample periods of even this length. The need for a long sample period is lessened to the extent that volatile costs are excluded from the study and the scale index does not assign a heavy weight to volatile scale variables such as delivery volumes and system peak demand.

Sources of Productivity Growth

Research by economists has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to attain given levels of scale with fewer inputs.

Economies of scale (*economies d'échelle*) are another important source of productivity growth. These economies are available in the longer run if cost has a tendency to grow less rapidly than scale. A company's potential to achieve incremental scale economies is greater the greater is the growth in its scale.

A third important driver of productivity growth is change in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum efficiency that technology allows. Productivity growth will increase (decrease) to the extent that X inefficiency diminishes (increases). The potential of a company to reduce X inefficiency is generally greater the lower is its current efficiency level.

Another driver of productivity growth is changes in the miscellaneous business conditions, other than input price inflation and demand, which affect cost. A good example for an electric power distributor is the share of distribution lines which are underground. An increase in the share of lines that are underground will tend to slow multifactor productivity growth but accelerate growth in the productivity of O&M inputs.

When the goal of productivity research is to calibrate the X factor of a revenue per customer index, another driver of productivity growth is the tendency of the scale index employed in the productivity research to mismeasure the trend in the number of customers served. If a volumetric scale index is employed, for example, the extent of mismeasurement is similar to the trend in R&C average use.

3.3 Capital Cost Specification

Monetary Methods for Capital Cost Measurement

Accurate measurement of trends in the cost and quantity of capital is important in distributor PMF research since the share of capital in the cost of base rate inputs is typically high. The main components of the annual cost of capital are amortization and depreciation expenses, the return on investment, and taxes. "Monetary" approaches to measuring capital costs, prices, and quantities are widely used in productivity research where the requisite data are available. This general treatment of capital cost has a solid basis in economic theory and is widely used in governmental and scholarly empirical work as well in X factor calibration studies.

Monetary approaches decompose capital cost into consistent capital price and quantity indexes such that

$$\text{Cost}^{\text{Capital}} = \text{Price}^{\text{Capital}} \times \text{Quantity}^{\text{Capital}} \quad [15a]$$

and

$$\text{growth Cost}^{\text{Capital}} = \text{growth Price}^{\text{Capital}} + \text{growth Quantity}^{\text{Capital}}. \quad [15b]$$

The capital quantity index is constructed by deflating data on the value of assets. In utility PMF research it is common to deflate the value of utility plant using construction cost indexes. The capital price index should reflect the cost of owning or using a unit of capital. Capital cost depends on asset prices (often proxied by construction costs) and market rates of return on capital. The trend in the capital price index should therefore reflect in some fashion the trends in both of these prices.

It is commonplace in PMF research to treat the capital quantity index as a measure of the flow of services which is drawn from acquired assets. The capital price index is then often treated as a consistent index of prices in a competitive market for the rental of capital services. It is important to note that this treatment is markedly at variance with the reality of utility operations, since utilities typically own most of the plant that they manage.

A key issue in the choice of a monetary method is whether assets are valued in historic dollars or current (aka replacement) dollars. Replacement valuation differs from the historical (aka "book") valuation that is commonly used in North American utility accounting. Replacement valuation makes capital price and quantity indexes simpler but implicit capital gains should be netted off of the cost of capital when asset prices (or construction costs) rise.

Depreciation and Decay Specifications

Another key issue in the choice of a monetary method is the assumed patterns of depreciation of assets and of decay in their quantity once acquired. The capital price and quantity index formulas should both reflect the decay specification. The decline in the quantity of capital from an investment has been called the "age-efficiency profile." Decay can occur for various reasons that include rusting or weathering of materials, wear and tear as assets are used, casualty (e.g. storm and fire) losses, increased maintenance requirements, and technological obsolescence.

Depreciation is the decline in the *value* of assets as they age. This reduces the opportunity cost of asset ownership. In competitive markets, depreciation can result from decay in the flow of services and from the dwindling number of years over which assets provide services.

Consider now that, in North American utility cost accounting, the value of each plant addition depreciates. This reduces the required return on rate base and thereby materially slows growth in the capital revenue requirement. Assets are commonly subject to *straight line* depreciation. However, regulators rarely make explicit assumptions about decay in the flow of services from assets. Rate and revenue cap indexes are intended to adjust utility rates between general rate cases that employ a cost of service ("COS") approach to capital cost measurement. The design of a revenue cap index should therefore reflect depreciation by some means.

Three monetary methods for calculating capital cost have been used in PMF studies used in X factor calibration. These have pros and cons that merit extended discussion here.

Cost of Service COS approaches to capital costing are designed to approximate the way capital cost is calculated in utility regulation. This approach is based on the assumptions of straight line depreciation and historic valuation of plant. The formulae are quite complicated, making them more difficult to code and review. PEG has used COS approaches to capital cost measurement in several X factor calibration and benchmarking studies.

Geometric Decay The geometric decay method assumes a constant rate of decay in the quantity of capital which results from each investment. The capital quantity index is essentially the inflation-adjusted *net* plant value. The geometric decay formulae for the capital price and quantity indexes are mathematically simple, intuitively appealing, and easy to code and review.

Academic research on the value of used assets has supported the geometric decay method to characterize depreciation in many industries.[19] The U.S. Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to measurement of capital stocks in national Income and product accounts.[20] Geometric decay has also been used in numerous productivity

---

[19] See, for example, C, Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulten, "Getting Depreciation (Almost) Right," University of Maryland working paper, 2008.
[20] The BEA states on p. 2 of its November 2015 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of

studies intended for X factor calibration in the energy and telecommunications industries, including many studies prepared for utilities. PEG has used the geometric decay method in most of our utility productivity studies over the years.

One Hoss Shay The one hoss shay method for measuring capital cost is based on the assumption that the quantity of capital that results from plant additions does not decay gradually but, rather, all at once as assets reach the end of their service lives. In the simple one hoss shay method that is most commonly used in utility PMF studies, the capital quantity index is essentially the inflation-adjusted *gross* plant value. This index rises with gross plant additions and falls with retirements. Some PMF practitioners have invoked the one hoss shay methodology to use physical asset measures of capital quantities such as generation capacity and kilometers of distribution line.

Proponents of the one hoss shay approach to capital costing argue that the assumption of a constant service flow from individual assets is more reasonable for electric utilities than the alternative assumption of gradual decline. The one hoss shay method has been used several times in research intended to calibrate utility X factors. It has tended in recent years to be favored by the productivity witnesses retained by utilities.

The one hoss shay approach also has some disadvantages. Here are some of the notable problems.

- Implementation of geometric decay and one hoss shay both require deflation of gross plant *additions*. Deflation of gross additions is facilitated by the fact that the dates of the additions are known. However, implementation of one hoss shay *also* requires deflation of plant *retirements*, which North American utilities value and report in historic dollars. The vintages of these retirements are unknown and must be "guesstimated" in a PMF study using an assumption about the average service life of assets. Research by PEG has found that PMF results using one hoss shay are quite sensitive to the assumption concerning the

---

fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

average service life of assets. Seemingly reasonable service life estimates can produce negative capital quantities.[21]

- In real-world productivity studies, capital quantity trends are rarely if ever calculated for individual assets. They are instead calculated from data on the value of plant additions (and, in the case of one hoss shay, retirements) which encompass multiple assets of various kinds. Even if each *individual* asset had a one hoss shay pattern of decay, the profile of the *aggregate* plant additions could be poorly approximated by one hoss shay for several reasons. Different kinds of assets can have markedly different service lives. Assets of the same kind could end up having different service lives. Individual assets, in any event, frequently have components with different service lives. The tires of an automobile, for example, can need replacement before the windshield of the vehicle does. It follows that one hoss shay may not approximate the capital service flow of the composite asset. Alternative capital cost specifications such as geometric decay can provide a better approximation of the service flow of a group of assets that individually have one hoss shay patterns or which are composites of assets with such patterns.

Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An

[21] Sensitivity to service life assumptions under OHS can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Unfortunately, itemizations of FERC Form 1 plant addition and retirement data are not publicly available before 1994, while data on total additions and retirements are available back to 1964.

important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[22] [italics in original]

- Alternative patterns of *physical* asset decay involve different patterns of asset value *depreciation*. Trends in used asset prices can therefore shed light on asset decay patterns. Several statistical studies of trends in used asset prices have revealed that they are generally not consistent with the one hoss shay assumption.[23] Instead, depreciation patterns like geometric decay appear to be the norm for machinery and are also generally the case for buildings.[24] One expert has concluded that "the empirical evidence is that a geometric depreciation pattern is a better approximation to reality than a straight line pattern [i.e., the pattern more consistent with one hoss shay decay], and is at least as good as any other pattern."[25] [bracketed remark from PEG]

- One hoss shay formulas are somewhat complicated and lack intuitive appeal.

- Depreciation in the value of assets can affect input quantity trends even under constant capital service flows. Under the one hoss shay assumption, increasing age would cause the values of individual assets to decline in real terms due to the shortening of the remaining service life. The annual capital cost of a utility is the sum of the annual costs of assets of various vintage. Cost tends to be lower for older systems.

---

[22] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 12.

[23] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts*," Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts", *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

[24] OECD, op. cit., p. 101.

[25] Fraumeni, op. cit., p. 17.

The trend in the capital quantity index can be calculated as a cost-weighted average of the trends in the quantities of assets of each vintage. A given rate of growth in the quantity has a lower impact on the capital quantity index the older is its vintage because of its lower weight. Growth in the average age of assets will therefore tend to slow capital quantity growth.[26] Under COS regulation, the impact of this phenomenon is magnified because assets are valued in historical dollars.

Common one hoss shay treatments gloss over the importance of vintaging by valuing all capital services by a "user cost" of capital methodology in which the capital service price is a function of prices of *new* assets. This treatment is tantamount to treating capital services from all assets as purchases from a market in which prices of services do not depend on the age of assets. Capital service markets in which asset age doesn't matter greatly may exist for some assets (e.g., transoceanic shipping containers), but the cost and efficiency of firms that supply these markets depends very much on the vintages of their assets. HQD is a manager of assets, leases very few assets, and its cost trend depends greatly on their changing vintage.

These disadvantages of the one hoss shay specification help to explain why alternative specifications are more the rule than the exception in capital quantity research. We have noted that geometric decay is widely used. Statistics Canada uses geometric decay in its multifactor productivity studies for sectors of the economy.[27] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand instead assume hyperbolic decay, but not one hoss shay, in their sectoral PMF studies.

[26] In much the same manner, a household can (at the risk of higher maintenance expenses), increase its wealth by continuing to drive the family car for a few more years. The resale value of the car falls each year due to depreciation. The household has no control over used car prices or the rate of return on alternative investments. The cost saving is instead achieved by (implicitly) reducing the quantity of cars that the household owns by owning a car with a diminishing resale value. Money freed up can be invested in the stock market or real estate.

[27] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program", *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14. p. 41 and Statistics Canada, *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204, January 2001.

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. The benchmark year adjustment should deflate net plant value if geometric decay is assumed and *gross* plant value if one hoss shay is assumed. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

3.4 Kahn X Factors

An alternative approach to choosing an X factor was developed by the noted American regulatory economist Alfred Kahn. Dr. Kahn detailed the method in a 1993 testimony for a group of shippers in a FERC proceeding on PBR for interstate oil pipelines.[28] The FERC still uses this method to set X factors for oil pipelines. In the words of Dr. Kahn, "The ideal indexation formula would be one that...tracked as closely as possible the actual average costs of the pipeline industry."[29]

The method is straightforward. Suppose, for example, that we seek an X factor for a revenue cap index with formula

---

[28] "Testimony of Alfred E. Kahn on Behalf of a Group of Independent Refiner/Shippers" in Docket No. RM93-11-000 (Revision to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992), August 12, 1993.

[29] Ibid., p. 2.

trend Revenue = trend Inflation – X + trend Customers.

We could then calculate the pro forma cost of service trends for a group of utilities over several years and find the value of X that causes hypothetical revenue cap indexes to have the same trends on average. That is, we seek the value of X such that on average

trend Inflation – X + trend Customers = trend Cost.

It can then be shown that

X^{Kahn} = (*trend Inflation – trend Input Prices) + (trend Customers – trend Inputs*).

A Kahn X factor thus reflects inflation as well as changes in productivity. Thus, it is not fully comparable to an PMF trend estimate. However, it sidesteps complicated productivity calculations and produces results consistent with COS accounting. The Kahn method can thus permit X factor calibration without calculating industry input price and PMF indexes. This "indirect" method can yield substantial regulatory cost savings; an ability to avoid calculating capital price and quantity indexes is especially valuable since these calculations are complicated.

In Table 3 we demonstrate the calculation of a Kahn X factor for HQD. The inflation measure reflects growth in labor and non-labor prices in Québec, represented by average weekly earnings and the Consumer Price Index, respectively. These price trends are weighted by the shares labor and non-labor costs represent in the distribution component of HQD's 2016 *revenu requis*. We consider the X factor necessary to track HQD's *revenu requis* from 2005 to 2015.[30] The exercise produces a Kahn X factor of **0.67%**.

3.5 Other Methodological Issues

Choosing a Base Productivity Growth Target

Research on the productivity of other utilities can be used in several ways to calculate base productivity growth targets. Using the average historical productivity trend of the entire industry to

[30] We leave out 2016 since reported costs in that year were apparently affected by a change in accounting standards.

Table 3

Calculating Kahn X Factors for HQD

	Revenu Requis (%) [A]	Inflation (%) [B]	Retail Customers (%) [C]	Implicit X Factor [D = (B + C) - A]
2005	4.34	2.44	1.37	-0.52
2006	5.53	1.69	1.65	-2.19
2007	8.47	2.04	1.40	-5.03
2008	4.74	2.03	1.14	-1.57
2009	5.88	0.70	1.19	-3.99
2010	4.97	1.61	1.31	-2.05
2011	-4.30	2.90	1.21	8.41
2012	0.28	2.14	1.17	3.03
2013	1.56	0.82	1.11	0.38
2014	1.13	1.51	0.91	1.29
2015	-7.50	1.25	0.83	9.58
2016	-7.47	0.81	0.71	8.99
2017	*9.53*	*1.12*	*0.96*	*-7.45*
2018	*-2.32*	*1.72*	*0.79*	*4.83*
Average annual growth rates:				
2005-2015	**2.28**	**1.74**	**1.21**	**0.67**
Sources:	Growth rates are for the distribution component of revenus requis (i.e., they do not include those for Achats d'Électricité or Service de Transport). For years 2004-2015, data are for "années reels" or "années historiques" as reported in the Regie's rate case decisions. Data for 2016 (année historique), 2017 (année de base), and 2018 (année témoin) are from HQD's most recent rate case filing.	Weighted average of labor and non-labor price growth rates. Labor prices are average weekly earnings in Québec, including overtime, for all employees within the industrial aggregate excluding unclassified businesses (Statistics Canada, Table 281-0026); 2017-2018 values are average weekly earnings in Canada as forecast by the Quebec Minister of Finance (2018 Actuarial Report on the Employment Insurance Premium Rate, Office of the Chief Actuary, 22 August 2017, pg. 52). Non-labor prices are represented by the Consumer Price Index - All Items for Québec (Statistics Canada, Table 326-0021); 2017-2018 values are forecasts by TD Economics for Québec (Provincial Economic Forecast, Dec 14, 2017). The labor weight is 0.19. This is the product of two values: 0.43, which is the average weight assigned to growth in salaries when calculating the "facteur d'évolution combiné des charges" used to establish the 2016 and 2017 "enveloppe des charges d'exploitation" (R-3933-2015, HQD-8, Doc. 1, pg. 6; R-3980-2016, HQD-8, Doc. 1, pg. 7), and 0.44, which is the share that the "charges d'exploitation" represent in the 2016 non-energy, non-transmission revenus requis (2017-07-31, HQD-5, Doc. 1, pg. 5).	2002-2009: Growth rates based on data from Rapport annuel 2003 (Ventes et revenus par catégories de tarifs et de clientèles, HQD-2, Doc. 3, p. 7), & Rapport annuel 2011 (Historique des ventes, des produits des ventes, des abonnements et de la consommation, HQD-10, Doc. 2, p. 6) 2010-2016: Growth rates based on data from Rapport annuel 2013 & Rapport annuel 2016 (Historique des ventes, des produits des ventes, des abonnements et de la consommation, HQD-10, Doc. 2, pp. 5 & 6) 2017 (D-2017-022), 2018 (année témoin): R-4011-2017 (Efficience et performance, HQD-2, Doc. 1, pg 19)	[calculated]

calibrate X is tantamount to simulating the outcome of competitive markets. The competitive market paradigm has broad appeal.

On the other hand, individual firms in competitive markets routinely experience windfall gains and losses. Our discussion above of the sources of productivity growth implies that differences in the external business conditions that drive productivity growth can cause different utilities to have different productivity trends. For example, power distributors experiencing brisk growth in the number of electric customers served are more likely to realize economies of scale than distributors experiencing average customer growth.

In the design of rate and revenue cap indexes, there has thus been considerable interest in methods for customizing base productivity growth targets to reflect local business conditions. The most common approach to customization to date has been to use the average productivity trends of *similarly situated* utilities. Relevant conditions for a power distributor include the pace of electric customer growth, growth in the number of gas customers served, and changes in the extent of undergrounding.

A variety of potential peer groups can merit consideration in an X factor calibration exercise. In choosing among these, the following principles are appropriate. First, the group should either exclude the subject utility or be large enough that the average productivity trend of the peer group is substantially insensitive to its actions. This may be called the externality criterion. It is desirable, secondly, for the group to be large enough that the productivity trend is not dominated by the actions of a handful of utilities. This may be called the sample size criterion. A third criterion is that the group should be one in which external business conditions that influence productivity growth are similar to those of the subject utility. This may be called the "no windfalls" criterion.

Sources of Data for X Factor Calibration Research

United States Data on operations of U.S. electric utilities are well-suited for the PMF research needed to calibrate an X factor for HQD. Standardized data of good quality have been available from federal government agencies for dozens of investor-owned electric utilities for decades. The primary source of these data is the Federal Energy Regulatory Commission ("FERC") Form 1, which collects detailed cost data and some useful data on operating scale. Major investor-owned electric utilities in the United States are required by law to file this form annually. Cost and quantity data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations. The data are credibly itemized, permitting calculations of the cost of power distributor services even for the numerous vertically integrated electric utilities ("VIEUs") in the States.

Itemized data on the net value of power distribution and general plant and the corresponding gross plant additions are available since 1964. This makes U.S. data the best in the world for accurate calculation, using monetary methods, of the consistent capital cost, price, and quantity indexes that are needed to calculate multifactor productivity trends.

Custom productivity peer groups have frequently been used in X factor calibration research, and that practice has by no means been confined to regulatory commissions and consumer advocates. In New England, for example, utilities have proposed and regulators have approved X factors in index-based PBR plans that are calibrated using research on the productivity trends of Northeast utilities.

Canada In Canada, standardized data on utility operations which could be used to accurately measure their productivity trends are not readily available in most provinces including Québec. A notable exception is Ontario. Standardized data are publicly and electronically available on operations of about seventy Ontario power distributors for more than a decade. PEG has used these data to estimate industry productivity trends in X factor calibration work commissioned by the Ontario Energy Board.

Based on our experience, we believe that the Ontario data have some notable disadvantages in an X factor calibration exercise for HQD.

- Plant value data are available for most Ontario distributors only since 1989. For several utilities (including Hydro One Networks), these data are available only since 2002. The benchmark year adjustments must therefore be fairly recent. Data on *gross* plant additions, which we prefer to use to calculate capital costs and quantities, are only available starting in 2013. It is necessary to impute gross plant additions in earlier years using data on changes in the gross value of all plant.[31] These circumstances tend to reduce the accuracy of statistical research on the capital cost and total cost performance of Ontario utilities.

[31] Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are not readily available.

- Many Ontario distributors are transitioning to International Financial Reporting Standards ("IFRS"). This has reduced capitalization of O&M expenses for some distributors, thereby materially slowing their O&M and multifactor productivity trends in the last few years.

- Itemization of O&M salary and wage and material and service expenses is not available so that company-specific cost share weights cannot be calculated for O&M input quantity indexes.

Due to the limitations of Canadian data, regulators in Alberta and British Columbia have based X factors in their MRIs for gas and electric power distributors on the productivity trends of national samples of U.S. distributors. The Ontario Energy Board used estimates of U.S. productivity trends to choose the productivity target in its third-generation MRIs for power distributors but used Ontario data in two other MRIs.

The complications of basing X on the productivity trends of other utilities have occasionally prompted regulators to base X factors on a utility's *own* recent historical productivity trend. This approach will weaken a utility's incentives to increase productivity growth if used repeatedly. Furthermore, a utility's productivity growth in one five or ten-year period may be very different from its productivity growth potential in the following five years. For example, a ten-year period in which productivity growth was slowed by high capex may be followed by a period of brisk productivity growth.

Data Quality

The quality of data used in index research has an important bearing on the relevance of results for the design of MRIs. Generally speaking, it is desirable to have publicly available data drawn from a standardized collection form such as those developed by government agencies. Data quality also has a temporal dimension. It is customary for statistical cost research used in MRI design to include the latest data available.

3.6 Choosing a Stretch Factor

The stretch factor term of a revenue cap index formula should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the plan compare to those in force for utilities in the productivity studies used to set the base productivity trend. It also depends on the company's operating efficiency at the start of the PBR plan. Productivity growth should be more rapid to the extent that inefficiency is greater.

Statistical benchmarking should be considered as a means of setting stretch factors. Benchmarking can address O&M expenses, capital cost, total cost, and reliability. Benchmarking is routinely used to set stretch factors for power distributors in Ontario. Benchmarking is also extensively used by Australian and British power distribution regulators. These precedents are noteworthy since these regulators have extensive PBR experience.[32]

4. Review of Productivity and Stretch Factor Evidence

4.1 Salient Proceedings

Productivity trends of energy and telecommunications ("telecom") utilities have often been considered by North American regulators in proceedings in which MRIs with rate or revenue cap indexes are proposed. The earliest proceedings to approve such MRIs for energy utilities took place in New England and California. An MRI with a price cap index was approved for the vertically integrated electric services of Central Maine Power in 1995. Price cap indexes were later twice approved for the company's distributor services after it restructured. Several MRIs with index-based price cap indexes were approved for Massachusetts energy distributors between 1996 and 2006. Massachusetts then rejected proposals by several energy distributors for rate or revenue cap indexes before recently approving one for power distributor services of Eversource Energy. Vermont has on several occasions approved rate plans with escalators for O&M revenue which reflect a multifactor productivity study filed by Central Vermont Public Service in a 2008 proceeding.[33]

[32] PEG Research has prepared transnational power distribution cost benchmarking studies for both the Australia Energy Regulator and the Ontario Energy Board, and benchmarks the costs of all Ontario Power distributors each year using the latest available Ontario data.

[33] Dr. Lowry was the company productivity witness.

MRIs with index-based rate or revenue caps were approved for three California energy utilities between 1996 and 1999. In addition, larger California energy utilities were for many years required to file studies of their own productivity growth in general rate cases. The Sempra companies (San Diego Gas and Electric and Southern California Gas) filed *industry* productivity studies on some of these occasions.[34]

The province of Ontario approved an MRI with price cap indexes in 2000. There have been three successor plans. In one of the four MRIs, the X factor was based on the productivity trends of U.S. power distributors while in two it was based on the productivity trends of Ontario distributors.[35] The Ontario Energy Board has, additionally, approved MRIs with index-based rate or revenue cap indexes twice for Enbridge Gas Distribution and three times for Union Gas.

In Alberta, an MRI with an indexed price cap was approved for ENMAX, the power distributor serving Calgary, in 2009. The Alberta Utilities Commission has since then mandated two generations of MRIs with index-based rate or revenue cap indexes for all of the larger provincial gas and electric power distributors. British Columbia approved MRIs for FortisBC and FortisBC Energy in 2014 with X factors based on U.S. productivity evidence.

Table 4 summarizes results of these proceedings for the Régie's convenience. In considering these results please note the following.

- Regulators do not always itemize their chosen X factors into key components of interest such as base productivity trends and stretch factors. One reason is that the X factors are sometimes the outcomes of settlements between parties where any components of X that might have been agreed to were not itemized.
- Rate and revenue cap indexes in the United States frequently feature macroeconomic inflation measures, as noted above. In these instances, the X factors have on several occasions been lowered to reflect the brisk PMF growth of the U.S. economy.

---

[34] Dr. Lowry was the productivity witness for the Sempra utilities in these proceedings.

[35] The X factor in a fourth plan was based on Board judgment. Dr. Lowry advised the Board in that proceeding.

Table 4

Index-Based ARMs of North American Energy Utilities[1]

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure (P)	Acknowledged Productivity Trend (A)	Stretch Factor[2] (B)	X-Factor [3]
Bundled Power Service	PacifiCorp (I)	California	1994-1997, extended to 1999	Price Cap	Industry-specific	1.40%	NA	1.40%
Bundled Power Service	Central Maine Power (I)	Maine	1995-1999	Price Cap	GDPPI	NA	NA	0.9% (Average)
Gas Distribution	Southern California Gas	California	1997-2002	Revenue Cap	Industry-specific	0.50%	0.80% (Average)	2.3% (Average)
Power Distribution	Southern California Edison	California	1997-2002	Price Cap	CPI	NA	NA	1.48% (Average)
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	GDPPI	0.40%	0.50%	0.50%
Power Distribution	Bangor Hydro Electric (I)	Maine	1998-2000	Price Cap	GDPPI	NA	NA	1.20%
Power Distribution	PacifiCorp (II)	Oregon	1998-2001	Revenue Cap	GDPPI	NA	NA	0.30%
Gas Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.68%	0.55% (Average)	1.23% (Average)
Power Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.92%	0.55% (Average)	1.47% (Average)
Power Distribution	All Ontario distributors	Ontario	2000-2003	Price Cap	Industry-specific	0.86%	0.25%	1.50%
Gas Distribution	Bangor Gas	Maine	2000-2009, extended to 2012	Price Cap	GDPPI	NA	NA	0.36% (Average)
Gas Distribution	Union Gas	Ontario	2001-2003	Price Cap	GDPPI	NA	NA	2.50%
Power Distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	GDPPI	NA	NA	2.57% (Average)
Power Distribution	Southern California Edison	California	2002-2003	Revenue Cap	CPI	NA	NA	1.60%
Power Distribution	EPCOR (I)	Alberta	2002-2005, Terminated at end of 2003	Price Cap	Industry-Specific	NA	NA	15% * Inflation
Gas Distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	GDPPI	0.40%	1.00%	1.00%
Gas Distribution	Blackstone Gas	Massachusetts	2004-2009	Price Cap	GDPPI	NA	NA	0.50%
Gas Distribution	Terasen Gas	British Columbia	2004-2009	Revenue Cap	CPI	NA	NA	63% x Inflation (Average)
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	GDPPI	0.58%	0.30%	0.41%
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	GDPIPI	NA	NA	1.00%
Power Distribution	Nstar	Massachusetts	2006-2012	Price Cap	GDPPI	NA	NA	0.63% (Average)
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	GDPPI	0.58%	0.40%	0.51%
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	Industry-specific	0.80%	0.40%	1.20%
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	47% x Inflation (Average)
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	1.82%
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	CPI	1.03%	NA	1.00%
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	GDPPI	NA	NA	1.00%
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	GDPPI	0.72%	0.40% (Average Across Firms)	1.12% (Average Across Firms)
Power Distribution	Green Mountain Power	Vermont	2010-2013	Revenue Cap	CPI	NA	NA	1.00%

Table 4 (continued)

Index-Based ARMs of North American Energy Utilities[1]

Applicable Service	Utility	Jurisdiction	Term	Cap Form	Inflation Measure (P)	Acknowledged Productivity Trend (A)	Stretch Factor[2] (B)	X-Factor [3]
Power & Gas Distribution	All Distributors	Alberta	2013-2017	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	0.96%	0.20%	1.16%
Power Distribution	Green Mountain Power	Vermont	2014-2017	Revenue Cap	CPI	NA	NA	1.00%
Gas Distribution	Union Gas	Ontario	2014-2018	Revenue Cap	GDPPI	NA	NA	60% x Inflation
Power Distribution	All Distributors except those who opt out	Ontario	2014-2018	Price Cap	Industry-specific	0.00%	Range of 0% to 0.6%	Range of 0% to 0.6%
Bundled Power Service	FortisBC	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.93%	0.10%	1.03%
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.90%	0.20%	1.10%
Power & Gas Distribution	All Distributors	Alberta	2018-2022	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	NA	NA	0.30%
Power Distribution	Eversource Energy	Massachusetts	2018-2023	Revenue Cap	GDPPI	-0.46%	0.25% if GDPPI growth exceeds 2%	-1.56%
Hydro Power Generation	Ontario Power Generation	Ontario	2017-2021	Price Cap	Industry-specific	0.00%	0.30%	0.30%

Averages*	**Gas Distributors**	**0.63%**	**0.46%**	**1.05%**
	Electric Utilities	**0.65%**	**0.29%**	**0.95%**
	Power Distributors	**0.60%**	**0.32%**	**0.96%**
	All Utilities	**0.62%**	**0.39%**	**1.00%**

*Averages exclude X factors that are percentages of inflation.

1 Shaded plans have expired.

2 Some approved X factors are not explicitly constructed from such components as a base productivity trend and a stretch factor. Many of these are the product of settlements.

3 X factors may not be the sum of the acknowledged productivity trend and the stretch factor, where these are itemized, for the following reasons: (1) a macroeconomic inflation measure is employed in the attrition relief mechanism, (2) a revenue cap index does not include a stand alone scale variable, or (3) the X factor may incorporate additional adjustments to account for special business conditions.

- Some rate and revenue cap indexes take the form of a percentage of measured inflation and thus do not have explicit X factors.

The following results in Table 4 are especially pertinent to the Régie's *jugement* process.

- The average of the utility PMF trends acknowledged by regulators has been **0.60%** for power distributors and **0.63%** for gas distributors.
- A negative base productivity trend has only once been acknowledged by a North American regulator.

- The average approved stretch factor has been **0.39%.**

4.2 A Closer Look at Recent Notable Studies

We now take a closer look at some recent energy utility productivity studies. Key results are summarized in Table 5.

Alberta (2012)

The Alberta Utilities Commission ("AUC") held a generic proceeding from 2010 to 2012 to develop MRIs applicable to multiple provincial gas and electric power distributors. The commission retained Jeff Makholm of National Economic Research Associates ("NERA") in Boston to prepare a study of the productivity trends of U.S. power distributors. Dr. Makholm had filed power distributor productivity studies in two prior MRI proceedings. His study used an unusually lengthy sample period (1973-2009), a volumetric output index, and a simple one hoss shay approach to capital cost measurement. PMF grew much more rapidly in the early years of his sample period than it did after 1998, when it typically declined. Makholm recommended as the PMF growth target the 0.96% trend for the *full* sample period and made no X factor recommendation.

Utilities in this proceeding hired several witnesses to appraise NERA's study. These witnesses embraced most aspects of NERA's methodology but argued that more recent sample periods beginning around the year 2000 were appropriate, during which productivity growth was negative.[36] They had mixed opinions about the need for a stretch factor.

Dr. Lowry of PEG, who had previously done more than a dozen energy utility productivity studies, including several for energy distributors, was retained by the Consumers' Coalition of Alberta in this proceeding. He submitted a study of U.S. *gas* utility productivity trends and recommended a 0.19% stretch factor for all distributors. His gas productivity study used the number of customers as the output measure and a COS approach to capital cost measurement. He reported a 1.32% productivity trend for the full sample but recommended that the X factor for gas distributors be based on the more rapid

[36] They also argued in favor of a national sample that ignored local business conditions in Alberta that are favorable to productivity growth.

Table 5

Survey of Recent Multifactor Productivity Studies

Proceeding	Industry Studied	Year	Author (Consultancy)	Client	Author Recommendations: Industry Productivity Trend	Author Recommendations: Recommended Stretch Factor	Author Recommendations: X Factor	Previous Known Energy Productivity Studies	Outcome
Ontario Energy Board, Cases EB-2007-0606 and EB-2007-0615	US Gas Distributors	2007	Lowry (PEG)	Ontario Energy Board	1.40% to 1.61%	0.5% for both Revenue per Customer Cap and Price Cap	**Union Gas**: 1.98% for Revenue per Customer Cap and 1.01% for Price Cap **Enbridge Gas:** 2.08% for Revenue per Customer Cap and 0.48% for Price Cap	More than 20 productivity studies submitted as testimony	PBR plan was approved outlined in separate settlements for Union Gas and Enbridge. Union adopted PEG methodology and results. Enbridge's settlement defined the X factor as a share of the inflation measure, which increased in each year of the plan.
			Carpenter & Bernstein (Brattle)	Enbridge Gas Distribution	-0.14% to -0.08%	0.00%	-0.14% to 0.01%	First known Brattle evidence on productivity. Research relied on PEG's database with some changes in methodology	
Alberta Utilities Commission Proceeding 566	US Power Distributors	2010-2012	Makholm & Ros (NERA)	Alberta Utilities Commsision	0.96%	No recommendation	No recommendation	Two prior studies of power distribution productivity	AUC adopted these productivity results for the first generation PBR plan
	US Gas Distributors	2011	Lowry (PEG)	Consumers' Coalition of Alberta	1.32% to 1.84%	0.19%	1.51% to 2.03%	More than 20 productivity studies submitted as testimony	AUC adopted X factor of 1.16%. This was the sum of a 0.96% productivity trend and a 0.20% stretch factor.
Régie de l'énergie, R-3693-2009, Phase 2	Gaz Metro	2011	Lowry (PEG)	Gaz Metro (Task Force)	1.11% to 1.67%	0.2% to 0.5%	1.31% to 2.17%	More than 20 productivity studies submitted as testimony	Gaz Metro's proposal was rejected. Company was ordered to file a revenue per customer indexing plan featuring revenue decoupling.
Québec's Régie de l'énergie, R-3693-2009, Phase 3	US Gas Distributors	2012	Lowry (PEG)	Gaz Metro	0.85% to 1.00%	0.20%	1.05% to 1.20%	More than 20 productivity studies submitted as testimony	Proceeding suspended to address other matters
Ontario Energy Board Case EB-2010-0379	Ontario Power Distributors	2013	Kaufmann (PEG)	Ontario Energy Board	0.00%	0% to 0.6% depending on cost performance	0% to 0.6% depending on cost performance	Previously reported productivity trends for numerous clients including Jamaica Public Service (2008), the Ontario Energy Board (2008), Bay State Gas (2004-05), Boston Gas (2002-03)	OEB adopted PEG results
British Columbia Utilities Commission, Project 3698719	US Power Distributors	2013	Overcast (Black & Veatch)	FortisBC	-3.9% to -5.5%	No explicit recommendation	0% (Company proposed 0.5% X factor)	None	BCUC adopted PEG results and rejected B&V study in its entirety.
			Lowry (PEG)	Commercial Energy Consumers Association of British Columbia	0.93% to 1.18%	0.20%	1.13% to 1.38%	More than 20 productivity studies previously submitted as testimony	
British Columbia Utilities Commission, Project 3698715	US Gas Distributors	2013	Overcast (Black & Veatch)	FortisBC	-3.2% to -4.9%	No explicit recommendation	0% (Company proposed 0.5% X factor)	None	BCUC adopted PEG results with one change and rejected B&V study in its entirety.
			Lowry (PEG)	Commercial Energy Consumers Association of British Columbia	0.96% to 1.13%	0.20%	1.16% to 1.33%	More than 20 productivity studies submitted as testimony	
Ontario Energy Board Case EB-2012-0459	US Gas Distributors	2013	Coyne, Simpson, and Bartos (Concentric)	Enbridge Gas Distribution	-0.32%	No explicit recommendation	0.00%	First publicly-released productivity study	Company proposed a Custom IR plan which did not include an explicit X factor. Much of the company's proposal was accepted.
Massachusetts Department of Public Utilities, D.P.U. 13-90	Northeast US Power Distributors	2013	Lowry (PEG)	Fitchburg Gas & Electric dba Unitil	1.19%	0.20%	0.01%	More than 20 productivity studies submitted as testimony	PBR proposal rejected by Department
			Dismukes (Acadian)	Massachusetts Office of the Attorney General	0.79% to 1.59%	No recommendation	No recommendation	Multiple energy utility productivity studies, all prepared in response to utility proposals	
Maine Public Utilities Commission, Case 2013-00168	Northeast US Power Distributors	2013	Lowry (PEG)	Central Maine Power	0.56% to 1.06%	0.00%	-1.9% to -1.02%	More than 20 productivity studies submitted as testimony	Settlement withdrew PBR plan proposal
Alberta Utilities Commission, Proceeding 20414	US Power Distributors	2016	Brown and Carpenter (Brattle)	ATCO Gas, ATCO Electric, Altagas, Enmax, FortisAlberta	-0.79%	0.00%	-0.79%	First power distributor productivity study. Brattle has not conducted an independent study to date.	AUC adopted an X factor of 0.3%. Meitzen study rejected. Brattle study set lower bound of reasonable X factor range.
			Meitzen (Christensen)	EPCOR	-1.11%	0.00%	-1.11%	First productivity study outside of telecom	
			Lowry (PEG)	Consumers' Coalition of Alberta	0.43% to 1.28%	0.20%	0.63% to 1.48%	More than 20 productivity studies submitted as testimony	

Table 5 (continued)

Survey of Recent Multifactor Productivity Studies

Ontario Energy Board Case EB-2016-0152	US Hydro Generators	2016	Frayer (London Economics)	Ontario Power Generation	-1.18% to -1.01%	No recommendation	No recommendation	Two prior studies on power distribution productivity	OEB adopted Ontario Power Generation proposed productivity trend, but rejected both productivity studies
			Lowry (PEG)	Ontario Energy Board	0.29%	0.30%	0.59%	More than 20 productivity studies submitted as testimony	
Massachusetts Department of Public Utilities, D.P.U. 17-05	US Power Distributors	2017	Meitzen (Christensen)	Eversource Energy	-0.41% (regional) to -0.46% (nationwide)	0%, Company proposed a 0.25% stretch factor if inflation exceeds 2%	-2.64%	Second productivity study outside of telecom, largely reliant on others' methodology	Massachusetts DPU adopted the results of the Meitzen study, An adjustment to X was made to reflect that grid modernization costs would be tracked
			Dismukes (Acadian)	Massachusetts Office of the Attorney General	0.37% to 0.85%	No explicit recommendation	-1.36%	Multiple energy utility productivity studies, all prepared in response to utility proposals	
Lawrence Berkeley National Laboratory	US Power Distributors	2017	Lowry (PEG)	Lawrence Berkeley National Laboratory	0.45%	No recommendation	No recommendation	More than 20 productivity studies submitted as testimony	Productivity study featured in a report about the effectiveness of MRIs.
Ontario Energy Board Case EB-2017-0049	Ontario Power Distributors	2017	Fenrick (PSE)	Hydro One Networks	-0.90%	0.45%	0.6% maximum	We are aware of 2 prior productivity studies Mr. Fenrick has undertaken.	Pending
Ontario Energy Board, Case EB-2017-0307	US Power Distributors	2017	Makholm (NERA)	Enbridge Gas Distribution and Union Gas Limited	0.54%	0.00%	0.00%	3 prior publicly-released productivity studies. First productivity study since 2010.	Pending

1.84% productivity trend of sampled distributors that, like those in Alberta, experienced brisk customer growth.

The AUC ultimately chose a 0.96% base productivity trend and a 0.20% stretch factor for all gas and electric distributors. In its decision, the commission ventured opinions on several methodological issues. With respect to the output specification, for example, the commission stated on page 82 of AUC Decision 2012-237 that

> The Commission agrees with NERA's and PEG's view that when selecting a particular output measure, it must be matched to the type (price cap or revenue-per-customer cap) of a PBR plan….The Commission agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study….Using similar logic, the Commission agrees with Dr. Lowry that output measures that place a heavy weight on volumetric and other usage measures should be used for TFP studies that are part of a price cap PBR plan.

Ontario (2013)

The X factors in the Ontario Energy Board's fourth-generation MRIs for most provincial power distributors were based on the average PMF trends of these distributors. PEG senior advisor Larry Kaufmann prepared productivity research and testimony for Board Staff. Dr. Kaufmann had undertaken several previous energy distributor productivity studies. Although this MRI (still in effect) features *price* cap indexes, an *elasticity*-weighted scale index was employed in the productivity research, due in part to the fact that data were not readily available which might provide the basis for a *revenue*-weighted scale index. This treatment placed considerable weight on the trend in system use. A variant on the geometric decay approach to measuring capital cost was employed. With this methodology, Dr. Kaufmann reported an Ontario industry productivity trend of -0.33% for the full sample period but nonetheless recommended a 0% base productivity trend for the price cap indexes due, in part, to data peculiarities in the last sample year.[37] The Board agreed to the 0% base PMF trend, and chose stretch factors for each utility which varied between 0.0 and 0.6% depending on the results of an econometric total cost benchmarking study that PEG prepared.

Maine (2014)

In 2013, Central Maine Power proposed a fourth generation MRI for its power distributor services. The company claimed a need for supplemental revenue to fund high capex after many years of operation under MRIs. Dr. Lowry was retained by the company to prepare productivity research and testimony. The company proposed a revenue cap (and decoupling), and his study used the number of customers as the scale variable. A COS approach to capital cost measurement was featured. Dr. Lowry reported annual PMF trends for two groups of Northeast power distributors which ranged from 0.56% for New York state and New England to 1.06% for the broader Northeast. He proposed a 0.0% stretch factor and a special adjustment to the X factor based on his finding that Northeast distributors with unusually old systems tended to have slow productivity growth. The company's proposal was dropped in the settlement approved by Maine's commission and no decisions on industry productivity trends or the stretch factor were rendered.

Massachusetts (2014)

In 2013, Unitil proposed an MRI for power distributor services of Fitchburg Gas and Electric. It retained Dr. Lowry to undertake research and testimony on the productivity trends of Northeast power distributors. He reported a 1.19% PMF growth trend for Northeast distributors and recommended a 0.20% stretch factor.

The Massachusetts Attorney General's Office retained Dr. David Dismukes of Acadian Consulting to review and comment on Dr. Lowry's study. His review of Dr. Lowry's evidence suggested that the

[37] The trend for 2003-11 period that excludes the last year 0.19%.

PMF trend should lie between 0.79% and 1.59%. He did not comment on the appropriate stretch factor. Unitil's proposal was rejected by the Massachusetts commission and no decisions on industry productivity trends or the appropriate stretch factor were rendered.

British Columbia (2014)

In 2013 FortisBC (formerly West Kootenay Power) and FortisBC Energy (formerly Terasen Gas) proposed MRIs for their gas and electric services which featured index-based revenue caps. Fortis retained a Black and Veatch consultant, who reported no prior productivity research experience, to prepare gas and electric power distribution productivity studies. Black and Veatch reported productivity trends for these industries in the neighborhood of -4% but nevertheless recommended a 0% productivity growth target and a 0% stretch factor for the companies. Notwithstanding the research results of its witness, Fortis recommended a 0.5% X factor for both utilities.

Dr. Lowry was retained by the Commercial Energy Distributors of British Columbia and prepared studies of U.S. gas and electric distributor productivity trends. He reported PMF trends of 0.93% for the full sample of power distributors and 0.96% for the full sample of gas utilities and recommended a 0.20% stretch factor for both companies. The BC commission chose a 0.93% base productivity trend and a 0.10% stretch factor for electric services. For gas it chose a 0.90% base productivity trend and a 0.20% stretch factor. The Black and Veatch study was rejected in its entirety.[38]

[38] The commission stated in its decisions on the Fortis MRIs that

> The Panel has a number of concerns about the B&V studies and is not persuaded that the TFP trend results reported by B&V can be used as a basis to establish an X-Factor. Dr. Overcast employs a study methodology that is, by his own admission, non-standard. There is no evidence that this methodology has been accepted in any other proceeding. Further, Dr. Overcast has not previously conducted a TFP trend study. The Panel previously found B&V's use of output and input level indexes inappropriate and cannot be relied upon to generate meaningful input and output trends. We have also made determinations in the areas of input cost inflation, the use of arithmetic vs logarithmic measures and the study length. In all cases, we found flaws in the study methodology that tend to understate TFP trends. **Given the number of shortcomings in B&V's methodology and the errors that arise from these shortcomings, the Panel does not accept B&V's study results.**

Reference: British Columbia Utilities Commission (2014), *In the Matter of FortisBC Inc. Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 Decision*, September 15, p. 56.

Alberta (2016)

The AUC held a proceeding 2015-2016 to resolve key issues in the design of next-generation MRIs for Alberta energy distributors. EPCOR hired Christensen Associates while other utilities hired the Brattle Group to prepare productivity studies. Although Christensen had previously done a few energy utility productivity studies, EPCOR retained Dr. Mark Meitzen, Christensen's expert on *telecommunications* productivity. Both consultancies updated NERA's power distributor study with few adjustments and then advocated basing X on results the later years of the full sample period, when PMF growth was materially negative. National samples were once again embraced. Brattle proposed a base PMF growth trend of -0.79% while Christensen proposed a trend of -1.11%. Both consultancies also proposed a 0% stretch factor.

The Consumers Coalition of Alberta hired Dr. Lowry again, and he prepared an independent study of U.S. power distributor productivity growth. He used the number of customers as the scale variable and a geometric decay approach to measuring capital cost. His sample was substantially larger than that used by the utility witnesses or in his own prior studies. Dr. Lowry reported a 0.43% PMF trend for the full sample of power distributors but recommended basing X on the higher 0.78% trend for rapidly-growing distributors. Lacking persuasive benchmarking evidence, Dr. Lowry recommended a 0.20% stretch factor for all companies.

The sample period was 1997-2014. Dr. Lowry reported a 0.43% PMF trend for the full sample of power distributors but recommended basing X on the higher 0.78% trend for rapidly-growing distributors. Lacking persuasive benchmarking evidence, Dr. Lowry recommended a 0.20% stretch factor for all companies.

Dr. Lowry once again lodged extensive criticisms of NERA's methodology for PMF measurement. His evidence showed that the decline in PMF growth over the full sample period was due chiefly to the slowdown and ultimate decline in average use of power by residential and commercial customers. He argued that this slowdown was irrelevant to the choice of X factors for Alberta's gas distributors, which operated under revenue per customer indexes.

Dr. Lowry also demonstrated that results using NERA's methodology were very sensitive to the assumption concerning the average service life of assets. NERA had assumed a 33-year service life, and this assumption was never well substantiated by Dr. Makholm or the utility witnesses in Alberta.[39] Based on Dr. Lowry's extensive experience, a materially higher average service life was warranted. EPCOR, for example, reported a 37-year average service life in the proceeding.

When various problems with NERA's method were corrected and a 37-year service life was used, the resultant PMF trend was similar to that from Dr. Lowry's method. Thus, the negative PMF trend of recent years was due to an inappropriate service life assumption that, over the *full* sample period, was masked by brisk growth in R&C average use in the earlier years of the sample period. *This evidence by Dr. Lowry, which is provided in Attachment 1 to this report, severely compromised the credibility of NERA's methodology. However, it was not considered by the AUC when it made its X factor decision,* ostensibly because Dr. Lowry had not provided working papers for his final research.[40] Working papers were prepared but not provided on the advice of PEG's client because the evidence was submitted in rebuttal testimony shortly before oral hearings and working papers were never requested by any party. We believe that this evidence is highly pertinent to the Régie's *jugement*

[39] Dr. Makholm noted the 33-year assumption in his report but did not defend or explain it. When asked to explain the assumption in a data request from PEG, he stated only that "The 33-year service life is a more updated average of the lifetimes of utility capital."

[40] The AUC did not mention this evidence in its decision on the MRI, but stated in the related cost award decision that

> The Commission also considers that there were certain areas of evidence that did not contribute to the Commission's understanding of the issues or was of limited assistance because the supporting information was not provided... Another example is related to PEG's evidence Table 2, "Summary of Corrections and Modifications to NERA/Brattle/LRCA Productivity Calculations," found in Pacific Economics Group's rebuttal evidence. Table 2 shows the steps in reconciling PEG's and NERA-based studies, which effectively resulted in Dr. Lowry's reproduction of the Brattle Group and Dr. Meitzen studies on the record of the original proceeding . . . These papers were not provided on the record to support the Table 2 calculations. Because working papers were not provided, the Commission and parties were unable to test the veracity of the numbers in Table 2 and the Commission was not able to assess the probative value of the information provided. While generally PEG's evidence was of assistance to the Commission, this specific information in Table 2 did not contribute to a better understanding of the total factor productivity to be used in determining X. Accordingly, the Commission cannot approve the hours related to the preparation of Table 2, the corresponding narrative to Table 2, and the associated working papers. (AUC Decision 22082-D01-2017, p. 12)

process and is just as valid as any other evidence that has not yet been completely vetted by opposing parties (e.g., the Fenrick study for Hydro One Networks).

The AUC ultimately chose a 0.30% X factor for both gas and electric power distributors and did not itemize a stretch factor.

Lawrence Berkeley National Laboratory (2017)

Dr. Lowry calculated the PMF trends of a large sample of U.S. power distributors in his recent study on multiyear rate plans for Lawrence Berkeley National Laboratory.[41] The number of customers was the scale variable and geometric decay was assumed with a 37-year average service life. He reported PMF trends of 0.45% for the full 1980-2014 sample period and of 0.39% for the more recent 1996-2014 sample period. Using his method, which is not sensitive to average use trends, there has *not* been a large slowdown in power distributor productivity growth since 2000 and recent productivity growth has not been negative.[42] In a fall 2017 presentation funded by LBNL which Dr. Lowry made to the New England Council of Public Utility Commissions, Dr. Lowry reported that the PMF trend of sampled power distributors for the more recent 1996-2016 sample period was 0.43% per annum for the full U.S. sample and 0.31% for the Northeast U.S.

Massachusetts (2017)

Eversource Energy retained Dr. Meitzen of Christensen Associates to prepare productivity research and testimony in support of an MRI proposal for its power distribution services in Massachusetts. Dr. Meitzen updated NERA's study to 2016, making only a few changes to the methodology. Eversource proposed a *revenue* cap index, and Dr. Meitzen used the number of customers served rather than a volumetric index as his scale variable. However, he did not reconsider the 33-year average service life assumption and did not report results for the earlier years of NERA's sample period. Thus Eversource, a company based in the Boston area, did not hire Boston's most experienced power distribution productivity consultant but instead hired Christensen's telecom

[41] Lowry, op. cit., p. B.18

[42] Slower growth in the number of customers served has, however, produced a modest (e.g., 10 basis point) slowdown in the realization of scale economies

productivity expert to use NERA's methodology for a recent sample period, a practice NERA had opposed. Meitzen reported productivity trends of around -0.40% for both regional and national distributor samples and proposed a 0% stretch factor.

The Massachusetts Office of the Attorney General retained Dr. David Dismukes of Acadian Consulting Group to prepare productivity research and testimony.[43] He reported a +0.37% simple average PMF trend for the full sample, a +0.42% weighted average for the full sample, a +0.71% simple average for the Northeast sample, and a +0.85% weighted average for the Northeast sample. He did not address the stretch factor issue.

In its decision approving an MRI for Eversource, the Massachusetts Department of Public Utilities acknowledged a -0.46% U.S. industry power distributor productivity trend. It also embraced the one hoss shay approach to measuring capital cost.

Ontario (2017)

Ontario Power Generation ("OPG") proposed an MRI for its regulated hydroelectric generating services in 2016. It retained London Economics to prepare a supportive study of trends in the productivity of North American hydroelectric generators. London Economics had done two prior productivity studies and used a "physical assets" approximation to a one hoss shay approach to measuring the capital quantity trend.[44] They reported a PMF trend in the -1.01 to -1.18% range and made no stretch factor recommendation. The company proposed a 0% base productivity trend and a 0.3% stretch factor.

Ontario Energy Board staff retained Dr. Lowry to prepare an independent study of the productivity trends of the company and a sample of U.S. hydroelectric generators. Using generation capacity as the scale metric and geometric decay to measure capital cost, he reported a 0.29% PMF trend and recommended a 0.3% stretch factor. Using a Khan method, Dr. Lowry also showed that the X factor implicit in the company's recent revenue and volume trends from 2008 to 2014 was +1.34%. The

---

[43] Dr. Lowry was not a witness in this proceeding so many of his criticisms of NERA's method were not considered.

[44] They specifically used generation capacity as the capital quantity index.

propriety of the one hoss shay and related physical asset approaches to capital cost and quantity measurement was a salient issue in the proceeding.

The Board issued a decision last month which approved a 0% base productivity trend and a 0.3% stretch factor. In its decision the Board declined to fully embrace the entire PMF methodology used by either witness but, unlike the AUC in its recent decision, did venture opinions on several methodological issues. In particular, it indicated a preference for Dr. Lowry's method for measuring capital cost stating that

> The OEB questions LEI's physical approach which uses MW capacity as an input, as this measure does not take into account financial considerations, such as the capital costs. Although many hydroelectric generation assets have very long useful lives, the OEB is not convinced that there is no functional depreciation until end of life. In fact, reviews of capital projects to sustain, refurbish and replace hydroelectric stations and assets in OPG's prior payment amount applications confirm that capital expenditures and operating costs are needed to maintain capacity to the end of a station's life. Absent ongoing capital and operating expenditures, hydroelectric generation assets will depreciate over time. In the OEB's view, LEI's physical method, which assumes no depreciation until the end of life, is not a realistic basis for the analysis of productivity of hydroelectric generation facilities.[45]

The Board stated the hope that its opinions on methodological issues would be considered in future productivity studies, stating that

> The OEB expects that OPG and other stakeholders will take into account the OEB's concerns about the approaches and limitations of the experts' analyses on the record in this proceeding. Improvements in methodology and data, and translation of the results of the studies as to how they more directly translate to rate-setting would provide more useful and convincing information on which OPG could make its next proposal and the OEB would make its determination for subsequent IRM plans.[46]

Ontario (2017)

Hydro One Networks filed evidence in 2017 in support of a custom MRI for its power distributor services. The company retained Steve Fenrick of Power Systems Engineering to prepare supportive productivity and benchmarking evidence. Mr. Fenrick had prepared a few previous energy distributor

---

[45] Ontario Energy Board, EB-2016-0152, Decision and Order, December 28, 2017, pp. 126-127.

[46] Ibid., p. 128.

productivity studies. He updated PEG's Ontario power distributor productivity study to 2015, reporting a -0.90% annual PMF growth trend for the full sample period, and proposed a 0.45% stretch factor based on the result of his total cost benchmarking study. Hydro One proposed a base productivity trend of zero and a 0.45% stretch factor. PEG has been retained by Board Staff to review Mr. Fenrick's submission. However, the project has been delayed and no review has yet been undertaken.

Ontario (2017)

Union Gas and Enbridge recently proposed a merger and an MRI for their consolidating Ontario gas utility operations. The so-called "Amalco" companies retained Dr. Makholm of NERA to update his power distributor PMF study. He reports a 0.54% PMF trend for his full 1973-2016 sample period, but the negative PMF trend in recent years has continued. Notwithstanding his support for basing X factors on results for the full sample period when he was a commission witness, Makholm recommends a 0% base productivity factor for the combined company and a 0% stretch factor. The Amalco made the same recommendations. Dr. Lowry has been retained by Board staff to respond to Makholm's new study. The project is just beginning, however, and Makholm's evidence has not yet been reviewed or challenged.

Canadian Utility Sector Productivity

CEA notes on p. 12 of its June 2017 X factor evidence the declining productivity of the Canadian utility industry as measured by *Statistique Canada*. The pertinence of the Canadian utility industry productivity indexes was discussed at some length by Dr. Lowry in the first Alberta MRI proceeding. He explained that *Statistique Canada* has calculated PMF indexes for the utility sector of the Canadian economy and two subsectors: “Electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems”. Though *Statistique Canada* continues to maintain the utility sector index, the two subsector indexes were terminated in 2010.

Each index has been calculated on a “gross output” and a “value added” basis. The gross output approach is more similar to that conventionally used in productivity studies for X factor calibration because it includes intermediate inputs like materials and services. The value-added approach does not include intermediate inputs because it is intended for use in the calculation of the PMF growth of Canada's aggregate business sector.[47]

Only results for the value-added utility PMF index are reported on a timely basis, and it is these results that CEA reports on p. 13 of its July submission. Between 1962-2015 this index exhibited a 0.41% average annual growth rate. However, over the last twenty years (1996 to 2015) this index averaged a 0.83% annual decline, and over the last ten years (2006 to 2015), it averaged a 1.75% annual decline.

Results of the value-added utility PMF index that CEA features are of limited relevance in setting an X factor for HQD, for several reasons.

- It is a value-added calculation. As such, it ignores productivity in the use of intermediate inputs.
- It is sensitive to developments in the generation sector of the electric utility industry. This has little relevance to network industries such as power distribution. For example, the growth in the index has in recent years been slowed by Hydro-Québec projects to develop remote hydroelectric resources.
- The electric utility industry restructured in Alberta and Ontario. It is not clear how well this has been handled by *Statistique Canada*.
- A volumetric scale index is employed. This makes results sensitive to changing business conditions including, particularly, the slowing growth in average use of energy. Declining average use has been more pronounced in the gas utility industry than in the electric utility industry.
- Measured productivity growth is slowed by growth in expenses for utility conservation and load management programs, which are large in several Canadian provinces, but will likely be Y factored in HQD's MRI.

The *Statistique Canada* PMF indexes for “electric power generation, transmission, and distribution” and “natural gas distribution, water, and other systems” are available on a gross value basis through 2010. On average, the productivity of the gas and water sector grew by 0.55% annually

[47] It is difficult to use macroeconomic data to compute the PMF of the aggregate private business sector if intermediate inputs are included.

between 1962-2010. For the most recent 20 years (1991-2010) productivity declined by 0.09% per year on average, and for the most recent ten (2001-2010) it declined by 1.44%. Note that output is measured volumetrically, and thereby reflects the material decline in average use of gas by Canadian residential and commercial customers that has been underway for many years.

As for the PMF index for the "electric power generation, transmission, and distribution," using the gross output approach, Statistics Canada reports a 0.61% average annual growth rate in utility sector productivity for the full 1962-2010 period. For the most recent 20 years (1991-2010), the average growth rate is 0.41%. For the most recent ten years (2001-2010), productivity declines by a modest 0.12% annually.

The Center for the Study of Living Standards ("CSLS") retained Statistics Canada to prepare a study of productivity trends at the provincial level. A report on the research was released in 2010.[48] This study reported results only for value-added PMF indexes. After extensive correspondence between PEG Research and principals of this study, the principals conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination.

The AUC stated in its decision on first-generation MRI for provincial energy distributors that

> Overall, the Commission considers that while Statistics Canada's MFP indexes and the CSLS report can be a useful reference for gauging the general productivity trends of the utilities sector, these analyses cannot be a substitute for a TFP study for either the electric or gas distribution industries.

Commentary

This review of recent PMF studies and MRI proceedings prompts several comments.

- Productivity research has various uses, and the methods appropriate for one use may not be appropriate for another. In this proceeding, we seek productivity research that can inform selection of an X factor for a revenue per customer index between *dossiers tarifaires*. A different methodology might be appropriate for a study concerned solely with cost efficiency or the calibration of X in a price cap index.

[48] CSLS, *New Estimates of Labor, Capital, and Multifactor Productivity Growth and Levels for Canadian Provinces at the Three Digit NAICS Level 1997-2007.*

- Commissions that have made X factor decisions often comment on the research methods used by PMF witnesses. This encourages witnesses to use better methods in subsequent MRI proceedings.
- Much of the recent variation in PMF trends reported by witnesses in MRI proceedings is due to research methods that the Régie may find objectionable or inappropriate for application to a revenue cap index. It is reasonable for the Régie to give little or no weight to such evidence in its decision.
- Utilities have frequently hired witnesses in recent years who have little experience in the measurement of PMF trends of energy utilities. It is chiefly these witnesses who have recommended substantially negative productivity growth trends. These witnesses also frequently propose 0% stretch factors.
- The slowdown in productivity growth which utility witnesses often highlight is due chiefly to slowing growth in residential and commercial average use which is irrelevant to the choice of an X factor for HQD. They often conjecture that slow productivity growth is also driven by high capex requirements but provide little evidence to substantiate this notion.
- Commissions are sometimes reluctant to embrace results of one productivity study because they do not prefer every aspect of any one study's methodology. However, this does not mean that they routinely take an average of the recommendations of all witnesses when choosing a base productivity trend or stretch factor. An averaging approach incentivizes parties to produce outlier results that can move the average. Judgement can instead focus on the most recent studies and the best methodologies.

5. Application to HQD

5.1 Inflation Measure

<u>Régie Ruling</u>

The Régie traced the outlines of an inflation measure for HQD's revenue cap index in D-2017-043 but made no final decision. It suggested that the inflation measure should summarize growth in two inflation subindexes: the *indice des prix a la consommation* ("IPC", aka consumer price index) for Québec and the average weekly earnings ("AWE") of Québec industrial workers. Both of these price indexes are calculated by Statistique Canada. The revenue cap index inflation measure would take the average AWE inflation in the last three years ending 31 March and the inflation in $IPC^{Québec}$ for the last year. Cost share weights would be used for these subindexes, following the precedent of the Company's current *formule paramétrique* for the *charges d'exploitation revenu requis.*

> **la Régie retient la proposition du Distributeur à l'effet que le facteur de pondération entre l'inflation et le taux de croissance des salaires soit déterminé selon une méthode similaire à celle utilisée actuellement dans les demandes tarifaires aux fins du calcul de l'enveloppe des charges d'exploitation, soit en fonction de la quote-part de la masse salariale, excluant la portion capitalisable, sur les charges totales couvertes par la formule paramétrique.** [49]

This general approach to the design of a rate or revenue cap inflation measure is sensible and is currently used to regulate energy utilities in Alberta, British Columbia, and Ontario. It helps the revenue cap index track local inflation pressures that utilities experience while sidestepping the complicated issue of capital price measurement which might be encountered with a more complex utility input price index.

We nonetheless have concerns with the Régie's suggested inflation measure treatment in three areas: the choice of a macroeconomic inflation measure, the cost share weights, and the appropriate time period to consider. We discuss these issues in turn.

Macroeconomic Inflation Measure

Table 6 shows trends in six macroeconomic price indexes that are sensible candidates for use in Québec. We also include the average weekly earnings of Canadian and Québec industrial workers. Here are the indexes with brief discussion of noteworthy features.

---

[49] Régie, op. cit., p. 37.

Table 6

Alternative Inflation Measures for Canada and Québec[1]

	Canada								Québec							
	IPC[1]		GDPIPIs[2]				AWE[3]		IPC[1]		GDPIPIs[2]				AWE[3]	
	All Items		Final Consumption		Final Domestic Demand		All Employees		All Items		Final Consumption		Final Domestic Demand		All Employees	
Year	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR	Level	GR
1982	56.1	10.4%	55.8	10.0%	59.0	9.1%			57.1	10.9%	58.1	10.6%	61.7	9.6%		
1983	59.4	5.7%	59.6	6.6%	62.2	5.4%			60.3	5.4%	61.4	5.6%	64.7	4.8%		
1984	62.0	4.2%	62.3	4.4%	64.9	4.1%			62.8	4.0%	64.4	4.8%	67.6	4.4%		
1985	64.4	3.9%	64.8	3.9%	67.2	3.6%			65.5	4.3%	67.1	4.1%	70.0	3.6%		
1986	67.1	4.0%	67.5	4.1%	69.8	3.8%			68.7	4.7%	69.9	4.1%	72.8	3.9%		
1987	70.0	4.3%	70.3	4.1%	72.8	4.1%			71.6	4.2%	73.0	4.4%	75.9	4.2%		
1988	72.8	3.9%	73.1	3.9%	75.5	3.7%			74.3	3.6%	75.6	3.5%	78.4	3.3%		
1989	76.5	4.9%	76.5	4.5%	78.9	4.4%			77.4	4.2%	78.9	4.2%	81.4	3.8%		
1990	80.2	4.7%	80.1	4.6%	82.0	3.8%			80.8	4.3%	82.4	4.4%	84.6	3.7%		
1991	84.7	5.5%	83.9	4.7%	84.7	3.3%			86.7	7.1%	86.5	4.8%	87.3	3.2%		
1992	85.9	1.4%	85.7	2.1%	86.4	2.0%			88.4	1.9%	87.9	1.7%	88.8	1.6%		
1993	87.5	1.9%	87.4	1.9%	88.0	1.8%			89.5	1.3%	89.3	1.5%	89.9	1.2%		
1994	87.6	0.1%	88.5	1.3%	89.5	1.7%			88.4	-1.3%	89.7	0.5%	90.9	1.1%		
1995	89.6	2.2%	89.8	1.4%	90.5	1.1%			89.9	1.7%	90.5	0.9%	91.7	0.9%		
1996	90.9	1.5%	90.9	1.2%	91.5	1.1%			91.3	1.6%	91.4	1.0%	92.2	0.6%		
1997	92.4	1.7%	92.2	1.5%	93.0	1.6%			92.7	1.4%	92.5	1.2%	93.3	1.2%		
1998	93.4	1.0%	93.5	1.3%	94.3	1.5%			94.0	1.4%	93.6	1.2%	94.4	1.2%		
1999	95.0	1.7%	95.2	1.8%	95.6	1.3%			95.4	1.5%	95.3	1.8%	95.8	1.4%		
2000	97.5	2.7%	97.9	2.8%	98.1	2.6%			97.8	2.4%	98.2	3.0%	98.2	2.5%		
2001	100.0	2.5%	100.0	2.2%	100.0	1.9%	657		100.0	2.3%	100.0	1.8%	100.0	1.8%	623	
2002	102.2	2.2%	102.4	2.3%	102.4	2.4%	673	2.4%	102.0	2.0%	102.2	2.2%	102.2	2.2%	639	2.4%
2003	105.1	2.8%	104.4	2.0%	104.0	1.5%	691	2.7%	104.6	2.5%	104.4	2.1%	103.9	1.6%	657	2.8%
2004	107.1	1.8%	106.1	1.6%	105.9	1.8%	709	2.6%	106.6	1.9%	105.9	1.5%	105.6	1.6%	673	2.4%
2005	109.4	2.2%	108.3	2.1%	108.2	2.1%	737	3.8%	109.1	2.3%	108.2	2.1%	107.6	1.9%	695	3.2%
2006	111.6	1.9%	110.3	1.9%	110.7	2.3%	755	2.4%	110.9	1.7%	109.8	1.5%	109.2	1.5%	707	1.8%
2007	114.0	2.2%	112.5	1.9%	113.4	2.4%	787	4.2%	112.7	1.6%	111.9	1.8%	111.1	1.7%	737	4.1%
2008	116.7	2.3%	114.8	2.1%	116.2	2.5%	810	2.8%	115.0	2.1%	113.5	1.5%	113.3	2.0%	751	1.9%
2009	117.0	0.3%	115.9	0.9%	117.6	1.2%	823	1.5%	115.7	0.6%	114.1	0.5%	114.4	1.0%	759	1.0%
2010	119.1	1.8%	117.4	1.4%	118.8	1.1%	852	3.6%	117.1	1.2%	115.4	1.2%	115.4	0.9%	784	3.3%
2011	122.6	2.9%	120.4	2.5%	121.7	2.4%	874	2.5%	120.7	3.0%	118.3	2.5%	118.2	2.4%	804	2.5%
2012	124.4	1.5%	122.2	1.5%	123.7	1.7%	895	2.5%	123.3	2.1%	120.5	1.8%	120.3	1.8%	823	2.4%
2013	125.6	0.9%	124.4	1.8%	125.9	1.7%	911	1.8%	124.2	0.7%	123.0	2.1%	122.8	2.0%	832	1.2%
2014	128.0	1.9%	126.9	2.0%	128.7	2.2%	935	2.6%	125.9	1.4%	125.2	1.7%	125.2	2.0%	850	2.0%
2015	129.4	1.1%	128.3	1.1%	130.8	1.7%	952	1.8%	127.2	1.0%	126.7	1.2%	127.1	1.5%	868	2.1%
2016	131.3	1.4%	129.6	1.0%	132.5	1.3%	956	0.4%	128.2	0.7%	127.7	0.8%	128.2	0.9%	878	1.2%
Average Annual Growth Rates																
1982-2016		**2.7%**		**2.7%**		**2.6%**		**NA**		**2.6%**		**2.6%**		**2.4%**		**NA**
1997-2016		**1.8%**		**1.8%**		**1.9%**		**NA**		**1.7%**		**1.7%**		**1.6%**		**NA**
2002-2016		**1.8%**		**1.7%**		**1.9%**		**2.5%**		**1.7%**		**1.6%**		**1.7%**		**2.3%**
Standard Deviations																
1982-2016		**1.9%**		**1.9%**		**1.6%**		**NA**		**2.2%**		**2.0%**		**1.7%**		**NA**
1997-2016		**0.7%**		**0.5%**		**0.5%**		**NA**		**0.6%**		**0.6%**		**0.5%**		**NA**
2002-2016		**0.7%**		**0.5%**		**0.5%**		**0.9%**		**0.7%**		**0.5%**		**0.5%**		**0.8%**

[1] All growth rates are logarithmic.
[2] Consumer price index (Statistics Canada, Table 326-0021).
[3] Gross domestic product implicit price index (Statistics Canada, Table 384-0039).
[4] Average weekly earnings, including overtime, for all employees in current dollars (Statistics Canada, Table 281-0026).

- The IPC for Canada is the inflation measure most familiar to Canadian consumers. This type of inflation measure is the norm in British and Australian MRIs. It is less common in North American MRIs because it places a fairly heavy weight on price-volatile consumer commodities like gasoline, natural gas, and food. These commodities make the IPC^{Canada} more volatile and have much more impact on the budget of a typical consumer than they do on the cost of a typical energy distributor's base rate inputs.[50] On the other hand, the revenue cap index for HQD may apply to *couts de combustibles* such as *diesel leger*, *diesel arctique*, and *mazout*.
- The IPC for Québec (IPC^{Québec}) has the drawbacks just noted for the CPI^{Canada} but has the advantage of being specific to the province. It should therefore be more sensitive to local business conditions than IPC^{Canada}.
- Gross domestic product implicit price indexes ("GDPIPIs") track inflation in prices of capital equipment and net exports as well as consumer products. They are periodically updated and are available for Québec as well as Canada. However, the GDPIPI for Québec is released with a considerable lag. In the United States, we noted above that a gross domestic product price index has been preferred over IPCs in MRIs because the impact of price-volatile consumer commodities is watered down. However, in Canada's economy with its sizable reliance on natural resource exports, this stabilizing benefit is offset by the impact of incorporating inflation in commodity exports. The GDPIPIs for final domestic demand (GDPIPI^{FDD}) remove the inflation impact of price volatile exports. They are available for Québec as well as Canada.

Table 6 shows that these indexes vary in their volatility, which we measure in the last three rows of the table by the standard deviations of their growth rates. The CPIs for Canada and Québec are more volatile than the corresponding GDPIPIs for final domestic demand. In 2009, for instance, the CPI (all items) for Canada and Québec grew only 0.3% and 0.6%, respectively, while the GDPIPIs for final

[50] Non-seasonal CPIs also have the characteristic of not being revised.

domestic demand in Canada and Québec rose by 1.2% and 1.0%. Average weekly earnings of Québec workers are even more volatile.

The table also shows that trends in Québec inflation tend to be fairly similar to those for Canadian inflation. Please also note that, in Canada and Québec alike, the growth trends in average weekly earnings are more rapid than those for the macroeconomic price indexes. This incentivizes utilities to propose heavier weights on the labor price indexes in the inflation measures of rate and revenue cap indexes.

We conclude that the $IPC^{Québec}$ is a reasonable subindex for HQD's inflation measure if the formule d'indexation applies to fuel costs. The GDPIPI for final domestic demand in Canada merits consideration if the Régie decides to add a price subindex for fuel cost to the inflation measure.

Cost Share Weights

The inflation in an input price index was shown in Section 3.1 to be a cost-weighted average of the growth in price subindexes for various input groups. This inflation measure for HQD will apply to most costs of base rate inputs, including capital costs. The weight on the labor price index in the inflation measure should therefore be the share of non-capitalized labor expenses in the applicable portion of the pro forma total cost of service. Table 7 summarizes precedents for inflation measures in current Canadian MRIs. It can be seen that similarly low labor price weights are used in Ontario inflation measures. Our review of HQD's *revenu requis* for 2016 suggests that a labor price index weight of approximately 19% is appropriate. This is roughly the share of labor in *charges d'exploitation* times the share of *charges d'exploitation* in the applicable total *revenu requis*. The weight assigned to labor would be reduced if pension and benefit expenses are Y factored.

Timing

With respect to timing, we recommend that the *revenu requis* of HQD be escalated on April 1 of the new rate year on the basis of historical inflation for the period ending on December 31st of the prior year. The requisite inflation measures should be available by early March.

Table 7

Inflation Measures in Current Canadian MRIs

Jurisdiction	Company	Term	Industry	Labor Price Subindex	Labor Weight	Non-Labor Price Subindexes	Non-Labor Weight
Ontario	Ontario Power Generation	2017-2021	Power Generation	Average Weekly Earnings for Ontario - Industrial Aggregate	12%	Canadian Gross Domestric Product Implicit Price Index - Final Domestic Demand	88%
British Columbia	Fortis BC Inc. and FortisBC Energy Inc	2014-2019	Bundled Power Service and Gas Distribution	Average Weekly Earnings for British Columbia	55%	Consumer Price Index - British Columbia	45%
Ontario	All Ontario Distributors	2014-2018	Power Distribution	Average Weekly Earnings for Ontario	30%	Canadian Gross Domestric Product Implicit Price Index - Final Domestic Demand	70%
Alberta	ATCO Electric, FortisAlberta, EPCOR, AltaGas, ATCO Gas	2018-2022	Power and Gas Distribution	Average Weekly Earnings for Alberta	55%	Consumer Price Index - Alberta	45%

5.2 X Factor

The preponderance of evidence assembled suggests that an X factor of +**0.30%** is just and reasonable for the first-generation MRI of HQD.

- The average power distributor PMF growth trend that North American regulators have acknowledged is **0.60%**. Only one North American regulator (Massachusetts) has ever acknowledged a negative productivity growth target. Dr. Lowry was not a witness in that proceeding.
- The OEB most recently set the base productivity growth target for Ontario power distributors at 0%. However, Ontario power distributor operating data have numerous flaws, and the scale index that the OEB uses assigns a substantial weight to usage variables (e.g., delivery volume) that are sensitive to the large energy efficiency programs in the province.
- With regard to productivity studies (rather than commission decisions), Dr. Lowry's method for measuring the PMF trend of power distributors has been shown to be the most appropriate one for setting an X factor for HQD, for several reasons. The number of customers served is clearly the most appropriate scale variable to use when calibrating the X factor of a revenue per customer index. The geometric decay approach to capital cost

measurement has many advantages. His assumptions about the average service life are empirically founded and reasonable, and results using his method are in any event not highly sensitive to the service life assumption. Dr. Lowry's sample includes more companies than those in other studies. He prepares productivity studies for diverse clients, and not just utilities. Dr. Lowry recently reported a **0.39%** power distributor PMF growth trend over the 1996-2014 period in his paper for Berkeley Lab. He reported a **0.43%** trend for his full sample for the more recent 1996-2016 period in a recent presentation for regulators which was funded by Berkeley Lab.

- Studies based on a one hoss shay capital cost specification also merit some consideration by the Régie. The most relevant of these are Dr. Meitzen's recent study for Eversource and Dr. Makholm's recent study for the Amalco gas utilities in Ontario. Both studies incorporate recent data. Dr. Meitzen's study additionally features the number of customers as the scale variable. His estimate of the PMF growth trend of all sampled utilities in recent years is **-0.46%**. Dr. Makholm continues to use a less appropriate volumetric index and reported a 0.54% trend for his full sample period but nonetheless recommended a 0% base PMF trend on the basis of his research.

  Both of these studies use an unrealistic and poorly substantiated 33-year average service life. PMF growth would likely be much higher with a higher and more realistic service life. Dr. Meitzen was under no obligation to use NERA's method and in fact has found errors with other aspects of the method. His failure to reconsider the 33-year average service life assumption in his Eversource testimony despite its being an issue in the Alberta proceeding is therefore noteworthy. In the simple one hoss shay methodology, average service life effectively becomes a "fudge factor" that can be used to produce any result. HQD reports a 39-year average service life in its current rate case.[51]

  It should also be noted that Dr. Meitzen routinely used the geometric decay approach to capital cost measurement in his telecommunications productivity research and testimony.

[51] HQD-3, document 2, p. 10.

All other productivity practitioners at Christensen who have prepared energy utility productivity studies have used geometric decay. Dr. Meitzen lacks the expertise to credibly argue that a one hoss shay approach is somehow relevant to power distribution but not to telecommunications. CEA witness James Coyne employed a geometric decay specification in gas productivity research and testimony for Enbridge Gas Distribution.

- Using the Kahn method, an inflation measure like that which the Régie has discussed, and data on HQD's *revenu requis* and customer trends for the 2005-2015 period, we found that an X factor of **0.67%** is indicated.
- The *cibles d'efficience* (efficiency improvement targets) in the Régie's current *formule paramétrique* for *charges d'exploitation* has risen since 2013 from 1% to 1.5%.
- While some utilities have recently proposed negative X factors on the basis of productivity studies prepared by their witnesses, others have not. For example, Fortis recently proposed an X factor of 0.50% in BC, and Hydro One Networks, Ontario Power Generation, and the gas Amalco have all proposed base productivity growth factors of 0%.

Our review of recent PMF studies and MRI proceedings has implications for the kind of PMF study that is appropriate for HQD after the Company's MRI begins. The study should

- calculate productivity trends in the use of capital and *charges d'exploitation* inputs as well as PMF;
- be based primarily on U.S. data, but also consider productivity trends of HQD;
- use the number of customers served by distributors as the scale variable (though other variables could be examined);
- exclude costs that are Y factored;
- consider a geometric decay capital cost specification, and possibly alternative specifications including one hoss shay;
- assemble solid evidence concerning the average service life of power distributor assets, and consider the sensitivity of productivity results to the service life assumption; and
- include a Kahn X factor exercise as a point of comparison.

5.3 Stretch Factor

We noted in Section 2 that the stretch factor term of an X factor should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the plan compare to those in force for utilities in the productivity studies that are used to set the base productivity trend. It also depends on the company's operating efficiency at the start of the PBR plan. Statistical benchmarking should be considered as a means of setting stretch factors.

Initial Operating Efficiency

Regarding HQD's operating efficiency, we note first that the Company has not previously operated under a comprehensive MRI. To the contrary, it has operated under frequent rate cases for many years, a system that typically yields week cost containment incentives. Growth in the Company's *revenu requis* for many *charges d'exploitation* has, however, been restricted by a *formule paramétrique* for several years.

In reaction to a marked increase in operating expenses, in 2007 the Régie directed HQD to present an integrated efficiency improvement plan in its next rate case that would control cost growth without compromising service quality or grid reliability.[52] Such a plan was approved in Décision D-2008-024, with the goal of reducing the net *charges d'exploitation* by $10 million on a recurring basis. This represented about 1% of controllable costs. In the same decision, the Régie adopted an ongoing efficiency target of 1% of the *charges d'exploitation*, and stated its expectation that HQD would maintain the average annual growth of a set of indicators below inflation over a moving five-year window going forward. In 2014 the Régie increased the efficiency target from 1% to 1.5%.[53]

The efficiency improvement plan was broadly conceived, and the actions taken were numerous. They can be divided roughly into actions taken by current management and those that are structural in nature. The former refers to minor adjustments to current practices, the implementation of which was

[52] Décision D-2007-12.

[53] Décision D-2014-037, pg. 80.

to be the responsibility of HQD's various business units. The latter refers to more major changes, which often required significant up-front investment and were to be individually approved and monitored.

Growth in the Company's *charges d'exploitation* has been slow in recent years. However, it is difficult to ascertain how its current level of efficiency compares to industry norms. For years HQD has participated in benchmarking studies of its customer services and distribution costs.[54] The company reports simple unit cost metrics and its general position related to the other participants in a benchmarking study but does not generally provide further details, nor describe the characteristics of the firms to which its scores are compared.[55] Controls for external business conditions in these studies are crude. The company refused to provide details of a recent benchmarking study in response to an information request from PEG. Thus, it is difficult to interpret the benchmarking results or know what weight to assign to them. On the basis of available evidence, it is reasonable to assume that the Company is an average cost performer.

There is no credible argument for setting stretch factors at zero just because utilities have operated for a few years under a cap on the *revenu requis* for *charges d'exploitation*.

- The performance incentives generated by this cap are not likely to be strong enough to eliminate the accumulated inefficiencies of utilities.
- Even if incentives provided by this cap were much stronger, it is notable that companies in competitive markets have widely varying degrees of operating efficiency.
- Sophisticated benchmarking studies of total cost performance like those required in Ontario have not been reported.

---

[54] Décision D-2008-024, pp. 27-30.

[55] Under the Hydro-Québec Act (sections 7.2 and 20.1), the effectiveness and performance of the company must be assessed by an independent firm every three years, and the results of any such benchmarking studies must appear in the company's annual reports (e.g., Annual Report 2012, pg. 114; Annual Report 2015, pg. 99). Benchmarking results are also discussed periodically in the context of regulatory proceedings.

Comparison to Other Regulatory Systems

The MRI will have a term of only four years. An MTER will be included and will likely share all surplus earnings between the Company and its customers. Meanwhile, the investor-owned utilities whose data are likely to be used in the productivity research have typically averaged rate cases about every three years in recent years. There is therefore not a large difference in the incentive power of HQD's new regulatory system and the systems under which U.S. power distributors have typically operated. Stronger incentives can be hoped for in future MRIs.

Conclusions

Considering all of these factors, and precedents in other jurisdictions, we believe that a stretch factor of **0.20%** is reasonable for HQD.

6. Other Plan Provisions

6.1 Y Factor

Régie Ruling

In D-2017-043, the Régie ruled that Y factor treatment should be permitted for costs that are recurrent but of unpredictable size, sensitive to events outside HQD's control, and in excess of a materiality threshold (*seuil de materialite*). Costs eligible for Y factor treatment shall include HQD's power purchase and transmission expenses and the impact of changes in market rates of return on the weighted average cost of capital (*cout moyen pondere du capital*). The Régie, suggested without rendering a final decision, that retirement costs would be addressed by the *formule d'indexation* but costs of *interventions en efficacite energetique* (*IEE*) would be Y factored. A $15 million materiality threshold was also suggested.[56] The Régie stated that each element of HQD's current variance and deferral accounts [*comptes d' ecarts et reports* (*CER*)] should be examined for eligibility for Y factor or Z factor treatment.

[56] Régie, op. cit., p. 76.

HQD Comments

HQD favors Y factor treatment for its costs of retirement, fuels, *IEE* and support for *Transition energetique Québec* ("TEQ"), bad debt (*mauvaises creances*), low income programs (*strategie por la clientele a faible revenue*), and vegetation management (*maitrise de la vegetation*).

PEG Response

Table 8 presents information on *charges d'exploitation* and accounts that are eligible for Y factoring in contemporary North American energy utility MRIs. It can be seen that diverse costs are typically accorded Y factor treatment. Costs that are commonly eligible for Y factoring include those for energy procurement, upstream transmission, and conservation. Some of the sampled utilities that do not Y factor costs of conservation programs do not have such programs.

PEG has a number of general concerns about the Y factoring of costs in an MRI. Y factoring can weaken incentives to contain the affected costs and raises the cost of regulation. Customers benefit when utilities absorb operating risk. On the other hand, some costs are difficult to address through a rate or revenue cap index because they are sensitive to volatile external business conditions or government directives. Y factoring can materially reduce operating risk.

PEG supports Y factoring all of HQD's costs for IEE and TEQ. These programs can produce material cost savings for HQD's customers. The MRI envisioned in D-2017-043 includes some incentives for the Company to embrace conservation and demand management. These incentives include the revenue cap and the capitalization of some IEE costs. They also include normalization of revenue for weather-induced load variances, since this reduces the risk to HQD from rate designs with high usage charges (including time sensitive rates) that encourage conservation and demand management. However, the incentive to contain load-related distribution capex is weakened in the contemplated MRI by the relatively brief four-year term of the plan, the lack of an efficiency carryover mechanism, the sharing of surplus earnings through the MTER, and the door (discussed further below) which has been opened for the Company to obtain supplemental capital revenue through the Z factor. HQD's incentive to use IEE to contain power supply costs and transmission capex is weakened by the tracking of these costs. Tracking all IEE and TEQ costs would encourage a better balance between Hydro-Québec's incentives to embrace conservation and demand management and its incentives for load-related

Table 8

Approved Y Factors in Current North American MRIs

Company	Jurisdiction	Plan Term	Eligible Costs and Accounts	Citation
Eversource Energy	Massachusetts	2018-2023	Not discussed in decision. Company currently has approved riders to address the costs of DSM programs, pensions, Attorney General Consulting Expenses, pensions and post-employment benefits, state funded renewable programs, solar program, and storm reserves. A Y factor to address the costs of an enhanced vegetation management pilot program was approved in this proceeding.	DPU 17-05
All Distributors	Alberta	2018-2022	All costs that meet the AUC's Y factor criteria. To date, the following costs have been found to meet these criteria: AESO flow-through items Farm transmission costs Accounts that are a result of Commission directions (e.g., AUC assessment fees, intervener hearing costs, UCA assessment fees, AUC tariff billing and load settlement initiatives, Commission-directed Rural Electrification Associations (REA) acquisitions, effects of regulatory decisions) Income tax impacts other than tax rate changes Municipal fees Load balancing deferral accounts Weather deferral account (ATCO Gas only) Production abandonment costs	Decision 20414-D01-2016 (Errata)
Ontario Power Generation	Ontario	2017-2021	Hydroelectric Water Conditions Variance Account Ancillary Services Net Revenues Variance Account – Hydroelectric and Nuclear Sub-Accounts Hydroelectric Incentive Mechanism Variance Account Hydroelectric Surplus Baseload Generation Variance Account Income and Other Taxes Variance Account Capacity Refurbishment Variance Account Pension and OPEB Cost Variance Account Hydroelectric Deferral and Variance Over/Under Recovery Variance Account Gross Revenue Charge Variance Account Pension & OPEB Cash Payment Variance Account Pension & OPEB Cash Versus Accrual Differential Deferral Account Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account	EB-2016-0152
FortisBC	British Columbia	2014-2019	Numerous costs are Y factored including pensions and other post retirement benefits, regulatory hearing costs, accounting standards changes, on-bill financing, interim rate variance	Project #3698719, Decision; September 2014
FortisBC Energy	British Columbia	2014-2019	Numerous costs are Y factored including overhead costs recovered from thermal energy customers, energy policy programs, pensions and other post-employment benefits, midstream gas costs, energy efficiency and conservation, biomethane program, hearing costs, on-bill financing, BCUC assessments, gains and losses on disposition or retirement of property	Project #3698715, Decision; September 2014
Union Gas	Ontario	2014-2018	Upstream gas and transportation costs, incremental DSM costs, LRAM volume reductions for contract rate classes, Unaccounted for Gas Volume Variances, 50% share of tax changes	EB-2013-0202
Incentive Regulation Mechanism Power Distributors except those who opt out	Ontario	2014-2018	**Group 1 includes accounts that do not require a prudence review. This group will include account balances that are cost pass-through and accounts whose original balances were approved by the Board in a previous proceeding.** Low Voltage Account Wholesale Market Service Charge Account Retail Transmission Network Charges Account Retail Transmission Connection Charge Account Power Account Global Adjustment Account **Group 2 includes accounts that require a prudence review.** Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs Other Regulatory Assets - Sub-Account - Incremental Capital Charges Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act Retail Cost Variance Account Board-Approved Conservation and Demand Management Variance Account Others	EB-2010-0239, Filing Requirements For Electricity Distribution Rate Applications (Group 1), EB-2008-0046 and 2018 DVA Continuity Schedule

transmission and distribution capex. PEG also supports Y factoring costs of the *strategie pour la clientele a faible revenu.*

Y factoring retirement costs is a judgement call as there are arguments on both sides. Y factoring these costs can encourage HQD to shift employee compensation from salaries and wages to retirement benefits. Review of these costs can be challenging. On the other hand, these costs are substantial and variable due to business conditions beyond HQD's control. The labor price subindex of the inflation measure tracks trends in salaries and wages but not retirement costs. Retirement costs have been Y factored in several MRIs. The decision on whether to Y factor retirement costs should depend on the extent to which the MRI protects HQD from other kinds of risk.

PEG opposes Y factoring vegetation management, fuel, and bad debt costs. Vegetation management costs are a normal cost of doing business and are very much within a distributor's control. The performance incentive mechanism for reliability should encourage effective vegetation management. Vegetation management is rarely Y factored in MRIs for electric utilities.

Tracking the costs of fuel would weaken the Company's IEE incentives. Indexation of fuel prices is fairly straightforward. Power procurement costs are typically Y factored in MRIs but this is due in part to the difficulty of indexing them in an era of complicated managed power markets. Gasoline prices receive a substantial weight in $IPC^{Québec}$. The inflation measure could, alternatively, include one or more generation fuel price subindexes with appropriate cost share weights. In that event, PEG recommends using the GDPIPI for Canada as the inflation measure for "other" (e.g., capital) inputs.

Bad debt costs rise and fall with the economy but are fairly small. In Québec, the risk of bad debts is limited by the low cost of the patrimonial power block. These costs are not commonly subject to Y factor treatment even in jurisdictions where power supply costs are much more volatile.

The method for Y factoring change in the weighted average cost of capital is up for discussion in Phase 3. PEG believes that, over a plan of only four years, it is necessary to index only the bond yield to market trends. PEG also believes that only 50% of the change in the bond yield should be Y factored since changes in market rates of return on capital are reflected in the IPC in the long run.

6.2 Z Factor

Régie Ruling

In D-2017-043, the Régie ruled that Z factor treatment should be permitted for *elements exogénes* which are particularly difficult to foresee, of unpredictable size, tied to events outside HQD's control, and in excess of a materiality threshold. The Régie also suggested that the Z factor could be used to obtain supplemental revenue for capital, stating that

> **La Régie ne croit donc pas nécessaire, ni souhaitable, d'inclure un mécanisme de suivi des dépenses en immobilisation. Cependant, et tel que le Distributeur le suggère dans son argumentation concernant l'inclusion de l'amortissement, si le Distributeur souhaite réaliser des investissements majeurs et d'une ampleur inhabituelle durant le MRI, il lui sera possible de demander à la Régie de traiter de tels investissements comme un exogène, de type Facteur Z.**[57]

HQD Comments

In its submission last July, Hydro-Québec recommended Z factoring unforeseeable events in the *reseaux autonomes,* unfunded costs of major outages (*pannes majeures*), contributions to connections, and miscellaneous other events including changes in the regulatory regime, demands flowing from decrees or changes in laws, and unforeseen major projects.

PEG Response

PEG supports allowing HQD to request Z factor treatment of unforeseeable events in the *reseaux autonomes*, unfunded costs of major outages (*pannes majeures*) that are attributable to external events, contributions to connections, the *tarif de maintien de la charge*, changes in accounting standards, and miscellaneous other events that include changes in the regulatory regime and demands flowing from decrees or changes in laws. However, PEG is very concerned about the Z factor "loophole" that the Régie has created for supplemental capital revenue. Z factors by their nature provide supplemental revenue for capex resulting from difficult to forecast events such as major storms. The protection afforded by Z factors can be broadened by expanding the eligibility criteria to generally include projects that are mandated for various reasons (e.g., highway relocations) by government agencies. The G factor reduces the risk of unexpectedly rapid growth in the demand for distribution

[57] D-2017-043 p. 64.

services. The term of the MRI is only four years, and underfunding in the last plan years is less problematic. Y factoring changes in the weighted average cost of capital further reduces capital cost risk.

To permit supplemental revenue for other kinds of capex surges opens the door to the several problems that PEG discussed in its Phase I report and responses to information requests. For example, HQD will be incentivized to exaggerate its capital spending requirements and to “bunch” its capex so that it qualifies for tracker treatment. The Company may receive dollar for dollar compensation for capital spending shortfalls when business conditions are unfavorable but receive the full revenue that indexing provides when business conditions are favorable. Customers are not then guaranteed the benefit of industry productivity growth even when it is achievable.

A mechanism for providing supplemental capital revenue such as the Incremental Capital Module in Ontario involves major design challenges and can have unforeseen consequences. In Alberta, a lengthy proceeding was devoted to finalization of capital cost trackers after the outlines of the first-generation MRI were approved. The tracker mechanism ultimately chosen was much more generous to utilities than originally envisioned, and was aggressively used by utilities during the MRI. The scope of capital cost tracking was substantially narrowed by the Commission in the next MRI.

The report and responses to information requests prepared by PEG in Phase 1 provide the Régie with several ideas to make provisions for supplemental capital revenue more reasonable. These include a substantial materiality threshold and the continued tracking of capital costs accorded tracking treatment in subsequent plans. There is currently a 10% adder to the materiality threshold in Ontario's Incremental Capital Module. The X factor can be raised to account for the fact that some large capital projects get Z factor treatment. PEG has addressed the size of X factor adjutments that might be needed in other proceedings.

6.3 Materiality Thresholds

Régie Ruling

In D-2017-043, the Régie suggested $15 million materiality thresholds for Y factors and Z factor events.

PEG Response

Materiality thresholds have several advantages in a system of cost trackers. They can reduce regulatory costs and strengthen a utility's incentive to contain costs. Thresholds can also reduce overcompensation for events (e.g., highway relocations and severe storms) that are routinely encountered by utilities in the productivity growth sample.

Table 9 presents information on materiality thresholds in contemporary MRIs for the Régie's perusal. It can be seen that Z factors are more typically subject to materiality thresholds in the surveyed plans than Y factors. Materiality thresholds are more common for capital cost trackers and are sometimes substantial. It should also be noted that incentivization of cost trackers by limiting the full true up of revenue requirements to actual costs also occurs in North American regulatory systems that do not feature MRIs.[58]

PEG believes that $15 million thresholds are reasonable for a Company of HQD's size. These should apply on a per event basis to Z factors. The first $15 million of variances between Y factored costs and the corresponding revenue requirements should be non-recoverable each year. The thresholds should be escalated annually by the revenue cap index.

6.4 Metrics

Régie Ruling

In D-2017-043, the Régie ruled that the MTER would be linked to an array of service quality and safety metrics.

PEG Response

PEG recommended a performance metric system for HQD in its Phase I report. There should at a minimum be performance incentive mechanisms for the system average interruption duration index, the system average interruption frequency index, various aspects of customer service, and worker safety. There should also be PIMs for analogous itemized reliability indexes for sensible regions of

[58] Cost trackers are widely used in U.S. regulation today.

Table 9

Materiality Thresholds for Y and Z Factors

Company	Jurisdiction	Plan Term	Y Factor Materiality Threshold	Z Factor Materiality Threshold	Citation
Eversource Energy	Massachusetts	2018-2023	Some Y Factors (e.g., $1.2 million per event for the storm fund) have a materiality threshold	$5 million escalated by GDPPI for each year of the plan for each Z factor event	DPU 17-05
All Alberta Distributors	Alberta	2018-2022	Common threshold for Y factor and Z factors: Dollar value of a 40 basis point change in ROE on an after-tax basis calculated on the distribution utility's equity used to determine the final approved notional revenue requirement on which going-in rates were established (2017). This dollar amount threshold is to be escalated by I-X annually. Z factor materiality is determined on a per event basis.		Decision 20414-D01-2016 (Errata)
Ontario Power Generation	Ontario	2017-2021	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	$10 million	EB-2016-0152
Enmax	Alberta	2015-2017	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	$1.7 million per event per year	Decision 21149-D01-2016 (Errata)
FortisBC	British Columbia	2014-2019	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	0.5% of 2013 Base O&M Expense, approximately $300,000 per Z factor event	Project #3698719
FortisBC Energy	British Columbia	2014-2019	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	0.5% of 2013 Base O&M Expense, approximately $1.15 million per Z factor event	Project #3698715
Union Gas	Ontario	2014-2018	O&M materiality threshold not discussed in decision, $5 million revenue requirement impact for capital projects	$ 4 million per Z factor event	EB-2013-0202
Incentive regulation mechanism power distributors except those who opt out	Ontario	2014-2018	O&M materiality threshold not discussed in decision, separate capital materiality threshold established	Per Z factor event: Utility with Revenue Requirement less than or equal to $10 million: $50,000 Utility with Revenue Requirement between $10 and $200 million: 0.5% of distribution revenue requirement Utility with Revenue Requirement above $200 million: $1 million	EB-2010-0379

Québec such as urban and rural areas. IEEE standard 1366 should be used to calculate reliability metrics in order to enhance the comparability of reliability metrics to those of other utilities. HQD already has several customer service quality metrics.

PEG also recommends that some additional metrics be monitored. These metrics include a momentary average interruption frequency index and metrics addressing worst performing circuits. Metrics addressing the quality of service to distributed generation customers are increasingly popular in the United States.

References

Baldwin, John, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program", *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14.

Baldwin, John, Huju Liu, and Marc Tanguay (2015), "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X.

Bureau of Economic Analysis (2015), "Updated Summary of NIPA Methodologies."

Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., Productivity Measurement in Regulated Industries, (Academic Press, New York) pages 172-218.

Fraumeni, Barbara M. (1997), "The Measurement of Depreciation in the U.S. National Income and Product Accounts*," Survey of Current Business*.

Handy-Whitman Index of Public Utility Construction Costs (2013), Baltimore, Whitman, Requardt and Associates.

Hulten, Charles and Frank Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute.

Hulten, Charles (2008) "Getting Depreciation (Almost) Right," University of Maryland working paper.

Lowry, Mark Newton, Matt Makos, and Jeff Deason (2017), *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory.

Organisation for Economic Co-operation and Development (2009), "Measuring Capital OECD Manual," Second Edition.

Statistics Canada (2001), *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204.

U.S. Department of Energy, Financial Statistics of Major U.S. Investor-Owned Electric Utilities, various issues.

TÉMOIGNAGE DE M. JAMES M. COYNE DE CONCENTRIC ENERGY ADVISORS SUR LE FACTEUR X RECOMMANDÉ POUR LE DISTRIBUTEUR

PERFORMANCE BASED REGULATION: RECOMMENDED X FACTOR

PREPARED FOR:
HYDRO-QUÉBEC DISTRIBUTION

BEFORE THE: RÉGIE DE L'ÉNERGIE

JANUARY 5, 2018

www.ceadvisors.com

Table of Contents

List of Tables

List of Figures

Section 1:
Introduction

The Régie determined in D-2017-043 the principal characteristics of a first-generation performance based regulation plan (MRI) for HQD.[1] In its April 2017 Decision, the Régie outlined the general framework for a revenue cap incentive regulation plan. The MRI is to be based on a cost-of-service methodology for year 1, and an indexed-based MRI for years 2, 3 and 4. In reaching this decision, the Régie determined certain parameters in its Phase I Decision, found that a Phase II would not be necessary, and left other parameters to be determined in Phase III, the subject of this immediate proceeding.

Concentric has been asked by HQD to provide an assessment and recommendation for the X factor. This report contains Concentric's analysis and recommendations for this parameter, and builds on the previous research Concentric has provided before the Régie on these matters.[2]

[1] D-2017-043, R-3897-2014 Phase 1, April 7, 2017.
[2] Performance Based Regulation: Recommendations, Prepared for: Hydro-Québec Distribution & Hydro-Québec Transmission, R-3897-2014, before the: Régie de L'énergie, Concentric Energy Advisors, Revised February 10, 2016. Performance Based Regulation: Productivity Factor for HQD, Prepared for: Hydro-Québec Distribution, R-3897-2014, before the: Régie de L'énergie, Concentric Energy Advisors, June 30, 2017. This report was attached to HQD's submission filed with the Régie on June 29th, however, the date on the Concentric report was left at June 30th. This report is referenced as Concentric June 30, 2017 Report.

Section 2:
X Factor

A. OVERVIEW

The purpose of the X factor ("X") in an MRI or PBR program, such as that approved for HQD, is to establish a revenue path for the company related to inflation ("I") rather than actual costs, thereby creating a direct incentive to control costs. The X parameter is a measure of "productivity", determining if revenues should increase at a faster or slower rate than inflation. In its simplest form, this relationship is expressed as:

$$Revenues_{(t+1)} = Revenues_{(t)} * (1 + \text{I-X})$$

Additional factors for growth (G), capital (K), variable cost items (Y), or one-time events (Z) may also be included in the formula. Productivity studies differ with respect to the approaches and inputs utilized in measuring the efficiency of individual companies, industries, or the entire economy. In utility regulation, productivity studies are intended to derive an estimate that can inform the establishment of X when applying an I-X PBR methodology, as recommended for HQD.

There are alternative ways to derive "X" that range from past observed productivity gains for the specific company to industry benchmarking studies and industry productivity studies. No one method is determinative and ultimately the X factor must be set using informed judgment by the regulator. The Régie, in agreeing that it would apply its judgement in determining the X factor for this first-generation MRI, required the Distributor to submit evidence on the appropriate X for HQD.[3]

Concentric's previously submitted research to the Régie summarized the studies, analyses, and reports available to it to inform the Régie as to the determination of X in this Phase 3.[4] Concentric highlighted recent trends in productivity research including:

- An update of its survey on productivity studies examined in response to the Régie's information request R4.2 at HQTD-4, document 1 (R-3897-2014, phase 1); and
- Recent trends in Canadian and US multifactor productivity.

This submission draws on that evidence, as well as HQD's past performance, and concludes with a recommended X factor for HQD in this first-generation MRI.

B. X FACTOR RESEARCH FROM OTHER JURISDICTIONS

Utility productivity studies are not routinely submitted in North American jurisdictions as these studies are costly and time consuming, and relatively few jurisdictions adhere to an I-X form of utility

[3] The Régie specifically ordered: "[T]he Distributor to submit, by June 30, 2017, the studies, analyzes and reports available to it in order to inform the Régie as to the determination of Factor X in Phase 3;" D-2017-043, R-3897-2014 Phase 1, April 7, 2017 at ¶ 167

[4] Concentric June 30, 2017 Report.

regulation. As cited by Concentric in its June 30, 2017 Report, there have been recent studies submitted in Alberta and Ontario.[5] Since that time, a more recent study was decided on in Massachusetts. The results of those studies are summarized here. Concentric is not aware of any other productivity studies that have been submitted since that time.

1. ALBERTA

The current PBR plans for Alberta's electric and gas distributors expire on December 31, 2017. The Commission initiated a proceeding to establish the "next generation of PBR plans" to be implemented for the 2018-2022 period in May 2015. Plan proposals, including recommended X-factors, were submitted in March 2016 and the Commission issued its decision in December 2016. Several experts provided productivity related evidence and studies, including: The Brattle Group ("Brattle"), Christensen Associates ("Christensen"), Pacific Economics Group ("PEG"), PCMG Associates ("PCMG")[6] and other individual experts.[7] Brattle and Christensen submitted evidence on behalf of the utilities, while PEG and PCMP submitted evidence on behalf of intervenors.

In its Decision, the Commission reduced the X-factor to 0.3% from the 1.16% (Total Factor Productivity "TFP" growth of 0.96% plus a stretch factor of 0.2%) adopted in 2012 for the prior plans. This current Decision is primarily based on three studies submitted in the proceeding, from Brattle, Christensen, and PEG as highlighted in Table 1. Each of the three studies produced results lower than the 0.96% adopted by the Commission in 2012. The AUC noted:

> The three studies filed in this proceeding provide a relatively wide range of TFP growth values, with all final recommendations smaller than, and in some cases much smaller than, the TFP growth number adopted by the Commission in Decision 2012-237. The issue that the Commission must address, therefore, assuming the Commission finds any of the studies to be acceptable, is not whether the TFP growth component of 0.96 per cent adopted in Decision 2012- 237 needs to be lowered for the next generation PBR plans, but rather the extent to which it needs to be lowered.[8]

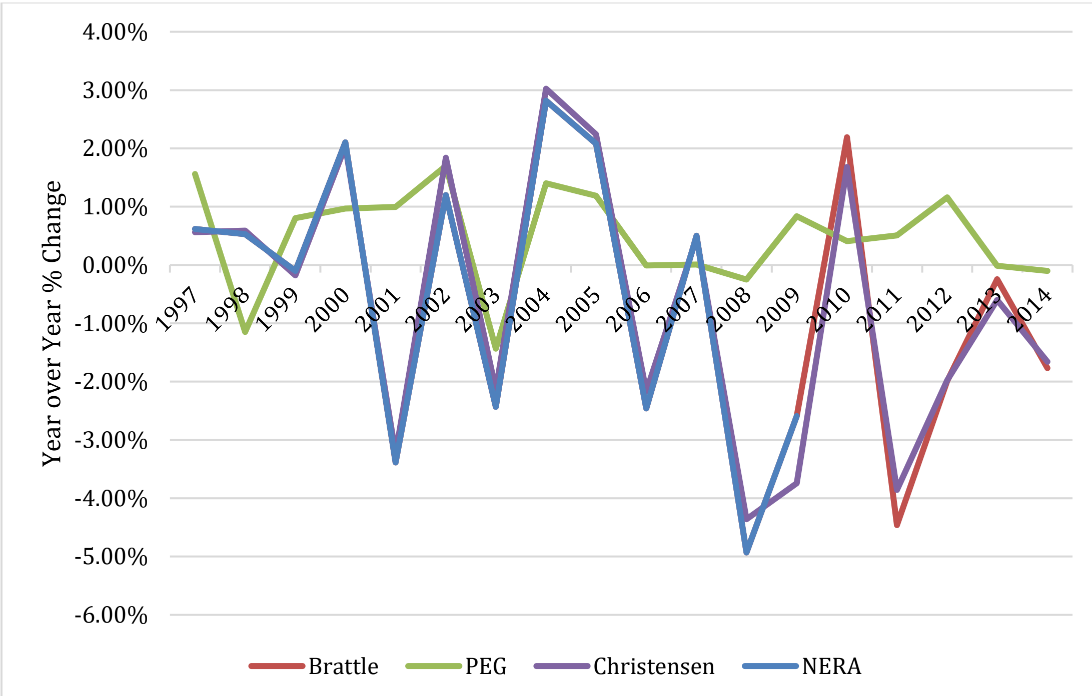
[5] Performance Based Regulation: Productivity Factor for HQD, Prepared for: Hydro-Québec Distribution, R-3897-2014, before the: Régie de L'énergie, Concentric Energy Advisors, June 30, 2017.
[6] PCMG submitted evidence but did not undertake a TFP or MFP study.
[7] AUC Decision 20414-D01-2016, December 16, 2016, at 1-3.
[8] AUC Decision 20414-D01-2016, December 16, 2016, at 24.

Table 1: 2016 Alberta Productivity Studies

Expert	*Participant*	*TFP Study Results*	*Proposed X Factor (%)*	*Sample / Time-Period*
Brattle (Brown and Carpenter)	Distribution Utilities (other than EPCOR)	-0.37% to -1.37%	-0.79%	67 utilities, 2000-2014
Christensen Associates (Meitzen)	EPCOR	-1.11%	-1.11%	68-72, Average of last 15 (2000-2014) and last 10 (2005-2014) years
PEG (Lowry)	CCA	0.36% to 1.03%	0.43% 0.78%	88, 21, 1997-2014
Final Commission Decision			0.30%	

The annual productivity estimates from these studies, as well as the 2012 NERA study upon which the 2012 AUC decision was based, are illustrated in Figure 1 as separate lines. The calculation of TFP is based on the difference between measured outputs (MWHs or customers) and inputs (labor, capital, and materials). Both outputs and inputs vary by year, and taking the difference between the two indices creates a volatile year-to-year profile, so the data is typically compiled over many years to reflect the industry trend. All the studies show an industry trend in productivity converging at or below zero over this two-decade period, indicating negative productivity growth. This does not mean the utilities in the sample are becoming less productive, per se, but that the rate of growth of inputs is exceeding the rate of growth in outputs. A contributing factor has been the decline in electric demand growth without offsetting declines in labor, capital and other operational costs required to maintain and upgrade these utility systems.

Figure 1: Productivity Study Results Submitted in Alberta



The AUC indicated that it considered several factors in its assessment of each study, including: objectivity; consistency and transparency of the three studies; the utility data set employed in each study; the calculation methods and assumptions; the output measures; and the time periods of each study.[9] The AUC also offered insight into its previous decision in the 2012 generic proceeding,[10] noting:

> Although NERA's was not the only TFP growth study considered in that proceeding, the Commission found the NERA study to be preferable because of the "objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad-based inclusion of electric distribution utilities from the United States." The final approved TFP growth value of 0.96 per cent, determined as the difference between growth in output and growth in inputs, was obtained as the average of 37 annual TFP growth values for the 1972-2009 period…[11]

The AUC discussed the value of, and the differences in, transparency, objectivity, and consistency of the studies. It considered the considerable differences between the utility studies and the study performed by PEG, but ultimately chose to give all studies the same weight.

---

[9] AUC Decision 20414-D01-2016, December 16, 2016, at 45.
[10] Alberta 2012 Generic PBR Proceeding resulted in Decision 2012-237, September 12 ,2012.
[11] AUC Decision 20414-D01-2016, December 16, 2016, at 22-23.

The AUC noted that in its judgment, "[T]he issue of whether the TFP growth value should be determined based on a customization or tailoring of firms selected to be included within the TFP growth study based on characteristics similar to the Alberta distribution utilities is directly related to the underlying objectives of a PBR plan." Ultimately, the Commission decided that since PBR in Alberta is meant to emulate competitive markets, it is preferable to use a broad sample that will represent the many factors that influence productivity in a market.[12]

Responding to varying input and output measures used in the studies, the AUC noted it was unwilling to state a preference for the set of assumptions used by any one TFP study over another. Underscoring the challenges of interpreting the results of TFP studies from alternative experts with varying assumptions and methods, the Commission noted:

> In the Commission's view, there is no overwhelming new evidence in this proceeding that any of these assumptions are correct or incorrect. The assumptions chosen reflects the practitioner's decisions and beliefs based on the available choices that can be applied to the data, and there is generally no test presented in evidence that can be applied to determine which assumptions are more applicable to particular data or the purposes for which it is used. It is unlikely that any group of unassociated practitioners will make the same choices for all the assumptions, even with the same universe of data series available to them. For this aspect of the analysis, the Commission is, therefore, unwilling to specify a preference for the set of assumptions used by any particular one of the three TFP growth studies.[13]

However, the AUC acknowledged that with the prevalence of both fixed and variable revenue components for distribution utilities, the number of customers (the output measure used by PEG) is a relevant output measure along with volume (the output measure used by Brattle and Christensen), where the relative weights assigned to these two output measures would ideally reflect the proportion of revenues generated through fixed versus variable (volumetric) charges.[14] The Commission noted that "after controlling for differences between the studies, the difference in output measures, number of customers versus volume, affects annual growth by between 0.24 and 0.41 percentage points for this period, a number that translates directly into TFP growth differences since TFP growth is output growth less input growth."[15] In other words, this difference can be accounted for and of itself does not account for the differences between the studies.

The period of each study was the last major consideration of the AUC in determining the X factor. Brattle and Christensen each highlighted the evolution of productivity results over time and argued that more weight should be given to results from more recent years. The Commission decided that the time period used remains an "open question."[16]

[12] AUC Decision 20414-D01-2016, December 16, 2016, at 28.
[13] AUC Decision 20414-D01-2016, December 16, 2016, at 30.
[14] AUC Decision 20414-D01-2016, December 16, 2016, at 30-33.
[15] AUC Decision 20414-D01-2016, December 16, 2016, at 34.
[16] AUC Decision 20414-D01-2016, December 16, 2016, at 36.

Expressing its view on the range of results from alternative studies, the Commission ultimately concluded:

> [T]he Commission views the variety of results that have been provided as confirming that the TFP growth value is likely not a correct single number, but that a reasonable value likely falls within a range of values, demarcated by the breadth of assumptions and data sets that may be reasonably employed in producing the studies.[17]

The Commission's conclusion is consistent with Concentric's observations regarding the estimation of utility productivity. In reaching its final determination of the appropriate X factor, the AUC reasoned:

> The Commission has determined an X factor, using its judgement and expertise in weighing the evidence and in taking into account the multitude of considerations set out above, in particular evidence demonstrating that the TFP growth value cannot with certainty be identified as a single number, but rather, in view of the variability resulting from the assumptions employed, must be considered as falling within a reasonable range of values, between -0.79 and +0.75. **The Commission finds that a reasonable X factor for the next generation PBR plans for electric and gas distribution utilities in Alberta, inclusive of a stretch factor, will be 0.3 per cent.**[18] (emphasis added)

In approving this second-generation plan, the AUC reconsidered the capital tracker element of the first-generation plan. The Commission summarized:

> In Decision 2012-237, the Commission recognized that while the TFP study used in determining the X factor for the Alberta distribution utilities reflected a rate of long run productivity growth for a set of distribution utilities over time and, therefore, necessarily included capital input costs, there are nevertheless circumstances where an Alberta distribution utility may require capital funding in addition to the funding generated under the I-X mechanism in order to provide for necessary capital additions. To address this need, a capital funding mechanism referred to as a "capital tracker" was established. The capital tracker mechanism provided for a COS application process, whereby the revenue requirement associated with approved capital projects or programs could be reviewed, approved, and collected from ratepayers by way of a K factor adjustment to the annual PBR rate-setting formula.[19]

On reconsideration in this second-generation plan, the AUC determined that incremental capital (not fully covered under I-X) should be broken into two categories:

- Type 1 Capital – capital investments outside of management's control, are unforecastable, or have a high degree of variability from year to year, and do not

[17] AUC Decision 20414-D01-2016, December 16, 2016, at 40.
[18] AUC Decision 20414-D01-2016, December 16, 2016, at 45.
[19] AUC Decision 20414-D01-2016, December 16, 2016, at 46-47.

qualify for Y[20] or Z factor treatment, for example: "These types of capital additions might include capital additions required by new government programs not previously experienced but would not include types of expenditures required by governments in the normal course of expectations, such as moves required to accommodate road or interchange reconfigurations." (These would be Type 2 capital). In sum, to qualify for Type 1:

(i) The project must be of a type that is extraordinary and not previously included in the distribution utility's rate base, and
(ii) The project must be required by a third party.

- Type 2 Capital – most other capital that is not fully funded by I-X, or covered by a Y or Z factor. The amount of this capital will be predetermined for each distributor for all, or a portion of the PBR plan. For example: "Growth, short-lived assets and replacement projects or programs would also be included in Type 2 because they have been experienced in the past." This approach to funding incremental capital is referred to as "K–bar".[21]

In justifying this change, the AUC noted:

> The Commission considers that any choice of the capital mechanism will result in trade-offs. The Commission accepts that there is considerable benefit to the distribution utility and to customers to ensuring that the same high-powered incentives present under the I-X mechanism apply to capital. A K-bar approach maximizes the ability of each distribution utility to manage its business and to discover and pursue efficiencies and costs saving by providing flexibility in how it plans and allocates capital funding throughout the next generation PBR plans while fulfilling its obligation to serve. **This increased flexibility and reduced regulatory burden is preferable to the present annual capital tracker forecast, approval, and true-up mechanism for all incremental capital requirements.** The Commission further considers that an amended pure I-X proposal, which only allows for restricted access to incremental capital funding, may be insufficient to provide the incremental capital funding for necessary capital additions given that the distribution utilities were able to demonstrate under existing capital tracker criteria that incremental capital funding was required to allow the distribution utilities to fund necessary capital additions under the 2013-2017 PBR plans.[22] (emphasis added)

In sum, the AUC's latest PBR plan allows for the recovery of capital costs outside of the I-X mechanism in two ways: Type 1 recovers the incremental revenue requirement of qualified projects on a cost of service basis; Type 2 recovers the incremental revenue requirement of

[20] The AUC's examples for Y factor treatment are typically non-capital related: (a) AESO flow-through items, (b) Farm transmission costs, (c) Accounts that are a result of Commission directions (e.g., AUC assessment fees, intervener hearing costs, UCA assessment fees, AUC tariff billing and load settlement initiatives, Commission-directed Rural Electrification Associations, (REA) acquisitions, effects of regulatory decisions)(d) Income tax impacts other than tax rate changes, (e) Municipal fees, (f) Load balancing deferral accounts, (g) Weather deferral account (ATCO Gas only), (h) Production abandonment costs. AUC Decision 20414-D01-2016, December 16, 2016, at 89-90.
[21] AUC Decision 20414-D01-2016, December 16, 2016, at 49-50, 52.
[22] AUC Decision 20414-D01-2016, December 16, 2016, at 57

a predetermined dollar amount of qualified investment. These replace the prior K factor. In reaching this decision, the AUC reasoned:

> Consistent with the findings in Decision 2012-237, the Commission continues to find that there is sufficient evidence that a capital mechanism in addition to I-X is required to deal with the unique circumstances of individual distribution utilities that may be in different places in their capital programs and business cycles.[23]

The Commission's decision to divide capital into the two categories appears to be based on the suggestion by some parties that utilities should be incented to control predictable capital expenditures (Type 2), reserving Type 1 for non-predictable capital.

> Several parties in the proceeding suggested dealing with incremental capital funding requirements by dividing capital additions on the basis of characteristics; for example, the ability of the distribution utility to forecast and control the capital additions.[24]

And:

> K-bar is able to provide incremental capital funding for programs that fail the Type 1 criteria while maintaining strong incentives for efficiency.[25]

Concluding:

> The significance of the capital tracker program was that its operation had the unintended effect of removing considerable capital from the productivity incentives created by the I-X mechanism.[26]

2. ONTARIO

Ontario's electric distributors are operating under the Ontario Energy Board's ("OEB's") 4th generation performance based ratemaking plans. Since that time, Hydro One, the province's largest electric distributor, has submitted a proposal for a five-year rate plan, covering the 2018-2022 rate period. The company's proposal is supported by a productivity study conducted by Power System Engineering ("PSE"). The study incorporates estimates of productivity for Hydro One, covering the 2002-2015 period, and an estimate based on updates to a study previously performed by PEG, the Board's consultant, for the entire Ontario electric industry. The updates by PSE added data for 2013, 2014 and 2015 to the 2002-2012 period previously analyzed.[27] These results are presented in Table 2.

---

[23] AUC Decision 20414-D01-2016, December 16, 2016, at 49.
[24] AUC Decision 20414-D01-2016, December 16, 2016, at 49.
[25] AUC Decision 20414-D01-2016, December 16, 2016, at 56.
[26] AUC Decision 20414-D01-2016, December 16, 2016, at 57.
[27] EB-2017-0049 – Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application and Evidence Filing, March 31, 2017, Exhibit A, Tab 3, Schedule 1, p. 6; and Exhibit A-3-2, Attachment 1, Total Factor Productivity Study of the

Table 2: Productivity Study Results Submitted by Hydro One

Expert	*Participant*	*Productivity Study Results*	*Proposed X Factor (%)*	*Stretch Factor (%)*	*Sample / Time-Period*
Power System Engineering	Hydro One Distribution	Hydro One TFP Unadjusted: -1.4% Adjusted: -0.9% Ontario Industry TFP (PEG Update): -0.9%	0.0%	0.6%	2002-2015, Hydro One TFP: 1 firm PEG Update: 73 firms

PSE did not recommend an X Factor based on Hydro One's productivity trend, but rather based on the Ontario trend consistent with the prior Board Decision on this matter. PSE explains:

> During the 4th Generation Incentive Regulation proceeding (EB-2010-0379), PEG conducted a TFP study for the Ontario electric distribution study (PEG Study). The study objective, as PSE understands it, was to provide an empirically-based recommendation on the productivity factor. This focused objective did not include an evaluation of the performance trend of individual distributors. Rather, the study was meant to inform the Board regarding the most appropriate productivity factor.
>
> The PEG study determined the Ontario electric distribution TFP for 2002 to 2012 was -0.3%. Since the time of that study, industry data has become available for the years 2013, 2014, and 2015. PSE has replicated PEG's methodology for the 2002 and 2012 period and updated the Ontario industry TFP study to 2015.
>
> The updated average annual growth rate in the Ontario TFP is -0.9%. Consistent with the prior study, this excludes Hydro One and Toronto Hydro.[28]

PSE's report, incorporated in the Hydro One filing, presented the following conclusions:

> **After updating the Ontario industry TFP to 2015, PSE found the 2002-2015 trend is -0.9%.** The 2002-2012 Ontario TFP trend was -0.3%. Based on the empirical evidence of declining industry TFP and the OEB's 4th Generation IR decision to set the productivity factor at 0.0%, **PSE recommends setting Hydro One's productivity factor no higher than 0.0%.** (emphasis added)
>
> The X-factor is calculated as the sum of the productivity factor and the stretch factor. Stretch factors are normally determined using benchmarking research. PSE is of the opinion that accurate total cost benchmarking is the best approach in setting stretch factors. The long term 2002-2015 Hydro One adjusted TFP trend of -0.9% and the

Electric Distribution Functions of Hydro One and the Ontario Industry, Power System Engineering, Inc., November 4, 2016, at 1.

[28] EB-2017-0049 – Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application and Evidence Filing, March 31, 2017, Exhibit A, Tab 3, Schedule 1, p. 6; and Exhibit A-3-2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, Power System Engineering, Inc., November 4, 2016, at 4.

> recent positive TFP growth of +0.5% provides evidence that there is the chance for modest TFP growth in the near term. On this basis, PSE recommends setting the stretch factor no higher than 0.6%. This is the maximum stretch factor put forth in 4th Generation IR and combined with a 0.0% productivity factor would amount to an X-factor of 0.6%.[29]

It is worthy to note that Hydro One's proposal falls under the OEB's Custom Incentive Rate-Setting "(IR)" option, and Hydro One's proposal is of the form:

> Revenue Cap Index = I – X + C

Where:

> "I" is the inflation factor, as determined annually by the OEB.
>
> "X" is the productivity factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
>
> "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.[30]

As illustrated in the table below, the proposed custom capital factor adds between 2.46% – 3.66% to the prior year's annual revenue requirement. As Hydro One explains:

> The Custom Capital Factor proposed in this Application and used in the RCI is designed to ensure that total revenue resulting from the Custom IR is able to meet Hydro One's specific circumstances arising from the proposed capital investments set out in Hydro One's DSP (Exhibit B1). The Custom Capital Factor is the percentage change in the Total Revenue Requirement (line 11 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers. This includes depreciation, return on equity, interest, and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The Capital Related Revenue Requirement (line 6) each year is based on the change in rate base.[31]

The projected impact of the capital factor is seen below, where the impact ranges from 1.64% to 2.86% above the revenue requirement that would otherwise be set by I-X. In effect, the nominal X factor of 0.6% is negative, ranging from -1.04 to -2.26% when the capital factor is considered.

---

[29] EB-2017-0049 – Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application and Evidence Filing, March 31, 2017, Exhibit A, Tab 3, Schedule 1, p. 6; and Exhibit A-3-2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, Power System Engineering, Inc., November 4, 2016, at 5-6.
[30] Hydro One Application, Exhibit A, Tab 3, p. 6.
[31] Hydro One Application, Exhibit A, Tab 3, Schedule 2, pp. 5-6.

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,672.3	8,049.1	8,476.8	9,035.4	9,434.7
2	Return on Debt	E1-1-1	190.9	200.3	211.0	224.9	234.8
3	Return on Equity	E1-1-1	269.5	282.7	297.7	317.3	331.3
4	Depreciation	C1-6-2	394.4	414.4	428.7	448.1	464.7
5	Income Taxes	C1-7-2	58.0	61.3	62.6	68.7	69.6
6	Capital Related Revenue Requirement		912.8	958.7	1,000.0	1,059.0	1,100.5
7	Less Productivity Factor (0.60%)			(5.8)	(6.0)	(6.4)	(6.6)
8	**Total Capital Related Revenue Requirement**		**912.8**	**953.0**	**994.0**	**1,052.6**	**1,093.9**
9	OM&A	C1-1-1	591.9	599.6	607.4	615.3	634.2
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,504.7**	**1,552.6**	**1,601.4**	**1,678.7**	**1,728.1**
12	Increase in Capital Related Revenue Requirement			40.2	41.0	58.6	41.3
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.67%	2.64%	3.66%	2.46%
14	Less Capital Related Revenue Requirement in I-X			0.79%	0.80%	0.81%	0.82%
15	**Capital Factor**			**1.88%**	**1.84%**	**2.86%**	**1.64%**

The Hydro One rate filing remains under review. According to the OEB's procedural schedule, OEB staff and any intervenors permitted to file expert evidence will file evidence with the OEB on December 14, 2017,[32] and an oral hearing is scheduled to begin on February 5, 2018.[33]

3. MASSACHUSETTS

A number of PBR programs for the state's gas and electric utilities in Massachusetts have expired, returning to a more traditional cost of service model with capital trackers for targeted investments, but Eversource applied for a new PBR program in January of 2017. This plan was approved by the Department of Public Utilities (DPU) on November 30, 2017.[34] The Eversource companies had operated under a series of rate freezes and long-term rate plans for the previous sixteen years.[35] Eversource serves approximately 1.4 million electric customers in Massachusetts, and 3.2 million in New England. In support of its PBR proposal, the company presented expert evidence including an electric industry productivity study.[36] The study utilized two different groups: (1) a sample of 67 electric distribution companies located across the U.S, representing approximately 75% of electric distribution customers in the country; and (2) a smaller sample of 17 electric distribution companies located in the Northeast U.S.

The data covered the 2001-2015 period, and relied on the number of customers as the measure of output, and standard measures of labor, materials, and capital measures of inputs. Based on the results of these studies, and placing reliance on the national sample group, Eversource's expert

32 As of December 19, 2017, it does not appear any intervenors have filed new TFP evidence.
33 EB-2017-0049, Hydro One Networks Inc. Application for Electricity Distribution Rates Beginning January 1, 2018 until December 31, 2022, Procedural Order No. 1, August 30, 2017.
34 DPU 17-05, Order Establishing Eversource's Revenue Requirement, November 30, 2017.
35 DPU. 17-05, Exhibit ES-GWPP-1, January 17, 2017, p 56.
36 Mark E. Meitzen, PhD, of Christensen Associates served as the company's principal expert on these matters.

calculated a productivity offset (X factor) of -2.56%[37] for the national sample and -2.47% for the Northeast sample.[38] The company also proposed the use of a national measure of inflation, the Gross Domestic Product Price Index (GDP-PI) with a floor of 1.0%. As a result, if actual inflation falls below 1.0%, the floor would be used in the formula.

The company also proposed a "consumer dividend" (stretch factor) of 0.25% for when inflation exceeds 2%. Eversource offered a consumer dividend to represent its "commitment to provide customers with an explicit, tangible benefit in relationship to operating-cost control." The company's evidence describes the consumer dividend rationale: "Dr. Meitzen advised the Company that the ultimate determination of a consumer dividend factor is recognized to be largely subjective and that there is a lack of a quantitative, empirical basis for establishing its magnitude." And "In this case, the Company is proposing to undertake substantial, incremental financial commitment to grid-modernization without a separate recovery mechanism, and without explicit recognition in the PBRM[echanism]. This commitment represents a consumer dividend of approximately 1.08 percent, which is a magnitude that is larger than the consumer dividend applied in previous PBR plans approved by the Department. In addition, the Company is proposing an additional 25 basis-point Consumer Dividend factor to demonstrate the company's commitment to provide customers with an explicit, tangible benefit in relation to operating-cost control. Under circumstances where inflation is greater than two percent, the Company's operating costs will be increasing at a fairly substantial pace, and the 25 basis-point Consumer Dividend will force the Company to work hard to find ways to suppress cost increases to the direct benefit of customers in the next rate case."[39]

While the stretch factor proposed was 0.25%, the Company and its expert noted that if customer growth was consistent with the prior 15 years, it would add an additional "implicit stretch factor of 0.56%", and "A revenue cap would not account for this customer growth and, therefore, the additional costs associated with this growth would be absorbed by the Company."

[37] Subsequently revised to -2.64%
[38] The company indicated the X factor would be substantially lower at -4.04% if sales were used as the output measure.
[39] DPU 17-05, Exhibit ES-GWPP-1, January 17, 2017, pp. 55-56.

Table 3: Productivity Study Results Submitted by Eversource

Expert	*Participant*	*Productivity Study Results*	*Proposed X Factor (%)*	*Stretch Factor (%)*	*Sample / Time Period*
Christensen Associates (Meitzen)	Eversource Energy	National Sample: -0.46% Northeast Sample: -0.41%	-2.56%[40] -2.47%	0.25%	2001-2015 67 Companies – U.S. 17 Companies – Northeast Sample
Final Commission Decision			-1.56%	0.25%	

In reviewing the company's application, and the positions of the opposing intervenors and expert witnesses, the DPU approved the company's plan with the following modifications and justifications. The DPU agreed that a national sample covering the 2001-2015 period was appropriate. The differences between the X factors for the regional sample and the national sample were small, and a national sample provided a more robust dataset. The Department also found the use of customers as the sole output measure to be appropriate, and better reflected changes in the industry's distribution system investment requirements. The Department concluded that the resulting X factor was determined in a reasonable manner. The company had indicated that the proposed plan would allow it to absorb the $400 million of grid modernization investments (equivalent to 1.08% in annual revenue requirement, as noted above), while amounts above that level would be recovered separately. The Department determined it was appropriate to address the $400 million grid modernization investment outside the PBR plan, and therefore reduced the X factor by that amount, resulting in an approved X factor of -1.56% (-2.64% + 1.08%). The proposed inflation floor of 1.0% was not approved, but approval of the stretch factor of 0.25% was conditioned on inflation exceeding 2%. Taken together, the resulting X factor including the stretch factor is -1.31% (-1.56% + 0.25%).[41] This X factor will be applied to the company's base revenue requirement.

The recommended X factor was computed based on a combination of the expert's TFP analysis and the adjustments made by the Company and DPU. The computation is illustrated below:

40 Subsequently revised to -2.64%.

41 DPU 17-05, Order Establishing Eversource's Revenue Requirement, November 30, 2017, pp. 334-395, and Direct Testimony of Mark E. Meitzen, Ph.D., Christensen Associates, Performance-Based Ratemaking Mechanism On behalf of NSTAR Electric Company and Western Massachusetts Electric Company, Each d/b/a EVERSOURCE ENERGY, January 17, 2017.

Table 4: Eversource X Factor Computation[42]

TOTAL FACTOR PRODUCTIVITY – U.S. ELECTRIC INDUSTRY SAMPLE, 2001-2015	-0.46%
DIFFERENCE BETWEEN ELECTRIC INDUSTRY PRODUCTIVITY AND OVERALL ECONOMY	-1.35%
DIFFERENCE BETWEEN ELECTRIC INDUSTRY INPUT PRICES AND OVERALL ECONOMY	-1.29%
X FACTOR	-2.64%
REMOVAL OF $400M INCREMENTAL INVESTMENT UNDER THE I-X PLAN	1.08%
FINAL X FACTOR	**-1.56%**
CONSUMER DIVIDEND (STRETCH FACTOR WHEN INFLATION >2%)	0.25%
X FACTOR WHEN INFLATION >2%	**-1.31%**

Note that the TFP result for the industry, which produced a result of -0.46%, is adjusted for differences in productivity and input prices between the industry and the economy overall for an X factor of -2.64%. The need for this adjustment is dependent on the inflation factor (I) used in the PBR plan. As the Company's expert explained: "If the I factor is represented by the change in economy-wide output inflation as in the GDP-PI, then the revenue cap X factor is the combination of TFP and input price differentials."[43] The adjustment of TFP results for the I factor used in the PBR plan varies by expert and jurisdiction. Conceptually, if the inflation measure used in the formula is based on measures of input prices (such as a labor price index) then no adjustment is required, but if a measure of output (such as a consumer price index) is used, then an adjustment may be required for these input price differentials. In the Eversource plan, the inflation index is an output measure (GDP-PI), so the adjustment was made. The adjustment accounts for differences in productivity between the economy and the utility industry, and differences between the price indices.

The Eversource plan was also approved with an earnings sharing mechanism. The Department found that "a 200 basis point deadband will provide the Companies with a strong incentive to pursue savings", and "in order to appropriately balance shareholder and ratepayer risk under the PBR as designed, the Department finds that the benefits of any earnings sharing above the deadband must inure largely to ratepayers." The DPU therefore approved a 75/25% sharing above the 200 basis point deadband in favor of ratepayers.[44]

The approved plan commences starting January 1, 2018, for a period of five years, and does not include an off-ramp, absent a showing of "extraordinary circumstances".[45]

B. STRETCH FACTOR

PBR plans often, but do not always, include a "stretch factor". The rationale for a stretch factor is generally that the measured productivity of the industry when largely operating under a cost of service model does not adequately reflect the potential efficiency gains of a performance-based rate

[42] Christensen, ibid, p. 52, as revised and approved by the DPU, DPU 17-05, Decision, pp. 391-395.
[43] Christensen, ibid, p. 40.
[44] Ibid, at pp. 400-401.
[45] Ibid, at p. 404.

model. A stretch factor provides an immediate benefit for customers above and beyond the industry trend in productivity.

The determination of whether a stretch factor is required, and its magnitude, is largely the judgement of the regulator. In the case of Alberta, the Commission did not separately determine the value of X without the stretch factor, as it did in its previous decision. The 0.3% is inclusive. The AUC reasoned:

> Given that current generation PBR plans include a COS-based capital trackers mechanism, which will be mostly replaced in the next generation PBR plans by the K-bar mechanism, the Commission expects that next generation PBR plans will be largely devoid of any significant COS elements. Therefore, the Commission finds merit in including a stretch factor component in the X factor for the next generation PBR plans for all distribution utilities.[46]

If its prior decision is a guide, the AUC determined a stretch factor of 0.2% was appropriate for Alberta's gas and electric distributors in its first-generation PBR.[47]

In Ontario, the OEB has set stretch factors for utilities operating under the I-X plan based on an analysis of the relative efficiency of its distributors. The Board summarizes:

> The OEB currently conducts total cost benchmarking for electricity distributors. An econometric model is used to generate efficiency rankings and assign electricity distributors to one of five groups based on their total cost performance, including both capital and OM&A costs. These results are used to set the productivity stretch factors for the incentive rate-setting mechanism (IRM) applications, and will also be a consideration in assessing a utility's cost trend performance.[48]

Based on data provided by Ontario's distributors to the Board, and analysis conducted by PEG, the OEB determined the following stretch factors:[49]

[46] AUC Decision 20414-D01-2016, December 16, 2016, at 40.

[47] AUC Decision 2012-237, paragraphs 514-515, the X factor of 1.16 per cent was determined as the sum of the underlying long-term industry TFP growth value of 0.96 per cent and a stretch factor of 0.2 per cent.

[48] OEB Handbook to Utility Rate Applications, October 13, 2016, p. 18.

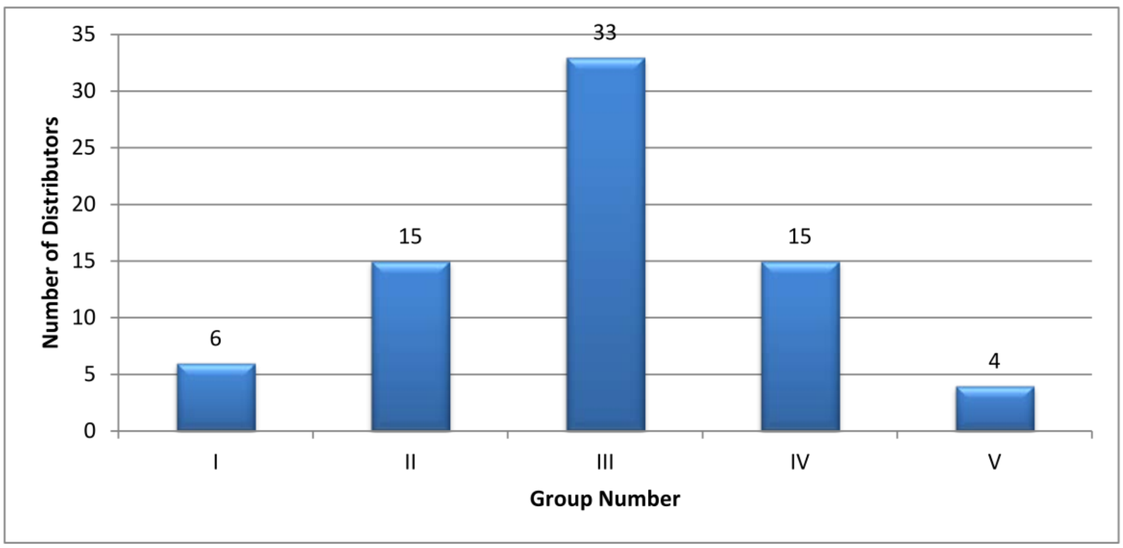
[49] EB-2010-0379, Report of the Board, Rate Setting Parameters, and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, issued on November 21, 2013 and as corrected on December 4, 2013, p. 21. The "predicted" vs. "actual" costs which served as the basis for the OEB's stretch factors were based on an econometric and benchmarking analysis of the Ontario distributors conducted by PEG, using data for each distributor over the 2009-2011 period. The "predicted" value was based on the model's estimates of the utility's costs given its actual output and input characteristics, and the relationship between the utility's costs and its peers.

OEB Determined Demarcation Points for Relative Cost Performance

Group	Demarcation Points for Relative Cost Performance	Stretch Factor
I	Actual costs are 25% or more below predicted costs	0.00%
II	Actual costs are 10% to 25% below predicted costs	0.15%
III	Actual costs are within +/-10% of predicted costs	0.30%
IV	Actual costs are 10% to 25% above predicted costs	0.45%
V	Actual costs are 25% or more above predicted costs	0.60%

Interpreting these results and their application, the OEB applies a range of stretch factors based on a distributor's relative efficiency to its Ontario peers of 0% for the most efficient distributors, and 0.6% for the least efficient. The distribution of the 73 distributors according to these rankings is as follows:[50]

Figure 2: Distribution of Ontario Distributors' Relative Cost Performance



Most utilities examined fall into the Group III category, with a stretch factor of 0.3%.

Concentric does not view the Ontario benchmarking as applicable to HQD because HQD was not compared to the Ontario utilities. The study which supported the development of these stretch factors was limited to Ontario's distributors, so HQD was not part of the analysis. And whereas in Ontario, data for 73 distributors was available for comparison, HQD is the sole major distributor in

[50] *Ibid,* p. 22.

the province of Québec. There is therefore no basis for determining HQD's relative efficiency to the Ontario distributors.

HQD has, however, provided evidence of its productivity in its document "Études, analyses et rapports pour la determination du Facteur X déposés dans le cadre de l'établissement du mécanisme de réglementation incitative du Distributeur" filed in response to the Régie's decision D-2017-043 (R-3897-2014, A-0161)[51], including a significant decrease in its workforce for the period 2008-2017. HQD has also seen improvements in efficiency indicators as presented in file R-4011-2017[52] .

Furthermore, the Régie has already accounted for an expectation that HQD should have economies of scale built into its formula with the G factor. By selecting a G of 0.75% of HQD's customer growth, the Régie has built in additional efficiency gains beyond those captured in the X factor. The Régie recognized this relationship in its Phase I Decision:

> [158] Economies of scale must be reflected in the G growth factor (Factor G). There is therefore a close link between the values of Factors X and G, as CEA points out:
>
> > « *And the expectation is that the company is expected to show returns to scale, to the extent it can, and that should be reflected in the overall structure of the parameters that are established in phase 3. And the X factor serves to promote continued efficiencies; the G factor should be selected to show the legitimate relationship between costs associated with serving accounts and the resulting implications on its included OPEX. So, we see that's where X and G get tied together, is in the analysis that supports the selection of those parameters in phase 3* ».[53]

As mentioned above, the recently decided Eversource decision in Massachusetts incorporated a stretch factor of 0.25%, as long as inflation exceeds 2.0%. The Régie notes in its Phase I Decision that after examining all the elements covered by the indexing formula it would consider whether any "favorable or unfavorable bias" might warrant accounting in the stretch factor.[54] This would be an inappropriate use of a stretch factor. Practically speaking, a stretch factor is a judgmental matter designed to guarantee consumers savings greater than the industry trend level. It is not designed to remedy any bias in other plan elements. Taking these recent examples, the previous Alberta and recent Massachusetts stretch factors of 0.2% and 0.25%, respectively, establish reasonable benchmarks.

[51] See also file R-4011-2017, HQD-2, document 1 (B-0009) and HQD-8, document 2 of (B-0026)
[52] R-4011-2017, HQD-2, document 1 (B-0009)
[53] D-2017-043, R-3897-2014 Phase 1, 2017 04 07 at 158.
[54] D-2017-043, R-3897-2014 Phase 1, 2017 04 07 at 233.

C. INFLATION FACTOR

HQD's evidence presents the Distributor's proposal for the inflation factor. The proposed "I" is a three-part index, with weights based on HQD's projected expenses in year 1 of the 4-year MRI.

1) Compensation Growth - fixed weighted index of average hourly earnings in Québec (all industries) to establish the indicator of changes in salary costs (weight: 16.6%)
2) Costs Related to Assets - implicit index of business investment, the fixed capital investment component, published in the quarterly economic accounts of Québec's GDP (weight 56.8%)
3) Other Expenses - the annual variations in the Québec CPI services, according to the method proposed by the Régie (weight: 26.6%).

Based on the components of the proposed index, 73.4% of the index would be comprised on input-based price indices. The remainder, based on the CPI for services, also approximates an input-based index, as it would reflect HQD's costs for acquiring these services. For this reason, Concentric does not recommend an adjustment to the industry TFP analyses in this case for differences between industry and economy-wide input price differentials. This is the same logic adopted by the AUC in determining if adjustments to X would be required.

> 426. The interaction between the I factor and the X factor described above is based on a wellestablished theoretical foundation, as demonstrated by the agreement of parties on the need to adjust TFP in determining an X factor if an output-based inflation measure is chosen for the purpose of the PBR plan. Consequently, the parties advised that, when possible, it is preferable to use input-based price indexes for the I factor of the PBR plan, since using such indexes avoids the need for an input price differential and a productivity differential adjustment to TFP.
>
> 427. As set out in Section 5 of this decision, the Commission approved a composite I factor consisting of AWE and CPI indexes for Alberta. While the AWE index represents an example of an input-based measure, the CPI is generally regarded as an output rather an in input price index .However, as the Commission explained in Section 5.2.3 above, in the context of this proceeding, the Alberta CPI will be used only to monitor price trends for the companies' non-labour inputs. EPCOR, AltaGas and ATCO Gas submitted that because the Alberta CPI is a good proxy for the price changes for that particular group of expenditures, it may be considered an input price index for the purpose of their composite I factors. The Commission agrees.
>
> 428. Accordingly, since both components of the approved I factors can be considered input based price indexes, there is no need in this case for the Commission to consider an adjustment to TFP for an input price differential or productivity differential in the calculation of the X factor.[55]

[55] AUC Decision 2012-237, September 12, 2012, at 89.

Section 3:
Conclusions & Recommendations

Concentric is of the view that the recent TFP studies submitted in Alberta, Ontario and Massachusetts provide a reasonable basis for informing the Régie's determination of an X factor for HQD's initial MRI program. These studies incorporate both broad and targeted samples of U.S. electric utilities in the case of the studies submitted in Alberta and Massachusetts, and an Ontario specific electric utility group in the study submitted in Ontario. The Alberta and Massachusetts studies were subject to considerable scrutiny and tested by intervenors and opposing witnesses. These studies cover the most recent periods for which data was available, incorporating data back to 1997 and up through 2015, depending on the study. The range of results is summarized below.

Table 5: Recent Productivity Study Ranges

Study	*Range*	*Midpoint*
Brattle (Alberta)	-0.37% to -1.37%	-0.87
Christensen (Alberta)	-1.11%	-1.11
PEG (Alberta)	0.36% to 1.03%	0.70
PSE (Ontario)	-0.90%	-0.90
Christensen (Massachusetts)[1]	-0.41% to -0.46%	-0.44
Median		-0.87
Mean		-0.52
[1] The Christensen TFP results are unadjusted for input price differentials.		

Four of the five experts estimate negative productivity growth for their industry samples over the entire period of analysis, consistent with the broader Canadian utility data Concentric presented in its June report. Statistics Canada's estimates a utility productivity trend of -1.1% over the 2000-2015 period, and -2.1% over the more recent 2011-2015 period.[56] As seen in the table below, utility sector multifactor productivity growth has been considerably slower when compared to business sector multifactor productivity growth, confirming the trends revealed in the industry analyses submitted in Alberta, Ontario, and Massachusetts. That data is presented in Table 6:

[56] Concentric June 30, 2017 Report, *op. cit*, p. 13.

Table 6: Canada and US Multifactor Productivity Trends

	Statistics Canada[57]	***Statistics Canada***[58]	***Bureau of Labor Statistics***[59]
	Utility Sector Multifactor Productivity	Business Sector Multifactor Productivity	Non-Farm Private Business Multifactor Productivity
2000	2.4%	2.1%	1.6%
2001	-7.9%	0.1%	0.5%
2002	7.8%	1.3%	2.2%
2003	-3.0%	-0.7%	2.3%
2004	-3.0%	-0.3%	2.6%
2005	2.8%	0.0%	1.5%
2006	-3.1%	-0.8%	0.4%
2007	4.2%	-1.1%	0.5%
2008	0.5%	-2.3%	-1.3%
2009	-6.7%	-2.6%	-0.4%
2010	-1.5%	1.8%	2.9%
2011	-1.0%	1.5%	0.3%
2012	-2.4%	-0.6%	0.9%
2013	-3.1%	0.9%	0.2%
2014	-1.9%	1.3%	0.7%
2015	-2.1%	-1.0%	0.6%
2000-2015	-1.1%	0.0%	1.0%
2011-2015	-2.1%	0.4%	0.5%

As seen in the evidence submitted in the Alberta, Ontario and Massachusetts evidence, the pattern of declining productivity growth in the utility sector has been exhibited more broadly across the

[57] Statistics Canada. Table 383-0021 - Multifactor productivity, value-added, capital input and labor input in the aggregate business sector and major sub-sectors, by North American Industry Classification System (NAICS), annual (index, 2007=100 unless otherwise noted), CANSIM (database). (accessed: June 2016)

[58] Statistics Canada. Table 383-0021 - Multifactor productivity, value-added, capital input and labor input in the aggregate business sector and major sub-sectors, by North American Industry Classification System (NAICS), annual (index, 2007=100 unless otherwise noted), CANSIM (database). (accessed: June 2016)

[59] Bureau of Labor Statistics, Office of Productivity and Technology, Division of Major Sector Productivity. *Net Multifactor Productivity and Costs, Private Non-Farm Business Sector*. March 30, 2017.

Canadian utility sector, as illustrated in the multifactor productivity data provided by Statistics Canada. The longer-term utility productivity growth of -1.1% declined to -2.1% over the most recent five-year period. All of the studies show lower (or more negative) productivity growth in the more recent time period, suggesting these longer-term averages may overstate current productivity trends due to the leveling of demand growth without a comparable reduction in inputs.

The Régie, in its Phase 1 Decision, set some expectations for an appropriate range for X. The Régie set out its preliminary logic as follows:

> [159] As for the determination of Factor X, the Régie notes from a table produced by PEG that the average value of the productivity factors used in the regulation of the North American electricity companies from 1994 to 2011 is 1,51%.
>
> [160] As indicated in the following table, this value is similar to that used by the Régie in the parametric formula to frame, in aggregate, the annual growth in operating expenses of the Distributor.[60]

Concentric notes, however, that the table presented by PEG cited by the Régie presents outdated studies that are not reflective of currently utilized X factors in Canada or the U.S.[61] In fact, 29 out of the 36 utility plans listed represent plans that have already expired, including plans that expired as long ago as 1997 and 1999. As illustrated in Concentric's research, the current range in Canada prior to the Massachusetts Decision is 0.3% (Alberta) to 0 to 0.6% (Ontario), inclusive of stretch factors.

Concentric recommends the Régie place weight on the studies presented by experts in the Alberta, Massachusetts, and Ontario proceedings. These studies incorporate data for relatively large groups of U.S. (the Alberta and Massachusetts studies) and Canadian utilities (the Ontario study). Considering the resulting X factor determined by the AUC of 0.3%, including a stretch factor, this would be an upper-end target for HQD in its first-generation MRI. The Mass DPU's adopted -1.31%, with a 0.25% stretch factor conditional on GDP-I greater than 2.0%, sets an appropriate lower bound. The DPU explicitly ruled that grid modernization investments proposed by the company would be considered outside of PBR, indicating the potential for significant investments outside the I-X revenue cap. The AUC's PBR also includes significant adjustments for capital investments outside of the formula, for which the Régie formula does not. Hydro One's proposal includes capital additions outside I-X that would place its effective X in the -1.04 to -2.26% range. A separate proceeding will be used in Massachusetts to determine how incremental grid modernization investment will be handled. For HQD, all capital investments, other than those excluded for a Z factor, are included in the formula. This creates a greater challenge in that regard than the Alberta utilities, Eversource or Hydro One face under their PBR plans.

Based on this evidence, Concentric recommends the Régie adopt a productivity factor of -0.75% for this first-generation MRI for HQD. This is greater (more negative) than the mean of the recent industry studies cited above, but below the midpoint. It is also below the Statistics Canada estimate

[60] *Op cit.*, at 159-160.
[61] R-3987-2014, C-AQCIE-CIFQ-0056.

of utility productivity. It recognizes that HQD has some growth in the G factor, but G factor growth is limited to 0.75% of actual growth, so HQD will have a built-in challenge compared to other programs for ongoing capital investments. Including a stretch factor of 0.25% would bring the X factor to -0.5%. Concentric believes this is an appropriate plan parameter, supported by substantial expert evidence submitted, and tested, in other jurisdictions and represents an appropriate starting point for HQD's first MRI.

This productivity factor will be revisited when HQD submits a productivity study within the next three years, as required by the Régie.[62]

[62] The Régie ordered the Distributor to conduct a multifactor productivity study within the first three years of the MRI and to transmit the results of the study to the Distributor within the third year, R-3897-2014 Phase 1, April 7, 2017 at ¶ 167.

Attachment 187.12

Management and Exempt Role Description

Job Title: Construction Supervisor	Band: 3
Department: PMO	Job Family: Operations and Delivery
Division/Business Area: Gas	Date: January 20, 2017

Job Summary:

Reporting to the Project Management Office this position is responsible to ensure safe, efficient and productive delivery of capital projects assigned and has primary responsibility for providing construction management and for identifying key resources and providing direction in order to meet project objectives. The Construction Supervisor will also ensure appropriate management, customer and stakeholder involvement throughout the life of the project.

Key Accountabilities:

Supervise and provide leadership to a team of skilled field resources to meet daily demands related to system operations, capital construction projects and programs, service and main installation, repair and maintenance, and emergency response procedures.

Ensure superior environmental, health and safety performance on capital projects. Coordinate project teams compromised of representatives from internal and external stakeholder groups, internal and external resources as required. Executes the project scope and priorities with the cross functional project team.

Supports the Project Management Office reporting requirements by providing Quality, Schedule and Cost (QSC) reports as directed by the Project Manager and others including the British Columbia Utilities Commission, weekly/monthly and/or Quarterly reports to FortisBC management, executive and Board.

Manages and communicates a clear vision of the project's objectives and motivates the project team to achieve them. Travel to work sites to provide quality oversight and maintain compliance with work and industry standards, applicable metrics, and service level agreements. Utilize field experience and technical knowledge to solve work related problems and/or collaborate and refer to others.

Compiles an accurate construction estimates, detailed project plans and schedules, with the assistance of FortisBC's business units and other involved stakeholders. Assists in the preparation and administration of contracts.

Analyzes and communicates risks, establishes contingency plans for the project. Manages change control for projects. Provides tracking and reporting progress to plan to the Project Manager. Analyzes performance to plan and makes recommendations for adjustments consistent with project objectives.

Establish and maintain effective relationships with internal stakeholders, customers, contractors, builders, municipal agencies, emergency response and environmental management personnel. Manages relationships with projects stakeholders, keeping them informed of progress and issues. Contributes and collaborates with the Project Manager to manage the financial aspect of projects: budgeting, actual to estimate variance, etc.

Management and Exempt Role Description

Job Title: Construction Supervisor	Band: 3
Department: PMO	Job Family: Operations and Delivery
Division/Business Area: Gas	Date: January 20, 2017

Education and Experience:

Bachelor's degree in a related discipline or Diploma of Technology in a related discipline from a recognized program, Certified Member in the Applied Science Technologists & Technicians of BC or a Professional equivalent, plus 4 to 7 years related field experience in a leadership capacity or an equivalent combination of education, training and experience. Utility (substation, regulating station, transmission, distribution, compression and generation) experience in project construction highly desirable.

Technical Competencies:

Knowledge of designated operational area and related systems, work methods and procedures
Knowledge of Company policies, standards and procedures
Knowledge of safety management, processes and procedures
Knowledge of computer and MS Office systems
Demonstrated ability to provide leadership to staff and contractors
Demonstrated ability in written and presentation skills
Demonstrated ability to negotiate within a context of political sensitivity and conflicting interests
Demonstrated ability to plan and facilitate meetings
Demonstrated ability to analyse and problem solve
Demonstrated ability to be flexible and facilitate change management
Demonstrated ability to interpret contracts and negotiate with contracts
Knowledge of and competency in construction management process required, including scheduling and resourcing, scope control, quality management, financial management and record keeping

Leadership Competencies:

Ability to ***drive for results*** through planning, alignment, execution, and customer experience/responsiveness
Ability to ***make optimal decisions*** through accountability, judgement, problem solving, prudent risk taking, market/industry awareness, and maintaining customer focus
Ability to ***drive and implement prudent change*** through continuous improvement, challenge the status quo/innovation, flexibility/adaptability and customer value – innovative customer solutions
Ability to ***build working relationships*** through respect & integrity, open communication, teamwork, negotiation/influence and customer relationship management
Ability to ***lead high performance*** through leading by example & initiative, continuous learning & coaching, measuring, rewarding & recognizing, customer service

Approval:

Manager Signature	***Job Title***	***Date***

Management and Exempt Role Description

Job Title: Construction Supervisor	Band: 3
Department: PMO	Job Family: Operations and Delivery
Division/Business Area: Gas	Date: January 20, 2017

Attachment 219.1

(Provided in electronic format only due to
document size and in order to conserve paper)

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 04-G-1047 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service.

CASE 04-G-0837 Petition of National Fuel Gas Distribution Corporation for a Waiver of the Requirements of the Commission's Order Issued February 14, 2000, filed in C 99-G-1369.

ORDER ESTABLISHING RATES AND TERMS OF TWO-YEAR RATE PLAN

Issued and Effective: July 22, 2005

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Buffalo on July 20, 2005

COMMISSIONERS PRESENT:

William M. Flynn, Chairman
Thomas J. Dunleavy
Leonard A. Weiss
Neal N. Galvin
Patricia L. Acampora

CASE 04-G-1047 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service.

CASE 04-G-0837 Petition of National Fuel Gas Distribution Corporation for a Waiver of the Requirements of the Commission's Order Issued February 14, 2000, filed in C 99-G-1369.

ORDER ESTABLISHING RATES AND TERMS OF TWO-YEAR RATE PLAN

(Issued and Effective July 22, 2005)

BY THE COMMISSION:

INTRODUCTION

By this Order, we adopt the terms and conditions of a two-year rate plan for National Fuel Gas Distribution Corporation (NFGD or the Company) commencing August 1, 2005. Among other things, the new rate plan increases NFGD's base rates; accounts for the phase-out of most of the Gross Receipts Tax; rationalizes the Company's tariffed balancing services, including the elimination of its Customer Balanced Aggregation Service; strengthens and expands existing safety and reliability, customer service performance, and low-income assistance programs; and introduces several new pilot programs designed to foster development of the retail gas market. Because the plan includes a credit to ratepayers to reconcile past tax collections, annual rates overall will go down by approximately $15 million.

The plan ordered today resolves a host of issues raised in the Company's filing and in the Staff and intervenor testimony. For a few other issues that were raised, however, we approve the parties' proposal to continue to address them in collaborative sessions. For some issues, we approve a rough outline of principles or program features on which the proponents agree, and we await further procedures before the detailed implementation issues are submitted for our approval.

PROCEDURAL HISTORY

This case was initiated when NFGD filed its proposed tariff amendments and base rate increase on August 27, 2004. The proposed changes provided for an increase of about $41.3 million or 5.5% in annual revenues based on the forecasted data accompanying the filing. The Commission suspended the proposed tariff revisions through January 28, 2005, by order issued September 27, 2004, and further suspended the proposed tariff leaves to July 28, 2005 on January 20, 2005.

Administrative Law Judge Elizabeth H. Liebschutz conducted a procedural conference on October 5, 2004 and thereafter set a schedule for the filing of testimony and conduct of hearings. Several motions relating to party intervention and discovery were brought before the Judge, and a ruling relating to discovery was appealed and resolved by Commission Order issued December 15, 2004.

Shortly after filing the rate case, the Company noted that it had not had an opportunity to address the Commission's Statement of Policy on Further Steps Toward Competition in Retail Energy Markets (hereinafter Retail Markets Policy Statement) or the Statement of Policy on Unbundling and Order

Directing Tariff Filings (hereinafter Unbundling Order), both issued August 25, 2004 in Case 00-M-0504.[1] Consequently, NFGD filed supplemental testimony and exhibits on October 1, 2004 to address the Retail Markets Policy Statement and the Unbundling Order.

Written direct testimony responding to both NFGD's initial and supplemental filing was pre-filed by Department of Public Service Staff (Staff), Multiple Intervenors (MI), the New York State Consumer Protection Board (CPB), the Small Customer Marketer Coalition (the SCMC), and the National Energy Marketers Association on December 31, 2004. The Company filed rebuttal testimony on January 1, 2005.

Pursuant to notice filed by NFGD, the parties commenced settlement negotiations, which continued through April of 2005. To accommodate the negotiations, the hearing scheduled by the ALJ was postponed several times, and the Company agreed to extend the suspension period as and if necessary due to the delays. On April 15, 2005, a Joint Proposal resulting from the settlement negotiations was submitted by NFGD, Staff, MI, CPB, Public Utility Law Project (PULP), Crown Energy Services, Inc., and National Fuel Resources, Inc. Following the filing of the Joint Proposal, North American Energy, Inc., the SCMC, and NOCO Energy Marketing LLC joined as signatories. Pursuant to the procedure ordered by ALJ Liebschutz, any party opposing the Joint Proposal was required to state the nature of its opposition by April 22, 2005. At that time, New York State Electric & Gas Corporation (NYSEG) and Rochester Gas & Electric Corporation (RG&E), filing jointly, indicated opposition limited to two of the retail access programs in the Joint Proposal.

Following the filing of the Joint Proposal, the active parties were given an opportunity to file statements in support

---

[1] Case 00-M-0504, Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities.

or opposition, and the Administrative Law Judge promulgated a series of questions to the parties regarding the Joint Proposal. An evidentiary hearing was held May 24, 2005. At that time, the pre-filed written testimony and exhibits were admitted into the record in the form of exhibits, in order to demonstrate the backdrop against which the Joint Proposal was negotiated. In addition, responses to the Administrative Law Judge's questions and further testimony and colloquy were placed on the record.

Public statement hearings seeking input on the Company's initially proposed filing were conducted in Buffalo and Amherst, New York on March 8, 2005 before Administrative Law Judge J. Michael Harrison and Commissioner Leonard A. Weiss. There were 28 speakers at the Buffalo session and two speakers at the Amherst session.

Extensive additional public comments were received by conventional mail, e-mails submitted on the Commission's Web site, and recorded telephone messages left on the Commission's toll-free Opinion Line. Through such means, we received 33 letters, 72 e-mails, and 173 telephone messages.

The public comments received were universally opposed to the proposed rate increase. Many of those submitting comments noted that they had already taken all steps possible to reduce their energy usage, such as lowering their thermostats and taking measures to increase the energy efficiency of their homes. Nevertheless, they asserted, the rising cost of natural gas has resulted in ever-higher gas bills. Many people commented on the poor economic conditions in NFGD's service territory, citing high unemployment and poverty levels. Many of those who sent in comments stated that they were living on fixed incomes and could not keep pace with higher taxes and higher utility bills.

Another theme that was common to a lesser number of comments was that retirement benefits offered to NFGD's executives were overly generous. The comments complained about salaries and benefits for current NFGD executives as well as for some executives who had recently retired.

In addition to comments from residential consumers, we also received correspondence from small business owners and social service and community development organizations. We received an official resolution from the Niagara County Legislature and correspondence from the Town Board of Colden, New York, and New York State Assemblyman Sam Hoyt.

In November 2004, New York State Senator Byron W. Brown submitted a petition signed by over 21,000 people stating that they "strongly" opposed the proposed rate increase by NFGD. The petition continues, "As National Fuel Gas customers, we believe that National Fuel Gas has done too little to reduce its costs. At a time of record profits for National Fuel Gas, and a stagnant NY economy, this request is harmful to our regional economy. In the Buffalo-Niagara region, **heat is a necessity, not an option!**" (emphasis in original). This petition was supplemented by an additional 1,200 signatures submitted by Senator Brown at the Buffalo public statement hearing on March 8, 2005.

Following the submission of the Joint Proposal on April 15, 2005, the Commission issued an additional notice calling for public comment on the terms of the Joint Proposal. The notice explained that, over the two years covered by the Joint Proposal, the net effect is an overall annual decrease of approximately $15 million in the bills paid by ratepayers, although bill impacts on different service classifications will vary. The notice included a four-page summary of the proposal prepared by its proponents and contained a link to the NFGD Web site where the full text of the Joint Proposal and appendices could be viewed. In response to this further public notice, we received no e-mails and no telephone calls. We received a single letter supporting the Joint Proposal, but expressing the desire that its term continue for longer than the proposed two years.

SUMMARY OF JOINT PROPOSAL[2]

Term

The Joint Proposal proposes rates and terms of service for a two-year period beginning August 1, 2005. However, several provisions, such as the service quality performance mechanism and safety performance mechanism, are intended to continue for substantially longer terms, as identified below. Other provisions, including base rates and earnings sharing, continue indefinitely. Therefore, although NFGD commits not to file for a rate increase before August 25, 2006 for rates commencing August 1, 2007, it is possible that the Company could choose to "stay out" for a longer period of time. The proposed rates and conditions are designed and structured so that no action by this Commission will necessarily be required at the conclusion of the second plan year.

Rate, Revenue and Bill Effects

Under the Joint Proposal, NFGD’s base rates would be increased and restructured. Base tariff rates would increase by a total of $15,859,063. In addition, the Joint Proposal calls for the elimination of two bill credits that had been put in place under prior rate plans to adjust revenues without altering base rates. These credits total $5,789,574. The Joint Proposal’s agreed-upon revenue requirement increase of $21 million reflects this base rate change plus the elimination of these credits, minus $648,637 in adjustments related to late payment charges and the Low Income Residential Assistance (LIRA) Program.

The bill impact of the $21 million revenue requirement increase would be nearly offset by changes in taxes resulting in a decrease of $20,147,589 annually. The Gross Revenue Tax (GRT) imposed on utility revenues was changed in 2000, resulting in a reduction in the Company's GRT obligations. In place of the

[2] The Joint Proposal (hereinafter cited “JP”) was admitted into the evidentiary record as Exhibit 8.

GRT, State Income Taxes are now assessed on utility income, but the net effect upon NFGD is a $20 million annual reduction. Although these tax changes took effect in 2000, their impact has not previously been fully reflected in NFGD's rates or bills. Instead, pursuant to our direction,[3] NFGD has continued to collect an amount equal to the former GRT during the transition period, until the setting of new base rates. NFGD’s State Income Tax obligations are proposed to be included in base rates and reflected in the $21 million revenue requirement under the Joint Proposal, while a much smaller amount will be collected as GRT.

Moreover, due to the tax overcollection for the 2000-05 period, a refund of the overcollected amounts is proposed to be paid to ratepayers over the next two years. The estimated amount of the tax refund credit is $16,250,000 per year for two years. Therefore, the net impact on bills for the two years of the rate plan covered by the Joint Proposal would be a reduction of $14,748,952 (approximately 2%) from current bill levels. Of course, once this credit expired after two years, absent another rate case or other action by us, bills would rise in year three by the $16.25 million amount, to a level that is $1,501,048 (approximately 0.2%) above current levels.

The base rate increase is proposed to be allocated across all service classifications in proportion to the non-gas revenue received from each such classification. However, under the Joint Proposal, both the effect of the tax changes and the allocation of the tax refund credit among the various service classifications would be based on total revenue, including commodity revenue. The impact of these three changes on total bills would be negative for bundled sales service customers and

---

[3] Case 00-M-1556, Proposed Accounting and Ratemaking for Tax Law Changes, Order Implementing Tax Law Changes (issued December 21, 2000) and Order Implementing Tax Law Changes on a Permanent Basis (issued June 28, 2001).

for residential and small commercial transportation service customers.

Another factor would affect the bills of large non-residential transportation customers. Under the Joint Proposal, the Company would phase out its current Customer Balancing and Aggregation ("CBA") tariff, requiring all customers currently on the CBA tariff to move either to the Company's Supplier Transportation, Balancing and Aggregation (STBA) service, if service is metered monthly, or to daily-metered transportation. Those customers electing to remain with monthly-metered transportation service would see an increase in their transportation charges, in addition to the base rate increase. However, customers switching to daily-metered transportation would experience a decrease in the transportation rate, to reflect the fact that they will take on most of the burden of balancing under that service.[4] Therefore, the bill impacts on large transportation customers from the Joint Proposal would depend upon their choice to switch to the monthly STBA service or the daily metered service. The former would experience rate increases, even during the initial years that the tax refund credit is in place, while the latter would mitigate such increases.[5]

---

[4] Of course, if these daily-metered customers failed to maintain an appropriate balance between delivery and usage, they would incur the cost of imbalance charges, which could increase their overall bills.

[5] For transportation customers remaining on monthly service, Exhibit 9, ALJ-2, Workpaper 1, pp. 5-9 shows increases ranging from 1.5% to 10.05%. If one calculates a total bill, assuming a natural gas supply cost of $8/Mcf, these delivery rate increases represent overall bill impacts ranging from 0.07% to 1.42%. For transportation customers who convert to daily metered service, Exhibit 9, ALJ-3, Workpaper, pp. 1-5 shows impacts ranging from a 15.95% decrease to a 0.67% increase (in one instance). Again calculating total bills, assuming a natural gas supply cost of $8/Mcf, these delivery rate changes represent overall bill impacts ranging from a 1.14% decrease to a 0.09% increase.

For all customers, proposed changes to the design of base rates would result in different bill impacts to customers within the same service classification, depending on their usage. As noted, most of these bill impacts would initially be mitigated through the two-year tax refund credit,[6] especially for residential and other non-industrial customers of bundled service, but their effect would be felt after the expiration of the proposed two-year Rate Plan. The rate increase would generally be recovered from the minimum charges, with the exception of SC3 (General Service) and SC13 TC4.1 (Large Volume Transportation) customers, from whom 50% of the increase is proposed to be recovered from the minimum charge and 50% from the usage rate blocks. As more cost recovery would thus shift to minimum charges, there would be a shift in ratepayer cost responsibility from greater-volume users to lesser-volume users.[7] Also, ratepayers such as residential customers, whose usage

---

[6] The effect of the tax refund credit would vary due to differences in its design: While it is proposed to be applied to minimum charges for S.C. 1 (Residential) and S.C. 3 (General Service) customers, the credit would be allocated on a volumetric basis for SC10 (Cogeneration), SC13 (Transportation), SC16 (Large Cogeneration Transportation) and S.C. 17 (Cogeneration Transportation) customers.

[7] See Exhibit 9, ALJ-2, Workpaper 1 (bill impacts assuming tax refund credit in Rate Year 1 and 2) and ALJ-4, Workpaper 1 (bill impacts following expiration of rate plan and credit, assuming no other changes). These show, for example, that during the two years of the rate plan, the bill of a residential customer using 20 Ccf per month will be reduced by $0.34, or 0.97% per month; the bill of a residential customer using 100 Ccf per month will be reduced by $1.93, or 1.56% per month; and the bill of a residential customer using 200 Ccf per month will be reduced by $3.86, or 1.66% per month. Upon expiration of the two-year rate plan and the tax refund credit, assuming no other changes, the bill of the residential customer using 20 Ccf per month will be increased $1.96, or 5.57%, above current levels; the bill of the residential customer using 100 Ccf per month will be increased $0.40, or 0.32%, above current levels; and the bill of the residential customer using 200 Ccf per month will be decreased by $1.51, or 0.65%, below current levels.

normally varies seasonally, would see a relative shift toward higher summer bills and lower winter bills.[8]

Rate Unbundling

Pursuant to the Unbundling Order, the Joint Proposal would unbundle the Company's charges for gas commodity into charges for gas supply and a merchant function charge. An unbundled billing service charge would be applied to bills rendered by the Company for delivery and/or sales service. These unbundled charges would eliminate the need for "back out credits" currently in place; therefore the Billing Back-Out Credit and Competition Back-Out Credit are proposed to be terminated.

The precise format of bills to reflect these unbundled charges is not finally determined under the Joint Proposal. Rather, the Company commits to submit an unbundled bill format, implementation timetable, draft tariffs, and consumer outreach and education plans to the Commission, with copies to Staff and the rate case parties, within 90 days of this Order. This filing would be intended to comply with our Order Directing Submission of Bill Formats, issued February 18, 2005 in Case 00-M-0504.

[8] Exhibit 9, ALJ-2, Workpaper 2 (projected monthly bills for average residential customer during Rate Plan) and ALJ-4, Workpaper 2 (projected monthly bills for average residential customer absent effect of tax refund credit). For example, during the two years of the rate plan, the bills of the average residential customer, using 1,072 Ccf per year, would go down only slightly, by amounts less than $1, in June through October, whereas the January bill would be $3.69, or 1.75%, less than the current bill. After the expiration of the rate plan, without the effect of the tax refund credit, bills would increase above current levels by amounts ranging from $0.77 to $2.09 per month in May through November but decrease compared to current levels in December through April.

Low-Income Residential Assistance Program (LIRA)

The Joint Proposal would modify the Low-Income Residential Assistance (LIRA) Program, which was established in its current form in Case 00-G-1858.[9] The first immediate change to the program would be to increase the discount per eligible customer from $100 annually to $170 annually and to increase the cap of the Company's expenditures on the program from $3 million to $5 million annually.

Further changes to the LIRA program would be developed in a second phase to be designed through further meetings with interested parties. The Joint Proposal sets as a goal the filing of the Phase 2 program for Commission approval by October 31, 2005 with a proposed effective date of May 1, 2006.

Other Rate Issues

Under the Joint Proposal, the "Lost and Unaccounted For" gas incentive mechanism would be revised, such that the percentage of lost and unaccounted for gas to be reflected in rates would be reduced from 2.0% to 1.95% on September 1, 2005 and further reduced to 1.90% on September 1, 2006. The Joint Proposal provides that the Company will make a filing, including a cost of service study, to justify suspension fees and reconnection charges. The Joint Proposal also proposes Business Development Rates and Empire Development Zone Rates.

Accounting Issues

Under the Joint Proposal, the parties propose to continue the previously established “Cost Mitigation Reserve” (CMR) as a separate account to record deferred amounts due to ratepayers or to shareholders. The Company would have discretion to offset amounts due to ratepayers against amounts due to shareholders. It is anticipated that there would be relatively little activity in this account over the term of this

[9] Case 00-G-1858, National Fuel Gas Distribution Corporation – Rates, Order Adopting Terms of Joint Proposal (issued April 18, 2002).

rate plan, once initial adjustments are made upon approval of the Joint Proposal.[10]

The chief use of CMR funds provided for in the Joint Proposal would be to reconcile differences between rate plan allowances and actual expenditures on pensions and other post-employment benefits (OPEBs) by the Company during the 2004 and 2005 fiscal years. The Joint Proposal proposes that the Company be authorized to reimburse itself up to $5 million for such shortfalls.

Another significant proposed use of CMR funds would be a one-time transfer of $4.5 million to the Company's Accumulated Provision for Uncollectible Accounts. In addition, $3.75 million would be earmarked for the Area Development Program under the Joint Proposal.

As part of the Joint Proposal, amounts due to ratepayers pursuant to earnings sharing provisions of former rate plans would be added to the CMR balance as a means to fund these expenditures. The current estimate of these amounts is $12,510,640.

The Joint Proposal sets forth depreciation rates to be used during the two-year term of the Rate Plan. It would require the Company to provide a depreciation study by the earlier of three months before the expiration of the second rate year or upon the filing of a major rate case. The Joint Proposal also states that the depreciation rates used prior to this Joint Proposal are appropriate and will not be adjusted, that the Accumulated Reserve for Depreciation for Production, Transmission, and General Plant and Intangible Property is appropriately represented, and that the Accumulated Reserve for Depreciation for Distribution Plant is at an appropriate total.

On a going-forward basis, the Company would continue to defer any differences between amounts allowed in rates for

[10] See Exhibit 9, ALJ-20, 3 of 3, showing sources and uses of CMR funds and little activity for Fiscal Years ending 2006, 2007 and 2008.

pensions and OPEBs and amounts actually spent, consistent with our Pension and OPEB Policy Statement.[11] The Joint Proposal specifies the amounts that would be included in rates and describes the methodology for computing interest on amounts deferred.[12] These deferrals would not be accounted for in the CMR; rather, they would be maintained in a separate account, to be recovered by shareholders or ratepayers only after our review and approval.

Earnings Sharing

Under the Joint Proposal, the Company would share earnings in excess of designated return on equity levels on a 50/50 basis. The return on equity thresholds for earnings sharing purposes are 11.08% for the fiscal year ending September 30, 2005; 11.5% for fiscal year ending September 30, 2006; and 11.5% for the fiscal year ending September 30, 2007. Moreover, the 50/50 sharing of earnings above 11.5% return on equity is proposed to continue indefinitely until changed or otherwise addressed in a subsequent proceeding. The Joint Proposal defines key elements of the Company's capital structure and otherwise sets forth the parameters for calculating the return of equity for the earnings-sharing mechanism.

Service Quality Performance Mechanism

The Joint Proposal provides for a Service Quality Performance Mechanism similar to ones that have been approved by us in the past.[13] Under this incentive mechanism, the Company

---

[11] Case 91-M-0890, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions (issued September 7, 1993).

[12] JP Appendix B (using hypothetical numbers only to demonstrate that interest is calculated only after average overfunding is deducted from the internal reserve debit balance).

[13] JP III.E., pp. 20-21; Summary of Joint Proposal, issued under cover of Commission notice May 2, 2005 at ¶ 13; Exhibit 9, ALJ-45.

would be subject to monetary assessments on a sliding scale in the event it fails to achieve defined performance on a range of service measures, comprising: percent of field-work appointments met; percent of new service line installations completed within ten calendar days of customer readiness; residential customer satisfaction; non-residential customer satisfaction; annual average of monthly PSC complaint rate; percent of customer telephone calls answered within 30 seconds; percent of bills rendered that are later adjusted; and percent of estimated meter readings. These are described in Exhibit 9, ALJ-45, as is the calculation of the assessment amount. The Joint Proposal provides that the Service Quality Performance Mechanism would continue until the later of July 31, 2009 or when the Company changes its base rates. Service would be measured annually for the period August 1 through July 31 of each plan year.[14]

Safety Performance Incentive Mechanism

The Joint Proposal provides for a Safety Performance Incentive Mechanism under which the Company would be assessed if it fails to achieve performance targets for infrastructure enhancement, leak management, prevention of excavation damages, and emergency response. Amounts assessed under this mechanism would be paid into the Cost Mitigation Reserve. Where attainment of the performance targets would require spending beyond budgeted levels for replacement of bare-steel mains and services, however, the Joint Proposal proposes that the Company be allowed funding of the additional amount. Such funding would come from the Cost Mitigation Reserve.

Affiliate Rules and Royalty Provision

The Joint Proposal proposes to continue in place, for the most part, rules governing transactions among NFGD and its

[14] Exhibit 9, ALJ-45, p. 3 of 4.

affiliates. These proposed rules would continue those adopted by the Commission in Case 00-G-1858,[15] with the added proviso that NFGD will not disclose to its parent or any affiliate any information relating to the availability of transportation services that it does not disclose to all marketers at the same time. Under the terms of the Joint Proposal, so long as NFGD continued to adhere to these affiliate rules, even beyond the two-year term of the rate plan, it would not be subject to the imputation of any royalty that might be asserted to be payable to NFGD.

Retail Access and Competition Programs

The Joint Proposal introduces several new retail access programs designed to comply with our Retail Markets Policy Statement.[16] Several of the retail access programs under the Joint Proposal would be pilot programs that expire after a finite term. In this respect they differ from most of the other aspects of the Joint Proposal, whose provisions tend to extend either indefinitely or for substantially longer periods of time.

It is proposed that the Company will designate a management employee as ESCO/Marketer Ombudsmen. At least during the term of the rate plan, NFGD would continue to survey residential customers annually to track changes in customer awareness and understanding of competition in the gas market. The Company would also continue to conduct an annual survey of ESCOs to measure their satisfaction. Under the Joint Proposal, NFGD commits to working with other parties to design an enhanced outreach and education plan, relying on the results of the

[15] Case 00-G-1858, National Fuel Gas Distribution Corporation – Rates, Order Adopting Terms of Joint Proposal (issued April 18, 2002).

[16] The Joint Proposal provides that the various retail access programs included in its terms suffice to comply with the Retail Markets Policy Statement. The Company would summarize the retail access provisions of the Joint Proposal and file that summary for record purposes to comply with the Retail Markets Policy Statement.

customer awareness surveys. The Joint Proposal includes an expense allowance of $350,000 annually for customer outreach during the two-year term of the Joint Proposal. The Company also commits to provide an annual report to the Director of the Office of Retail Market Development describing the results of its various surveys and lessons learned from them as well as recommending ways to improve the survey designs.

NFGD commits to develop a "Market Match" Program targeted to at least 1,000 of its largest sales customers. The program would provide these customers the opportunity to exchange information electronically and allow ESCOs to offer interested eligible customers competitive supply offers. The further details regarding the Market Match Program are proposed to be developed in consultation with Staff and other interested parties. NFGD also commits to sponsor and conduct a minimum of two "Market Expos" over the two-year term of the rate plan for non-residential business customers, provided that at least five ESCOs commit in writing to participate. The Market Expo is designed to provide a forum to exchange information regarding retail choice and a platform for customers to receive offers from ESCOs. The Market Expos would be targeted to S.C. 3-General Service customers. Again, the Company commits to consulting with Staff and other interested parties to develop the contents of the Expos.

The Joint Proposal includes a Purchase of Receivables (POR) Program. Under the POR Program, the Company would provide a consolidated bill to ESCO customers at the same time the Company billed its bundled sales customers for each of the Company's 21 billing cycles per month.[17] For each billing cycle, NFGD would purchase the ESCO's receivables 23 days after the ESCO's customer is billed, at a price that is 2.6% less, in the case of residential customers, and 0.71% less, for commercial and industrial customers, than the face amount of the

[17] Exhibit 9, ALJ-32.

receivable.[18] The Company's purchase of the accounts receivable would be without recourse.

The Joint Proposal spells out the proposed rights and terms of the respective parties to suspend or disconnect service to residential and non-residential customers under the Public Service Law and applicable PSC regulations. It also addresses security deposits and late payment charges. The POR program would be available only on accounts of the Company's firm transportation customers who receive a consolidated bill from NFGD that includes gas commodity service provided by an ESCO. NFGD would not be required to offer additional utility consolidated billing options to any ESCO apart from the option available for the POR pilot. Under the POR pilot the Company would be exempted from proration of partial customer payments made upon consolidated bills.

The POR pilot would continue for a period of three years, terminable by NFGD at the end of the third year following 12 months' prior notice to participating ESCOs. In an addendum to the Joint Proposal, the signatory parties commit to review the program after one year to explore whether changes should be made, depending upon enrollment levels.

The Joint Proposal also proposes a Discounted Retail Access Transportation Service Program, although it contains only a broad outline of the program. As to the details, the parties are to confer regarding the design of the program and to file a proposal with us no later than December 1, 2005, for an anticipated effective date of April 1, 2006.

Another program that is presented only conceptually in the Joint Proposal is a pilot program to support marketer hedged price options. The Joint Proposal proposes that the Company convene interested parties to design a two-year pilot program pursuant to which the Company will purchase or financially settle any part of a marketer's hedged supply offering that is

---

[18] Exhibit 9, ALJ-32; JP VI.A.1., p. 41.

unsubscribed. The Company would recover the costs of such purchased hedges through its normal gas cost adjustment. The proponents of the Joint Proposal assert that there will be no net cost impact to sales customers due to purchases from marketers under this program.[19]

The Joint Proposal also includes the provision whereby NFGD commits to convene a collaborative meeting of interested parties to study the feasibility and possible implementation of a mass market migration pilot program, such as those discussed in the Retail Markets Policy Statement.

The Joint Proposal includes an incentive mechanism under which the Company could be awarded up to a total of $2.7 million over the two-year term of the rate plan, based upon numbers of customers who migrate from bundled sales service to firm transportation service.[20] The Company would recover the incentive from the Cost Mitigation Reserve.

Funding Programs

Under the Joint Proposal, the parties propose a recalculated surcharge to fund the "Millennium Fund" for research and development programs. The Joint Proposal also identifies programs that qualify for Millennium Fund proceeds and proposes a refund of an existing over-funded balance under the prior Millennium Fund surcharge.

Under the Joint Proposal, the Company would develop a five-year Area Development Program to provide grants to community-based organizations or local development authorities for specific economic development projects to expand economic opportunities in NFGD's service territory. Unlike the research and development programs which are funded through the Millennium

[19] Exhibit 9, ALJ-7.

[20] The incentive requires net minimum migration of 10,000 accounts annually. It awards $30 per account migrated between 10,000 and 15,000 accounts and $50 per account migrated above 15,000 accounts.

Fund surcharge, funds for the Area Development Program would come from the Cost Mitigation Reserve.

Capacity Release

In the testimony originally filed by the Company and that filed by Staff and intervenors in response, a particularly contentious issue was the Company's proposal that, once a certain number of additional customers migrate from sales to transportation service, the marketer serving those customers be required to assume responsibility for the associated capacity released by NFGD. The Joint Proposal does not provide a substantive resolution of this issue. Rather, it provides that the Company will hold collaborative discussions with the parties to discuss the issue. Such discussions would address reliability and cost allocation of released capacity and not contradict efforts under way in the Commission's reliability collaborative.

PARTY COMMENTS ON JOINT PROPOSAL

Statements in support of the Joint Proposal were submitted by Staff, NFGD, CPB, MI, PULP, and the SCMC. A Statement of Limited Opposition was filed by NYSEG and RG&E, filing jointly.

1. Statements in Support[21]

DPS Staff

In its statement of support, Staff states that the Joint Proposal is fair to ratepayers and shareholders, promotes the Commission's competitive agenda, and produces reasonable results relative to the uncertain range of possible litigation results. Staff further asserts that the record is adequate to

[21] Although only one round of comments was submitted, some of the proponents of the Joint Proposal addressed NYSEG/RG&E's opposition in their Statements in Support. These comments are summarized separately, following the description of the opposition.

justify adoption of the Joint Proposal and that the proposed terms are in the public interest.

Staff points out that the two-year term of the rate plan was developed only through negotiations, in contrast to a one-year litigated case. Staff notes that all supporters of the Joint Proposal agree on the need to increase NFGD's rates in order for it to continue to provide safe and adequate gas service. The revenue requirement, according to Staff, compares favorably with a litigated outcome. In an appendix to its statement, Staff compares its position in its litigated case to the revenue requirement agreed upon in the Joint Proposal, demonstrating the areas in which it reasonably compromised its litigated position to arrive at the agreed-upon $21 million revenue requirement.[22]

Staff asserts that the earnings sharing provision is in the public interest because it provides NFGD with an incentive to mitigate its costs of providing service while allowing ratepayers to share in the benefit of efficiencies achieved. Staff asserts that the sharing triggers of 11.08% for fiscal year ending September 30, 2005 and 11.5% for fiscal years thereafter are reasonable in light of Staff's forecasts that the Company will earn an average return on equity in the range of 9.4% to 10.4% over the two fiscal years ending September 30, 2007. According to Staff, sharing caps generally range from 100 to 200 basis points above the implicit return on equity for the rate period.

Staff supports the revenue allocation and rate design features of the Joint Proposal as consistent with cost allocations and representative of a balanced approach to competing policy concerns. Staff notes that the allocation of charges to initial blocks helps NFGD better recover the embedded

[22] Staff explains, for example, that it moved from its litigated position on return on equity of 9.1% to an average return on equity of 9.88% over two years, which Staff states is consistent with the higher risk to the utility of adopting rates for a multi-year period.

costs of serving customers. At the same time, the various means of allocating the State Income Tax refund to various service classifications best ameliorates the bill impacts for those customers. Moreover, Staff points out, customers retain the incentive to conserve when commodity prices are higher by virtue of those separate commodity prices, which are not impacted by the present rate decision.

Staff supports the Joint Proposal's changes to NFGD's transportation services, including NFGD's elimination of stand alone monthly-metered service. According to Staff, NFGD's balancing options will now be better aligned with those of other upstate utilities, promoting uniformity within the State and helping to alleviate confusion for transportation customers. Moreover, the provisions that tend to promote the switch to daily-metered transportation service can help to improve distribution system reliability, according to Staff, because daily balancing of gas deliveries imposes greater discipline on transporters. Previously, according to Staff, the lack of real-time meters in NFGD's territory hindered the development of daily-balancing services. Consequently, the Joint Proposal provides for the installation of meters capable of recording gas flows on a daily basis. The combination of these new meters and the daily-metering service will help to ensure that smaller customers do not subsidize the gas usage of larger customers and will provide an incentive for ESCOs to deliver accurate amounts of gas. Funding for installation of such meters is in the public interest because it will benefit all customers, by improving the Company's ability to monitor the daily use of its largest customers, thus increasing system reliability.

Staff's statement explains its rationale for supporting provisions relating to lost and unaccounted for gas, the Millennium Fund surcharge, suspension fees, retail access and competition programs, and the service quality and safety performance programs. In general, Staff asserts that these provisions are consistent with Commission policies and procedures and will help to promote Commission policies favoring competition, high-quality service, and safety and reliability.

NFGD

NFGD supports the Joint Proposal and urges Commission adoption of the proposal in its entirety. According to the Company, the base-rate increases recommended in this Joint Proposal reflect a realization that cost cutting and containment cannot, alone, continue to keep the many other upward pressures on costs at bay. According to the Company, it has not had a base-rate increase since 1996, and those base rates were reduced in 1998 and have been frozen since then. Thus, the Company states, in real, inflation-adjusted terms, base rates have declined since 1998. Moreover, NFGD states the base-rate increase is wholly mitigated by available credits such that, for the next two-year period, no customer will see a bill increase due to the base-rate increase. The Company asserts that the lack of a bill impact from the base-rate increase is, on its face, in the public interest. The Company further asserts that the allocation of all or some of the rate increase in various classes to the minimum charge is consistent with the Commission's trend away from including fixed costs in volumetric charges.

The Company asserts that the Joint Proposal balances the interests of customers and company shareholders. According to the Company, the interests of low-income customers are protected through revisions to the LIRA program. All customers will benefit, the Company states, from safety and customer service protections. Also, NFGD contends, marketers and all customers will benefit from the extensive range of retail access programs. Indeed, NFGD asserts, "there are few, if any [retail access] programs that the Commission has advocated or endorsed over the past few years that are not incorporated in the Joint Proposal."[23]

[23] NFGD Statement in Support at 6.

NFGD emphasizes that many of the programs made available through the Joint Proposal would not normally be available through litigation. It contends that the earnings-sharing provision, the Purchase of Accounts Receivable program, the Discounted Retail Access Transportation Service Program, and the pilot program to promote marketer fixed-price options are programs that could not be achieved without a utility's consent. Moreover, NFGD asserts, the customer service and safety programs, which were developed collaboratively, might not have been available in a litigated case.

NFGD states that the other benefit from a negotiated settlement is "the sheer volume and scope of information exchanged between the parties in an environment that promoted the free exchange of ideas."[24] NFGD asserts that this exchange of ideas helped to produce an outcome that would not be achievable in litigation. It notes that the Joint Proposal reflects the agreement of a uniquely diverse range of interests. As a result, the Joint Proposal achieves a delicate balance among diverse and normally adversarial parties, including gas marketers, large-volume commercial and industrial consumers, the Public Utility Law Project, CPB, Staff, and the Company.

Finally, NFGD states that the Joint Proposal is fully consistent with various Commission policy objectives. In particular, according to NFGD, the Joint Proposal implements the Commission's unbundling objectives and materially advances the goals in the retail markets policy statement. NFGD asserts that programs similar to the Joint Proposal's safety and customer service programs and the earnings sharing provision were expressly found desirable and in the public interest by the Commission in its recent order adopting a rate plan for Consolidated Edison Company of New York, Inc.[25] The Company

---

[24] Id. at 7.

[25] Id. at 6, citing Case 04-E-0572, Consolidated Edison Company of New York, Inc., Order Adopting Three-Year Rate Plan, (issued March 24, 2005).

asserts that the treatment of the Millennium Fund mechanism and fund balance adjusts the surcharge to more closely match expenditures with approved research and development programs that further the Commission's energy efficiency goals. Moreover, the provision to increase the allowance for use of local production sources will, according to the Company, materially advance New York State's interests in promoting the sale of indigenous natural gas, a valuable resource that reduces the State's need to purchase other domestic and foreign supplies.

CPB

The CPB supports the Joint Proposal and asserts that it will provide substantial consumer benefits. CPB contends that the bill reductions, frozen rates for two years, and other benefits from the Joint Proposal are superior to the likely outcome of a litigated proceeding. It asserts that the proposal is fair to investors and will not damage NFGD's financial viability. In addition, according to CPB, the Joint Proposal is consistent with the social, economic and environmental policies of the State, i.e., lower energy costs for all residential and business consumers, protection of the interests of low-income New Yorkers, and avoidance of unnecessary harm to the environment.

CPB comments favorably on several aspects of the Joint Proposal in particular. First, it asserts that the favorable impact on customer bills provides a significant economic benefit for ratepayers. Also, it cites the earnings sharing provision as providing protections against unexpectedly high earnings, providing the Company an incentive to reduce costs, and ensuring that a reasonable portion of cost savings accrue to ratepayers. CPB hails the service quality performance mechanism and the reliability performance mechanism as incentives that will help ensure that NFGD's customers obtain reliable and high-quality gas service. CBP calls the low-income program "an essential component of the Proposal" and asserts that it will help ensure that necessary energy services are available to all New Yorkers at a reasonable cost.[26] CPB mentions the retail access program as a highlight of the Proposal and states that these provisions are expected to further promote competition in retail energy markets in NFGD's service territory. CPB also praises the Business Development and Empire Development Zone discount rates and the Area Development Program as programs to encourage relocation, growth, expansion, and retention of business customers in NFGD's service territory. Together, according to CPB, these programs will make the Company's service territory a more attractive place for business, thereby expanding employment opportunities for all New Yorkers.

MI

MI supports adoption of the Joint Proposal, asserting that its provisions are in the public interest and fall within the range of reasonable outcomes had this proceeding been litigated fully. MI focuses its comments on the transportation balancing issues of greatest concerns to its constituency. It notes that the parties interested in those issues – the appropriate rates for monthly and daily balancing service and the extent to which migration of large transportation customers to daily-balancing service should be promoted or mandated - initially held very divergent positions, but those differences were resolved by the Joint Proposal. MI asserts that it would not have agreed to the elimination of the monthly Customer Balancing and Aggregation (CBA) service, which is appreciably cheaper than the Supplier Transportation, Balancing & Aggregation (STBA) monthly balancing service, but for the Joint Proposal's provisions (1) allowing monthly-metered CBA customers to continue to be balanced monthly by switching to the STBA service, (2) establishing the proposed daily balancing service charges, which are considerably lower than the monthly balancing charges, and (3) allowing monthly-metered customers to pay the

[26] CPB Statement in Support at 6.

prior monthly balancing charges during the transition to daily balancing services.

Moreover, MI asserts that all of the issues in the Joint Proposal are interrelated, representing a single integrated compromise. MI asserts that the support of the Joint Proposal by both the Company and representatives of various customer groups is evidence that the Joint Proposal strikes a fair balance among the interests of ratepayers and investors. It notes the considerable time and effort expended by the signatory parties to reach a negotiated resolution of the issues, and it hails the two-year term of the agreement as providing a measure of stability and eliminating the possibility of rate case litigation commencing immediately following resolution of the proceeding.

PULP

PULP states that it supports the Joint Proposal, and it cites in particular four aspects of greatest importance to it. First, PULP points to the mitigation of the bill impacts associated with the revenue requirement increase through the refund of past over-collected State Income Tax. PULP cites this provision as recognition that the western New York service territory is particularly hard hit at the present time by adverse economic news. According to PULP, "By acting aggressively to mitigate fully the impacts associated with the NFGD revenue requirement increase, the Joint Proposal is commendably in tune with the reality of western New York's economy in the immediate future."[27]

Second, PULP praises the Low-Income Residential Assistance Program. PULP sees an improvement in the program's funding from base rates rather than, as previously, through separate accounts in which resources failed to match needs. PULP also hails the increase in funds available and the creation of differential benefits based on customer need. It notes that

[27] PULP Statement in Support at 3.

NFGD is administering a similar program in Pennsylvania, and PULP states that the program under the Joint Proposal will permit the parties to incorporate the best practices from the Pennsylvania program into the New York program.

PULP also comments upon the various retail access programs by noting that similar programs are being implemented and scrutinized closely in the service territories of other utilities. According to PULP, the fact that the terms of the discounted retail access program and any mass-market migration pilot will be submitted for further action by the Commission assures that the lessons learned elsewhere will not be lost when the specifics of these programs must be finalized for implementation by NFGD.

Finally, PULP supports the Area Development Program, which will provide grant funds for economic development projects in the NFGD service territory. According to PULP, the criteria for the selection of grantee projects will assure that many of the projects will be located in low-income communities and that the economic development benefits associated with these projects will be afforded to low-income residents.

SCMC

The SCMC notes that it was an active participant in the negotiations leading to the development of the Joint Proposal and is a signatory to the final Joint Proposal. It urges adoption of the Joint Proposal by the Commission on the grounds that the proposal will enhance the development of a robust competitive retail market, enhance the competitive economic framework in which ESCOs must compete against the incumbent utility, and is consistent with the established policy of the Commission favoring the growth and development of retail energy markets. The SCMC states that the Joint Proposal will foster competitive choice, which will give ratepayers the benefit of the ability to choose a supplier that best suits their needs without impairing the financial health of NFGD. Moreover, by aiding retail access development, states SCMC, the Joint Proposal will advance the Commission's policy favoring the development of robust competitive energy markets. The SCMC notes that the Joint Proposal is supported by a highly diverse group of parties who are normally adversarial, thereby positively bridging the gap between parties of diverse views and concerns.

2. Statement in Opposition

NYSEG/RG&E

NYSEG/RG&E filed a Statement of Limited Opposition to the Joint Proposal's provisions regarding the Discounted Retail Access Transportation Service Program (JP VI.B) and the collaborative to discuss a Mass-Market Migration Pilot Program (JP VI.D.4).[28]

NYSEG/RG&E's primary objection to the discounted retail access program is their allegation that participating customers may be effectively "slammed" to prices unilaterally established by an ESCO after the two-month discount period. NYSEG/RG&E assert, "Like O&R's PowerSwitch Program, the DRS Program would permit customers to be transferred to an ESCO without any requirement for an agreement between an ESCO and the customer for rates and terms after the initial discount period."[29] This practice, NYSEG/RG&E assert, contravenes §5.B of the Uniform Business Practices.

Second, NYSEG/RG&E request the Commission to defer consideration of the Discounted Retail Access Transportation Service Program until it has fully investigated the impact of this type of program on customers. In particular, they note that they have requested an investigation of a similar program, Orange and Rockland's "PowerSwitch" Program, and they urge the

[28] NFGD moved to strike NYSEG/RG&E's opposition on several grounds, but its motion was denied by the ALJ's Ruling Denying Motion of National Fuel Gas Distribution Corporation To Strike Opposition (issued June 6, 2005).

[29] NYSEG/RG&E Statement of Limited Opposition at 5.

Commission to complete that investigation before authorizing the institution of a similar program at NFGD.

NYSEG/RG&E also object to the convening of a collaborative to discuss a mass migration pilot program if such a collaborative would be free to consider, among other proposals, "opt-out" auctions. NYSEG/RG&E note that, in the Retail Markets Policy Statement, the Commission expressed concern "with the consistency of such an approach with our UBPs (§5(k)), which generally consider transfers of customers without their affirmative consent to be slamming, and with our statutes which guarantee customers (subject to limited exceptions) that the utilities will always be available as a supplier."[30] NYSEG/RG&E argue that, because the collaborative process proposed in §VI.D.4 of the Joint Proposal does not preclude the consideration of an opt-out retail market pilot auction, it is thereby inconsistent with these concerns.

3. Responses to Opposition[31]

CPB

CPB responds to the limited opposition indicated by NYSEG/RG&E, noting that it shares some of the substantive concerns NYSEG/RG&E raise. However, CPB asserts that the Joint Proposal does not finally address the issues of concern, because NYSEG/RG&E, as well as the other parties, will have a continued opportunity to participate in meetings and collaboratives and to work out their concerns or otherwise present them to the Commission. Accordingly, CPB urges the Commission to dismiss

---

[30] Retail Markets Policy Statement at 28 (citing Public Service Law §65 and Transportation Corporations Law §12).

[31] As noted above, all comments were submitted in a single round, simultaneously. Consequently, there were no separate responses filed. The comments described here were included in parties' Statements in Support, but we have placed them here to provide a more logical presentation of the issues.

the concerns raised by NYSEG/RG&E and to approve the Joint Proposal.

SCMC

The SCMC responds to the opposition of NYSEG/RG&E by calling that opposition either time-barred or premature. First, the SCMC states that NYSEG/RG&E failed to challenge the Commission's Retail Markets Policy Statement and therefore are time-barred from now challenging the Commission's policy with respect to retail access programs. On the other hand, the SCMC asserts, to the extent that NYSEG/RG&E seek to challenge a specific detail or component of any retail access program that may subsequently be proposed, their opposition is premature. The SCMC notes that NYSEG/RG&E will be able to make their views known first in collaboratives and second in comments on the collaborative results that are presented to the Commission.

The SCMC also states that criticisms of the Orange and Rockland retail access programs have no place in a proceeding dealing only with NFGD. Finally, it calls unreasonable any position that would preclude parties from even discussing an approach that has received favorable mention in the Commission's Retail Markets Policy Statement.

DISCUSSION

The Joint Proposal is the product of settlement negotiations that were noticed and carried out in accordance with our settlement guidelines and rules of procedure, and we have evaluated it under our standards for reviewing settlements.[32] We have reviewed the terms of the Joint Proposal in the context of the parties' pre-filed testimony, comments of the public, parties' Statements of Support and one Statement of Limited Opposition, and additional testimony and exhibits introduced at the evidentiary hearing in response to the

[32] 16 NYCRR §3.9; Cases 90-M-0255, et al., Opinion No. 92-2, Settlement Procedures and Guidelines (issued March 24, 1992).

Administrative Law Judge's questions. Based on our review, we find that the rate plan presented in the Joint Proposal will establish just and reasonable rates, terms and conditions and that approval, consistent with the discussion herein, is in the public interest.

We note that the Joint Proposal is endorsed by ten parties and has only limited opposition from NYSEG/RG&E regarding two narrow provisions unrelated to NFGD's own retail offerings. As such, the Joint Proposal reflects a compromise among ordinarily adversarial parties representing a wide range of interests, including those of large industrial customers, residential consumers generally and low-income residential consumers in particular, marketers, and competitors. The willingness of these disparate parties to endorse the Joint Proposal reflects a "win-win" outcome in which a variety of interests are met. Moreover, whereas we received extensive public criticism of the Company's initial proposed rate increase, our call for public comments on the Joint Proposal elicited only one letter generally supporting the proposal.

The $21 million revenue requirement set forth in the Joint Proposal is within the range of reasonable litigation outcomes that could result from the opposing positions of the parties. The revenue requirement was robustly contested between the pre-filed testimony of NFGD, proposing an increase of $60,861,000, and Staff, whose adjustments resulted in a $13,383,000 decrease. Key elements in dispute included the forecast of future sales, return on equity, uncollectibles, pensions and other post-employment benefits, and rate base. In addition, CPB and MI proposed specific adjustments to return on equity, recovery of uncollectible expense, and earnings base adjustment that would have reduced the Company's claimed revenue requirement.

In its Statement in Support of the Joint Proposal, Staff revealed its view of the elements of the $21 million revenue requirement increase. Staff's presentation represents a realistic assessment of the strengths and weaknesses of its litigated position and demonstrates that the Joint Proposal level is a reasonable outcome. The presentations by MI, CPB and PULP further support a finding that the rate levels proposed under the Joint Proposal satisfy ratepayer interests. The Company's endorsement of the Joint Proposal supports our finding that the revenue requirement is sufficient for NFGD to meet its obligations to operate and maintain its system and to satisfy its shareholders.

The rate levels reflect an appropriate balance between customer and Company interests. The mitigation of the impact of the base rate increase by the two-year credit addresses concerns regarding the poor economic health of NFGD's service area. These concerns are also addressed by the Area Development Program, the Business Development and Empire Zone Rates, and local production provisions, all of which will help bolster the economy in the service territory. Finally, those with the least ability to pay will benefit from the improvements to the Low Income Residential Assistance Program included in the Joint Proposal.

The Joint Proposal also goes a long way toward rationalizing NFGD's base rates. Throughout the past several rate cases, the parties have arrived at a settlement that has utilized various credits or debits as an overlay to otherwise unchanged base rates. Now, with base rates themselves revised, these credits can be eliminated. Similarly, changing base rates allows for the accurate reflection of taxes.

The revenue allocation and rate design proposals are consistent with our public policy objectives. The Joint Proposal's allocation of the revenue requirement increase mirrors the Company's initially filed proposal, which was not contested by any party and was accepted by Staff as a reasonable means of distributing the increase fairly across service classifications. Moreover, the credit to refund overcollected past State Income Tax is allocated consistently with the manner in which the tax was collected, thus matching the credit as closely as possible with past overpayments. The rate design reflects an appropriate balance among various policy considerations, such as the mitigation of rate impacts, the sending of economically efficient and environmentally sound price signals, and the need to recover more of the embedded costs of serving residential customers through the initial rate block.

The increased balancing charges for large transportation customers reflect the costs of serving those customers and the type of service provided to particular customers. Customers will be able to mitigate this increase if they elect to use daily-metered service. The anticipated increase in the installation and use of daily meters will allow sophisticated customers to follow and adapt to daily price signals and otherwise respond to market forces, thereby fostering the further development of the competitive market as the preferred alternative to regulation.

The service quality and safety performance mechanisms in the Joint Proposal are reasonably designed to ensure that service, safety, and reliability are maintained at high levels. The Company retains incentives to operate efficiently, while at the same time passing some efficiency benefits along to ratepayers, through the earnings sharing provision. Our policies in favor of development of the competitive market are advanced by the provisions for rate and bill unbundling, affiliate rules, restructured transportation service, and the extensive retail access programs in the Joint Proposal. In crafting the Joint Proposal's retail access programs, the parties have mitigated the risk of placing an undue burden on NFGD's bundled sales service customers through means such as ensuring that the costs of the POR program are funded through the discount rate that marketers will pay[33] and that there will

[33] Exhibit 9, ALJ-38, page 2 of 2.

be no net cost impact to sales customers under the company's program to support marketer hedges.[34]

The only elements of the Joint Proposal that are opposed by any party are two isolated provisions relating to retail access, to which NYSEG/RG&E object. We have considered the merits of NYSEG/RG&E's opposition carefully. Our analysis leads us to reject NYSEG/RG&E's arguments, for the most part, although we make one modification that may help to alleviate some of NYSEG/RG&E's concerns.

First, NYSEG/RG&E's concern regarding the Discounted Retail Access Transportation Service Program involves features that may never be recommended or approved. The broad outline of the program contained in the Joint Proposal includes the requirement that "participating ESCOs provide enrolled customers with the terms and conditions, including price, for serving those customers beyond the two billing cycle introductory period."[35] Nothing in this statement specifies whether customers are provided these terms and conditions at the outset of the program, prior to initiating service with the ESCO; whether the information is provided prior to the conclusion of the two-month introductory period; or whether, as NYSEG/RG&E seem to believe, the information is only provided at a later point in time, after customers have already incurred charges due and owing to the participating ESCOs. NYSEG/RG&E's concern that one of these three alternatives may become a feature of the program is premature at this point.

As to NYSEG/RG&E's request that we reject the Discounted Retail Access Transportation Service Program until we have investigated the Orange and Rockland "PowerSwitch" Program, we rejected a similar argument by NYSEG/RG&E regarding Central

---

[34] Exhibit 9, ALJ-7. We approve this program based upon this representation, and we caution the Company against making any commitment that would make it responsible to cover the costs of excessive or over-priced ESCO hedges.

[35] JP at 45.

Hudson Gas & Electric Corporation's Retail Energy Markets Plan.[36] As we noted in that order, the PowerSwitch type of program is intended as a transitional mechanism to encourage customers to explore the benefits of the competitive marketplace.[37] The goal espoused by NYSEG/RG&E of obtaining additional information regarding customer benefits under such programs can best be met by allowing programs to go forward, potentially with variations arising out of various collaboratives, in order to generate additional experience and data on the programs' effectiveness. A retail access discount pilot program of limited duration such as that proposed in the Joint Proposal can add to our body of knowledge regarding the best ways to foster competition in retail energy markets. Therefore, we deny NYSEG/RG&E's request that we forbid the parties from developing a discount program.

In meeting collaboratively to develop a discount program, the parties can best incorporate the knowledge gleaned to date if they are unfettered by any particular requirements for the program at this juncture. Therefore, while the program elements set forth in the Joint Proposal may be useful as a starting point for discussion, we will not require or expressly approve any particular discount program element. Rather, the parties should feel free to design a program of their choice, which can then be presented to us for approval in its complete form. At that time, we can fully evaluate the program in its entirety, and parties such a NYSEG/RG&E can be heard if they wish to voice opposition.

---

[36] Case 05-M-0332, Central Hudson Gas & Electric Corporation – Retail Energy Markets Plan, Order Accepting Retail Access Plan, Modifying Rate Plan, and Establishing Further Procedures (issued June 1, 2005) at 21-24.

[37] In the Retail Markets Policy Statement, we described the program as an "interim near-term strategy," and we noted that we "expect that it would be made obsolete and be superseded by ESCOs undertaking customer care functions for residential customers over the longer term." Retail Markets Policy Statement at 29.

We also reject NYSEG/RG&E's request that we forbid the parties to meet to consider the feasibility of a mass market (i.e., residential) migration pilot program. Again, NYSEG/RG&E's concerns are premature. The purpose of encouraging knowledgeable and experienced parties to collaborate on programs is to encourage the creativity and innovation that come from the free exchange of ideas among those with the most expertise. Through that collaborative process, which is open to participation by NYSEG and RG&E, the parties may very well conclude that they will not propose an opt-out auction program for these customers. We see nothing to be gained by forbidding the parties to consider any and all alternatives that might foster the development of competition in retail energy markets in the state. Moreover, there is nothing to be gained from limiting our own consideration of a mass market migration pilot program before a record is fully developed. Through the collaborative process proposed in the Joint Proposal, the parties can hone their arguments and evidence, which can be presented to us if and when such a program is proposed. At that time, we can better consider the arguments of all parties in the context of a concrete proposal.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated April 15, 2005, as supplemented April 22, 2005, filed in this proceeding and attached hereto as Attachment 1, are adopted and incorporated herein to the extent consistent with the discussion in this Order.

2. National Fuel Gas Distribution Corporation shall file a written statement of unconditional acceptance of this Order, as of the date of the tariff filing required by ordering clause number three below.

3. National Fuel Gas Distribution Corporation is directed to file a supplement, on not less than one day's notice, to be effective on July 28, 2005, to cancel the tariff leaves and supplements listed in Attachment 2.

4. National Fuel Gas Distribution Corporation is directed to file, on not less than one day's notice, to take effect on August 1, 2005 on a temporary basis, such tariff amendments as are necessary to effectuate the terms of this Order. Upon filing these tariff amendments, National Fuel Gas Distribution Corporation shall serve copies on all active parties to this proceeding. Any party wishing to comment on the tariff amendments may do so by filing an original and five copies of its comments with the Secretary and serving its comments upon all active parties within ten days of service of the tariff amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission and will be subject to refund if any showing is made that the revisions are not in compliance with this Order.

5. The requirement of the Public Service Law Section 66(12)(b) that newspaper publication be completed prior to the effective date of the amendments is waived; provided, however, that National Fuel Gas Distribution Corporation shall file with the Secretary, no later than six weeks following the effective date of the amendments, proof that a notice to the public of the changes set forth in the amendments and their effective date has been published once a week for four consecutive weeks in one or more newspapers having general circulation in the service territory of the Company.

6. Upon acceptance by National Fuel Gas Distribution Corporation of this Order, the Company shall withdraw its petition for rehearing of our September 28, 2004 Order in Case 00-G-1858, denying its request for removal of a bill credit.

7. The waiver request sought by National Fuel Gas Distribution Corporation in Case 04-G-0837 seeking approval to apply Millennium Funds toward specific natural gas appliance applications is granted to the extent that National Fuel Gas Distribution Corporation is permitted to use Millennium Funds for approved end-use energy efficiency programs, not including

distributed generation projects, up to a total limit of $500,000 annually.

8. Within 45 days of the date of this Order, or as the Secretary may require, National Fuel Gas Distribution Corporation shall file with the Secretary an original and five copies of an updated cost of service study relating to the suspension of utility service by marketers pursuant to the procedures set forth in the Home Energy Fair Practices Act, in order to justify proposed suspension fees and reconnection charges.

9. Within 90 days of this Order, or as the Secretary may require, National Fuel Gas Distribution Corporation shall file with the Secretary an original and five copies of proposed bill format, implementation timetable, draft tariffs, and consumer outreach and education plans and shall serve a copy on all active parties in this proceeding, in compliance with the Order Directing Submission of Unbundled Bill Formats issued in Case 00-M-0504 on February 18, 2005.

10. Within 120 days of the date of this Order, or as the Secretary may require, National Fuel Gas Distribution Corporation shall summarize the retail access provisions of this Order and file an original and five copies of such summary with the Secretary for record purposes in Case 00-M-0504 as compliance with the requirement that it file a retail competition plan included in the Statement of Policy on Further Steps Toward Competition in Retail Energy Markets issued August 25, 2004 in Case 00-E-0504.

11. Upon the filing of its next major rate case, or by April 30, 2007, whichever occurs first, National Fuel Gas Distribution Corporation shall provide a depreciation study using the parameters shown in Appendix C to the Attachment 1 of this Order. If a major rate filing including the study is not made by April 20, 2007, the study shall be provided to the Director of the Office of Gas and Water.

12. National Fuel Gas Distribution Corporation shall take all other steps necessary to implement the terms of this Order.

13. Case 04-G-0837 is closed.

14. Case 04-G-1047 is continued.

By the Commission,

(SIGNED) JACLYN A. BRILLING
Secretary

ATTACHMENT 1

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

---x
Case 04-G-1047 - Proceeding on motion :
of the Commission as to the rates, charges, :
rules and regulations of National Fuel Gas :
Distribution Corporation. :
---x

JOINT PROPOSAL

Dated: April 15, 2005

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

---x
Case 04-G-1047 - Proceeding on motion :
of the Commission as to the rates, charges, :
rules and regulations of National Fuel Gas :
Distribution Corporation. :
---x

JOINT PROPOSAL

This JOINT PROPOSAL ("Joint Proposal") is made this 15th day of April 2005, by and between National Fuel Gas Distribution Corporation ("Distribution" or "the Company"), Staff of the New York State Department of Public Service ("Staff"), the Consumer Protection Board of the State of New York ("CPB"), Multiple Intervenors ("MI"), Public Utility Law Project of New York, Inc., North American Energy, Inc., National Fuel Resources, Inc. ("NFR"), Small Customer Marketer Coalition and other parties whose signature pages are attached to this Joint Proposal (collectively referred to herein as the "Signatory Parties").

This Joint Proposal was developed pursuant to, and in accordance with, the New York State Public Service Commission's ("Commission") Settlement Procedures, as set forth in 16 NYCRR § 3.9. Following exploratory discussions, parties and other persons with an interest in the outcome of discussions[1] were notified of pending settlement

[1] In addition to serving notice as specified in 16 NYCRR §3.9, the Company notified every marketer and natural gas producer doing business in its service territory. Persons identified on the Commission's Active Parties Service List issued in this proceeding are referred to herein as the "Parties."

negotiations. A Notice of Impending Negotiation was filed with the Secretary on January 11, 2005.

All party settlement conferences were held, and duly noticed to all parties, in Albany, Buffalo, Niagara Falls and New York City in January, February and March 2005. By agreement of the parties, other smaller breakout groups held various settlement meetings and conference calls with prior notice to all parties.

I. Overall Framework.

On August 27, 2004, Distribution filed new tariffs to be effective August 1, 2005. The new tariffs were designed to increase annual revenue recovered in base rates by $60.9 million. Elimination of surcharges and other changes, however, produced a net aggregate bill increase of $41.3 million, or an increase, including commodity charges, of 5.6%.

Following the filing of direct testimony and exhibits responsive to the Company's request, Distribution invited the parties, including Staff, marketers[2], consumer advocates and others to attend a conference to determine if an agreement could be reached that would settle the rate case and provide for a multi-year rate agreement. In response to that invitation, the Company, Staff, CPB, MI, marketers and gas producer representatives convened settlement discussions on January 10, 2005. Notwithstanding the commencement of negotiations, Distribution filed its rebuttal testimony and exhibits according to the schedule established by Administrative Law Judge Elizabeth H. Liebschutz. Following the Company's rebuttal filing, the parties held numerous

---

[2] "Marketer" is used interchangeably with "ESCO" and "Supplier" in this Joint Proposal, identifying the same entity defined in the Company's tariff (at Leaf No. 12) and under the Uniform Business Practices, Case 98-M-1343.

settlement conferences in order to reach a comprehensive settlement of rates and related matters, including competition initiatives. This Joint Proposal is the product of those meetings.

This Joint Proposal covers a two-year period and provides for a revenue requirement increase of $21 million, effective August 1, 2005. Available credits will mitigate the effect of the base rate increases on customers' bills for the term of this Joint Proposal. Through the implementation of a revenue tax surcharge decrease (described *infra* at Section II. C.) and the return of tax overcollections through a bill credit, the net effect on customer bills when compared to rates currently in effect will be a decrease. With the application of adjustments including these credits and revenue tax reductions totaling $36 million, the result will be an actual, overall annual bill decrease of $15 million or 2.0% compared to bills at currently effective rates.

This Joint Proposal also provides for continuation of the earnings sharing arrangement that has provided an effective incentive for productivity gains in the past. This Joint Proposal also provides for programs designed to maintain safety, ensure the continued high level of customer service and provide needed support to help low income customers pay their gas bills. This Joint Proposal also establishes programs intended to further the Commission's competition agenda, including the purchase of marketers' accounts receivable, a promotional program modeled on Orange and Rockland's "Power Switch" plan and other programs to support customers' awareness and understanding of the availability of choice. Further, this Joint Proposal contains various rate design mechanisms that materially advance the rate unbundling process.

The Signatory Parties believe that this Joint Proposal represents a fair and reasonable resolution of the issues presented in the case and should be adopted by the Commission. Therefore, the Signatory Parties hereby agree as follows:

II. Gas Rates and Revenue Levels.

This Joint Proposal covers Distribution's gas rates and charges for retail gas sales and gas transportation services for a two-year term ending on July 31, 2007. Provisions that extend beyond or otherwise depart from the two-year term of this Joint Proposal are expressly identified.

A. Revenue Levels.

The rates contained in this Joint Proposal are designed to become effective August 1, 2005. There shall be a total revenue requirement increase of $21 million. The $21 million revenue requirement increase will be achieved by the elimination of a current bill credit ($4.5 million) (described *infra*), the elimination of the current Home Insulation and Energy Conservation Act ("HIECA") credit[3] ($1.3 million), and a base rate increase which accounts for the balance of the revenue requirement increase ($15.2 million). Appendix A summarizes the amount of the increase in base rates. The Signatory Parties take note of the fact that Distribution has voluntarily extended the suspension period on four separate occasions – from an effective date of August 1, 2005 to October 26, 2005 - in order to facilitate the negotiations that gave rise to this Joint Proposal. It is the specific recommendation and desire of the Signatory Parties that Distribution be made-whole for this accommodation, through either an effective date of August 1, 2005 or through a rate design or other compensatory mechanism that provides the same revenue in the First Rate

3 The HIECA and other credits are described in more detail *infra* at Section II. H..

Year ending July 31, 2006 as if such rates were effective on August 1, 2005.[4] The Signatory Parties recommend, however, that in order to fully achieve the benefits of programs in this Joint Proposal, it should become effective no later than August 1, 2005.

As discussed in greater detail in Section II. C. below, the Company will also reflect the implementation of state income taxes in base rates and begin to refund the balance of overcollected state income taxes through a credit to customers' monthly bills. Volumetric quantities and number of bills by rate class as provided in the Company's filing will be utilized solely for rate design purposes and for monthly accounting entries where needed (e.g., in the calculation of the over/under revenue collection for pension, postretirement benefits other than pension ("OPEB"), and Research Development and Demonstration ("RD&D"), and for lost revenues associated with the Merchant Function Charge ("MFC")), but not to establish an agreed-upon sales forecast methodology.

B. Rate Design.

1. Delivery Rates.

The Company's gas delivery rates will be designed to implement the base rate increases discussed in Section II. A. and a low income rate program (described next below), in accordance with Appendix A. The base rate increases will be recovered through an allocation to the rate classes based on the non-gas cost revenues of each firm rate class. Increases by rate class will be recovered from the minimum charges of rate classes allocated an increase with the exception of Service Classification ("SC") 3 (General Service) and SC13 TC4.1 (Large Volume Transportation), where 50% of the

[4] Each time Distribution agreed to extend the suspension of its rates in order to facilitate further settlement discussions, the Company filed a petition with the Commission requesting that it be "made-whole" with respect to any decrease in revenues resulting from a later effective date for rates. As of the date of this Joint Proposal, those requests remain pending.

allocated increase will be recovered from the usage rate blocks and 50% from the minimum charge.

2. Low Income Rates.

The Company has offered various low income programs for many years. The Company currently provides a discounted rate for up to 28,500 low income customers under its Low Income Residential Assistance ("LIRA") tariff. LIRA was established in its current form in the Company's 2002 settlement agreement in Case 00-G-1858.[5] Currently, the LIRA discount is $100 annually, or $8.33/month for eligible customers, and LIRA expenditures, including administrative expenses, are capped at $3 million. The Signatory Parties recommend that the Company be permitted to modify LIRA in two phases. Phase I, to take effect when rates under this Joint Proposal become effective, increases the size of the discount from the current annual amount to a uniform maximum level of $170 per eligible customer. The total amount of LIRA discounts and the cost of administering the LIRA program will be capped at $5 million. The amount of the LIRA discount may be adjusted downward by the Company in a separate statement to be filed with monthly gas cost filings if it is anticipated that the amount of discount at forecast enrollment levels will cause the Company to exceed the $5 million expense cap. If the Company incurs less than $5 million of discounts and expenses, the amount below the $5 million cap will be deferred, and may be used to cover additional costs in Phase II of the LIRA program.

[5] Case 00-G-1858, National Fuel Gas Distribution Corporation, *Order Adopting Terms of Joint Proposal* (issued April 18, 2002) ("2002 Rate Plan").

Upon the approval of this Joint Proposal, the Company will convene a collaborative process to design Phase II of the modified LIRA program. Phase II of the LIRA program shall be governed by the following principles:

a. The Company will meet with interested parties within four weeks of the effective date of the order approving this Joint Proposal to continue the design and implementation of Phase II, which takes effect on May 1, 2006.

b. To the extent funds are available, factors for Phase II program eligibility will include, but need not be limited to, the Home Energy Assistance Program ("HEAP") income eligibility standards and a record of payment difficulty (or demonstrable risk of becoming payment troubled).

c. Phase II program features may include, but are not limited to, variable bill discounts based on household income, arrearage forgiveness, conservation education, financial management education and referrals to other programs. The central feature of the Phase II program shall be a discount which varies from customer-to-customer based on the customer's household income. Toward that end, discounts implemented under the Phase II program may vary from the uniform Phase I maximum of $170 per customer, will vary from customer-to-customer, and in some cases may significantly exceed the $170 Phase I maximum. Given the cap on funding levels, it is expressly understood, and intended, that the LIRA rates developed under Phase II will likely require a reduction in the number of eligible LIRA customers to fewer than 28,500 customers.

d. After collaborating with the interested parties, Distribution will submit the newly designed Phase II program by October 31, 2005 for approval by the

Commission and an effective date of May 1, 2006. In the event interested parties agree that the eligibility requirements described above should be revised for the purpose of creating a more effective program, the parties may jointly propose such eligibility modifications in the context of the October 31, 2005 filing.

Distribution will design a program for the collection of data after discussions with Staff and other parties and will implement such data collection program to be effective with Phase II of the LIRA program on May 1, 2006.

3. Tariff Filings by the Company.

Except as provided in Section VII. E. below, the Signatory Parties agree that, within five business days following the Commission's order approving this Joint Proposal, Distribution will file tariffs and within a practicable time modify its Procedures Manual[6] in a manner consistent with the terms herein.

C. State Income Tax Effectiveness and Credits.

The Signatory Parties agree that the base rates determined in this Joint Proposal include State Income Taxes ("SIT"). A reconciliation of booked SIT expense to tariff surcharge revenue for SIT shall be provided from the implementation of SIT in 2000 until the effective date of rates in this proceeding. The Company will also provide a reconciliation of booked SIT expense to SIT Tax Returns from 2000 until the effective date of rates in this proceeding by February 15, 2007.

---

[6] Gas Transportation Operations Procedures Manual. For purposes of convenience, words and phrases used in this Joint Proposal shall have the same meaning as identical words and phrases that appear in Distribution's tariff. To aid readability of this document, however, some of those words and phrases will be identified herein.

The Company has collected the SIT via the revenue tax surcharge ("RTS") as directed in Case 00-M-1556.[7] The difference between the SIT rate (effective but not included in base rates) and the RTS (currently charged) created a SIT overcollection estimated to be approximately $34,815,000 as of September 30, 2005. This estimate is subject to audit by Staff and the State Department of Taxation and Finance. The overcollection will be returned to customers through bill credits, as more fully described below. The Company will include a monthly bill credit statement with its monthly gas cost filings.

Provided sufficient overcollected tax revenue is available, the bill credits will be equal to the following amounts: For the 12 months beginning August 1, 2005, a credit of $16.25 million will be applied to customer bills to reflect reconciliation of the SIT overcollection. If available, for the 12 months beginning August 1, 2006 a credit of $16.25 million will be applied to customer bills. The bill credits shall be allocated to the rate classes based on forecasted total revenue provided in the Company's testimony submitted in this proceeding. For SC1 (Residential) and SC3, the bill credits will be applied to the minimum charges. For SC10 (Cogeneration), SC13 (Transportation), SC16 (Large Cogeneration Transportation) and SC17 (Cogeneration Transportation) customers, the credits will be allocated on a volumetric basis. Any remaining balance of SIT overcollections shall continue to accrue interest at the Other Customer Capital rate.

D. Uncollectible Accounts Expense.

On the date rates become effective under this Joint Proposal, the Company will be permitted to transfer $4.5 million from the Cost Mitigation Reserve ("CMR" which is

---

[7] Case 00-M-1556, In the Matter of the Proposed Accounting and Ratemaking for the Tax Law Changes Included in the 2000-2001 New York State Budget, *Order Implementing Tax Law Changes on a*

described in detail in Section III. G.) to its Accumulated Provision for Uncollectible Accounts. This is a one-time transfer of funds and notwithstanding anything else in this Section, there will be no additional reconciliation of the Accumulated Provision for Uncollectible Accounts.

Upon acceptance by the Company of a final Commission order approving this Joint Proposal, the Company will withdraw its request for rehearing of the Commission's order denying the Company's request for removal of the bill credit issued on September 28, 2004 in Case 00-G-1858.

The Signatory Parties agree that final billed accounts awaiting write-off serve as the basis for calculating a revenue requirement for uncollectible expense. For the purpose of computing an initial rate for the MFC (detailed *infra* at Section IV. C.), uncollectible expense is assumed to be $14.1 million. This assumption, however, is not intended to limit the Company's discretion to recognize and record an appropriate level of uncollectible expense.

In 2003, the Company reduced the uncollectible reserve by $1.3 million arising from a bankruptcy of Iroquois Energy Management, Inc. ("Iroquois"), a marketer that, until October 2000, served nearly 30,000 customers on Distribution's system. Under a prior rate plan, the Company was permitted to transfer funds from the CMR to the uncollectible reserve if the uncollectible expense level exceeded a pre-established target. That target was achieved with the unpaid Iroquois receivable, and Distribution transferred funds from the CMR into the uncollectible reserve. The Company has been involved in extensive litigation against Iroquois and Iroquois' sureties. Although the outcome of the

---

Permanent Basis (issued June 28, 2001).

Iroquois litigation cannot be ascertained at this time, the Company agrees that if any funds are recovered from the Iroquois litigation, they will be credited to the CMR.

E. Pension and OPEBs.

The Company has applied the deferral mechanism for differences in Pension and OPEBs recognized in rates and calculated as an expense as permitted in the Commission's Pension and OPEB Policy Statement.[8] The Signatory Parties agree that the Pension and OPEB Policy Statement's provision should continue to govern the Company's accounting treatment. Beginning August 1, 2005, allowed Pension expense shall be $9,908,000 and OPEB expense shall be $12,076,000. Any Pension and OPEB expenses above or below the allowance shall be deferred in accordance with the Pension and OPEB Policy Statement.

The Pension and OPEB Policy Statement recognized that regulated companies may provide funding to Pension and OPEB costs in an amount greater than the rate allowance. In such circumstances, the Company will have a pre-paid debit balance in its internal pension reserve. The Pension and OPEB Policy Statement recognized this potential circumstance and permitted companies to either petition the Commission to apply interest to this balance or include the balance in rate base in a rate case filing. In its filed case, the Company included the balance in its claim for rate base. In this Joint Proposal, the Signatory Parties agree that the debit balance in the internal pension reserve shall be excluded from the rate base. Instead, the Signatory Parties agree that interest will be accrued at the pre-tax rate of return of 11.31% on the debit balance, as provided in Appendix B. As demonstrated in Appendix B, the ability to accrue interest on the debit balance will be contingent on the Company's funding level at the start and end of the Pension Plan year as calculated by the Company's actuary for purposes of determining Statement of Financial Accounting Standards ("SFAS") 87 expense.

F. Depreciation.

The depreciation rates to be used during the settlement period are the rates as shown in Appendix C. The rates used prior to the implementation of this Joint Proposal are appropriate and will not be adjusted.

The Accumulated Reserve for Depreciation for Production, Transmission, General and Intangible Plant is also appropriately represented prior to the implementation of this Joint Proposal. The Accumulated Reserve for Depreciation for Distribution Plant is at an appropriate total and may be reallocated to specific accounts within the Distribution function.

The Company will provide a depreciation study using the parameters shown in Appendix C the earlier of three months before the expiration of the Second Rate Year, or upon the filing of a major rate case.

The Company will expense negative net salvage in excess of 60% in Account 376 – Mains if total negative net salvage for this specific account exceeds that amount. This will be determined on a total account basis. The amount to be expensed will be calculated on an annual basis. Future changes to the negative net salvage rate for Account 376 – Mains will be capped at 60% until reviewed at the Company's next change in base rates.

---

[8] Case 91-M-0890, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits other than Pensions (issued September 7, 1993) ("Pension and OPEB Policy Statement").

G. Medicare Prescription Drug Improvement Act of 2003.

The effects of the Medicare Prescription Drug Improvement Act of 2003 (the "Act") have been included in the actuarial costs calculated for OPEB expenses. The intention of the Signatory Parties is that the Company remain on the Commission's Pension and OPEB Policy Statement. The impact of the Act on deferred income tax calculations has not been established in this Joint Proposal. On February 2, 2005, the Commission instituted a proceeding in Case 04-M-1693 to investigate the impact of the Act on deferred income taxes.[9] The Signatory Parties agree that this issue will be determined in that proceeding.

H. Cessation of Credits.

Upon the implementation of rates under this Joint Proposal, the following credits shall terminate:

1. Back-out Credits to Marketers.

A "back-out credit" is a credit applied to a customer or marketer bill designed to remove charges for utility services that are provided by the marketer. Back-out credits were adopted by the Commission as a temporary proxy for unbundling until replacement unbundled rates were established under the Commission's Unbundling Policy Statement. In this Joint Proposal, the Signatory Parties recommend adoption of unbundled rates as more fully described below. Accordingly, the Company's existing back-out credits will be eliminated.

---

[9] Case 04-M-1693, Proceeding on Motion of the Commission as to the Accounting and Ratemaking Related to the Implementation of the Prescription Drug and Medicare Improvement Act of 2003, *Order Clarifying Prior Policy Statement and Order Instituting a Proceeding and Soliciting Comments* (issued February 2, 2005).

a. Billing Back-out Credit.

The billing back-out credit was established pursuant to the Commission's directive in the Billing Proceeding.[10] The Company will make a final lost revenue reconciliation filing consistent with the methodology approved by the Commission in Case 04-G-1138.[11] The Company will be permitted to recover lost revenue so calculated from the CMR upon a finding by the Commission that such filing is consistent with the methodology used in Case 04-G-1138.

b. Competition Back-out Credit ("CboC").

The Competition Back-out Credit was adopted under the 2002 Rate Plan and most recently continued in the Commission's Order Canceling Rate Schedule Amendments and Continuing Low Income and Competitive Market Programs (issued September 28, 2004 in Cases 04-G-0718 and 00-G-1858). Pursuant to these cases the Company will continue to recover such CboCs costs from the CMR until replaced by the unbundled rates adopted in this proceeding.

2. Other Credits.

a. Bill Credit.

Under the terms of the Company's 2003 Rate Plan[12] and prior rate plans, a bill credit in the aggregate amount of $5 million is applied to customers' bills. This bill credit was designed to continue until it was replaced or eliminated in a subsequent

---

[10] Case 99-M-0631, In the Matter of Customer Billing Arrangements, *Order Providing for Customer Choice of Billing Entity* (issued March 22, 2000) ("Billing Proceeding").

[11] National Fuel Gas Distribution Corporation - *Order re: Recovery of Lost Revenues Resulting from Billing Back Out Credit to Energy Service Companies* (issued January 19, 2005).

[12] Case 00-G-1858, National Fuel Gas Distribution Corporation, *Order Establishing Rate and Restructuring Plan* (issued September 18, 2003) (adopting the Parties' "2003 Rate Plan").

proceeding. The Signatory Parties agree that the $5 million bill credit will be eliminated upon the effective date of rates established in this proceeding.

b. HIECA Credits.

A credit is applied to customer rates equal to the expense level formerly reflected in rates to support costs generated by the State's now defunct HIECA program. HIECA costs were not included in the development of base rates calculated in this proceeding. Therefore, the Signatory Parties agree that the current HIECA bill credit should be terminated.

I. Commitment Not to File and Other Issues.

Conditioned upon the Commission's approval of this Joint Proposal without changes, the Company agrees not to file a base rate increase before August 25, 2006 for a rate year commencing August 1, 2007.

Subject to the foregoing provision, changes to the Company's base rates during the First and Second Rate Years will not be permitted, except for (a) changes provided for in this Joint Proposal and (b) subject to Commission approval, changes as a result of the following circumstances:

1. A minor change in any individual base rate or rates whose revenue effect is *de minimis* or essentially offset by associated changes in other base rates, terms or conditions of service -- for example, an increase in a specific base rate charge in one service classification that is offset by a decrease in another base rate charge in the same or in other service classifications. It is understood that, over time, such minor change filings are routinely made and that they may continue to be made during the term of the Rate Plan, provided they will not result in a change (other than a *de minimis* change) in

the revenues that Distribution's base rates are designed to produce overall before such changes. Provided further that except for changes to bill credits including the SIT credit described *supra*, the Company will not file to make any change to the residential minimum charge effective prior to August 1, 2007 unless directed to do so by the Commission.

2. The parties hereby acknowledge and recognize that the Commission, pursuant to its statutory responsibility, reserves the authority to act to insure the provision of safe and adequate service at just and reasonable rates. Further, nothing in this Joint Proposal shall be construed to limit the Company's right to petition the Commission for rate relief if unforeseen circumstances render the rates produced by this Joint Proposal unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

3. The Signatory Parties recognize that the Commission reserves the authority to act on the level of Distribution's rates in the event that, in the Commission's opinion, Distribution's rates are unreasonable or insufficient for the provision of safe, reliable and adequate service.

4. Nothing herein shall preclude Distribution from petitioning the Commission for approval of new services or rate design or revenue allocation changes on an overall revenue-neutral basis, including, but not limited to, the implementation of new service classifications and/or cancellation of existing service classifications. Provided, however, that except for changes to bill credits including the SIT bill credit described *supra*, the Company will not file to make any change to the residential minimum charge effective prior to August 1, 2007 unless directed to do so by the Commission.

III. Other Rate and Rate-Related Provisions.

A. Lost and Unaccounted For Gas Incentive Mechanism.

The percentage of the Lost and Unaccounted For Gas ("LAUF") to be reflected in rates which is currently set at 2.0% shall be reduced to 1.95% effective September 1, 2005. Effective September 1, 2006, the LAUF factor shall be further reduced to 1.90%, which level will remain in place until updated in a future base rate case. The calculation of the LAUF incentive mechanism shall be in a manner consistent with the methodology employed in the Company's most recent annual gas cost reconciliation filing. Further, the commodity cost of gas as specified in the Commission's recent order relating to the LAUF adjustment[13] shall be utilized in the LAUF incentive calculation.

B. Accrual of Interest on Deferred Items.

Unless otherwise provided in this Joint Proposal, the Company shall accrue interest on all deferred debits or credits provided for or arising out of the operation of this Joint Proposal until such time as the amounts deferred are reflected in base rates. Interest shall be accrued at the rate determined by the Commission for Other Customer Capital.

C. Sharing of Earnings.

The Company shall share with its customers on a 50/50 basis, earnings on equity in excess of the targeted equity level stated herein. For the purposes of determining any sharing of earnings, the target return on equity shall be as follows:

---

[13] Case 04-G-1278, In the Matter of the Filing of Annual Reconciliations of Gas Expenses and Gas Cost Recoveries, filed in C. 21656, *Order Establishing Methodology for Lost and Unaccounted For Gas Adjustment* (issued April 5, 2005).

Fiscal Year 2005 (October 1, 2004 – September 30, 2005)	11.08%
Fiscal Year 2006 (October 1, 2005 –September 30, 2006)	11.5%
Fiscal Year 2007 (October 1, 2006 – September 30, 2007)	11.5%

The earnings sharing mechanism shall be determined on a cumulative basis over Fiscal Years 2006 and 2007. Earnings for each fiscal year shall be measured individually. Any excess or deficiency in the Fiscal Year 2006 shall be carried forward in its entirety to the Fiscal Year 2007. Earnings in Fiscal Year 2007 shall be measured, and a 50/50 sharing of earnings between shareholders and ratepayers shall occur only if Distribution exceeds its threshold rate of return on equity in Fiscal Year 2007 (which includes any cumulative excess or deficiency carried over from the Fiscal Year 2006). Distribution agrees to calculate its earnings as described in Appendix D, such calculation to include, among other things: (1) the common equity portion of capital structure of National Fuel Gas Company ("National") shall be the lesser of the average between the start and finish of each Fiscal Year based on National's capital structure (excluding Other Comprehensive Income [14]) or 49%; (2) capital structure components will include Common Equity (but Common Equity shall exclude items of Other Comprehensive Income or Loss), Long Term Debt (including current portion), Short Term Debt (notes payable) and Amounts Payable to Customers (customer deposits), (3) the Earnings Base/Capitalization ("EB/Cap") adjustment shall be an addition of $28,173,000 to rate base, (4) expenses associated with Stock Appreciation Rights and restricted stock dividends shall be excluded. Earnings calculated for sharing purposes will exclude

[14] The term "Other Comprehensive Income" ("OCI") refers to revenues, expenses, gains, and losses that under generally accepted accounting principles are included in comprehensive income but excluded from net income. See SFAS 130, *Reporting Other Comprehensive Income* (Financial Accounting Standards Board 1997). OCI has been excluded from Distribution's common equity calculation in prior rate plans.

positive or negative incentive revenues. An example of the calculation is provided in Appendix D. The Earnings Sharing report will be provided within 120 days of the end of the Company's fiscal year.

The provision for the sharing of earnings above 11.5% ROE shall continue beyond July 31, 2007 until changed or otherwise addressed in a subsequent proceeding. Interest on the ratepayers' share of earnings, if any, shall be applied at a rate equal to the Commission-determined Other Customer Capital rate. Interest on the ratepayers' share of earnings will be applied from the first month after the earnings sharing period until the provision is transferred to the Cost Mitigation Reserve ("CMR"), a deferral account described *infra* at Section III. G..

D. Affiliate Rules and Royalty Provision.

Distribution is a wholly-owned subsidiary of National, a holding company registered under the Public Utility Holding Company Act of 1935 ("PUHCA"). National also owns a Federal Energy Regulatory Commission ("FERC")-regulated pipeline company subsidiary, National Fuel Gas Supply Corporation ("Supply"), a state regulated pipeline, Empire State Pipeline, and an unregulated marketing company, NFR, among other companies. All of these companies are "associated companies" under PUHCA, and all, by virtue of the relationship with National, are affiliated with Distribution. Although PUHCA governs transactions among Distribution and its affiliates, the Signatory Parties have agreed that the Commission will further regulate certain transactions between Distribution and Distribution's affiliates to insure the fair and non-discriminatory treatment of non-affiliated entities doing business on Distribution's system, and to prohibit transactions that unduly favor Distribution's affiliates over other entities.

Toward that end, Distribution agrees to follow the Affiliate Rules contained in Appendix J to the Joint Proposal adopted by the Commission in its Order issued on April 18, 2002 in Case 00-G-1858, which rules are contained herein at Appendix E. Section 5.0 of those rules has been revised to provide that Distribution will not disclose to its parent or any affiliate, including any marketer affiliate any information relating to the availability of transportation services that it does not disclose to all marketers at the same time.

Adherence to the terms of the Affiliate Rules eliminates any "royalty" payments that could or might be asserted to be payable or imputed to Distribution, including any period following the expiration of the Second Rate Year of this Joint Proposal. If Distribution violates a term of the Affiliate Rules, the evidence of such violation shall be submitted to the Commission for remedial action, if any, which may include the imposition of a royalty, redress or penalties, as applicable. No remedial action shall be taken until after notice to the Company and an opportunity for an on-the-record, evidentiary hearing. Any royalty, redress or penalty imposed shall be proportionate to the nature and degree of the violation of the Affiliate Rules.

E. Service Quality Performance Mechanism.

The Company shall be subject to a Service Quality Performance Mechanism ("SQPM"). The SQPM is applicable for the longer of a) the period August 1, 2005 through July 31, 2009 or b) until the Company changes its base rates. The provisions of the SQPM are set forth in Appendix F. Under this mechanism, the Company is subject to a maximum assessment of $1,500,000 based on its measured performance in certain designated areas of customer service. Any penalties under the SQPM shall be paid into the CMR. There shall be a null zone of 0 to 125 Units. The Company shall submit quarterly reports of its performance, with an annual report to be submitted within 90 days following the July 31st conclusion of each program year. The annual reports shall include a narrative description of the results, including methodology, trends and recommendations for improvements in operations.

F. Safety Performance Mechanism.

Distribution represents that it operates and maintains its system in accordance with all applicable laws, orders and regulations governing the safe operation of its pipeline system. Nevertheless, it is recommended that a penalty-only performance regime be adopted for the Company to continue maintaining and improving its system in the current manner and not as a mechanism to establish a higher standard of care.

The safety performance measures will be in effect for the longer of the three-year period ending December 31, 2007 or the Company's next rate case. Penalties, if any, will be based on the schedule contained in Appendix G. Penalties assessed under this mechanism will be paid into the CMR.

The Safety Performance Mechanism is intended to maintain the Company's historic capability and capital expenditures. It is not intended to divert resources from projects targeted for implementation by the Company's risk prioritization program for identifying and prioritizing replacement segments. However, with respect to replacement of bare steel mains and services, in circumstances where attainment of performance targets would require spending beyond budgeted levels, the Company will be allowed funding of the additional amount. The amount of funding required will be determined by calculating the revenue effect of investment in facilities greater than that forecasted in this proceeding resulting from complying with targeted investments under the Safety

Performance Mechanism. The calculation and an explanation supporting and justifying this funding will be filed with the earnings sharing calculation. Appendix G provides a pro-forma example of the calculation of the revenue effect. The additional funding requirement so calculated will be funded from the CMR.

G. Continuation of CMR and Transfer of Balances in the Gas Restructuring Reserves.

Previous Joint Proposals presented to and adopted by the Commission have provided for the continued use of two deferral accounts; the CMR and the Gas Restructuring Reserve ("GRR"). The Signatory Parties agree that the CMR should continue and that the balance of funds in the GRR should be transferred into the CMR at the effective date of this Joint Proposal.

The Company shall accrue interest on all deferred debits or credits provided for or arising out of the operation of the rate plan adopted in this Joint Proposal from the time of inception of the credit or debit until such time as the amounts deferred are reflected in base rates or transferred to other interest bearing accounts. Interest shall be accrued at the rate determined by the Commission for Other Customer Capital.

The CMR shall be continued during the effectiveness of rates established by this Joint Proposal. It is within the Company's discretion to determine the order in which the balance in the CMR will be used to offset deferred costs and expenses determined herein. It is also within the Company's discretion to apply credit balances from any identified Costs and Expenses, to any other identified Costs and Expenses debit balance.

Any remaining CMR balance not used for the purposes identified below shall be returned to customers unless otherwise determined by the Commission. Any remaining balance of additional Costs and Expenses listed below for which deferral accounting treatment has not been previously approved shall, subject to the approval of the Commission, be deferred for collection at the next time base rates are changed following the expiration of this Joint Proposal. Deferral accounting treatment for such items for which deferral accounting has been previously granted shall continue at the end of this Joint Proposal or until these items are addressed in a base rate proceeding.

Funding sources for the CMR shall be as follows:

a. Capacity Release Credits and Off-System Sales. The Signatory Parties anticipate that the Company will achieve savings from interstate pipeline and storage capacity releases and off-system sales[15] that cannot be quantified in advance. For the Rate Year, the first $1 million of such savings and revenues will be applied to the CMR. Eighty-five percent of any remaining capacity release savings and/or net revenue from off-system sales shall be accumulated. Such accumulated amounts shall be distributed to the Company's customers during each subsequent five-month period beginning in November and ending in March, through the gas adjustment clause ("GAC") and 15% of such savings and revenues shall be retained by the Company.

b. Assessments from the penalty only mechanisms (SQPM, Section III. E. and Safety Performance Measures, Section III. F.) will be paid into the CMR by the Company.

c. Previous Rate Plans contained Sharing Mechanisms that are currently being audited by Staff. Amounts determined to be owed the customer through a signed document between the Company and Staff for Previous Plans or the current plan or by a determination by the Commission will be placed in the CMR. The filing for the period of Fiscal Year 2001 through Fiscal Year 2003 will be settled by 2005.

[15] Pending further developments, the Company has suspended off-system sales in response to recent changes in federal regulations governing interstate sales activities by local distribution company affiliates of regulated interstate pipelines. Standards of Conduct for Transmission Providers, 68 FR 69134 (December 11, 2003), III FERC Stats. & Regs. ¶31,155 (November 25, 2003).

d. The Empire Synergy Deferral established in Case 02-G-1291[16] will be transferred into the CMR. The implementation of rates in this proceeding has taken into account the affect of the purchase of the Empire Pipeline by National, therefore the synergy deferral will cease.

e. The reconciliation of the 2003 Rate Plan $5 Million Bill Credit will be transferred into CMR.

f. The GRR (including the System Enhancement account) will be transferred into the CMR.

g. Interest shall be accrued on a monthly basis on the balance of the CMR at the rate determined by the Commission for Other Customer Capital.

Use of funds from the CMR shall be:

a. Transfer to Uncollectible Reserve (Section II. D.)
Upon implementation of this Joint Proposal, the Company shall be permitted to transfer $4.5 million into the Accumulated Provision for Uncollectible Account as described in Section II. D.. This is a one time transfer of funds and there will be no additional reconciliation of the Account 144000 Accumulated Provision for Uncollectible Accounts. Any funds recovered from the Iroquois bankruptcy will be credited to the CMR.

b. Pensions/OPEBs (Section II. E.)
The Company has applied the deferral mechanism for differences in Pension and OPEBs recognized in rates and calculated as an expense as permitted in the Commission Pension and OPEB Policy Statement and will continue to do so under this Joint Proposal. The deferral balances for Fiscal 2004 and Fiscal 2005 may be funded through the CMR to a maximum of $5 million. The remaining deferral balances will be recovered in future rate proceedings consistent with the Pension and OPEB Policy Statement.

c. Area Development Program (Section III. K.)
Upon implementation of the Joint Proposal a transfer of $3,750,000 from the CMR to a new account entitled Area Development Funds. Grants provided from this fund will be debited to the new account. This represents the entire obligation for the five-year program.

d. Migration Incentive (Section VI. C.)

[16] Case 02-G-1291, National Fuel Gas Company, *Order Approving Transfers* (issued January 30, 2003) at page 8.

The annual migration incentive will be funded through the CMR.

e. Discounted Retail Access Transportation Service Program ("DRS") (Section VI. B)
Funds required to support DRS will be provided from the CMR. The costs include bill inserts, print advertisements and outsourced call center support. The expenditures will be limited to $500,000 for the term of this Joint Proposal.

f. System Enhancements
Previous rate plans for Expenditures for System Enhancements related to the Restructuring effort have provided that these expenditures will be funded through the GRR to a maximum of $5,000,000. These expenditures will now be funded through the CMR. $2,771,587 has been spent through September 30, 2004. Descriptions of the various enhancements are included in Appendix H. Expenditures over the $5,000,000 cap will be deferred and a petition will be filed with the Commission requesting recovery.

g. Real Time Meter Installation (Section IV. B. 3)
Program costs for initial software, data collection infrastructure measurement correction devices and meters at locations of customers with annual consumption greater than 55,000 Mcf, continue to be funded through the CMR.

h. Safety Performance Budget Recovery Mechanism (Section III. F.)
If the Company recovers any funds using the Safety Performance Budget Recovery Mechanism as described in Appendix G, the funding shall come from the CMR. CMR funding shall not exceed $1,000,000 annually for the duration of the Safety Performance Mechanism.

H. Millennium Fund Surcharge.

On February 14, 2000, the Commission issued an Order in Case 99-G-1369 (the "Millennium Order") directing the establishment of a mechanism to replace the FERC Gas Research Institute ("GRI") surcharge on interstate pipeline rates. The Commission was responding to a FERC order that established a schedule to phase out the GRI surcharge. The GRI surcharge was adopted by FERC to support broad-based gas-related research and development. The Millennium Order recognized the continuing value of gas-related Research and Development ("R&D") for New York customers and established a permanent funding mechanism and R&D project guidelines. More particularly, the Millennium Order established a surcharge on firm retail gas rates (the "Millennium Fund Surcharge") that increased as the FERC GRI surcharge was decreased. This Joint Proposal addresses three issues related to the Millennium Fund Surcharge: (1) a recalculated Millennium Fund Surcharge unit rate effective with the approval of this Joint Proposal; (2) the refund of the current overrecovery balance of Millennium Fund Surcharges; and (3) the ability to utilize the funds collected from the Millennium Fund Surcharge for approved energy efficiency programs. Each of these items is set forth in greater detail below.

1. Recalculated Millennium Fund Surcharge.

Under the Millennium Order, Local Distribution Companies ("LDCs") were authorized to apply a surcharge on utility rates equal to the FERC GRI surcharge decrement as the GRI surcharge was phased out of pipeline rates (the Millennium Fund Surcharge was capped at $0.0174/Dth). LDCs were required to file tariffs with the Commission providing for a mechanism to implement the Millennium Fund Surcharges. As required, the Company has made five Millennium Fund Surcharge filings with the Commission since the mechanism was first established. In this proceeding, the Signatory Parties have agreed to recalculate the Millennium Fund Surcharge based on a forecast amount of annual expenditures of $900,000. This amount more closely approximates the anticipated qualified R&D requirements for the year. The volumetric true-up reflected in the current rate will be eliminated. Subsequent years will include an expenditure true-up to correct for the variance between collections and actual expenditures.

Based on these changes, the Millennium Fund Surcharge reflected in the rates billed to firm service customers effective on August 1, 2005 will be reduced from the current level of $0.0203/Mcf to $0.0091/Mcf. The calculation of these rates is provided in Appendix I.

2. Refund of Current Millennium Fund Overrecovery Balances.

The Signatory Parties further agree that the Millennium Fund balance, which currently reflects an overcollection of Millennium Fund costs, as of August 31, 2005 will be refunded to customers as a credit effective January 1, 2006.[17] The accrued balance will be refunded to customers consistent with the requirements of the Millennium Order. The Company will include the calculation of the overcollection and associated refund in its gas cost reconciliation filing filed in October 2005. Based on the current overcollection balance and on the proposed annual Millennium Fund Surcharge amount of $900,000, the Millennium Fund Surcharge effective January 1, 2006 would provide customers with a credit of $0.031/Mcf.[18]

3. Utilization of Millennium Funds for Approved Programs.

The Millennium Order set forth guidelines for approved use of Millennium Fund proceeds and allowed interested LDCs the opportunity to petition the Commission for waiver of the guidelines on an as-needed basis. In Case 04-G-0837[19], Distribution filed a waiver request with the Commission on July 7, 2004, seeking approval to apply Millennium Funds toward specific natural gas appliance applications, including end-use

[17] The Millennium Fund balance as of February 28, 2005 was an overcollection of $3,962,163.

[18] A pro forma calculation based on current estimates is provided in Appendix I. The actual amount to be credited will be determined based on the actual overcollection balance as of August 2005.

[19] Petition of National Fuel Gas Distribution Corporation for a Waiver of the Requirements of the Commission's Order Issued February 14, 2000, filed in C 99-G-1369.

energy efficiency programs and distributed generation ("DG") projects.[20] In this Joint Proposal, the Signatory Parties agree that the Commission should permit Distribution to utilize Millennium Funds for approved end-use energy efficiency programs, not including DG projects, up to a total limit of $500,000 annually.

4. System Benefits Charge.

On January 28, 2005 in Case 05-M-0090, the Commission issued a Notice Soliciting Comments seeking public remarks on several questions relating to the Commission's System Benefits Charge ("SBC") program for electric companies. Among the issues before the Commission in that proceeding is whether gas projects should be funded by the SBC and if a gas SBC should be established.[21] The Signatory Parties agree that the Millennium Fund end-use funding provisions agreed to in this Joint Proposal shall be modified, consistent with Case 05-M-0900, if SBC funding is modified to include gas projects, or a gas SBC is established to eliminate any potential double recovery. Nothing herein prevents the Commission from revising the Millennium Fund treatment in this Joint Proposal in the event a gas SBC is established.

I. Suspension Fees.

The 2002 amendments to the Home Energy Fair Practices Act ("HEFPA") enable marketers to effect a "suspension" of utility service for a customer's failure to pay amounts due in compliance with HEFPA procedures. Utilities are entitled to "reasonable compensation" from the marketer for the cost of such suspensions. On October 25, 2004 the Commission issued an order in Case 03-M-0117 ("Suspension Order") directing

---

[20] Case 99-G-1369 – Gas Research and Development Programs, Petition of National Fuel Gas Distribution Corporation for Limited Waiver of Conditions Governing Use of R&D Funds (July 7, 2004).

[21] This provision is not to be construed as setting forth a position of any party on the issue of whether a gas SBC should be established.

utilities to file updated suspension fees, to be filed when the a utility files its next rate case.[22] Accordingly, the Company will file revised suspension fees based on an updated cost of service study, including the assumptions upon which the proposed suspension fee is based.

Reconnection charges are charged to customers by an LDC when a customer previously disconnected for failure to pay the LDC's bill requests service reconnection. The Company will also provide updated cost justification for the reconnection charge. The revised fees, reconnection charges and cost of service study justifying the proposed fees will be filed within 45 days after the Commission issues its order approving this Joint Proposal. The filing will be subject to Commission review and the Commission may require a change in either the reconnection charge or proposed suspension fee.

J. Business Development Rates.

The Business Development Rates ("BDR") was a rate discount program provided to business customers who qualified under criteria designed to promote the development of new and expanding businesses. The BDR expired under the terms of the Company's tariff. The Signatory Parties agree that the BDR will be restored for SC3, SC13M and SC13D. The following additions to the qualifying Standard Industrial Codes will be made to the BDR rider: 01-14 (Agriculture, Forestry, Fishing and Mining); 64 (Insurance Agents, Brokers and Services) and 73 (Business Services). The Empire Development Zone ("EDZ") is another business development rate discount offered to applicants located in EDZs designated by the State. The EDZ rider will continue as currently structured with the exception of the rate discounts described below. The unit rate

---

[22] Case 03-M-0117, In the Matter of Chapter 686 of the Laws of 2002, *Order Modifying Suspension Fees and Other Tariff Provisions and Granting Further Relief* (issued October 25, 2004).

discounts per Ccf for BDR and EDZ are provided in Appendix J. Promotional/-advertising funds of $20,000 annually will be allocated for the purpose of promoting use of the BDR and EDZ rates.

K. Area Development Program.

An Area Development Program will be developed to provide development grants to community based organizations or local development authorities for specific economic development projects in order to expand economic opportunities in Distribution's service territory. Such projects will have either a natural gas application or will provide increased use of the natural gas infrastructure. Qualified projects shall receive grants from the Company under the Area Development Program based upon written applications which demonstrate the proposed project's capacity to:

i. Stimulate investment in infrastructure for the development or redevelopment of underutilized industrial or commercial property, including but not limited to brownfield sites or brownfield opportunity areas receiving state assistance pursuant to Section 970-r of the General Municipal Law;

ii. Create new employment opportunities or higher value employment opportunities;

iii. Provide workforce training or retraining to assure that higher value skills are available in the workforce, when needed; and

iv. Stimulate the expenditure of private investment in direct capital expenditures needed to expand employment opportunities in Distribution's service territory.

This is a five-year program. Grants will be funded up to $750,000 annually, as described in Section III. G.. Unspent funds will carry over and may be spent in the following year. Staff will work with the Company and with interested parties to finalize program details, including description of "targeted areas," and criteria by which grant recipients will be identified, the maximum amount of individual grants, reporting requirements and such other relevant criteria as may be material. Toward this end, the Company agrees to schedule a meeting to be convened within 45 days of the Commission's order adopting this Joint Proposal. The completed program will then be filed with the Commission for its approval.

IV. Changes to Transportation Services.

A. Description.

The Company provides a variety of unbundled services on its system. Firm transportation service (SC13) to large volume customers is currently offered in two broad service classes: Monthly Metered Transportation and Daily Metered Transportation.

Monthly Metered Transportation service is available to customers that have their volumes measured on a monthly basis. These services allow customers (or their marketers) to arrange for the delivery of gas, within prescribed tolerances, to serve retail customers according to a delivery schedule that provides for customers' metered usage and deliveries to be reconciled ("balanced") once monthly.

Daily Metered Transportation service is available to customers that have their volumes measured on a daily basis. This service allows the customers (or their marketers) to arrange for the delivery of gas on a daily basis and modify this arrangement during the day to provide more control between usage and deliveries. Daily service requires that deliveries and usage be balanced each day.

Monthly service is available on Distribution's system on a "stand-alone" or on an "aggregated" basis. Both transportation services are largely the same from an operational perspective, and are nearly the same in price.

Stand-alone monthly service evolved from the initial transportation tariff offered to large-volume customers in the 1980s, and for that reason has long been the most popular firm transportation service for commercial and industrial uses. Aggregated monthly service was developed in response to the Commission's 1996 requirement that transportation service be made available to all customers regardless of size. Marketers are permitted to aggregate customers' requirements of any size into a single, larger delivery requirement.

The principal distinction between aggregation and stand-alone monthly service is that aggregation service combines the requirements of multiple customers. Stand-alone monthly service customers may arrange for nomination and delivery of gas supplies on their own behalf.

Over the years, the responsibility for managing nomination and deliveries for stand-alone monthly service shifted from the individual customer to the customer's marketer. In recognition of this shift, the Company created an imbalance aggregation service for stand-alone customers called Customer Balancing and Aggregation ("CBA") service. This service expressly transfers monthly balancing responsibilities from the stand-alone customer to the marketer. As a result, the combination of stand-alone monthly service plus CBA service formed a service that responded to a market requirement prior to the establishment of the aggregated service.

The aggregation service is known as Supplier Transportation, Balancing and Aggregation ("STBA") service. Although STBA service is similar to CBA service, there are important distinctions. Balancing charges for CBA service are lower than balancing charges for STBA service. This occurred, in part, because original monthly balancing costs were developed in a previous base rate proceeding and have not been modified in over ten years. STBA balancing costs were developed in a more recent rate filing and the cost of upstream pipeline contracts supporting STBA imbalance service is updated monthly.

It is appropriate that these services be modified to reflect current circumstances. Therefore, the Signatory Parties agree that stand-alone monthly service and CBA service will be phased out during the term of this Joint Proposal. Eligible customers receiving service under the stand-alone CBA service classification will have the choice of receiving STBA service or stand-alone daily service.

Larger-volume Monthly Metered Transportation service classification customers, with annual usage greater than 55,000 Mcf, will be required to install daily metering capability and may elect to receive Daily Metered Transportation service.

B. Detailed Description of Changes.

1. STBA Program.

As explained above, stand-alone monthly service will be phased out. Current stand-alone monthly customers will have the choice of either STBA service or Daily

Metered Transportation and balancing services. To facilitate these changes, STBA service will be modified as follows:

a. Imbalance charges to be included in rates are to be determined based on capacity to meet a 62 Heating Degree Day ("HDD") requirement.

b. Capacity assignment rules will not change and the capacity requirements will remain based on the standard of 62 HDD.

c. The allocation of capacity assets to support the STBA program and to set balancing charges shall be as specified in Appendix K. These new balancing charges will not go into effect prior to September 1, 2005. The existing balancing charges included in Monthly Metered Transportation rates will be included in rates effective August 1, 2005.

d. Because all Monthly Metered Transportation customers will now be served under the STBA program, and the majority of large volume transportation customers (annual throughput greater than 25,000 Mcf) were transportation customers prior to aggregation service, transition cost charges associated with the Company's contracted pipeline capacity will not be included in large volume customer rates.

2. Standard Monthly Metered Transportation (CBA) Service Phase-Out.

a. Meters capable of real-time readings were installed for most of Distribution's largest customers with annual consumption exceeding 55,000 Mcf.[23] In this Joint Proposal, the Signatory Parties agree that real-time meters will be installed for the remaining large-volume transporters except as noted below. This is a

[23] SC13 – TC 3.0, 4.0 and 4.1.

requirement of service whether those customers migrate to Daily Metered Transportation service or not.[24]

b. Any firm transportation customer with annual usage between 5,000 and 55,000 Mcf[25], may volunteer for real-time meter installation and Daily Metered Transportation service. However, once installed, the installation must be maintained similar to the larger volume (greater than 55,000 Mcf annually) customers. This decision must be made by September 1, 2005 to avoid being charged the higher standard Monthly Metered Transportation STBA balancing service rates.

c. All other delivery rates and imbalance charges associated with Monthly Metered Transportation STBA service will apply.

d. Costs for software, data collection infrastructure, installation of measurement correction devices and meters for customers with annual consumption greater than 55,000 Mcf continue to be funded through the CMR. The same costs for customers with annual consumption between 5,000 and 55,000 Mcf, who volunteer for real-time metering and Daily Metering Transportation service, will receive rate base treatment.

e. The gas costs included in rates to be charged to Monthly Metered Transportation customers electing Daily Metered Transportation service during the transition from monthly to daily service shall be equal to the current charges included in the Monthly Metered Transportation CBA service rates ($0.0378/Mcf for SC13 TC 4.0

---

[24] Customers in this category with more than 15 meters per account will be permitted to opt out of the real-time measurement requirement. Where these customers opt for real-time measurement, the Company will investigate alternative metering configurations to minimize installation and operating costs. This decision must be made by September 1, 2005 to avoid being charged the increased standard STBA service rates. Notwithstanding the September 1, 2005 date, customers will have 30 days to make a decision after the presentation of alternative metering options by the Company.

[25] SC13 – TC 1.1, and 2.0.

and $0.0928/Mcf for all other SC13 customers). This lower transition rate shall cease on April 1, 2006, i.e., the customer must make its election by September 1, 2005 and convert to Daily Metered Transportation service by April 1, 2006 to avoid being charged the increased standard STBA service rates.

g. In all cases, customers will be responsible for communication expenses related to providing meter data to the Company on a real-time basis (e.g. telephone line or wireless service and subscription costs).

3. SC13 Daily Metered Transportation Service.

a. Real-time metering is required for SC13 Daily Metered Transportation service.

b. Daily balancing band widths shall be 10% year round, but the end of month band width shall be 5% from November through March of each year and 10% for the rest of the year.

c. The allocation of capacity assets to support this program and set balancing charges are provided in Appendix K.

4. Mandatory Capacity Release.

The Company shall hold collaborative discussions with the parties to address the release, by the Company to marketers participating in the Company's aggregation program, of upstream capacity that the Company has under contract. Such discussions shall address, among other things, reliability and cost allocation of released capacity and shall not contradict efforts in the Commission's Reliability Collaborative.[26] The collaborative will attempt to implement a program for the next heating season.

C. Unbundled Rate Design Format.

On August 25, 2004, the Commission issued a Statement of Policy on Unbundling and Order Directing Tariff Filings ("Unbundling Order") in Case 00-M-0504. The Company timely filed an updated embedded cost of service study ("ECOS Study") and unbundled competitive service rates in supplemental testimony filed in this case. Consistent with the Unbundling Order, the Signatory Parties agree that an unbundled rate design format will be implemented, as set forth in Appendix A.

The unbundled rates in this proceeding were developed based on ECOS Study results, which included the allocation of gas storage inventory, theft of service, corporate goodwill and promotional advertising costs on a revenue basis, consistent with the requirements of the Unbundling Order. ECOS Studies that allocate the Company's total cost of service to its delivery services, merchant (energy sales) service and billing service were developed. These cost of service studies provided the cost guidance that was used to develop the unbundled rates agreed to by the Signatory Parties.

A MFC will be included in the Company's monthly gas supply rate to sales customers. The MFC will be calculated monthly to reflect changes in gas costs. This Joint Proposal also proposes an unbundled billing service rate to be applied to customers receiving a bill from the Company.

The Unbundling Order also provided for the recovery of lost revenues due to increases in customer migration over imputed levels. Each year for the 12 months ended

---

[26] Established pursuant to the Commission's Policy Statement in Case 97-G-1380, In the Matter of Issues Associated with the Future of the Natural Gas Industry and the Role of Local Gas Distribution Companies

July 31, the Company shall calculate lost MFC and billing revenues resulting from customers migrating from sales to transportation service. Revenues are lost if there has been a decline in imputed billing and MFC activity based on weather normalized volumes as a result of customers migrating from sales to transportation service. The imputed billing service activity shall be 5,680,162 bills. The imputed MFC volumes shall be 44,324,153 Mcf for SC1 and 8,431,124 Mcf for SC3. The lost billing revenues and lost MFC revenues shall be recovered in the Delivery Adjustment Charge ("DAC") to the delivery rates of SC1 and SC3 customers for the 12 months beginning January 1 of each year. The Company shall file the lost revenue calculation with its annual gas cost reconciliation filing.

The determination of lost billing and lost MFC revenue shall be based on actual migrated customers and actual weather normalized customer consumption. The actual migration activity shall be determined by summing all volumes and bills associated with customers migrating from Company provided firm natural gas supply service and billing service commencing August 1, 2005. Pro-forma monthly gas supply statements are provided in Appendix L. Pro-forma lost revenue statements are also provided in Appendix L.

D. Bill Format.

Bill presentation will be implemented in compliance with the Commission's Order Directing Submission of Unbundled Bill Formats, issued in Case 00-M-0504 on February 18, 2005 ("Bill Format Order"). In the Bill Format Order, the Commission required LDCs to submit bill formats, implementation timetables, draft tariffs and consumer outreach and education plans with copies to Staff and rate case parties. The

---

(issued November 3, 1998).

Company will make a filing complying with the Bill Format Order requirements, with copies submitted to Staff and other parties, within 90 days of the Commission's order adopting this Joint Proposal.

V. Local Production Issues.

Approximately five percent of the gas flowing on Distribution's system comes from production within the Company's New York franchise area. Historically the Company permitted the use of local production to replace a portion of the upstream pipeline capacity required to sustain STBA service so long as the local production output could be monitored electronically as is pipeline-delivered gas. Electronic monitoring, however, is a costly requirement that deterred the use of local production for STBA service. Therefore, in prior rate plans, the Company agreed to accept a portion of local production without electronic monitoring – currently 65% of flowing supplies - as a substitute for the STBA upstream capacity requirement. In this Joint Proposal the Company has proposed, and the Signatory Parties agree, to increase the 65% allowance to 100% of projected monthly volume.

A. Assets Utilized to Accommodate Increased Allowance.

To maintain reliability for STBA service requirements, the Company will allocate storage assets to enable the increased allowance for non-telemetered local production such that its reliability is equivalent to the previously established 65% level for STBA service. The rates provided in Appendix K for Monthly Metered Transportation customers include the costs of storage required to support local production.

B. Producer Committee.

Under previous rate plans, a committee of natural gas producers, the Company, Staff and other interested persons was convened to address issues related to local production. The Signatory Parties agree that the Producer Committee will continue as established. Meetings will be held twice yearly at a minimum.

C. Meter Maintenance Fee.

The Meter Maintenance Fee (the "Fee") is a fee charged to producers to recover the Company's cost of maintaining meters and appurtenant facilities required to enable and measure the flow of local production at interconnection points on the Company's system. The Fee will be reviewed to determine the appropriate cost of service. The Company will complete its study of the Fee and report the results to the Commission by April 1, 2006. Comments of the Producers Committee will be included in the report, along with the approval of the Committee, if obtained.

VI. <u>Retail Access and Competition Programs.</u>

A. Purchase of Accounts Receivable.

Within 90 days of when rates become effective under this Joint Proposal, the Company will offer a pilot Purchase of Accounts Receivable Program ("POR Pilot") to ESCOs who are authorized to provide gas commodity service in its territory. Under the POR Pilot, the Company will purchase gas commodity service accounts receivable, at a discount and without recourse, on the accounts of the Company's firm transportation customers who receive a consolidated bill from the Company that includes gas commodity service provided by the ESCOs. At the outset of the POR Pilot, Distribution will purchase existing ESCO accounts receivable in place as of the date the POR Pilot commences, not including ESCO accounts receivable arising from bills rendered by ESCOs and not by Distribution. The POR Pilot shall continue for a period of three years, terminable by the Company at the end of the third year following 12 months prior notice to participating ESCOs. The POR Pilot is premised on implementation in accordance with the following provisions.

1. Discount Rate.

The discount rate applicable to accounts receivable purchased from the commencement of the POR Pilot through the end of the Second Rate Year will be 2.6% for residential customers and 0.71% for commercial and industrial customers.[27] The discount rate applicable to accounts receivable purchased after July 31, 2007 will be adjusted to reflect (1) changes in the MFC arising out of any change in base rates or by order of the Commission and (2) any additional incremental costs beyond those included in the initial discount rate associated with the POR Pilot incurred by the Company. Proposed changes to the MFC and discount rate made outside a general rate filing will be filed with the Commission and notice with opportunity to comment will be provided to ESCOs participating in the POR Pilot. The POR Pilot exempts the Company from proration of partial customer payments.

The discount rate for residential customers reflects a compromise position consisting only of:

(a) a 2.56% discount related to the cost of uncollectibles associated with gas costs included in the MFC to residential customers;

---

[27] POR billing for STBA customers enrolled in a Restricted STBA Group existing as of the date of this Joint Proposal, i.e. aggregation accounts under single ownership as defined by the Company, and with good payment history, shall be exempt from the discount.

(b) a 0.04% to recover administrative costs of the POR Pilot; and

(c) a 0.00% risk factor to reflect uncertainty of cost recovery of the purchased receivables (reduced to 0.00% for this Joint Proposal).

The discount rate for commercial and industrial customers of 0.71% reflects the sum of:

(a) a 0.61% discount related to the cost of uncollectibles associated with gas costs included in the MFC for non-residential customers;

(b) a 0.05% to recover administrative costs of the POR Pilot; and

(c) a 0.05% risk factor to reflect uncertainty of cost recovery of the purchased receivables.

2. Remittance of Payment.

The Company will remit payment to the ESCO for purchased accounts receivable on the 23rd day following the issuance of the bill to the ESCO's customer.

3. Disconnection of Service.

When Distribution has purchased an account receivable for residential service to a residential customer, Distribution, in accordance with applicable provisions of law including but not limited to Public Service Law §32, may, as agent for the ESCO, implement a suspension of the ESCO's service to such customer who fails to make full payment of all amounts due for such service on the consolidated bill,. Residential customers whose service is suspended under the POR Pilot will be returned to service upon the payment of the arrears that were the subject of the disconnection, which may include both delivery and supply charges, or a lesser amount as specified in Public Service Law §32(5)(d).

Distribution is also authorized to disconnect its delivery service and the ESCO commodity service, in accordance with 16 NYCRR Part 13, to non-residential customers where: (i) the customer fails to make full payment of all amounts due on the consolidated bill; (ii) the Company purchased the ESCO accounts receivable; and (iii) the ESCO furnishes the Company an affidavit from an officer of the ESCO representing to the Company that the ESCO has notified its current non-residential customers and will notify its future non-residential customers that Distribution is permitted to disconnect the customer for non-payment of the ESCO charges. The ESCO will indemnify the Company for any cost, expense, or penalty if the customer's service is discontinued for non-payment and the customer establishes that it did not receive such notification.

4. Charge Back.

Where Distribution reconnects service to a residential customer in accordance with Public Service Law §32(5)(d), at the time Distribution writes off the account the Company is permitted to charge back to the ESCO the difference between the purchase amount and the amount the residential customer would have been charged as a full service customer. Charge back may be accomplished by netting out the amounts owed the Company by the ESCO from the payments otherwise due the ESCO from the Company.

5. Billing Options.

Distribution is not required to offer additional utility consolidated billing options to any ESCO apart from the consolidated billing option available for the POR Pilot. ESCOs may also provide their own bill to residential customers under the procedures applicable to the dual billing model or the single retailer model.

6. Security Deposits and Late Payment Charge.

The Signatory Parties agree that Distribution may require as a condition of receiving POR Pilot service that ESCOs delegate to Distribution the ESCO's right to obtain security deposits and other forms of security on the commodity portion of commercial and residential accounts so that Distribution may be secured to the same extent as is authorized for bundled utility service under 16 NYCRR Parts 11 and 13. The Signatory Parties further agree that Distribution may also require as a condition of POR Pilot service that ESCOs delegate to Distribution the ESCO's right to assess late payment charges on the total balance of consolidated bills under the POR Pilot.[28]

B. Discounted Retail Access Transportation Service Program.

Within 30 days of the Commission's adoption of this Joint Proposal, Distribution will provide to Signatory Parties its outline for a Discounted Retail Access Transportation Service ("DRS") program to be effective through the term of this Joint Proposal and convene a meeting, to be held no later than October 1, 2005, to confer with interested parties regarding the design of DRS. Under DRS, participating ESCOs will offer firm residential and small non-residential customers who enroll with the ESCO a 7% discount from Distribution's current month Gas Supply Charge for a two-billing cycle introductory period, provided that each gas account will receive only one discount over the two-year term of this rate plan. The DRS program will be filed with the Commission no later than December 1, 2005 for an anticipated effective date, upon the Commission's approval, of April 1, 2006. The DRS program shall expire on July 31, 2007. DRS as filed will include the following:

1. A procedure for the timely provision of program-related information to customers and for customer enrollments. Such enrollment procedures shall be reasonably designed to provide each ESCO a generally equivalent number of accounts by rate classification, and location. Customers enrolling through this program are permitted to select a specific ESCO;

2. Distribution will obtain customer authorization, process enrollments and provide customer information to the assigned ESCO;

3. Calculation by Distribution of the price to be charged customers enrolled under the program on the two bills issued during the two-billing cycle introductory period;

4. A requirement that participating ESCOs provide enrolled customers with the terms and conditions, including price, for serving those customers beyond the two billing cycle introductory period;

5. ESCOs will not penalize a customer who returns to utility service during or following the two-billing cycle introductory period but before concluding a new agreement for commodity service with the ESCO; and

6. A requirement that ESCOs indemnify the Company against any damages, penalties or other costs associated with or arising from a claim that the ESCO misrepresented the terms of the ESCO service that was initiated through DRS..

7. Participating ESCOs will be enrolled in the Company's POR Pilot.

The Company may, after consultation with Staff and with consensus among ESCOs authorized to provide service in the Company's service territory, adjust the 7%

---

[28] Marketers participating in the Company's POR Pilot shall be required by the terms of the Company's Billing Services Agreement to authorize a late payment charge on the commodity portion of the

discount prospectively for the purpose of maximizing both ESCO and customer participation in DRS.

To promote DRS, Distribution will use a marketing approach that includes, but is not limited to, the use of customer bill inserts and print advertisements. The Company's advertising may include a statement that this is a Commission-endorsed program. The Company shall be permitted to "outsource" call center contacts for this program in order that telephone inquiries related to this program are handled by contracted call center personnel and not Distribution employees. The contracted call center will handle telephone calls in accordance with the standards contained in the SQPM. Upon presentation of reasonable costs of the DRS program (not to exceed $500,000) for approval by the Commission, it is intended that the Company will recover such costs associated with the DRS program from the CMR.

C. Migration Incentives.

In order to encourage Distribution to promote retail access in its service territory, a migration incentive will be made available to the Company for the First Rate Year and Second Rate Year provided there is a net minimum migration of at least 10,000 accounts. The incentive will be calculated using the Company's "monthly LDC sales report" in accordance with the following methodology:

1. During each Rate Year, the Company will earn $300,000 if 10,000 customer accounts migrate to ESCO service.

2. During each Rate Year, for each account between 10,000 and 15,000 that migrates to ESCO service, the Company will earn $30.

3. During each Rate Year for each migrated account above 15,000,

consolidated bill equal to the utility portion, or 1.5% monthly.

the Company will earn $50 per account. Each Rate Year shall constitute a separate incentive period.

4. For purposes of the migration incentives, migrating customers include new customers that commence taking firm transportation service calculated as set forth in subparagraph (5), provided that the Company can only receive an incentive once on each eligible gas account.

5. The Company will determine the net increase in customers on firm transportation service at the end of each Rate Year as compared to the number of customers who were taking firm transportation service as of the beginning of each Rate Year. If the Company meets the 10,000-customer migration threshold during the First Rate Year and again during the Second Rate Year, the incentive will be $300,000 for each of the two Rate Years; however, if fewer than 10,000 customers migrate or negative migration occurs during the First Rate Year, but additional customers migrate during the Second Rate Year, the migration incentive will be the total net increase over two years (First and Second Rate Years migrating customers), measured from the beginning of the First Rate Year, for additional migration up to 10,000 customers ($300,000), plus any balance of the net increase over the cumulative 10,000 customers times the appropriate tier amount. Customers who resume taking firm sales service from Distribution during the Second Rate Year due to an ESCO's cessation of retail marketing operations in or departure from Distribution's service territory will be considered to have remained with the ESCO for purposes of calculating the incentive.

6. The total incentive that the Company may receive over the period these provisions remain in effect will be capped at $ 2.7 million.

7. The Company may recover the incentive from the CMR. If the funds in the CMR are insufficient, the Company shall defer the incentive amounts for collection at the time of its next base rate case. Within 60 days following the end of each Rate Year, Distribution will file with the Commission verification of migration during that period, the computation of any requested incentive, the available credits, and the proposed deferral, if any. Appendix M contains examples of the migration incentive calculation for purposes of illustration.

D. Other Measures to Foster Retail Choice.

1. Retail Competition Plan.

The programs presented in this Joint Proposal to foster the development of retail energy markets are specifically recognized to be in compliance with the Commission's directive contained in the August 25, 2004 Statement of Policy on Further Steps Toward Competition in Retail Energy Markets issued in Case 00-M-0504 ("Competition Policy Statement") that the utility is required to file a plan that will outline the next steps/initiatives on how interested parties and the Company can collaborate to increase migration and further the development of the competitive retail market. The Company agrees to collaborate on retail access issues as provided for in this Joint Proposal. The Company agrees to summarize retail access provisions of this Joint Proposal and to file such summary for record purposes in Case 00-M-0504. No Signatory Party will challenge the sufficiency of the Company's response to the Competition Policy Statement in this Joint Proposal so long as the programs contained herein are implemented as agreed.

2. Customer Awareness Surveys.

Distribution will continue to survey its residential customers annually for the purpose of tracking changes in customer awareness and understanding of competition in the gas market. Distribution will meet with Staff and interested parties to review the most recent customer awareness and understanding survey to research the reasons why customers are reluctant to choose alternate suppliers. The research will be conducted within 45 days after the Company's acceptance of the order in this proceeding is issued. The Company will report the results of the survey by January 31, 2006.

3. Market Match and Market Expo Programs.

Distribution will develop Market Match and Market Expo programs. The Market Match program will be targeted to at least 1,000 of the Company's largest sales customers within 60 to 120 days of the Company's acceptance of the Commission's order adopting this Joint Proposal. The Market Match program will provide the opportunity to exchange information electronically and allow ESCOs to offer interested eligible customers competitive supply offers. The program elements of Market Match will be developed in consultation with Staff and interested parties.

Provided that at least five ESCOs commit in writing to participate, Distribution will sponsor and conduct a minimum of two Market Expos ("Expos") over the term of the Rate Plan for non-residential business customers. The purpose of the Market Expo Program is to bring Staff, ESCOs, non-residential customers and Distribution together to provide a forum for an exchange of information regarding retail choice and a platform for customers to receive offers from ESCOs. The Expos will be targeted to SC3 customers. The content of the Expos will be developed in consultation with Staff and interested parties within 60-120 days of the Company's acceptance of the Commission's order adopting this Joint Proposal.

4. Mass Market Migration Pilot Collaborative.

Distribution will convene a collaborative within 180 days of acceptance of the order approving this Joint Proposal to study the feasibility and possible implementation of a mass market migration pilot program discussed on page 26 of the Competition Policy Statement. All customers that migrate as a result of this pilot program, if adopted, shall be included in the migration incentive calculation.

5. ESCO Satisfaction Survey.

Distribution will continue to conduct the annual ESCO survey to measure ESCO satisfaction. Distribution will consult with Staff and ESCOs operating in its service territory to determine if any changes need to be made in the existing survey. All ESCOs will be contacted to participate in the survey. Distribution will report the results of the survey and its plans for addressing marketer concerns, if any, identified by the survey by December 31, 2005.

6. ESCO/Marketer Ombudsman.

Within 30 days after the Commission's approval of this Joint Proposal, Distribution will formally announce the continued designation of a management employee who will be responsible for addressing ESCO concerns and issues and who will serve as a liaison between ESCOs and the Company. ESCOs will be provided with the Ombudsman's name and telephone number and the Ombudsman will be available directly to ESCOs.

7. Competition Outreach and Education.

Distribution will meet with Staff and interested parties to design an enhanced Retail Market Education plan using the results of the research findings (described in paragraph 2 above) and incorporating the Retail Market Outreach and Education messages listed in Appendix N. The expense allowance for the enhanced Retail Market and Education effort shall be $350,000 annually for the term of this Joint Proposal.

8. Pilot Program to Promote Marketer Fixed Price and Other Hedged Options

The Signatory Parties agree that Distribution will develop a pilot program to support marketer hedged price options. As soon as possible, but no later than sixty days following approval of this Joint Proposal, Distribution will convene interested Parties for the purpose of designing a two-year pilot program to become effective, if achievable, for use beginning winter 2005-2006.

The pilot program would be limited to the winter season (November through March). Total program volume would be limited to 1.5 MMDth (approximately 17,500 customers). Under the pilot, marketers will hedge supplies for their offers to customers and the Company will purchase or financially settle a part of the marketer's unsubscribed enrollment volume. The cost of the purchased hedge or financial settlement will be charged as a gas cost for recovery through the Company's normal gas cost adjustment.

9. Annual Report.

The Company will include in an Annual Report to the Director of the Office of Retail Market Development the research results and lessons learned from them, as well as an evaluation of the customer awareness and understanding survey's effectiveness, and an explanation of how the survey design will be improved and tailored in the following year.

VII. Miscellaneous Provisions.

A. Dispute Resolution.

In the event of any disagreement over the interpretation of this Joint Proposal which cannot be resolved informally among the Signatory Parties to this proceeding, the party claiming a dispute shall serve a Notice of Dispute on the remaining parties, briefly identifying the provision or provisions of this Joint Proposal under dispute and the nature of the dispute, and convening a conference in a good faith attempt to resolve the dispute. If any such dispute cannot be resolved by agreement among the parties, the Signatory Parties agree to submit the matter to the Commission for an expedited determination, with a hearing as would be appropriate under the circumstances.

B. Change of Law.

If a change in any law, rule, regulation, order, or other requirement (or any repeal or amendment of an existing law, rule, regulation, order or other requirement) of the state, local or federal government or court having competent jurisdiction results in an increase in Distribution's annual operating expenses, to the extent that the aggregate amount of the effect of such changes in the First or Second Rate Years or any subsequent 12-month period exceed 3% of the Company's net income, Distribution may seek deferral treatment of any such expense, and any such deferrals are to be reflected in rates at the next time the Company's base rates are changed following the rate changes specified in this Joint Petition, subject to prudence review.

C. Binding Effect.

The Signatory Parties believe that this Joint Proposal should be approved by the Commission as being in the public interest. The Signatory Parties further agree that they consider this Joint Proposal to be binding on themselves for all purposes herein.

D. Severability.

It is the Signatory Parties' intent that the terms of this Joint Proposal not be separately interpreted and applied. To that end, it is understood that each provision of this Joint Proposal was given in consideration and support of all other provisions, and expressly conditioned upon the acceptance of the Joint Proposal in its entirety by the Commission. In the event or to the extent that the Commission does not adopt this Joint Proposal according to its terms, the parties to this Joint Proposal shall be free to pursue their respective positions in this proceeding and any remedies at Law or in equity without prejudice upon reasonable notice to the other parties.

E. Commission Action on This Joint Proposal.

The Signatory Parties understand that this Joint Proposal requires the approval of the Commission and agree to act so as to expedite the Commission's approval of this Joint Proposal.

If the Commission does not approve this Joint Proposal in its entirety, without modification, the Company may choose not to be bound by the terms of this Joint Proposal after that date by serving written notice on the other parties.

F. General Reservation.

It is specifically understood and agreed that this Joint Proposal represents a negotiated resolution of the Company's rates and services for the period of the Rate Plans contained herein and, except as otherwise expressly provided for herein, is intended to be binding only in this proceeding and only as to the matters specifically addressed herein. Neither the Company, the Commission, nor its Staff, shall be deemed to have approved, agreed to, or consented to any principle or methodology underlying or supposed to underlie any agreement provided for herein. None of the terms and provisions of the Joint Proposal and none of the positions taken herein by any Signatory Party may be referred to, cited or relied upon by any party in any fashion as precedent or otherwise in any proceeding before this Commission or any regulatory agency or before any court for any purpose except in furtherance of the purposes and results of this Joint Proposal.

G. Extension.

Nothing herein shall be construed as precluding the parties from convening additional conferences and from reaching agreement to extend this Joint Proposal on mutually acceptable terms and from presenting an agreement concerning such extension to the Commission for its approval.

H. Continuation of Ratemaking Mechanisms.

This Joint Proposal is predicated upon the continuation in their present form (except as may be altered by this Joint Proposal) of the following ratemaking mechanisms: the Weather Normalization Clause; the GAC, the 90/10 Symmetrical Sharing Mechanism (which shall exclude the effect of the SIT refund) (see Appendix O), Pension and OPEB deferrals, environmental clean-up cost deferrals (see below) and Company RD&D.[29] These rate mechanisms shall not be eliminated or significantly changed for Distribution during the effectiveness of this Rate Plan.

29 $1,117,000 shall be used for RD&D deferral accounting.

The Signatory Parties further agree that $600,000 included in the Company's rate case O&M presentation for Site Investigation & Remediation ("SIR") will continue to offset the Company's expenditures for SIR which are currently deferred and will continue to be deferred under previously-granted deferral authority. Each month, on a volumetric basis, an amount (for an annual amount of $600,000) will be debited to Account 583420 Miscellaneous General Expense and credited to 186635 Site Remediation Cost Amortization.

I. Execution in Counterpart Originals.

This Joint Proposal is being executed in counterpart originals, and shall be binding on each party when the counterparts have been executed.

AGREED to this 15th day of April 2005.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

BY: R J Kraski

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

BY:______________________________

CONSUMER PROTECTION BOARD

BY:______________________________

MULTIPLE INTERVENORS

BY:______________________________

The Signatory Parties further agree that $600,000 included in the Company's rate case O&M presentation for Site Investigation & Remediation ("SIR") will continue to offset the Company's expenditures for SIR which are currently deferred and will continue to be deferred under previously-granted deferral authority. Each month, on a volumetric basis, an amount (for an annual amount of $600,000) will be debited to Account 583420 Miscellaneous General Expense and credited to 186635 Site Remediation Cost Amortization.

I. Execution in Counterpart Originals.

This Joint Proposal is being executed in counterpart originals, and shall be binding on each party when the counterparts have been executed.

AGREED to this 15th day of April 2005.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

BY:______________________________

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

BY: Linda S. Hoolbeck

CONSUMER PROTECTION BOARD

BY:______________________________

MULTIPLE INTERVENORS

BY:______________________________

The Signatory Parties further agree that $600,000 included in the Company's rate case O&M presentation for Site Investigation & Remediation ("SIR") will continue to offset the Company's expenditures for SIR which are currently deferred and will continue to be deferred under previously-granted deferral authority. Each month, on a volumetric basis, an amount (for an annual amount of $600,000) will be debited to Account 583420 Miscellaneous General Expense and credited to 186635 Site Remediation Cost Amortization.

L. Execution in Counterpart Originals.

This Joint Proposal is being executed in counterpart originals, and shall be binding on each party when the counterparts have been executed.

AGREED to this 15th day of April 2005.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

BY:______________________________

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

BY:______________________________

CONSUMER PROTECTION BOARD

BY: John G. Walters

MULTIPLE INTERVENORS

BY:______________________________

The Signatory Parties further agree that $600,000 included in the Company's rate case O&M presentation for Site Investigation & Remediation ("SIR") will continue to offset the Company's expenditures for SIR which are currently deferred and will continue to be deferred under previously-granted deferral authority. Each month, on a volumetric basis, an amount (for an annual amount of $600,000) will be debited to Account 583420 Miscellaneous General Expense and credited to 186635 Site Remediation Cost Amortization.

I. Execution in Counterpart Originals.

This Joint Proposal is being executed in counterpart originals, and shall be binding on each party when the counterparts have been executed.

AGREED to this 15th day of April 2005.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

BY:______________________________

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

BY:______________________________

CONSUMER PROTECTION BOARD

BY:______________________________

MULTIPLE INTERVENORS

BY: Michael B. Mager

COUCH WHITE, LLP

Attorneys for Multiple Intervenors

PUBLIC UTILITY LAW PROJECT

BY: Ryan Wilson 4/15/05

CROWN ENERGY SERVICES, INC.

BY:______________________________

NATIONAL FUEL RESOURCES, INC.

BY:______________________________

NORTH AMERICAN ENERGY, INC.

BY:______________________________

SMALL CUSTOMER MARKETER COALITION

BY:______________________________

PUBLIC UTILITY LAW PROJECT

BY:____

CROWN ENERGY SERVICES, INC.

BY: Robert C. Hen

NATIONAL FUEL RESOURCES, INC.

BY:____

NORTH AMERICAN ENERGY, INC.

BY:____

SMALL CUSTOMER MARKETER COALITION

BY:____

PUBLIC UTILITY LAW PROJECT

BY:______________________________________

CROWN ENERGY SERVICES, INC.

BY:______________________________________

NATIONAL FUEL RESOURCES, INC.

BY:______________________________________ aac

NORTH AMERICAN ENERGY, INC.

BY:______________________________________

SMALL CUSTOMER MARKETER COALITION

BY:______________________________________

Deleted: .

BY:______________________________

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

BY:______________________________

CONSUMER PROTECTION BOARD

BY:______________________________

MULTIPLE INTERVENORS

BY:______________________________

PUBLIC UTILITY LAW PROJECT

BY:______________________________

NORTH AMERICAN ENERGY, INC.

BY:______________________________ 4/15/05

ENERGETIX, INC.

BY:______________________________

NATIONAL FUEL RESOURCES, INC.

BY:______________________________

PUBLIC UTILITY LAW PROJECT

BY:______________________________

CROWN ENERGY SERVICES, INC.

BY:______________________________

NATIONAL FUEL RESOURCES, INC.

BY:______________________________

NORTH AMERICAN ENERGY, INC.

BY:______________________________

SMALL CUSTOMER MARKETER COALITION

BY:______________________________

4/18/05

PUBLIC UTILITY LAW PROJECT

BY:____________________________________

CROWN ENERGY SERVICES, INC.

BY:____________________________________

NATIONAL FUEL RESOURCES, INC.

BY:____________________________________

NORTH AMERICAN ENERGY, INC.

BY:____________________________________

SMALL CUSTOMER MARKETER COALITION

BY:____________________________________

NOCO ENERGY MARKETING, LLC

BY: Timothy D. Wyjo

National Fuel Gas Distribution Corporation
New York Division
Summary of Proposed Revenue Increase Allocation

	Allocation of Increase		
	Non-Gas Revenue	Allocation %	Increase By Class
Residential			
SC-1 Sales	$151,742,493		
SC-1 Aggregated Transportation	$23,580,457		
SC-1 Aggregated Transportation - DSS	$2,225,390		
SC-2 LIRA	$8,214,334		
SC-2-A EBD LIRA	$114,727		
SubTotal Residential	$185,877,401	74%	$11,803,001
Small Non-Residential			
SC-3 Sales	$21,734,223		
SC-3 Aggregated Transportation	$16,765,317		
SC-13 TC 1.0 Non Aggregated Trans	$306,431		
Streetlighting Sales	$13,059		
Streetlighting Aggregated Transporation	$143,065		
SubTotal Small Non-Residential	$38,962,096	16%	$2,474,048
Large Non-Residential			
Total SC-13 TC 1.1 Trans (5-25 MMcf/Yr)	$11,476,985	5%	$728,775
Total SC-13 TC 2.0 Trans (25-55 MMcf/Yr)	$4,839,994	2%	$307,334
Total SC-13 TC 3.0 Trans (55-150 MMcf/Yr)	$3,395,895	1%	$215,635
Total SC-13 TC 4.0 Trans (>150 MMcf/Yr)	$4,089,595	2%	$259,685
Total SC-13 TC 4.1 Trans (>150 MMcf/Yr)	$1,111,578	0%	$70,584
Subtotal Large Non-Residential	$24,914,048		
Total Non-Gas Cost Revenue	$249,753,544	100.00%	$15,859,063

Summary of Base Tariff Rate Increase	
Proposed Revenue Requirement Increase	$21,000,000
Increase Due to Late Payment Change	$106,547
Revenue Adjustment For Fully Subscribed LIRA	$542,090
Total Revenue Requirement Increase	$21,648,637
Less: Increase Due to Elimination of Bill Credit	$4,480,870
Less: Increase Due to Elimination of HEICA Credit	$1,308,704
Base Tariff Rate Increase	$15,859,063

Summary of Total Bill Impact	
Total Revenue Increase	$21,648,637
Revenue Tax Change	($20,147,589)
State Income Tax Credit	($16,250,000)
Total Bill Impact	($14,748,952)

Summary of Base Tariff Rate Increase Due to Revenue Requirement	
Base Tariff Rate Increase	$15,859,063
Less: Increase Due to Late Payment Charge	$106,547
Less: Revenue Adjustment For Fully Subscribed	$542,090
Base Tariff Rate Increase Due to Revenue	$15,210,426

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
SUMMARY OF CURRENT AND PROPOSED BASE RATES
TWELVE MONTHS ENDED JULY 31, 2006

	CURRENT RATES	Final Settlement Unbundled Service Rates	Final Settlement Service Rates with Transitional Transportation	Final Settlement Service Rates with Daily Transportation
SC-1 - Sales				
Base Non Gas Cost Rate:				
Minimum Bill	$12.98	$13.54		
Billing Charge		$2.00		
0 - .4 Mcf	$0.00000	$0.00000		
.4 - 5 Mcf	$2.89494	$2.70216		
Over 5 Mcf	$2.36184	$2.16906		
Merchant Function Charge		$0.21979		
Minimum Bill Credit		($2.25)		
HEICA Credit	($0.01930)	$0.00000		
Revenue Credit/SIT Credit	($0.06513)	$0.00000		
SC-2 LIRA				
Base Non Gas Cost Rate:				
Minimum Bill	$4.65	($0.63)		
Billing Charge		$2.00		
0 - .4 Mcf	$0.00000	$0.00000		
.4 - 5 Mcf	$2.89494	$2.70216		
Over 5 Mcf	$2.36184	$2.16906		
Merchant Function Charge		$0.21979		
Minimum Bill Credit		($1.37)		
HEICA Credit	($0.01930)	$0.00000		
Revenue Credit/SIT Credit	($0.05977)	($0.09195)		
SC-2-A EBD LIRA				
Base Non Gas Cost Rate:				
Minimum Bill	$9.23	$9.23		
Billing Charge		$0.00		
Over .4 Mcf	$0.95030	$0.75752		
Merchant Function Charge		$0.21979		
Minimum Bill Credit		($2.25)		
HEICA Credit	($0.01930)	$0.00000		
Revenue Credit/SIT Credit	($0.00803)	$0.00000		
SC-3 Sales				
Base Non Gas Cost Rate:				
Minimum Bill	$16.61	$17.55		
Billing Charge		$2.00		
0 - 1 Mcf	$0.00000	$0.00000		
1 - 50 Mcf	$2.50774	$2.57806		
50 - 950 Mcf	$1.92624	$1.99656		
Over 950 Mcf	$1.60154	$1.62309		
Merchant Function Charge		$0.02440		
Minimum Bill Credit		($5.71)		
HEICA Credit	($0.01930)	$0.00000		
Revenue Credit/SIT Credit	($0.04374)	$0.00000		
SC-10 Sales to Large Cogen				
Base Non Gas Cost Rate:				
Margin	$0.36623	$0.36623		
Revenue Credit/SIT Credit	$0.00000	($0.16191)		

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
SUMMARY OF CURRENT AND PROPOSED BASE RATES
TWELVE MONTHS ENDED JULY 31, 2006

	CURRENT RATES	Final Settlement Unbundled Service Rates	Final Settlement Service Rates with Transitional Transportation	Final Settlement Service Rates with Daily Transportation
SC-1 Aggregated Residential Transporation				
Base Non Gas Cost Rate:				
Minimum Bill	$12.98	$13.54		
Billing Charge		$2.00		
0 - .4 Mcf	$0.00000	$0.00000		
.4 - 5 Mcf	$2.89494	$2.70216		
Over 5 Mcf	$2.36184	$2.16906		
Minimum Bill Credit		($2.25)		
HEICA Credit	($0.01930)	$0.00000		
Revenue Credit/SIT Credit	($0.06509)	$0.00000		
SC-3 Aggregated Transportation				
Volume:				
Base Non Gas Cost Rate:				
Minimum Bill	$16.61	$17.55		
Billing Charge		$2.00		
0 - 1 Mcf	$0.00000	$0.00000		
1 - 50 Mcf	$2.50774	$2.57806		
50 - 950 Mcf	$1.92624	$1.99656		
Over 950 Mcf	$1.60154	$1.62309		
Minimum Bill Credit		($5.71)		
HEICA Credit	($0.01930)	$0.00000		
Revenue Credit/SIT Credit	($0.04795)	$0.00000		
SC-13 TC1.0 Non Aggregated Transportation				
Base Non Gas Cost Rate:				
Minimum Bill	$16.47	$17.55		
Billing Charge		$2.00		
0 - 1 Mcf	$0.00000	$0.00000		
1 - 50 Mcf	$2.45870	$2.57806		
50 - 950 Mcf	$1.87720	$1.99656		
Over 950 Mcf	$1.55250	$1.62309		
Minimum Bill Credit		($5.71)		
HEICA Credit	($0.01930)	$0.00000		
Revenue Credit/SIT Credit	($0.03797)	$0.00000		
SC 13 - TC-1.1 Non Aggregation		Monthly	Transitional Monthly	Daily
Base Non Gas Cost Rate:				
Minimum Bill	$250.00	$321.94	$321.94	$321.94
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$1.33320	$1.38672	$1.33320	$1.25620
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.02468)	($0.03885)	($0.03885)	($0.03885)
SC-13 TC 1.1 Aggregation				
Base Non Gas Cost Rate:				
Minimum Bill	$250.09	$321.94	$321.94	$321.94
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$1.33320	$1.38672	$1.33320	$1.25620
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.02710)	($0.03885)	($0.03885)	($0.03885)
SC-13 TC 2 Non Aggregation				
Base Non Gas Cost Rate:				
Minimum Bill	$500.00	$705.83	$705.83	$705.83
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$1.00420	$1.05772	$1.00420	$0.92720
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.01698)	($0.02674)	($0.02674)	($0.02674)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
SUMMARY OF CURRENT AND PROPOSED BASE RATES
TWELVE MONTHS ENDED JULY 31, 2006

	CURRENT RATES	Final Settlement Unbundled Service Rates	Final Settlement Service Rates with Transitional Transportation	Final Settlement Service Rates with Daily Transportation
SC-13 TC 2 Aggregation				
Base Non Gas Cost Rate:				
Minimum Bill	$498.50	$705.83	$705.83	$705.83
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$1.00420	$1.05772	$1.00420	$0.92720
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.01938)	($0.02674)	($0.02674)	($0.02674)
SC-13 TC 3 Non Aggregation				
Base Non Gas Cost Rate:				
Minimum Bill	$1,400.00	$1,713.42	$1,713.42	$1,713.42
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$0.69760	$0.75112	$0.69760	$0.62060
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.01517)	($0.02088)	($0.02088)	($0.02088)
SC-13 TC 3 Aggregation				
Base Non Gas Cost Rate:				
Minimum Bill	$1,400.00	$1,713.42	$1,713.42	$1,713.42
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$0.69760	$0.75112	$0.69760	$0.62060
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.01898)	($0.02088)	($0.02088)	($0.02088)
SC-13 TC 4				
Base Non Gas Cost Rate:				
Minimum Bill	$3,000.00	$3,696.30	$3,696.30	$3,696.30
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$0.32400	$0.33952	$0.32400	$0.29340
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.00720)	($0.00940)	($0.00940)	($0.00940)
SC-13 TC 4.1				
Base Non Gas Cost Rate:				
Minimum Bill	$3,000.00	$3,365.80	$3,365.80	$3,365.80
Billing Charge		$2.00	$2.00	$2.00
0 - 1 Mcf	$0.00000	$0.00000	$0.00000	$0.00000
Over 1 Mcf	$0.46050	$0.52932	$0.47580	$0.39880
Minimum Bill Credit		$0.00000	$0.00000	$0.00000
HEICA Credit	$0.00000	$0.00000	$0.00000	$0.00000
Revenue Credit/SIT Credit	($0.00960)	($0.01362)	($0.01362)	($0.01362)
SC-16				
Base Non Gas Cost Rate:				
Minimum Bill	$0.00000	$0.00		
All Volume	$0.24410	$0.24410		
Revenue Credit/SIT Credit	$0.00000	($0.00559)		
SC-17				
Volume:				
Minimum Bill	$0.00000	$0.00		
All Volume	$0.93490	$0.93490		
Revenue Credit/SIT Credit	$0.00000	($0.02146)		

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
INTERNAL PENSION RESERVE INTEREST MECHANISM

Assumptions: Fair Market Value of Assets (FMV) less Accumulated Benefit Obligation (ABO)
= (under)over funded status
Acturial Funding report is for Plan Year ending June and is used for following FY

	9/30/2004	9/30/2005	9/30/2006	9/30/2007
FMV of Assets	373,889	400,000	420,000	400,000
ABO	397,550	350,000	430,000	425,000
(Under)Over Funded	(23,661)	50,000	(10,000)	(25,000)

Average	FY 05	FY 06	FY 07
FMV of Assets	386,945	410,000	410,000
ABO	373,775	390,000	427,500
(Under)Over Funded	13,170	20,000	(17,500)

	FY 05	FY 06	FY 07
Internal Reserve Debit Balance (below)	45,000	48,600	44,335
Less: Average Overfunding	13,170	20,000	0
Balance for Interest purposes	31,831	28,600	44,335
Pretax Rate of Return	11.31%	11.31%	11.31%
Interest accrued during FY	3,600	3,235	5,014

	9/30/2006	9/30/2007
Balance at beginning of year	$45,000	$48,600
Interest booked last day of previous FY	3,600	3,235
Balance at beginning of FY	48,600	51,835
Rate Allowance	15,000	15,000
Funding	15,000	0
Balance end of FY	$48,600	$36,835
Average of beginning and end of FY *	$48,600	$44,335

*Actual calculation will use average of monthly averages rather than
an average of the beginning and end balance

DEPRECIATION ACCRUAL RATE COMPARISONS
@ JULY 31, 2006

							PER COMPANY						PER STAFF				
ACCOUNT NO. /GROUP	ORIGINAL COST AT 7/31/2006 [1] $	AVERAGE SERVICE LIFE [1]	SURVIVOR CURVE [1]	NET SALVAGE PERCENT [1] %	ANNUAL ACCRUAL RATE [1] %	ANNUAL ACCRUAL AMOUNT [1] $	WHOLE LIFE ACCRUAL RATE [2] %	WHOLE LIFE ACCRUAL AMOUNT $	WHOLE LIFE VS AVG. REM. LIFE $	CURRENT ACCRUAL RATE [3] %	CURRENT ACCRUAL AMOUNT $	CURRENT VS PROPOSED $	AVERAGE SERVICE LIFE	SURVIVOR CURVE	NET SALVAGE PERCENT %	ANNUAL ACCRUAL RATE %	ANNUAL ACCRUAL AMOUNT $
INTANGIBLE PLANT																	
303 MISC.	$ 5,015,960	10	SQ	0%	10.00%	$ 501,824	10.00%	$ 501,596	$ (228)	10.00%	$ 501,596	$ (228)	10	SQ	0%	10.00%	$ 501,596
PRODUCTION PLANT																	
325.4 RIGHTS OF WAY	$ 372,137	55	H3.75	0%	1.61%	$ 5,981	1.82%	$ 6,766	$ 785	2.00%	$ 7,443	$ 1,462	55	H3.75	0%	1.82%	$ 6,766
327 COMPRESSOR STA. STR.	$ 178,880	40	SQ	-5%	0.44%	$ 791	2.63%	$ 4,696	$ 3,905	4.00%	$ 7,155	$ 6,364	40	SQ	-5%	2.63%	$ 4,696
328 MEAS. & REG. STA. STR.	$ 17,139	45	H3.25	-5%	0.23%	$ 40	2.33%	$ 400	$ 360	4.40%	$ 754	$ 714	45	H3.25	-5%	2.33%	$ 400
332 FIELD LINES	$ 10,690,101	50	H2.75	-15%	0.73%	$ 78,161	2.30%	$ 245,872	$ 167,711	3.43%	$ 366,670	$ 288,509	50	H2.75	-15%	2.30%	$ 245,872
333 COMPRESSOR STA. EQUIP.	$ 1,301,221	25	H2.25	-5%	3.24%	$ 42,146	4.20%	$ 54,651	$ 12,505	4.00%	$ 52,049	$ 9,903	25	H2.25	-5%	4.20%	$ 54,651
334 MEAS. & REG. STA. EQUIP	$ 4,115,671	30	H1.50	-20%	4.47%	$ 183,814	4.00%	$ 164,627	$ (19,187)	3.33%	$ 137,052	$ (46,762)	30	H1.50	-20%	4.00%	$ 164,627
	$ 16,675,149				1.86%	$ 310,933	2.86%	$ 477,012	$ 166,079	3.42%	$ 571,123	$ 260,190				2.86%	$ 477,012
TRANSMISSION PLANT																	
365.2 RIGHTS OF WAY	$ 250,782	75	H3.50	0%	1.20%	$ 3,001	1.33%	$ 3,344	$ 343	1.33%	$ 3,335	$ 334	75	H3.50	0%	1.33%	$ 3,344
366.2 STR. & IMPR.	$ 224,270	55	H2.00	-5%	0.98%	$ 2,191	1.91%	$ 4,282	$ 2,091	2.88%	$ 6,459	$ 4,268	55	H2.00	-5%	1.91%	$ 4,282
367 1 MAINS - EXCL CATH. PROT.	$ 11,084,481	60	H2.25	-25%	2.17%	$ 240,453	2.08%	$ 230,927	$ (9,526)	2.00%	$ 221,690	$ (18,763)	60	H2.25	-25%	2.08%	$ 230,927
367.2 MAINS - CATH. PROT.	$ 2,034,855	24	H2.25	0%	4.18%	$ 85,021	4.17%	$ 84,786	$ (235)	2.00%	$ 40,697	$ (44,324)	24	H2.25	0%	4.17%	$ 84,786
369 MEAS. & REG. STA. EQUIP.	$ 2,334,984	35	H1.50	-15%	3.10%	$ 72,307	3.29%	$ 76,721	$ 4,414	3.67%	$ 85,694	$ 13,387	35	H1.50	-15%	3.29%	$ 76,721
	$ 15,929,372				2.53%	$ 402,973	2.51%	$ 400,058	$ (2,915)	2.25%	$ 357,875	$ (45,098)				2.51%	$ 400,058
DISTRIBUTION PLANT																	
374.2 RIGHTS OF WAY	$ 8,243,687	75	H3.50	0%	1.34%	$ 110,517	1.33%	$ 109,916	$ (601)	1.33%	$ 109,641	$ (876)	75	H3.50	0%	1.33%	$ 109,916
375 STR. & IMPR.	$ 1,224,612	65	h2.50	-5%	1.42%	$ 17,334	1.62%	$ 19,782	$ 2,448	2.00%	$ 24,492	$ 7,158	65	h2.50	-5%	1.62%	$ 19,782
376.1 MAINS - CAST IRON	$ 1,758,376	73	h2.25	-50%	3.21%	$ 56,491	2.05%	$ 36,131	$ (20,360)	1.69%	$ 29,717	$ (26,774)	73	h2.25	-50%	2.05%	$ 36,131
376.2 MAINS - STEEL & OTHER - 1939 AND PRIOI	$ 5,986,409	73	H2.25	-50%	3.14%	$ 188,230	2.05%	$ 123,008	$ (65,222)	2.25%	$ 134,694	$ (53,536)	73	H2.25	-50%	2.05%	$ 123,008
376.2 MAINS - STEEL & OTHER - 1940 AND AFTEI	$ 167,689,424	53	H2.00	-50%	3.27%	$ 5,491,633	2.83%	$ 4,745,927	$ (745,706)	2.25%	$ 3,773,012	$ (1,718,621)	53	H2.00	-50%	2.83%	$ 4,745,927
376.3 MAINS - CATH. PROT.	$ 2,533,862	24	H2.25	0%	4.64%	$ 117,618	4.17%	$ 105,578	$ (12,040)	2.25%	$ 57,012	$ (60,606)	24	H2.25	0%	4.17%	$ 105,578
376.4 MAINS - PLASTIC	$ 414,895,534	55	H3.00	-50%	2.97%	$ 12,310,301	2.73%	$ 11,315,333	$ (994,968)	2.25%	$ 9,335,150	$ (2,975,151)	70	H3.00	-50%	2.14%	$ 8,890,619
377 COMPRESSOR STA. EQUIP.	$ 1,375,412	30	H2.50	0%	2.21%	$ 30,341	3.33%	$ 45,847	$ 15,506	4.00%	$ 92,296	$ 61,955	30	H2.50	0%	3.33%	$ 45,847
378 MEAS. & REG. STA. EQUIP.	$ 12,860,357	35	H1.00	-25%	3.43%	$ 441,032	3.57%	$ 459,298	$ 18,266	3.91%	$ 502,840	$ 61,808	35	H1.00	-25%	3.57%	$ 459,298
380 SERVICES	$ 338,156,577	52	H1.25	-30%	2.19%	$ 7,389,971	2.50%	$ 8,453,914	$ 1,063,943	3.64%	$ 12,308,899	$ 4,918,928	52	H1.25	-30%	2.50%	$ 8,453,914
381 METERS	$ 11,513,438	36	H3.00	0%	2.79%	$ 320,924	2.78%	$ 319,818	$ (1,106)	2.11%	$ 242,934	$ (77,990)	36	H3.00	0%	2.78%	$ 319,818
381.1 METERS - AMR	$ 2,523,160	10	H2.00	0%	4.28%	$ 107,949	10.00%	$ 252,316	$ 144,367	11.59%	$ 292,434	$ 184,485	10	H2.00	0%	10.00%	$ 252,316
382 METER INSTALLATIONS	$ 5,439,771	52	H1.25	0%	1.98%	$ 107,549	1.92%	$ 104,611	$ (2,938)	1.82%	$ 99,004	$ (8,545)	52	H1.25	0%	1.92%	$ 104,611
383 HOUSE REGULATORS	$ 42,367	30	H2.75	0%	6.27%	$ 2,656	3.33%	$ 1,412	$ (1,244)	3.00%	$ 1,271	$ (1,385)	30	H2.75	0%	3.33%	$ 1,412
384 HOUSE REGULATOR INSTA.	$ 1,799,284	52	H1.25	0%	1.90%	$ 34,125	1.92%	$ 34,602	$ 477	1.82%	$ 32,747	$ (1,378)	52	H1.25	0%	1.92%	$ 34,602
385 IND. MEAS. & REG. STA. EQUIP.	$ 15,981,131	45	H1.50	-25%	2.99%	$ 477,942	2.78%	$ 443,920	$ (34,022)	2.00%	$ 319,623	$ (158,319)	45	H1.50	-25%	2.78%	$ 443,920
387 OTHER EQUIP.	$ 78,466	35	H3.50	0%	0.00%	$ -	2.86%	$ 2,242	$ 2,242	3.33%	$ 2,613	$ 2,613	35	H3.50	0%	2.86%	$ 2,242
	$ 992,101,847				2.74%	$ 27,204,613	2.68%	$ 26,573,655	$ (630,958)	2.76%	$ 27,358,378	$ 153,765				2.43%	$ 24,148,941
GENERAL PLANT																	
398.2 RIGHTS OF WAY	$ 284	75	SQ	0%	0.35%	$ 1	1.41%	$ 4	$ 3	1.33%	$ 4	$ 3	75	SQ	0%	0.35%	$ 1
390.1 STR. & IMPR. - LARGE STR.	$ 20,074,952	55	H1.50	0%	7.52%	$ 1,509,771	3.46%	$ 694,593	$ (815,178)	1.82%	$ 365,364	$ (1,144,407)	55	H1.50	0%	7.52%	$ 1,509,771
390.2 STR. & IMPR. - SMALL STR.	$ 4,822,739	20	H1.75	-5%	10.64%	$ 513,306	3.74%	$ 180,370	$ (332,936)	1.82%	$ 87,774	$ (425,532)	20	H1.75	-5%	10.64%	$ 513,306
391.1 OFFICE FURN. & EQUIP. - FURN.	$ 3,781,741	25	SQ	0%	11.89%	$ 449,487	2.77%	$ 104,754	$ (344,733)	2.22%	$ 83,955	$ (365,532)	25	SQ	0%	11.89%	$ 449,487
391.2 OFFICE FURN. & EQUIP. - EQUIP.	$ 1,595,684	15	SQ	0%	26.64%	$ 425,146	1.55%	$ 24,733	$ (400,413)	5.28%	$ 84,252	$ (340,894)	15	SQ	0%	26.64%	$ 425,146
391.3 OFFICE FURN. & EQUIP. - COMP.	$ 1,689,301	5	SQ	0%	21.32%	$ 360,183	13.14%	$ 221,974	$ (138,209)	25.00%	$ 422,325	$ 62,142	5	SQ	0%	21.32%	$ 360,183
392 TRANSPORTATION EQUIP.	$ 3,839,173	14	H2.00	0%	7.15%	$ 274,668	7.14%	$ 274,227	$ (441)	20.00%	$ 767,835	$ 493,167	14	H2.00	0%	7.15%	$ 274,668
393 STORES EQUIP.	$ 58,298	30	SQ	0%	0.12%	$ 71	1.45%	$ 845	$ 774	3.00%	$ 1,749	$ 1,678	30	SQ	0%	0.12%	$ 71
394.1 TOOLS & WORK EQUIP.	$ 5,709,003	25	SQ	0%	8.85%	$ 505,397	3.23%	$ 184,401	$ (320,996)	2.57%	$ 146,721	$ (358,676)	25	SQ	0%	8.85%	$ 505,397
394.2 SHOP EQUIP.	$ 712,917	25	SQ	0%	8.20%	$ 58,488	2.48%	$ 17,680	$ (40,808)	2.22%	$ 15,827	$ (42,661)	25	SQ	0%	8.20%	$ 58,488
394.3 GARAGE EQUIP.	$ 4,621,491	25	SQ	0%	5.77%	$ 266,888	3.85%	$ 177,927	$ (88,961)	2.88%	$ 132,175	$ (134,713)	25	SQ	0%	5.77%	$ 266,888
395 LABORATORY EQUIP.	$ 6,842	30	SQ	0%	48.74%	$ 3,335	3.33%	$ 228	$ (3,107)	4.00%	$ 274	$ (3,061)	30	SQ	0%	48.74%	$ 3,335
396 POWER OPER. EQUIP. - UNAMORTIZED	$ 2,367,701	20	H1.75	0%	4.71%	$ 111,445	5.00%	$ 118,385	$ 6,940	10.00%	$ 236,770	$ 125,325	20	H1.75	0%	4.71%	$ 111,445
396 POWER OPER. EQUIP. - AMORTIZED	$ 1,150,979	15	SQ	0%	9.49%	$ 109,242	5.47%	$ 62,959	$ (46,283)	10.00%	$ 115,098	$ 5,856	15	SQ	0%	9.49%	$ 109,242
397 COMMUNICATION EQUIP.	$ 1,316,563	10	SQ	0%	22.30%	$ 293,607	6.73%	$ 88,605	$ (205,002)	5.00%	$ 65,828	$ (227,779)	10	SQ	0%	22.30%	$ 293,607
398 MISC. EQUIP.	$ 42,164	20	SQ	0%	0.08%	$ 33	3.37%	$ 1,421	$ 1,388	3.17%	$ 1,337	$ 1,304	20	SQ	0%	0.08%	$ 33
	$ 51,789,832				9.42%	$ 4,881,068	4.16%	$ 2,153,107	$ (2,727,961)	4.88%	$ 2,527,287	$ (2,353,781)				9.42%	$ 4,881,068
TOTAL	$ 1,081,512,160					$ 33,301,411		$ 30,105,429	$ (3,195,982)		$ 31,316,258	$ (1,985,153)					$ 30,408,676

1 EXHIBIT__(JJS-1) SHEETS 1 THRU 3 OF 3
2 RESPONSE TO DPS-32
3 RESPONSE TO STA-4

Appendix C

Sharing of Earnings

The Joint Proposal ("JP") provides for the comparison of the Company's earnings over the term of the JP and beyond to a target sharing level. Earnings exceeding the target sharing level are to be shared equally with ratepayers. Below, the basic terms of this earnings measurement mechanism are defined, and pages 3 through 17 provide an example of how the actual computations will be performed. In the example, the actual results for the twelve months ended September 30 2004 (Fiscal 2004) are being used as an aid to avoid confusion in the future when the actual calculations are performed.

Target Sharing Level =	Fiscal Year 2005 (TME 9/30/05)	11.08%
	Fiscal Year 2006 (TME 9/30/06)	11.50%
	Fiscal Year 2007 (TME 9/30/07)	11.50%

Operating Income Before Taxes = The Company's financial statements provide utility operating revenues plus other operating revenues less utility operating and maintenance expenses, depreciation and taxes other than income taxes for each of the fiscal years, which will be used to determine the initial Operating Income Before Income Taxes. This is shown in column 1 of page 3, with a copy of the actual twelve month current financial report GL2103 supplied on page 10.

Adjustments to Operating Income Before Taxes = As shown in column 2 of page 3, three adjustments are to be made, if applicable during the fiscal year. The first reverses any entry made by the Company which reduces revenues for a potential obligation to dispose of the excess earnings (ie. Debit Other Revenues, credit Provision for Refund). The second adjustment removes any dollar amount expensed for Stock Appreciation Rights and Restricted Stock Expense (commonly referred to as "SARs"). The third adjustment reflects the reversal of any reward/penalty assessment.

Income Taxes = The Company's financial statements provide current state and federal income taxes, Investment Tax Credit, and deferred state and federal income taxes for each fiscal year. These amounts are shown on column 1 of page 3.

Adjustments to Income Taxes = Required adjustments will be made to the income tax calculation and deferred income taxes for each of the fiscal years. These adjustments are shown on page 4. First, non-ratemaking Schedule M adjustments and non-ratemaking deferred taxes have been removed. The interest calculation has also been adjusted as described below.

Utility Operating Income = For each fiscal year, the Operating Income Before Taxes, as defined above, less the Income Taxes, provide the Utility Operating Income

Interest Charges =	For each fiscal year, the Interest Charges shall be determined based on rate base, as defined below, multiplied by the weighted debt cost as determined in the Return on Equity section described below.
Rate Base =	The average of the monthly averages (i.e. Thirteen months ended September less ½ of each September and the total divided by 12) of actual Rate Base balances, excluding O&M Allowance and the Earnings Base/Capitalization ("EB/Cap") adjustment, for each fiscal year. Deferred Income Taxes - Liberalized Depreciation will include both federal and state income taxes. Where applicable, the balances will be net of both federal and state income taxes. The O&M Allowance will be 1/8th of the fiscal year's Operation and Maintenance expense. The EB/Cap will be $27,064,000 ($26,842,000 x 10/12 + $28,173,000 x 2/12) addition to rate base for Fiscal 2005. The EB/Cap will be $28,173,000 addition to rate base for Fiscal 2006 and 2007.
Rate of Return on Rate Base =	The Utility Operating Income as defined above divided by the Rate base also defined above.
Capital Structure =	The capital structure components will include Common Equity (but Common Equity shall exclude items of Other Comprehensive Income[1] or Loss), Long Term Debt (including current portion), Short Term Debt (notes payable) and Accounts Payable to Customer (Customer Deposits). The capital structure will be calculated by averaging the start and finish of each fiscal year of National Fuel Gas Company's capital structure. The Common Equity component will be limited to the lower of actual average or 49%. The capital structure will also reflect the actual long term, short term and customer deposit rates experienced during each fiscal year.

[1] The term "Other Comprehensive Income" refers to revenues, expenses, gains, and losses that under generally accepted accounting principles are included in comprehensive income but excluded from net income. See SFAS 130, Reporting Other Comprehensive Income (Financial Accounting Standards Board 1997).

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
INCOME STATEMENT
($000)

Fiscal 2004 Actual

	Actual GL2103	Adjustments	Adjusted Actual		Revenue Requirement	As Adjusted
Operating Revenues						
Gas Revenues	$754,373	$0	$754,373		$2,045	$756,418
Transportation Revenues	64,880	0	64,880		0	64,880
Purchased Gas Cost	536,818	0	536,818		0	536,818
Revenue Taxes	12,703	0	12,703		77	12,780
	269,732	0	269,732		1,968	271,700
Other Operating Revenues	681	0	681	(1)	0	681
Total Operating Revenues	270,413	0	270,413		1,968	272,381
Operating Revenue Deductions						
Operations & Maintenance Expenses	132,044	(184)	131,860	(2)	26	131,886
Depreciation Expense	28,085	0	28,085		0	28,085
Taxes Other Than Income Taxes	31,556	0	31,556		0	31,556
Total Operating Revenue Deductions	191,685	(184)	191,501		26	191,527
Operating Income Before Income Taxes	78,728	184	78,912		1,942	80,854
Current Federal Income Taxes Payable	12,201	(2,772)	9,429		629	10,058
Current State Income Taxes Payable	621	1,563	2,184		146	2,330
Investment Tax Credit Adjustment	(1)	0	(1)		0	(1)
Deferred Income Taxes - Federal	10,392	(14)	10,378		0	10,378
Deferred Income Taxes - State	3,665	(1,797)	1,868		0	1,868
Net Income Taxes	26,878	(3,020)	23,858		775	24,633
Utility Operating Income	$51,850	$3,204	$55,054		$1,167	$56,221
Rate Base	$664,439	($22)	$664,439		$0	$664,439
Rate Of Return	7.80%		8.29%			8.46%
Cost of Equity	9.59%		10.63%			11.00%

(1) Reflects reversal of Provision for Refund if booked by Company. Also reflects reversal of any reward/penalty assessment.
(2) Reflects removal of SARs expense pursuant to Settlement Agreement.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
FEDERAL AND STATE INCOME TAXES
($000)

Fiscal 2004 Actual

	Actual GL2103	Adjustments	Adjusted Actual	Revenue Requirement	As Adjusted
Operating Income Before Income Taxes	$78,728	$184	$78,912	$1,942	$80,854
Adjustments:					
Interest Expense	16,664	5,196	21,860	0	21,844
Cost of Retiring Property	2,076	0	2,076	0	2,076
Book Depreciation	(28,085)	0	(28,085)	0	(28,085)
Income Tax Depreciation	53,747	0	53,747	0	53,747
Meals/Entertainment/Dues	(47)	0	(47)	0	(47)
Contributions in Aid of Construction	(1,200)	0	(1,200)	0	(1,200)
Bad Debts - Net	4,236	0	4,236	0	4,236
Capitalized Overheads	(2,800)	0	(2,800)	0	(2,800)
Misc.	25,860	(25,860)	0	0	0
Total Adjustments	70,451	(20,664)	49,787	0	49,771
Income Subject to State Income Tax	8,277	20,848	29,125	1,942	31,083
State Income Taxes @ 7.50%	$621	$1,563	$2,184	$146	$2,331
Additional FIT Adjustments					
Miscellaneous	(27,205)	27,205	0	0	0
Total Adjustments	(27,205)	27,205	0	0	0
Income Subject to Federal Income Tax	34,861	(7,920)	26,941	1,796	28,752
Federal Income Taxes @ 35.00%	$12,201	($2,772)	$9,429	$629	$10,063

DEFERRED INCOME TAXES
($000)

	Actual GL2103	Adjustments	Adjusted Actual	Revenue Requirement	As Adjusted
Capitalized Overheads - NYS	($244)	$0	($244)	$0	($244)
Contributions in Aid of Construction - NYS	(75)	0	(75)	0	(75)
Bad Debts - Net - State	250	0	250	0	250
Miscellaneous - State	1,797	(1,797)	0	0	0
Accelerated Depreciation - State	1,937	0	1,937	0	1,937
Subtotal State Deferred Income Taxes	3,665	(1,797)	1,868	0	1,868
Accelerated Depreciation - Fed	10,075	0	10,075	0	10,075
Miscellaneous - Fed	14	(14)	0	0	0
Capitalized Overheads - Fed	(895)	0	(895)	0	(895)
Contributions in Aid of Construction - Fed	(197)	0	(197)	0	(197)
Bad Debts - Net - Fed	1,395	0	1,395	0	1,395
Subtotal Federal Deferred Income Taxes	10,392	(14)	10,378	0	10,378
Total Deferred Income Taxes	$14,057	($1,811)	$12,246	$0	$12,246

TAXES - OTHER THAN INCOME
($000)

	Actual GL2103	Adjustments	Adjusted Actual	Revenue Requirement	As Adjusted
FICA	$3,748	$0	$3,748	$0	$3,748
Federal Unemployment Compensation	43	0	43	0	43
New York Unemployment Compensation	114	0	114	0	114
Property Tax	27,586	0	27,586	0	27,586
Sales & Use Tax	40	0	40	0	40
Miscellaneous	25	0	25	0	25
Total	$31,556	$0	$31,556	$0	$31,556

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
CALCULATION OF INTEREST DEDUCTION
($000)

Fiscal 2004 Actual

Rate Base	$664,439
Debt Component Interest Rate	3.29% *
Total	21,860
Interest - Per Books	16,664
Adjustment	$5,196

*Debt Component Interest Rate	Capital Structure Ratios	Cost Rates	Weighted Rate
Long Term Debt	47.56%	6.68%	3.18%
Short Term Debt	5.15%	1.97%	0.10%
Gas Storage	0.00%	7.50%	0.00%
Customer Deposits	0.22%	2.45%	0.01%
	52.93%		3.29%

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
RATE BASE
($000)

Fiscal 2004 Actual

	Actual GL2103	Adjustments	Adjusted Actual	Revenue Requirement	As Adjusted
Net Plant	$707,127	$0	$707,127	$0	$707,127
Working Capital					
Cash Allowance	16,483	0	16,483	0	16,483
Prepayments	9,861	0	9,861	0	9,861
Materials And Supplies	5,970	0	5,970	0	5,970
Gas Storage Inventory	(3,375)	0	(3,375)	0	(3,375)
Total Working Capital	28,939	0	28,939	0	28,939
Deferred Income Taxes					
Liberalized Depreciation	(95,959)	0	(95,959)	0	(95,959)
Investment Tax Credit	(5,077)	0	(5,077)	0	(5,077)
Deferred HIECA costs	0	0	0	0	0
Deferred NY PSC Assessment	1,287	0	1,287	0	1,287
Deferred Management Audit	0	0	0	0	0
Deferred R,D & D	(192)	0	(192)	0	(192)
Deferred Sales Tax	0	0	0	0	0
Deferred Site Remediation Costs	(2,533)	0	(2,533)	0	(2,533)
Deferred Income Taxes - IRS Audit	0	0	0	0	0
Deferred Gas Planning	0	0	0	0	0
Deferred Income Taxes - FIT Audit	0	0	0	0	0
TRA Impacts - Uncollectibles	4,098	0	4,098	0	4,098
Deferred LIRA	0	0	0	0	0
Elimination of Reorganization Costs per C 27934	(93)	0	(93)	0	(93)
Earnings Base in Excess of Capitalization	26,842	0	26,842	0	26,842
Rate Base	$664,439	$0	$664,439	$0	$664,439

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
REVENUE REQUIREMENT
($000)

Fiscal 2004 Actual

Projected Rate Base	$664,439
Rate of Return	8.46%
Required Utility Operating Income	56,222
Projected Utility Operating Income	55,054
Additional Operating Income Required	$1,168
Retention Factor *	0.5710687
Additional Revenue Requirement	$2,045
Increase in Rates	$2,045
Less: Revenue Taxes	77
Uncollectibles	26
Informational Advertising	0
	0
Taxable Income	1,942
State Income Taxes (7.50%)	$146
Federal Income Taxes (35.00%)	$629

* Retention Factor Calculation	
Revenue	100.000000
Less: Revenue Tax	3.766304
Uncollectibles	1.253459
	94.980237
Reciprocal of State Tax Rate	0.925000
	87.856719
Reciprocal of Federal Tax Rate	0.650000
Retention Factor	57.106867
Uncollectibles - Rate Year	10,269
Revenues - Rate Year	819,253
	0.01253459

NATIONAL FUEL GAS COMPANY
CAPITAL STRUCTURE ANALYSIS

	Actual at September 30, 2003	Add: OCI *	Adj. Balance at September 30, 2003
Common shareholder equity	$ 1,137,390	$ 65,537	$ 1,202,927
Notes payable to banks and commercial paper	118,200		118,200
Long-term debt (including current portion)	1,389,510		1,389,510
Total debt	$ 1,507,710		$ 1,507,710
Customer Deposits	5,401		5,401
Total capitalization	$ 2,650,501		$ 2,716,038

	Actual at September 30, 2004	Add: OCI	Adj. Balance at September 30, 2004
Common shareholder equity	$ 1,253,701	$ 54,775	$ 1,308,476
Notes payable to banks and commercial paper	156,800		156,800
Long-term debt (including current portion)	1,147,577		1,147,577
Total debt	$ 1,304,377		$ 1,304,377
Customer Deposits	6,088		6,088
Total capitalization	$ 2,564,166		$ 2,618,941

		Average
Common shareholder equity	47.07%	$ 1,255,702
Notes payable to banks and commercial paper	5.15%	$ 137,500
Long-term debt (including current portion)	47.56%	$ 1,268,544
Total debt		$ 1,406,044
Customer Deposits	0.22%	$ 5,745
Total capitalization	100.00%	$ 2,667,490

* OCI = Other Comprehensive Income

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
CAPITAL STRUCTURE AND
CALCULATION OF ACTUAL RETURN ON EQUITY
TWELVE MONTHS ENDED SEPTEMBER 30, 2004

CAPITAL STRUCTURE	Capital Structure Ratios	Cost Rates	Weighted Rate
Long Term Debt	47.56%	6.68%	3.18%
Short Term Debt	5.15%	1.97%	0.10%
Customer Deposits	0.22%	2.45%	0.01%
Common Equity	47.07%	11.00%	5.18%
	100.00%		8.46%

ACTUAL OVERALL RATE OF RETURN	
Actual Net Operating Income	$55,054
Rate Base (see Page 5)	664,439
Actual Overall Rate of Return	8.29%
Less: Weighted Rate for Debt	3.28%
Weighted Rate for Common Equity	5.00%
Common Equity Ratio	47.07%
Calculated Actual Return on Equity	10.63%

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
FINAL CALCULATION OF EARNINGS PURSUANT TO SETTLEMENT AGREEMENT
FOR BOOK DETERMINATION OF REFUND PROVISION
AS OF TWELVE MONTHS ENDED SEPTEMBER 30, 2004
($000)

	FY 04	
Utility Operating Income Adjusted for Ratemaking Purposes	$55,054	$0
Rate Base Adjusted for Ratemaking Purposes	$664,439	$0
Overall Rate of Return - Actual	8.29%	0.00%
Adjusted Target Rate of Return for Sharing Purposes	8.46%	0.00%
Realized Rate of Return Variance	-0.18%	0.00%
Rate Base Adjusted for Ratemaking Purposes	664,439	0
After Tax Fiscal Year Over(Under) Earnings	(1,168)	0
Retention Factor	57.106867%	0.000000%
Fiscal Year Over(Under)Earnings in Revenues	($2,045)	$0
Total Cumulative Earnings for Sharing Purposes		($2,045)
Sharing Percentage (50% if Cumulative Earnings is Positive)		0%
Refund to Ratepayers		$0

National Fuel

Income_Statement - 12 Months Ended
For The Period Ended September 30, 2004

Business Unit: NFG Distribution Co - NY
Report Number: GL2103

Run Date: 10/21/2004
Run Time: 16:13

			Current
		Gas Revenues	$754,372,770
		Less: Purchased Gas Sold	533,162,809
		Revenue Taxes	11,815,565
		Net Gas Revenues	**209,394,396**
		Transportation Revenues	64,880,303
		Less: Purchased Gas Sold	3,654,845
		Revenue Taxes	886,954
		Net Transportations Revenue	**60,338,505**
		Other Operating Revenues	680,714
		Total Net Revenues	**270,413,614**
		Operating Revenue Deductions:	
		Operation Expense	123,236,750
		Maintenance Expense	8,806,981
		Depletion, Depreciation & Amortization	28,084,518
		Income Tax Federal - Current	12,200,980
		Income Tax State - Current	620,651
		Provision For Deferred Income Tax	14,057,205
		Investment Tax Credit	-1,032
		Other Taxes	31,556,917
		Total Operating Revenue Deductions	**218,562,969**
		Operating Income/(-)Loss	**51,850,645**
		Other Income:	
		Interest	388,856
		AFUDC	211,047
		Miscellaneous	-165,785
		Investment Tax Credit	437,179
		Total Other Income	**871,297**
		Gross Income/(-)Loss	**52,721,941**
		Other Deductions:	
	{	Interest - Associate Companies	13,012,396
Interest	16,664,190 {	Interest - Other	3,768,911
	{	Interest - Borrowed Funds During Const.	-117,116
		Miscellaneous	560,411
		Total Other Deductions	**17,224,601**
		Taxes On Other Income & Deductions:	
		Federal - Current	-930,686
		State - Current	0
		Provision For Deferred Income Taxes	0
		Miscellaneous Other Taxes	0
		Total Taxes On Other Income & Deductions	**-930,686**
		Net Income/(-)Loss	**$36,428,026**

NATIONAL FUEL GAS COMPANY (PARENT COMPANY)
COMPOSITE INTEREST RATE OF DEBT
ACTUAL FOR THE THIRTEEN MONTHS ENDED SEPTEMBER 30, 2004

Total Long-term Debt		Average Balance	Effective Interest Rate	Annualized Cost	Composite Interest Rate
	Debentures				
125,000,000	7 3/4% due 2004	46,875,000	8.04%	3,768,750	
	Medium-Term Notes				
49,000,000	7.395% due 2023	49,000,000	7.43%	3,640,700	
50,000,000	7.375% due 2025	50,000,000	7.43%	3,715,000	
200,000,000	6.303% due 2008	200,000,000	6.38%	12,760,000	
100,000,000	6.000% due 2009	100,000,000	6.15%	6,150,000	
100,000,000	6.820% due 2004	87,500,000	6.96%	6,090,000	
200,000,000	7.500% due 2010	200,000,000	7.66%	15,320,000	
150,000,000	6.700% due 2011	150,000,000	6.79%	10,185,000	
97,272,000	6.500% due 2022	97,366,417	6.66%	6,484,603	
250,000,000	5.25 % due 2013	250,000,000	5.34%	13,350,000	
1,096,272,000	Total Long-Term Debt	1,230,741,417		81,464,053	6.62%
	Net Premium and Issuance Expense Adjustments				
	1986 & 1988	(20,108)			
	1992 (February)	(57,494)			
	1993 (March)	(445,665)			
	1993 (July)	(1,585,550)			
	1994 (July)	(492,905)			
	2002 (September)	(2,913,988)			
	2003 (February)	(2,154,906)			
	Annual Amortization of Premium (Net of Tax)				
	1986 & 1988			108,520	
	1992 (February)			177,430	
	1993 (March)			20,232	
	1993 (July)			196,920	
	1994 (July)			52,740	
	2003 (February)			165,420	
	Reduction of Annualized Cost Resulting from Recovery of Annual Premium Amortization				
	1986 & 1988			(92,513)	
	1992 (February)			(125,590)	
	1993 (March)			(16,459)	
	1993 (July)			(150,364)	
	1994 (July)			(40,099)	
	2003 (February)			(8,681)	
	Total Long-Term Debt	$1,223,070,801		$81,751,609	6.68%
	Short-Term Debt	$103,645,000	1.272%	$1,318,779	
	Committed Line of Credit Fee			725,795	
	Total Short-Term Debt	$103,645,000		$2,044,574	1.97%
	Total Debt	$1,326,715,801		$83,796,183	6.32%

NATIONAL FUEL GAS COMPANY
CALCULATION OF EFFECTIVE INTEREST RATE OF [illegible] TERM DEBT BY SERIES

	Date of Issuance	Date of Maturity	Term of Issue in Years	Remaining Principal Amount of Issue	Underwriter's Expense and Prem./(Disc.) at Issuance	Issuance Expense	Net Proceeds	Net Proceeds Ratio	Effective Interest Rate (1)
Debentures:									
7.750% due 2004	2/18/1992	2/1/2004	12	$125,000,000	$2,272,500	$2,091,104 (2)	$120,636,396	0.9651	8.04%
Medium-Term Notes:									
Outstanding Issues:									
7.395% due 2023	3/30/1993	3/30/2023	30	$49,000,000	$367,500	$113,854 (3)	$48,518,646	0.9902	7.43%
7.375% due 2025	6/12/1995	6/13/2025	30	$50,000,000	$726,500	$125,972	$49,147,528	0.9830	7.43%
6.303% due 2008	05/26/1998	05/27/2008	10	$200,000,000	$1,250,000	$344,041	$198,405,959	0.9920	6.38%
6.000% due 2009	02/26/1999	03/01/2009	10	$100,000,000	$1,264,000	$229,409	$98,506,591	0.9851	6.15%
6.820% due 2004	07/12/1999	08/01/2004	5	$100,000,000	$519,000	$168,997 (5)	$99,312,003	0.9931	6.96%
7.500% due 2010	11/21/2000	11/22/2010	10	$200,000,000	$2,706,000	$397,403	$196,896,597	0.9845	7.66%
6.700% due 2011	11/20/2001	11/21/2011	10	$150,000,000	$1,023,000	$370,952	$148,606,048	0.9907	6.79%
6.500% due 2022	9/18/2002	9/15/2022	20	$97,700,000	$2,833,300	$317,657	$94,549,043	0.9677	6.66%
5.250% due 2013	2/18/2003	3/1/2013	10	$250,000,000	$1,487,500	$755,965 (4)	$247,756,535	0.9910	5.34%

Notes:

1) The effective cost rate for each issue is computed on the basis of coupon interest rates using as inputs the term of the issue, premiums or discounts, underwriters expenses, issuance expenses, and the face value of debt. This methodology was adopted by the PSC in case 328447

2) Reflects unamortized costs associated with refinancing activities during 1986, 1988, and 1992. Unamortized costs are $1,525,824. This debenture was due on Feb 1, 2004, however the effective interest rate is still needed for the Composit Interest Rate Schedule, which uses the average outstanding balance.

3) Reflects unamortized costs associated with refinancing activities during March 1993. Unamortized costs are $64,073.

4) Reflects issuance costs and unamortized costs associated with refinancing activities in February 2003. Unamortized costs are $394,967.

5) This medium-term note was due on Aug 1, 2004, however the effective interest rate is still needed for the Composit Interest Rate Schedule, which uses the average outstanding balance.

12

NATIONAL FUEL GAS COMPANY
AMORTIZATION OF CAPITAL STRUCTURE ADJUSTMENTS
FOR RATEMAKING PURPOSES

		Base Year Adjustment	Months of Amort.	Monthly Amort.	Start Date	At Sept. 30, 2003 # of Mos.	At Sept. 30, 2003 Amount Amortized	At Sept. 30, 2003 Balance Outstanding	At Sept. 30, 2004 # of Mos.	At Sept. 30, 2004 Amount Amortized	At Sept. 30, 2004 Balance Outstanding	Avg. Bal. Outstanding
1)	1986/1988											
	- 1986	$5,428,513	240	$22,619	Sep-86	71	$1,605,949		71	$1,605,949		
	- 1988	427,910	216	$1,981	Dec-88	44	$87,164		44	$87,164		
		$5,856,423		$30,169	Jul-92	128	$3,861,632	$301,678	138	$4,163,310	$0	$20,108
2)	1992 February	$7,947,796	144	$55,193	Feb-92	133	$7,340,673	$607,123	144	$7,947,796	$0	$57,494
3)	1993 March	$703,682	360	$1,955	Mar-93	126	$246,289	$457,393	138	$269,745	$433,937	$445,665
4)	1993 July	$4,060,554	210	$19,336	Jul-93	122	$2,358,989	$1,701,565	134	$2,591,020	$1,469,534	$1,585,550
5)	1994 July	$1,101,170	210	$5,244	Jul-94	110	$576,803	$524,367	122	$639,727	$461,443	$492,905
6)	2002 September	$3,150,257	240	$13,126	Sep-02	12	$157,513	$2,992,744	24	$315,026	$2,835,231	$2,913,988
7)	2003 February	$2,416,717	120	$20,139	Feb-03	7	$140,975	$2,275,742	19	$382,647	$2,034,070	$2,154,906
												$7,670,615

13

NATIONAL FUEL GAS COMPANY
ACTUAL WEIGHTED SHORT TERM DEBT RATE
THIRTEEN MONTHS ENDED SEPTEMBER 30, 2004

	(A) Avg. Rate for Month	(B) Avg. Bal for Month	(A * B)		Weighted Rate
September 03	1.1877%	173.7	2.0629		
October	1.1927%	114.3	1.3637		
November	1.1754%	129.3	1.5196		
December 03	1.2002%	109.1	1.3090		
January	1.2046%	83.1	1.0005		
February	1.1625%	166.8	1.9389		
March 04	1.1568%	130.4	1.5079		
April	1.1602%	71.1	0.8251		
May	1.1741%	53.9	0.6330		
June 04	1.2366%	50.8	0.6286		
July	1.4430%	34.3	0.4953		
August	1.5790%	113.3	1.7896		
September 04	1.7446%	122.3	2.1333		
13 mo. Avg.	1.2783%				
Totals		1,352.3	17.2073		
		/	1,352.3	=	1.2724%

Distribution Total Company
FISCAL YEAR 2004

NFG DIST - YTD SEP CO TAX PROV

	Total	Elimination	Subtotal	NFG Dist - NY 13-2759381	NFGD ELIM	NFG Dist - PA 13-2759381	NFGD ELIM
'K INCOME	46,717,524		46,717,524	36,428,032	(2,945,398)	13,234,890	
ERAL INCOME TAX	24,320,400		24,320,400	21,224,126	(2,620,630)	5,716,904	
ATE INCOME TAX	6,399,237		6,399,237	4,285,813		2,113,424	
PRE TAX NET BOOK INCOME	77,437,161		77,437,161	61,937,971	(5,566,028)	21,065,218	
PERMANENT DIFFERENCES:							
AFUDC - Perm	(286,295)		(286,295)	(211,047)		(75,248)	
* Depreciation, Depletion & Amort.	4,792,961		4,792,961	5,027,615		(234,654)	
~~Cost of Removal - Perm~~	~~(3,235,020)~~		~~(3,235,020)~~	~~(2,076,022)~~		(1,158,998)	
RSP - Perm	(35,540)		(35,540)	(24,878)		(10,662)	
NQSO / SARS	(1,781,448)		(1,781,448)	(1,247,014)		(534,434)	
Meals & Entertainment	61,344		61,344	46,565		14,779	
Lobbying	250,486		250,486	157,718		92,768	
Club Dues	13,000		13,000	10,000		3,000	
Spousal Travel	14,000		14,000	14,000			
Motor Fuels Credit	13,512		13,512	9,456		4,056	
Incentive Stock Options	(399,201)		(399,201)	(279,441)		(119,760)	
State Income Tax - Prior Yr.	2,323,584		2,323,584	2,323,584			
TOTAL	1,731,383		1,731,383	3,750,536		(2,019,153)	
TAXABLE INCOME BEFORE TEMPORARY DIFFERENCES	79,168,544		79,168,544	65,688,507	(5,566,028)	19,046,065	
TEMPORARY DIFFERENCES:							
Contrib-In-Aid-of-Construction	1,359,996		1,359,996	1,200,000		159,996	
* Depreciation, Depletion & Amort.	(40,720,080)		(40,720,080)	(30,690,420)		(10,029,660)	
~~Sec. 263A - Unicap~~	~~4,399,992~~		~~4,399,992~~	~~2,799,996~~		1,599,996	
Capitalized meter install costs	(100,547)		(100,547)	(100,547)			
Capitalized Repair & Maint	162,500		162,500	162,500			
Unrecovered Purchased Gas Costs	20,545,875		20,545,875	9,883,236		10,662,639	
Unrecoverd Purchased Gas Costs-Con	2,316,028		2,316,028		2,316,028		
Take-or-Pay	(2,666)		(2,666)	25,503		(28,169)	
Deferred Transitional Costs	6,190		6,190	3,326		2,864	
Refund Provision	531,820		531,820	531,820			
Deferred GRR	(1,834,684)		(1,834,684)	(1,834,684)			
Deferred CMR	(2,670,674)		(2,670,674)	(2,670,674)			
Refund Margin	(2,378,145)		(2,378,145)	(2,378,145)			
RSP - Compensation	116,122		116,122	82,642		33,480	
NQSO / SARS	(520,977)		(520,977)	(364,684)		(156,293)	
ERP Costs	1,087,729		1,087,729	699,539		388,190	
Deferred Compensation	119,764		119,764	120,181		(417)	
Accured Death Benefit	12,544		12,544			12,544	
Pension	(10,225,936)		(10,225,936)	(8,012,682)		(2,213,254)	
Accrued Bonus	170,000		170,000	120,000		50,000	
Capitalized Software	(692,680)		(692,680)	(500,263)		(192,417)	
Bad Debts	(3,762,371)		(3,762,371)	(4,236,164)		473,793	
Cons Bad Debt	4,000,000		4,000,000		4,000,000		
Injuries and Damages	(750,000)		(750,000)		(750,000)		
Deferred NYS GRT	8,768,091		8,768,091	8,768,091			
NYS Sales Tax - Assmts	34,366		34,366			34,366	
LIRA	(2,066)		(2,066)			(2,066)	
Savings Power	(182)		(182)	(49)		(133)	
Sen. Alphonso Program	(95,913)		(95,913)			(95,913)	
Management Audit Expense	(4,063)		(4,063)			(4,063)	
Debenture Premium - Net	809,184		809,184	585,006		224,178	
Site Cleanup	(2,831,154)		(2,831,154)	(2,481,154)		(350,000)	
Deferred Costs - Meter Transfer	(30,158)		(30,158)			(30,158)	
Deferred OPEB	(8,511,519)		(8,511,519)	(5,768,295)		(2,743,224)	
Deferred Order 636 Costs	30,158		30,158			30,158	
Prepaid Membership Dues	(10,708)		(10,708)	(10,708)			
TOTAL	(30,674,164)		(30,674,164)	(34,066,629)	5,566,028	(2,173,563)	
'ABLE INCOME BEFORE STATE TAX DEDUCTION	48,494,380		48,494,380	31,621,878		16,872,502	
TE TAX DEDUCTION	4,650,594		4,650,594	2,625,388		2,025,206	
TAXABLE INCOME BEFORE NOL AND SPECIAL DEDUCTIONS	43,843,786		43,843,786	28,996,490		14,847,296	
NOL							
SPECIAL DEDUCTIONS	888,000		888,000	760,000		128,000	
TAXABLE INCOME	42,955,786		42,955,786	28,236,490		14,719,296	
EFFECTIVE TAX RATE	0.35						
TAX AT EFFECTIVE RATE	15,034,525		15,034,525	9,882,772		5,151,754	
CREDITS:							
FUEL TAX CREDIT	13,510		13,510	9,457		4,053	
TOTAL CREDITS:	13,510		13,510	9,457		4,053	
INCOME TAX AFTER CREDITS	15,021,015		15,021,015	9,873,315		5,147,701	
ALTERNATIVE MINIMUM TAX							
OTHER TAXES							
ENVIRONMENTAL TAX							
FEDERAL TAXES PAYABLE	15,021,015		15,021,015	9,873,315		5,147,701	
FOREIGN TAX							
PRIOR YEARS TAX ADJUSTMENT	(288,498)		(288,498)	854,014		(1,142,512)	
APB 25 ADJUSTMENT	775,667		775,667	542,967		232,700	
TOTAL CURRENT FEDERAL PROVISION	15,508,184		15,508,184	11,270,296		4,237,889	

* Calculation of Tax Depreciation

	5,027,615
	(30,690,420)
Deduction	(25,662,805)
Book	(28,084,518)
Tax	(53,747,323)

16

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
DEFERRED FEDERAL INCOME TAXES
PEOPLESOFT QUERY = NFGGLQL001

Product	Year	Period	Total Amt		
2943 Total			1,123,781.00	NR	Prepaid & Accrued Income Tax
3002 Total			226.45	NR	
3008 Total			(197,365.80)	R	Tax - CIAC
3010 Total			10,075,245.80	R	Tax - Normalization
3012 Total			(894,641.05)	R	UNICAP
3020 Total			(3,234,135.65)	NR	Deferred Gas Costs
3022 Total			(9,099.55)	NR	Take or Pay
3034 Total			(1,044.25)	NR	Transitional Costs
3035 Total			(171,165.80)	NR	Refund Provision
3036 Total			1,023,387.80	NR	Opinion 315
3037 Total			797,074.65	NR	Refund Provision Margin
3040 Total			(26,672.65)	NR	Restricted Stock Plan
3041 Total			117,532.05	NR	NQSO/SARs
3042 Total			(223,737.50)	NR	ERP/SERP
3043 Total			(39,740.65)	NR	Deferred Comp
3044 Total			2,590,387.15	NR	Pension
3045 Total			(38,701.95)	NR	Accrued Bonus
3047 Total			33,240.45	NR	Capitalized Meter Installation
3048 Total			(53,722.50)	NR	Capitalized Repair & Maintenance
3049 Total			161,654.40	NR	Capitalized Software
3051 Total			1,395,313.15	R	Bad Debts
3060 Total			(2,898,732.70)	NR	NYS GRT Assessments
3063 Total			666.75	NR	PA Sales Tax Assessments
3069 Total			(911.15)	NR	LIRA
3070 Total			14.05	NR	Saving Power
3071 Total			(2,019.80)	NR	LIURP
3072 Total			(23,069.30)	NR	Mgt Audit
3073 Total			(204,752.00)	NR	Loss on Reacquired Debt
3074 Total			468,024.85	NR	RD&D
3076 Total			811,931.80	NR	SIR
3084 Total			1,853,779.90	NR	Deferred OPEB
3086 Total			0.00	NR	Deferred 636 Costs
3093 Total			3,540.10	NR	Prepaid Membership Dues
3099 Total			(2,044,245.35)	NR	ITC Amortization
Grand Total			10,392,042.70		

NR = Non Ratemaking
R = Ratemaking

 17

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
DEFERRED STATE INCOME TAXES
PEOPLESOFT QUERY = NFGGLQL001

Product	Year	Period	Total Amt		
3008 Total			(75,383.00)	R	Tax - CIAC
3010 Total			1,937,212.00	R	Normalization
3012 Total			(243,885.00)	R	UNICAP
3020 Total			(1,203,562.00)	NR	Deferred Gas Costs
3022 Total			(155.00)	NR	Take or Pay
3034 Total			(343.00)	NR	Transitional Costs
3035 Total			(44,260.60)	NR	Refund Provision
3036 Total			275,771.00	NR	Opinion 315
3037 Total			67,581.00	NR	Ref Provision - Margin
3039 Total			(22,214.00)	NR	
3040 Total			(6,436.00)	NR	Restricted Stock Plan
3041 Total			28,877.00	NR	NQSQ/SARs
3042 Total			(60,290.00)	NR	ERP/SERP
3043 Total			(6,638.00)	NR	Deferred Comp
3044 Total			611,571.00	NR	Pension
3045 Total			(9,423.00)	NR	Accrued Bonus
3047 Total			5,573.00	NR	Capitalized Meter Program
3048 Total			(9,009.00)	NR	Capitalized Repair & Maintenance
3049 Total			38,394.00	NR	Capitalized Software
3051 Total			249,558.00	R	Bad Debts
3060 Total			(485,998.00)	NR	NYS GRT Assessments
3063 Total			(1,905.00)	NR	PA Sales Tax Assessments
3069 Total			2,608.00	NR	LIRA
3070 Total			9.00	NR	Saving Power
3071 Total			5,771.00	NR	LIURP
3072 Total			65,912.00	NR	Mgt Audit
3074 Total			(5,531.00)	NR	RD&D
3076 Total			161,348.00	NR	SIR
3084 Total			471,777.00	NR	Deferred OPEB
3086 Total			(3,846.00)	NR	Deferred 636 Costs
3093 Total			594.00	NR	Prepaid Membership Dues
3099 Total			1,921,485.00	NR	ITC Amortization
Grand Total			3,665,162.40		

R = Ratemaking
NR = Non-Ratemaking

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Affiliate Rules

1.0 Affiliate Relations – In General

1.1 National Fuel Gas Distribution Company ("NFGD") and National Fuel Gas Company's ("NFG")[1] other subsidiaries will be operated as separate entities.

1.2 Any transfer of assets or the provision of goods or services, other than tariffed services and corporate governance, administrative, legal and accounting services by NFGD to an unregulated subsidiary or an unregulated subsidiary to NFGD, will be pursuant to regulations of the Securities Exchange Commission ("SEC") and the Public Service Commission of New York ("PSC").

1.3 Cost allocation guidelines if amended and/or supplemented will be filed with the Director of the Office of Accounting and Finance of the Department of Public Service 30 days prior to becoming effective.

1.4 All cost allocations will be subject to review during rate proceedings.

2.0 Non-Discriminatory Application of Tariffed Services

2.1 NFGD shall apply its tariffs in a nondiscriminatory manner.

2.2 NFGD shall not apply a tariff provision in any manner that would give its affiliates an unreasonable preference over other parties with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, or non-delivery, and all other services provided to its affiliates.

2.3 Tariff provisions cannot be waived by NFGD absent prior approval of the PSC.

---

[1] NFG holding company is registered as a holding company under the Public Utility Holding Company Act of 1935.

2.4 If a tariff provision is not mandatory or permits discretionary waivers, NFGD shall grant the waivers without preference to its affiliates. NFGD shall apply the provisions of its Gas Transportation Operating Procedures Manual without preference to its affiliates.

2.5 NFGD shall process requests for distribution services promptly and in a nondiscriminatory fashion with respect to other requests received in the same or a similar period.

2.6 If NFGD provides a distribution service discount, fee waiver or rebate to customers of its affiliated marketer, NFGD shall offer the same distribution service discount, fee waiver or rebate to other similarly situated parties. Offers shall not be tied to any unrelated service, incentive or offer on behalf of either the natural gas distribution company or its affiliates.

3.0 Personnel

3.1 Unregulated affiliates will have separate operating employees.

3.2 Non-administrative operating officers of NFGD will not be operating officers of any of the unregulated subsidiaries.

3.3 Officers of NFG may be officers of NFGD.

3.4 Employees may be transferred between NFGD and an unregulated affiliate upon mutual agreement. Employees transferred to a marketing affiliate may not be reemployed by NFGD for a minimum of 12 months from the transfer date. Employees returning to NFGD from a marketing affiliate may not be transferred to a marketing affiliate for a minimum of 24 months from the date of return or in the case of a transfer to an unregulated affiliate, for a minimum of 12 months. The foregoing limitations will not apply to employees covered by a collective bargaining agreement.

3.5 NFGD will not restrict by any means the employment with marketers of employees of NFGD unless NFGD applies the same restriction to its affiliated marketer(s). NFGD may negotiate restrictive employment conditions in severance agreements with employees under which the employee, as a result of a bargained-for exchange, receives value.

3.6 The foregoing provision in no way restricts the loaning of employees from any affiliate to NFGD to respond to an emergency that threatens the safety or reliability of service to consumers. Nor does the foregoing provision restrict the "loaned and borrowed labor" arrangement traditionally maintained between NFGD and National Fuel Gas Supply Corporation ("NFGS") for routine system operational purposes.

3.7 The compensation of NFGD employees may not be tied to the performance of any of NFG's unregulated subsidiaries. However, the stock of NFG may be used as an element of compensation and the compensation of common officers of NFG and NFGD may be based upon the operations of NFG and NFGD.

3.8 The employees of NFG, NFGD, NFGS and the unregulated affiliates may participate in common pension and benefit plans.

4.0 Goods, Services and Transactions Between NFGD and Affiliates

4.1 NFGD shall justly and reasonably allocate to its affiliates the costs or expenses for general administration or support services provided to said entities.

4.2 NFGD shall not condition or tie the provision of any product, service or price agreement by it (including release of interstate pipeline capacity) to the provision of any product or service by its affiliates.

4.3 NFGD shall not give its affiliates preference over non-affiliated marketers in the provision of goods and services including processing requests for information, complaints and responses to service interruptions. NFGD shall provide comparable treatment in its provision of such goods and services without regard to a customer's chosen marketer.

4.4 NFGD and affiliated marketers shall not be located in the same building or share office structures or centralized computer and/or communication networks. The NFG Corporate Website and corporate-governance transactions (such as those performed for financial reporting purposes) are exempt from the restriction pertaining to joint use of centralized computer and/or communications network.

4.5 NFGD shall maintain separate books and records from its affiliates. Further transactions between NFGD and its affiliates shall not involve cross-subsidies. Any shared facilities shall be fully and transparently allocated between the distribution company and affiliates. NFGD's accounts and records shall be maintained such that the costs incurred on behalf of an affiliate may be clearly identified.

4.6 NFGD may provide other services to affiliates, except that NFGD may not use any of its marketing or sales employees to provide services to NFGS or an affiliated marketer. NFGS and the affiliated marketers shall compensate NFGD for the services of employees performing such services in accordance with the orders, rules and regulations of the SEC governing same.

4.7 NFGD’s affiliates, including NFGS and any affiliated marketers may provide services to NFGD, subject to any applicable requirements of this PSC, the SEC and the Federal Energy Regulatory Commission.

4.8 Common property/casualty and other business insurance policies may cover NFG, NFGD, NFGS, and other affiliates. The costs of such policies shall be allocated among the entities in an equitable manner.

4.9 Notwithstanding the above, the Commission’s Order on Rehearing in Case 98-G-0122 – Proceeding on Motion of the Commission to Review the Bypass Policy Relating to Pricing of Gas for Electric Generation, dated June 29, 2001, and any additional review of that order, continues to control the issues resolved there.

5.0 Customer Information

5.1 Release of proprietary customer information relating to customers within NFGD’s service territory shall be subject to the Uniform Business Practices (“UBPs”) and, if required, prior authorization by the customer and subject to the customer’s direction regarding the person(s) to whom the information may be released. If a customer authorizes the release of information to an affiliate and one or more of the affiliate’s competitors, NFGD shall make that information available to the affiliate and such competitors on an equal and contemporaneous basis.

5.2 NFGD will not disclose to marketing or pipeline affiliates any customer or marketer information that it receives from a marketer, non-affiliated pipeline or gatherer, customer, or potential customer, which is not available from sources other than NFGD. Excluded from this restriction is operational information supplied to a pipeline affiliate necessary to implement changes in system operations.

5.3 Subject to customer privacy or confidentiality constraints, NFGD shall not disclose, directly or indirectly, any customer proprietary information to its affiliate unless authorized by the customer or the UBPs.

5.4 Distribution shall not disclose to its affiliates including marketing affiliates any information relating to the availability of transportation services that it does not disclose to all marketers at the same time. Excluded from this restriction is operational information supplied to a pipeline affiliate necessary to conduct day-to-day and long term system operations.

6.0 Customer Communications

6.1 NFGD shall not directly or by implication, represent to any customer, natural gas supplier or third party that an advantage may accrue to any party through use of NFGD's affiliates, such as:

a. That the PSC regulated services provided by NFGD are of a superior quality when such services are purchased from its affiliated marketer; or

b. That the commodity services (for natural gas) are being provided by NFGD when they are in fact being provided by an affiliated marketer;

c. That the natural gas purchased from a non-affiliated marketer may not be reliably delivered;

d. That natural gas must be purchased from an affiliated marketer in order to receive the PSC regulated services.

6.2 On a one-time basis NFGD shall disclose to all of its affiliated marketer's customers the distinction between the LDC and its marketing affiliate. NFGD will disclose the same information to new customers of its marketing affiliate in the anti-slamming letter required by the UBPs. Proposed disclosure language shall be distributed to the marketer signatories to this agreement and shall be subject to their approval.

7.0 Standards of Competitive Conduct

The following standards of competitive conduct shall govern NFGD's relationship with any energy supply and energy service affiliates:

7.1 There are no restrictions on affiliates using the same name, trade names, trademarks, service name, service mark or a derivative of a name, of NFG or NFGD, or in identifying itself as being affiliated with NFG or NFGD. However, NFGD will not provide sales leads for customers in its service territory to any affiliate and will refrain from giving any appearance that NFGD speaks on behalf of an affiliate or that an affiliate speaks on behalf of NFGD. If a customer requests information about securing any service or product offered within the service territory by an affiliate, NFGD may provide a list of all companies known to NFGD operating in the service territory who provide the service or product, which may include an affiliate, but NFGD will not promote its affiliate.

7.2 NFGD will not represent to any entity that an advantage may accrue to anyone in the use of NFGD's services as a result of that customer, supplier or third party dealing with any affiliate. This standard does not prohibit two or more of the unregulated subsidiaries from lawfully packaging their services.

7.3 All similarly situated customers, including but not limited to energy services companies and customers of energy service companies, whether affiliated or unaffiliated, will pay the same rates for NFGD's utility services. NFGD shall apply any tariff provision in the same manner if there is discretion in the application of the provision.

8.0 Enforcement of Standards

8.1 If any competitor or customer of NFGD believes that NFGD has violated the standards of conduct established in this section of the agreement, such competitor or customer may file a complaint in writing with NFGD. NFGD will respond to the complaint in writing within 20 business days after receipt of the complaint. Within 15 business days after the filing of such response, NFGD and the complaining party will meet in an attempt to resolve the matter informally. If NFGD and the complaining party are not able to resolve the matter informally, the matter will be subject to the Dispute Resolution Procedures in accordance with the UBPs.

8.2 Nothing in this section prevents the PSC from taking action to enforce its statutory obligations.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
SERVICE QUALITY PERFORMANCE MECHANISM (SQPM)

Appointments	≥ 98%	0
	97.0% - 97.9%	-25
	96.0% - 96.9%	-50
	95.9% -88.0%	-100
	<88%	-126
New Service Installations	≥ 98%	0
	97.0% - 97.9%	-25
	96.0% - 96.9%	-50
	95.9% -88.0%	-100
	<88%	-126
Residential Satisfaction	≥ 85.1%	0
	84.1% - 85.0%	-25
	83.1% - 84.0%	-50
	83.0% -79.0%	-100
	<79.0%	-126
Non- Residential Satisfaction	≥ 86.0%	0
	83.3% - 85.9%	-25
	80.6% - 83.2%	-50
	80.5% -76.0%	-100
	<76.0%	-126
Customer PSC Complaints	≤ 2.1	0
	2.1 – 2.3	-25
	2.4 – 2.6	-50
	2.6 –3.5	-100
	>3.5	-126
Telephone Response	≥ 74%	0
	72.0% - 73.9%	-25
	70.0% - 71.9%	-50
	69.9% -66.0%	-100
	<66.0%*	-126
Adjusted Bills	≤ 1.9%	0
	2.0% - 2.4%	-50
	2.5% 3.5%	-100
	>3.5%	-126
Estimated Meter Readings	≤ 15.9%	0
	16.0% - 18.4%	-25
	18.5% - 20.9%	-50
	21.0% -24.0%	-100
	>24.0%	-126

Total Penalty Units	Penalty Assessment
0 – 125	$0
126 –800	increases in a linear manner from $200,000 - $1,500,000
800 and above	$1,500,000

* In recognition of potential increased call volumes due to new competition programs.

SAFETY PERFORMANCE MEASURES

(1) **Infrastructure Enhancement**

(a) **Bare Steel and Cast Iron Main**
Remove a minimum amount of unprotected steel pipe and cast iron mains by December 31, 2007, in accordance with the following chart. A penalty of $120,000 will apply for any single year in which a minimum of 60 miles is not removed. Determination of mains to be removed shall be left up to the company's discretion and chosen from risk-based analyses. Pipe eliminated as a result of municipal infrastructure improvement projects may be counted toward achieving the minimum goals.

Miles removed by 12/31/07	Penalty for failure to achieve target ($$)
230	60,000
215	120,000
200	180,000

(b) **Bare Steel Services**
Remove a minimum amount of unprotected steel services by December 31, 2007, in accordance with the following chart. A penalty of $120,000 will apply for any single year in which a minimum of 3500 such services are not removed.

Bare steel services removed by 12/31/07	Penalty for failure to achieve target ($$)
12,000	60,000
11,000	120,000
10,000	180,000

(2) **Leak Management**
Achieve a maximum year-end backlog of leaks requiring repair in accordance with the following charts. However, if the backlog of leaks requiring repair exceeds the target in a given year, and the company is at or below 0.065 in the leak management measure as contained in Staff's annual Gas Safety Performance Measures Report, then the penalty will not be imposed.

12/31/05 backlog of leaks requiring repair	Penalty for failure to achieve target ($$)
220	180,000

12/31/06 backlog of leaks requiring repair	Penalty for failure to achieve target ($$)
190	120,000
220	180,000

12/31/07 backlog of leaks requiring repair	Penalty for failure to achieve target ($$)
175	60,000
190	120,000
220	180,000

(3) **Prevention of Excavation Damages**
Achieve maximum levels of overall damages per 1000 One-Call Tickets in accordance with the following chart.

Overall damages/1000 One-Call Tickets	Penalty for failure to achieve target ($$)
7.5	60,000
8.5	120,000
9.0	180,000

Achieve maximum levels of damages due to mismarks per 1000 One Call Tickets in accordance with the following chart.

Mismark damages/1000 One-Call Tickets	Penalty for failure to achieve target ($$)
1.6	60,000
1.8	120,000
2.0	180,000

(4) **Emergency Response ($120,000 each)**
Meet the following targets for response to gas emergencies:

(a) Respond to 90% of all gas leak and odor calls within 45 minutes.

(b) Respond to 95% of all gas leak and odor calls within 60 minutes.

The Company may make a case to the Commission that circumstances beyond the Company's control prevented it from meeting the performance targets. Examples of such circumstances include, but are not limited to:

- Gas leak calls resulting from mass odor complaints
  (ex: odorant spill).

- Major weather-related occurrences.

- Municipal infrastructure improvement projects requiring replacement of an unusually large amount of large-diameter pipe, thereby causing the appropriated capital budget to be exceeded.

This SPM shall remain in effect for the longer of three years or until the Company's next rate case. Performance targets after the initial three-year term shall be equal to the annual minimum for measures (1)(a) and (b), and the targets in effect as of December 31, 2007 for measures (2), (3) and (4).

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
SAFETY PERFORMANCE BUDGET RECOVERY MECHANISM

Assumption: Budget = signed fiscal year budget
Single Year Scenarios

Scenario 1
Assumption: Budget is $35,000,000
Prep Score: Higher # = Higher priority
Project I satisfies safety goal

Project	Prep Score	Cost	Completed
Project A	0.8	$5,000,000	$5,000,000
Project B	0.7	$4,000,000	$4,000,000
Project C	0.65	$10,000,000	$10,000,000
Project D	0.5	$6,000,000	$6,000,000
Project E	0.4	$2,000,000	$2,000,000
Project F	0.3	$3,000,000	$3,000,000
Project G	0.3	$2,000,000	$2,000,000
Project H	0.2	$3,000,000	$0
Project I	0.1	$6,000,000	$6,000,000
		$41,000,000	$38,000,000

Amount over budget = $3,000,000
ROR=8.13%

Rate Base	$3,000,000
ROR	8.13%
	$243,900
Retention Factor	0.570764467
Revenue Requirement	$427,322

Amount to be moved from CMR to Other Revenues

Scenario 2
Assumption: Budget is $35,000,000
Prep Score: Higher # = Higher priority
Project I satisfies safety goal

Project	Prep Score	Cost	Completed
Project A	0.8	$5,000,000	$5,000,000
Project B	0.7	$4,000,000	$4,000,000
Project C	0.65	$3,000,000	$3,000,000
Project D	0.5	$6,000,000	$6,000,000
Project E	0.4	$2,000,000	$2,000,000
Project F	0.3	$3,000,000	$3,000,000
Project G	0.3	$2,000,000	$2,000,000
Project H	0.2	$3,000,000	$3,000,000
Project I	0.1	$6,000,000	$6,000,000
		$34,000,000	$34,000,000

Amount over budget = $0
No additional funding

Scenario 3
Assumption: Budget is $35,000,000
Prep Score: Higher # = Higher priority
Must Do Municipal Job and/or other priority job must be
regardless of Prep score
Project I satisfies safety goal

Project	Prep Score	Cost	Completed
Project A	0.8	$5,000,000	$5,000,000
Priority Job		$6,000,000	$6,000,000
Project B	0.7	$4,000,000	$4,000,000
Project C	0.65	$10,000,000	$10,000,000
Project D	0.5	$6,000,000	$6,000,000
Project E	0.4	$2,000,000	$0
Project F	0.3	$3,000,000	$0
Project G	0.3	$2,000,000	$0
Project H	0.2	$3,000,000	$0
Project I	0.1	$6,000,000	$6,000,000
		$47,000,000	$37,000,000

Amount over budget = $2,000,000
ROR=8.13%

Rate Base	$2,000,000
ROR	8.13%
	$162,600
Retention Factor	0.570764467
Revenue Requirement	$284,881

Amount to be moved from CMR to Other Revenues

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
SAFETY PERFORMANCE BUDGET RECOVERY MECHANISM

Assumption: Budget = signed fiscal year budget
Cumulative Scenarios

Cumulative Scenario 1 - Underbudget First Year
Assumption: Budget is $35,000,000
Prep Score: Higher # = Higher priority

Project I satisfies safety goal

Project	Prep Score	Cost	Completed
Project A	0.8	$5,000,000	$5,000,000
Project B	0.7	$4,000,000	$4,000,000
Project C	0.65	$3,000,000	$3,000,000
Project D	0.5	$6,000,000	$6,000,000
Project E	0.4	$2,000,000	$2,000,000
Project F	0.3	$3,000,000	$3,000,000
Project G	0.3	$2,000,000	$2,000,000
Project H	0.2	$3,000,000	$0
Project I	0.1	$6,000,000	$6,000,000
		$34,000,000	$31,000,000

Amount over budget = $0
No additional funding

Cumulative Scenario 1 - Overbudget Second Year
Assumption: Budget is $35,000,000
Prep Score: Higher # = Higher priority

Project I satisfies safety goal

Year 2

Project	Prep Score	Cost	Completed
Project A	0.8	$5,000,000	$5,000,000
Project B	0.7	$4,000,000	$4,000,000
Project C	0.65	$10,000,000	$10,000,000
Project D	0.5	$6,000,000	$6,000,000
Project E	0.4	$2,000,000	$2,000,000
Project F	0.3	$3,000,000	$3,000,000
Project G	0.3	$2,000,000	$2,000,000
Project H	0.2	$3,000,000	$0
Project I	0.1	$6,000,000	$6,000,000
		$41,000,000	$38,000,000

Amount over budget = $3,000,000
Amount underspent in Year 1 = $1,000,000
ROR=8.13%

Rate Base	$2,000,000
ROR	8.13%
	$162,600
Retention Factor	0.570764467
Revenue Requirement	$284,881

Amount to be moved from CMR to Other Revenues

Cumulative Scenario 2 - Overbudget First Year
Assumption: Budget is $35,000,000
Prep Score: Higher # = Higher priority

Project I satisfies safety goal

Project	Prep Score	Cost	Completed
Project A	0.8	$5,000,000	$5,000,000
Project B	0.7	$4,000,000	$4,000,000
Project C	0.65	$10,000,000	$10,000,000
Project D	0.5	$6,000,000	$6,000,000
Project E	0.4	$2,000,000	$2,000,000
Project F	0.3	$3,000,000	$3,000,000
Project G	0.3	$2,000,000	$2,000,000
Project H	0.2	$3,000,000	$0
Project I	0.1	$6,000,000	$6,000,000
		$41,000,000	$38,000,000

Amount over budget = $3,000,000
ROR=8.13%

Rate Base	$3,000,000
ROR	8.13%
	$243,900
Retention Factor	0.570764467
Revenue Requirement	$427,322

Amount to be moved from CMR to Other Revenues

Cumulative Scenario 2 - Overbudget Second Year
Assumption: Budget is $35,000,000
Prep Score: Higher # = Higher priority

Project I satisfies safety goal

Year 2

Project	Prep Score	Cost	Completed
Project A	0.8	$5,000,000	$5,000,000
Project B	0.7	$4,000,000	$4,000,000
Project C	0.65	$10,000,000	$10,000,000
Project D	0.5	$6,000,000	$6,000,000
Project E	0.4	$2,000,000	$2,000,000
Project F	0.3	$3,000,000	$3,000,000
Project G	0.3	$2,000,000	$2,000,000
Project H	0.2	$3,000,000	$0
Project I	0.1	$5,000,000	$5,000,000
		$40,000,000	$37,000,000

Amount over budget = $2,000,000
Amount Overspent in Year 1 = $3,000,000
ROR=8.13%

Rate Base	$5,000,000
ROR	8.13%
	$406,500
Retention Factor	0.570764467
Revenue Requirement	$712,203

Amount to be moved from CMR to Other Revenues

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
ACCOUNTING TREATMENT OF CMR

This Appendix sets forth the methodology that the Company will follow to implement Section G – "Continuation of CMR and Transfer of Balances in the Gas Restructuring Reserves"

I. Funding of CMR

1. The aggregate of Capacity Release Savings and Net Revenues from Off-System Sales greater than $0 and less than or equal to $1,000,000 shall be credited to Account 253518 CMR 00-G-1858 during each fiscal year.

2. If the Company is assessed a penalty under the Service Quality Performance Mechanism (SQPM) (Section E Service Quality Performance Mechanism), a journal entry will be made to debit Account 495 Other Revenues and credit Account 253518 CMR 00-G-1858.

3. If the Company is assessed a penalty under the Safety Performance Mechanism (Section F Safety Performance Mechanism), a journal entry will be made to Debit Account 495 Other Revenues and credit Account 253518 CMR 00-G-1858.

4. Account 229003 Estimated Refund Prov 00-G1858 will be transferred into Account 253518 CMR 00-G-1858 after a final amount is determined through a signed settlement between the Company and Staff or if necessary by a determination by the Commission.

5. If an excess earnings sharing amount is determined to exist at the end of this settlement, and a final amount is determined through a signed agreement between the Company and Staff, that amount shall be credited into Account 253518 CMR 00-G-1858.

6. Account 253521 NYD Empire Synergy Deferral will be transferred into Account 253518 CMR 00-G-1858 by debiting Account 253521 NYD Empire Synergy Deferral and crediting Account 253518 CMR 00-G-1858 in the amount of the balance in Account 253521 NYD Empire Synergy Deferral at the time of implementation.

7. Account 253024 Accrued Bill Credit -9/30/03-NY will be transferred into Account 253518 CMR 00-G-1858 by debiting Account 253024 Accrued Bill Credit -9/30/03-NY and crediting Account 253518 CMR 00-G-1858 in the amount of the balance in Account 253024 Accrued Bill Credit -9/30/03-NY at the time of implementation.

8. Account 253506 Gas Restructuring Reserve will be transferred into Account 253518 CMR 00-G-1858 by debiting Account 253506 Gas Restructuring Reserve and crediting Account 253518 CMR 00-G-1858 in the amount of the balance in Account 253506 Gas Restructuring Reserve at the time of implementation.

9. Account 253519 GRR Systems will be transferred into Account 253518 CMR 00-G-1858 by debiting Account 253519 GRR Systems and crediting Account 253518 CMR 00-G-1858 in the amount of the balance in Account 253519 GRR Systems.

10. Interest shall be accrued on a monthly basis on the balance of Account 253518 CMR 00-G-1858 at the rate determined by the Commission for Other Customer Capital. (Section VI, A.1.e.)

II. Use of CMR Funds

It is within the Company's discretion to determine the order in which the balance in Account 253518 CMR 00-G-1858 will be used to offset deferred costs and expenses determined herein. It is also within the Company's discretion to apply credit balances from any identified Costs and Expenses, to any other identified Costs and Expenses debit balance.

Any remaining balance of additional Costs and Expenses listed in this Appendix for which deferral accounting treatment has not been previously approved shall, subject to the approval of the Commission, be deferred for collection at the next time base rates are changed following the expiration of this Comprehensive Joint Proposal. Deferral Accounting Treatment for such items for which deferral accounting has been previously granted shall continue at the end of this Comprehensive Joint Proposal or until these items are addressed in a base rate proceeding.

1. Transfer to Uncollectible Reserve

Upon implementation of the Joint Proposal the Company will transfer $4.5 million by debiting Account 253518 CMR 00-G-1858 and crediting Account 144000 Accumulated Provision for Uncollectible Accounts. This is a one time transfer of funds and there will be no additional reconciliation of the Account 144000 Accumulated Provision for Uncollectible Accounts.

Parties agree that final billed accounts awaiting write-off serve as the basis for calculating a revenue requirement for uncollectible expense. For the purpose of computing an initial rate for the Merchant Function Charge, uncollectible expense is assumed to be $14.1 million. However, the settlement is not intended to limit the company's discretion to recognize and record an appropriate level of uncollectible expense.

Any funds recovered from the Iroquois Energy bankruptcy will be credited to Account 253518 CMR 00-G-1858.

2. Pension/OPEBs

Pension and OPEBs Costs are accounted for in accordance with the Pension and OPEB Policy statement. Under the Pension and OPEB Policy Statement there is deferral treatment for the difference between the rate allowance and the latest actuarial amounts and for the difference between the rate allowance and the account collected from customers. These deferrals are recorded in various 186000 accounts. The Company may fund the balance existing at the end of Fiscal 2005 (Twelve months ended September 2005). To the extent amounts are applied to these deferrals from Account 253518 CMR 00-G-1858 and income is recognized in Account 495000 Other Income these deferrals will be reduced and pension and OPEB expense will be recognized in the appropriate expense accounts. The amounts applied to these deferrals shall be deposited to either an external funding vehicle or credited to the internal reserve accounts as is appropriate under the Pension and OPEB Policy Statement.

3. Area Development Program

Upon implementation of the Joint Agreement a transfer of $3,750,000 from Account 253518 CMR 00-G-1858 to a new account entitled Area Development Funds. Grants provided from this fund will be debited to the new account.

4. Migration Incentive

The annual migration incentive will be funded through the CMR. Once the total migration incentive is determined an entry debiting Account 253518 CMR 00-G-1858 and crediting Account 495000 Other Revenue will be made.

5. Discounted Retail Access Transportation Service Program ("DRS")

Funds required to support DRS will be provided from the CMR. The expenditures will be limited to $500,000 over the term of this Joint Proposal. The entry to fund the expenditures will be made in September and will debit Account 253518 CMR 00-G-1858 and credit a new 182000 account set up for tracking the expenditures related to DRS.

6. System Enhancements

Expenditures for System Enhancements related to the Commission's restructuring effort, which are incremental, will continue to be funded through the CMR to a maximum of $5,000,000 as set up in Previous Rate Plans. The Company has expended $2,771,587 through September 30,2004 for these enhancements. Expenditures over the $5,000,000 cap will be deferred and a petition will be filed with the Commission requesting recovery. The Company will file a report with Staff detailing the System Enhancement expenditures each year and the necessity of the expenditures to further the Commission's restructuring goals. These expenditures will be subsequently audited to assure compliance with the incremental restructuring spending requirement.

System Enhancement Programs previously funded include:

Account 186619 PTA/STBA-NY	Expenditures necessary in order to deal with the introduction of choice into Distribution's system.
Account 186626 TBO	This program (Transportation Billing Options) enhances processing bills to suppliers in aggregation programs and special rate treatment customers.
Account 186630 NY Neural Net	A package program (NOSTRADAMUS) that was purchased to facilitate the forecasting of gas requirements, especially during weekend periods.

Ongoing Programs include but are not limited to:

Account 186611 Gas Management Systems Account 186612 Gas Management Systems	Expenditures for the purchase and customization of Gas Master software that manages key business functions.
Account 186613 TSS Account 186616 TSS	These expenditures were to integrate the information required by the Company dealing with the many transporters on the system. This also includes many of the changes required by the UBPs.
Account 186622 EDI Account 186623 EDI	Expenditures as order by Case 98-M-0667
Account 186631 Misc. Restructuring Programming Costs	Expenditures necessary to implement Case 00-G-1858 Settlement
Account 186633 Web Customer Choice Account 186636 Web Customer Choice	Expenditures to enable customers to better make Choice decisions and to manage their account(s) better.
Account 186634 NY Daily Balancing Project	Expenditures for the installation of real time meters as required in Case 00-G-1858

At the end of each fiscal year a journal entry will be made which debits Account 253518 CMR 00-G-1858 and credits the deferral accounts and any additional accounts that arise due to System Enhancements until the cap of $5,000,000 is reached.

7. Real Time Meter Installation

Program costs for initial software, data collection infrastructure measurement correction devices and meters at locations of customers with annual consumption greater than 55,000 Mcf, continue to be funded through the CMR. At the end of each fiscal year a journal entry will be made which debits Account 253518 CMR 00-G-1858 and credits Account 186634 NY Daily Balancing Project.

8. Safety Performance Budget Recovery Mechanism

If the Company recovers any funds using the Safety Performance Budget Recovery Mechanism as described in Appendix G, the funding shall come from the CMR. A debit to Account 253518 CMR 00-G-1858 and a credit to Account 495 Other Revenues will be made to recover the funds. CMR funding shall not exceed $1,000,000 annually for the duration of the Safety Performance Mechanism.

Appendix I

National Fuel Gas Distribution Corporation
New York Division
Calculation of Research and Development Surcharge

Total Annual Costs to Be Collected	$	900,000	
Throughput Excluding Interruptible and Competitive Volumes (1/1/05 RD&D Filing)		98,787,080	Mcf
RD&D Surcharge Effective 8/1/2005	$	0.0091	/Mcf
Over Recovery Balance of RD&D Surcharge as of February 28,2005	$	(3,962,163)	
Throughput Excluding Interruptible and Competitive Volumes (1/1/05 RD&D Filing)		98,787,080	Mcf
Per Unit Refund	$	(0.0401)	/Mcf
RD&D Surcharge Effective 8/1/2005	$	0.0091	/Mcf
Estimated R&D Surcharge Effective 1/1/2006	$	(0.0310)	/Mcf

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION

Calculation of BDR/EDZ Discount Rates

SC 3							
BDR				EDZ			
Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)	Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)
1	40%	$1.48	$0.59	1-3	50%	$1.48	$0.74
2	30%	$1.48	$0.44	4-6	30%	$1.48	$0.44
3	20%	$1.48	$0.30	7-10	10%	$1.48	$0.15
4	10%	$1.48	$0.15				
5	5%	$1.48	$0.07				

SC 13 TC 1.1							
BDR				EDZ			
Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)	Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)
1	40%	$1.24	$0.50	1-3	50%	$1.24	$0.62
2	30%	$1.24	$0.37	4-6	30%	$1.24	$0.37
3	20%	$1.24	$0.25	7-10	10%	$1.24	$0.12
4	10%	$1.24	$0.12				
5	5%	$1.24	$0.06				

SC 13 TC 2.0							
BDR				EDZ			
Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)	Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)
1	40%	$1.16	$0.47	1-3	50%	$1.16	$0.58
2	30%	$1.16	$0.35	4-6	30%	$1.16	$0.35
3	20%	$1.16	$0.23	7-10	10%	$1.16	$0.12
4	10%	$1.16	$0.12				
5	5%	$1.16	$0.06				

SC 13 TC 3.0							
BDR				EDZ			
Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)	Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)
1	40%	$0.60	$0.24	1-3	50%	$0.60	$0.30
2	30%	$0.60	$0.18	4-6	30%	$0.60	$0.18
3	20%	$0.60	$0.12	7-10	10%	$0.60	$0.06
4	10%	$0.60	$0.06				
5	5%	$0.60	$0.03				

SC 13 TC 4.0							
BDR				EDZ			
Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)	Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)
1	40%	$0.29	$0.11	1-3	50%	$0.29	$0.14
2	30%	$0.29	$0.09	4-6	30%	$0.29	$0.09
3	20%	$0.29	$0.06	7-10	10%	$0.29	$0.03
4	10%	$0.29	$0.03				
5	5%	$0.29	$0.01				

SC 13 TC 4.1							
BDR				EDZ			
Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)	Year	% Discount	Tailblock Margin ($/Mcf)	Unit Discount ($/Mcf)
1	40%	$0.38	$0.15	1-3	50%	$0.38	$0.19
2	30%	$0.38	$0.11	4-6	30%	$0.38	$0.11
3	20%	$0.38	$0.08	7-10	10%	$0.38	$0.04
4	10%	$0.38	$0.04				
5	5%	$0.38	$0.02				

National Fuel Gas Distribution Corporation
New York Division
Reserve Capacity Cost

Section (1) Retained Capacity and Associated Costs

(1)	(2)		(3)	(4)	(5)
				Aug-04	
Daily Temperature Swing/Peaking/ Balancing/Capacity Costs	Total NY Daily Capacity	Page 2 Ref.	Total NY Annual Capacity	Demand Rate	Total Demand Cost
	Dth		Dth	$/Dth	$
NFGSC EFT Capacity	158,367.0	**A**	1,900,404.0	$3.5568	$6,759,357
NFGSC ESS Delivery	92,303.2	**B**	1,107,638.9	$2.1345	$2,364,255
NFGSC ESS Capacity	646,122.7	**C**	7,753,472.2	$0.0432	$334,950
Nexen	27,412.0	**D**	328,944.0	$5.0167	$1,650,213
Empire	27,412.0	**E**	328,944.0	$0.7694	$253,090
Nexen	16,000.0	**F**	192,000.0	$4.5400	$871,680
Central NY Oil & Gas	24,264.0	**G**	291,168.0	$2.2500	$655,128
Tennessee Lateral	24,000.0	**H**	288,000.0	$1.3000	$374,400
					$13,263,073

Section (2) Determination of Capacity Costs Incurred to Support Firm Monthly Metered Delivery Services

(1)	(2)	(3)	(4)	(5)	(6)
Company Peak Requirements by Class	Dth	% Dth		Normalized Throughput (Mcf)	Base Cost of Gas
Large Industrial TC 4.0 /1	7,143	4.641%	$615,484	11,543,808	$ 0.05332
Total Peaking Other Firm Classes	146,777	95.359%	$12,647,589	86,435,392	$ 0.14632
Total Peaking Requirements	153,920	100.000%	$13,263,073	97,979,200	

/1

	Total Extreme Day Demand (MI-14 pg 8)	Total Extreme Day Demand W/ 2% Shrink (MI-14 pg 8)	Total Extreme Day Delivery (MI-14 pg 8)	Deficiency	DTH @1.027
TC 4.0 (>150,000 Mcf/Yr)	35,063	35,779	29,261	6,517	6,692.96
TC 4.0 (>150,000 Mcf/Yr) Negotiate	13,290	13,561	13,123	438	449.83
Total	48,353	49,340	42,384	6,955	7,142.79

Section (3) Determination of Capacity Costs Incurred to Support Daily Delivery Services

(1)	(2)	(3)	(4)	(5)
DMT Base Cost of Gas	Peak Consumption	2% Peak Consumption	% Of Total Peaking Requirements	DMT Base Cost of Gas
Large Industrial TC 4.0	48,353	967	13.54%	$ 0.0072
Total Peaking Other Firm Classes	790,150	15,803	10.77%	$ 0.0158

Appendix K

PSC NO: 8 GAS
COMPANY: NATIONAL FUEL GAS DISTRIBUTION CORPORATION
INITIAL EFFECTIVE DATE:

STATEMENT TYPE: NGS
STATEMENT NO:

STATEMENT OF MONTHLY GAS SUPPLY CHARGE
(Issued Under Authority of 16 NYCRR Sec. 270.55)

Effective With Usage On and After , 2005
Applicable to Billings Under Service Classification Nos. 1, 2, and 3
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

	¢ Per Ccf
APPLICABLE SERVICE TERRITORY	All Territory
AVERAGE COST OF GAS	
The average cost of gas (as defined in Leaf No. 74) determined on March 29, 2005, by applying the rates and charges of the Company's gas suppliers' in effect on April 1, 2005.	80.166
ANNUAL REFUND/SURCHARGE	
Adjustment of gas sold, pursuant to Annual Surcharge or Refund Provision on General Information Leaf Nos. 78 and 81 of P.S.C. No. 8 - Gas. Amount applicable during the period January 1, 2005 through December 31, 2005 referable to gas adjustment undercollection for the twelve Months ended August 31, 2004.	0.000
INTERIM ANNUAL REFUND/SURCHARGE	
Adjustment of gas sold, pursuant to Interim Annual Surcharge Or Refund provision on General Information Leaf No. 81 of P.S.C. No. 8 – Gas. Amount applicable during the period March 1, 2005 through August 31, 2005 referable to gas Adjustment undercollection for the twelve months ending August 31, 2005	0.000

Issued by D.F. Smith, President, 6363 Main Street, Williamsville NY 14221
(Name of Officer, Title, Address)

STATEMENT OF MONTHLY GAS SUPPLY
(Issued Under Authority of 16 NYCRR Sec. 270.55)

Effective With Usage On and After , 2005
Applicable to Billings Under Service Classification Nos. 1, 2, and 3
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

	¢ Per Ccf All Territory
APPLICABLE SERVICE TERRITORY	
BOILER FUEL SALES AND TRANSPORTATION SERVICE BENEFITS	
Adjustment of gas sold, pursuant to Boiler Fuel Sales and Transportation Service Benefits on General Information Leaf Nos. 83 and 84 of P.S.C. No. 8 - Gas; Surcharge applicable during the period January 1, 2005 through December 31, 2005.	0.000
OFF-SYSTEM SALES, CAPACITY RELEASE CREDIT AND SC11 MARGIN	
Amount applicable during the period November 1, 2004 through March 31, 2005 for Off-System Sales, Capacity Release Credit, and Service Class 11 Margin pursuant to General Information Leaf No. 82 of P.S.C. No. 8 – Gas	0.000
REFUND PROVISION	
Amount applicable during the period February 1, 2003 through Jan 31, 2004 For Gas Supplier Refund received November 27, 2002 pursuant to General Information Leaf No. 77 of P.S.C. No. 8 – Gas.	0.000
SUBTOTAL	0.000
TOTAL MONTHLY GAS SUPPLY CHARGE BEFORE MFC FOR SC 1, SC2 & SC 3	80.166
MERCHANT FUNCTION CHARGE FOR SC 1 AND SC 2	2.198
Commencing with the gas used on and after , 2005 and thereafter until changed, the monthly gas supply charge will be for SC 1 & 2	82.364
MERCHANT FUNCTION CHARGE FOR SC 3	0.244
Commencing with the gas used on and after , 2005 and thereafter until changed, the monthly gas supply charge will be for SC 3	80.410

Date: , 2005

Issued by D.F. Smith, President, 6363 Main Street, Williamsville NY 14221
(Name of Officer, Title, Address)

PSC NO: 8 GAS | STATEMENT TYPE: DAC
COMPANY: NATIONAL FUEL GAS DISTRIBUTION CORPORATION | STATEMENT NO:
INITIAL EFFECTIVE DATE:

Page 1 of 1

STATEMENT OF DELIVERY ADJUSTMENT CHARGE
(Issued Under Authority of 16 NYCRR Sec. 270.55)

Effective With Usage On and After , 2005
Applicable to Billings Under Service Classification Nos. 1, 2, 3, 5, 7, 8 and 9
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

	¢ Per Ccf
APPLICABLE SERVICE TERRITORY	All Territory
TAKE OR PAY RECOVERY	
Amount applicable during the period July 1, 2004 through June 30, 2005 for Take or Pay Reconciliation pursuant to General Information Leaf No. 144 of P.S.C. No. 8 - Gas	(0.007)
R & D FUNDING MECHANISM	
Amount applicable during the period March 1, 2005 through February 28, 2006 For R & D Funding Mechanism pursuant to Commission Order in Case 04-G-1047	(0.310)
TRANSITION COST SURCHARGE	
Intermediate Transition Cost Surcharge pursuant to General Information Leaf No. 148.2 applicable during the period April 1, 2005 through April 30, 2005	0.114
Upstream Transition Cost Surcharge pursuant to General Information Leaf No. 148.1 applicable during the period April 1, 2005 through April 30, 2005	0.000
RESERVE CAPACITY COST ADJUSTMENT	
Amount Applicable to changes in reserve capacity costs as calculated in the attached Reserve Capacity Cost Adjustment Statement	0.000
LOST REVENUE ASSOCIATED WITH MFC AND BILLING CHARGE	
Amount Applicable to loss revenue associated with the Merchant Function Charge and the Billing Charge	0.000
TOTAL DELIVERY COST ADJUSTMENT	
Commencing with the gas used on and after , 2005 And therafter until changed, the delivery cost adjustment will be	(0.203)

Date: , 2005

Issued by D.F. Smith, President, 6363 Main Street, Williamsville NY 14221
(Name of Officer, Title, Address)

PSC NO: 8 GAS
COMPANY: NATIONAL FUEL GAS DISTRIBUTION CORPORATION
INITIAL EFFECTIVE DATE:

STATEMENT TYPE: GTR
STATEMENT NO.

GAS TRANSPORTATION STATEMENT

Effective With Usage During Billing Period Commencing
Applicable to Billings Under Service Classification No. 13M
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

I) Summary of Maximum and Minimum Allowable Prices

		Transportation Service Classification No. 13M				
Tariff Class		TC-1.1	TC-2.0	TC-3.0	TC-4.0	TC-4.1
Minimum Charge		$321.94	$705.83	$1,713.42	$3,696.30	$3,365.80
Billing Charge		$2.00	$2.00	$2.00	$2.00	$2.00
Base Rate per Mcf		$1.3867	$1.0577	$0.7511	$0.3395	$0.5293
Plus:	Revenue Credit in Case 04-G-1047	($0.0389)	($0.0267)	($0.0209)	($0.0094)	($0.0136)
Plus:	Reserve Capacity Cost Charge in Case 00-G-1858	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Plus:	Amount applicable during the period March 1, 2005 through February 28, 2006 for R&D Funding Mechanism pursuant to Commission Order in Case 04-G-1047	($0.0310)	($0.0310)	($0.0310)	($0.0310)	($0.0310)
	Amount applicable during the period July 1, 2004 through June 30, 2005 for Take or Pay Reconciliation pursuant to General Information Leaf No. 144 of P.S.C. No. 8 - Gas	($0.0007)	($0.0007)	($0.0007)	($0.0007)	($0.0007)
	Amount applicable during the period March 1, 2005 through March 30, 2005 for Inter .Transition Cost Surcharge pursuant to General Leaf No. 148.2 of P.S.C. No. 8 - Gas	$0.0114	$0.0000	$0.0000	$0.0000	$0.0000
	Amount applicable during the period March 1, 2005 through March 30, 2005 for Upstream Transition Cost Surcharge pursuant to General Leaf No. 148.1 of P.S.C. No. 8 - Gas	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Base Rate, per Mcf		$1.3275	$0.9993	$0.6985	$0.2984	$0.4840
Minimum Allowable Rate		$0.1000	$0.1000	$0.1000	$0.1000	$0.1000

II) Statement of Billing Rates in Effect

Pursuant to Service Classification No. 13M of National Fuel Gas Distribution Corporation's P.S.C. No. 8 - Gas tariff, and the maximum and minimum allowable rates identified above, the Company establishes the following S.C. 13M transportation rates effective

TC-1.0 through TC-4.1 - Default Rate Qualifications Transportation service customers requesting S.C. 13M transportation service for the month.
Rate The default S.C. 13M transportation rates shall be the maximum allowable prices.

Date:

Issued by D.F. Smith, President, 6363 Main Street, Williamsville, NY 14221
(Name of Officer, Title, Address)

GAS TRANSPORTATION STATEMENT

Effective With Usage During Billing Period Commencing
Applicable to Billings Under Service Classification No. 13D
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

I) Summary of Maximum and Minimum Allowable Prices

	Transportation Service Classification No. 13D				
Tariff Class	TC-1.1	TC-2.0	TC-3.0	TC-4.0	TC-4.1
Minimum Charge	$321.94	$705.83	$1,713.42	$3,696.30	$3,365.80
Billing Charge	$2.00	$2.00	$2.00	$2.00	$2.00
Base Rate per Mcf	$1.2562	$0.9272	$0.6206	$0.2934	$0.3988
Plus: Revenue Credit in Case 04-G-1047	($0.0389)	($0.0267)	($0.0209)	($0.0094)	($0.0136)
Plus: Reserve Capacity Cost Charge in Case 00-G-1858	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Plus: Amount applicable during the period March 1, 2005 through February 28, 2006 for R&D Funding Mechanism pursuant to Commission Order in Case 04-G-1047	($0.0310)	($0.0310)	($0.0310)	($0.0310)	($0.0310)
Amount applicable during the period July 1, 2004 through June 30, 2005 for Take or Pay Reconciliation pursuant to General Information Leaf No. 144 of P.S.C. No. 8 - Gas	($0.0007)	($0.0007)	($0.0007)	($0.0007)	($0.0007)
Amount applicable during the period March 1, 2005 through March 30, 2005 for Inter. Transition Cost Surcharge pursuant to General Leaf No. 148.2 of P.S.C. No. 8 - Gas	$0.0114	$0.0114	$0.0114	$0.0114	$0.0114
Amount applicable during the period March 1, 2005 through March 30, 2005 for Upstream Transition Cost Surcharge pursuant to General Leaf No. 148.1 of P.S.C. No. 8 - Gas	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Base Rate, per Mcf	$1.1970	$0.8802	$0.5794	$0.2637	$0.3649
Minimum Allowable Rate	$0.1000	$0.1000	$0.1000	$0.1000	$0.1000

II) Statement of Billing Rates in Effect

Pursuant to Service Classification No. 13D of National Fuel Gas Distribution Corporation's P.S.C. No. 8 - Gas tariff, and the maximum and minimum allowable rates identified above, the Company establishes the following S.C. 13D transportation rates effective

TC-1.0 through TC-4.1 - Default Rate Qualifications

Transportation service customers requesting S.C. 13D transportation service for the month.

Rate

The default S.C. 13D transportation rates shall be the maximum allowable prices.

Date:

Issued by D.F. Smith, President, 6363 Main Street, Williamsville, NY 14221
(Name of Officer, Title, Address)

GAS TRANSPORTATION STATEMENT

Effective With Usage During Billing Period Commencing
Applicable to Billings Under Service Classification No. 13M for customers who switch from MMT to DMT
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

I) Summary of Maximum and Minimum Allowable Prices

		Transportation Service Classification No. 13M				
Tariff Class		TC-1.1	TC-2.0	TC-3.0	TC-4.0	TC-4.1
Minimum Charge		$321.94	$705.83	$1,713.42	$3,696.30	$3,365.80
Minimum Bill Credit		$2.00	$2.00	$2.00	$2.00	$2.00
Base Rate per Mcf		$1.3332	$1.0042	$0.6976	$0.3240	$0.4758
Plus:	Revenue Credit in Case 04-G-1047	($0.0389)	($0.0267)	($0.0209)	($0.0094)	($0.0136)
Plus:	Reserve Capacity Cost Charge in Case 00-G-1858	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Plus:	Amount applicable during the period March 1, 2005 through February 28, 2006 for R&D Funding Mechanism pursuant to Commission Order in Case 04-G-1047	($0.0310)	($0.0310)	($0.0310)	($0.0310)	($0.0310)
	Amount applicable during the period July 1, 2004 through June 30, 2005 for Take or Pay Reconciliation pursuant to General Information Leaf No. 144 of P.S.C. No. 8 - Gas	($0.0007)	($0.0007)	($0.0007)	($0.0007)	($0.0007)
	Amount applicable during the period March 1, 2005 through March 30, 2005 for Inter .Transition Cost Surcharge pursuant to General Leaf No. 148.2 of P.S.C. No. 8 - Gas	$0.0114	$0.0000	$0.0000	$0.0000	$0.0000
	Amount applicable during the period March 1, 2005 through March 30, 2005 for Upstream Transition Cost Surcharge pursuant to General Leaf No. 148.1 of P.S.C. No. 8 - Gas	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Total Base Rate, per Mcf		$1.2740	$0.9458	$0.6450	$0.2829	$0.4305
Minimum Allowable Rate		$0.1000	$0.1000	$0.1000	$0.1000	$0.1000

II) Statement of Billing Rates in Effect

Pursuant to Service Classification No. 13M of National Fuel Gas Distribution Corporation's P.S.C. No. 8 - Gas tariff, and the maximum and minimum allowable rates identified above, the Company establishes the following S.C. 13M transportation rates effective

TC-1.0 through TC-4.1 - Default Rate Qualifications Transportation service customers requesting S.C. 13M transportation service for the month.

Rate The default S.C. 13M transportation rates shall be the maximum allowable prices.

Date:

Issued by D.F. Smith, President, 6363 Main Street, Williamsville, NY 14221
(Name of Officer, Title, Address)

PSC NO: 8 GAS STATEMENT TYPE: MBC
COMPANY: NATIONAL FUEL GAS DISTRIBUTION CORPORATION STATEMENT NO:
INITIAL EFFECTIVE DATE:

Page 1 of 1

STATEMENT OF MINIMUM BILL CREDITS

Effective With Usage During Billing Period Commencing , 2005
Applicable to Usage Under Service Classification No. 1, 2, 3, 13D, 13M & 20
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

Pursuant to the order in Case 04-G-1047 issued ____________, the following revenue credits shall be in effect on and after ____________ for the stated service classifications:

S.C. 1	($2.25)	per Bill
S.C. 2	($1.37)	per Bill
	(0.09195)	per Mcf
S.C. 2A	($2.25)	per Bill
S.C. 3	($5.71)	per Bill
S.C. 13D TC-1.1	($0.0389)	per Mcf
S.C. 13D TC-2.0	($0.0267)	per Mcf
S.C. 13D TC-3.0	($0.0209)	per Mcf
S.C. 13D TC-4.0	($0.0094)	per Mcf
S.C. 13D TC-4.1	($0.0136)	per Mcf
S.C. 13M TC-1.1	($0.0389)	per Mcf
S.C. 13M TC-2.0	($0.0267)	per Mcf
S.C. 13M TC-3.0	($0.0209)	per Mcf
S.C. 13M TC-4.0	($0.0094)	per Mcf
S.C. 13M TC-4.1	($0.0136)	per Mcf
S.C. 24	($2.25)	per Bill

Date:, 2005

Issued by D.F. Smith, President, 6363 Main Street, Williamsville NY 14221
(Name of Officer, Title, Address)

PSC NO: 8 GAS — STATEMENT TYPE: LMC
COMPANY: NATIONAL FUEL GAS DISTRIBUTION CORPORATION — STATEMENT NO:
INITIAL EFFECTIVE DATE

Page 1 of 1

STATEMENT OF LIRA MINIMUM CHARGE

Effective With Usage During Billing Period Commencing , 2005
Applicable to ____________________
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

Pursuant to ____

Minimum Charge	$(0.63)
Billing Charge	$ 2.00
Net Minimum Charge	$ 1.37

Pursuant to the terms of the Settlement Agreement and Joint Proposal in Case 04-G-1047 the amount of the LIRA discount may be adjusted downward by the Company if it is anticipated that the amount of discount at forecast enrollment levels will cause the Company to exceed the $5 million expense cap.

Date:, 2005

Issued by D.F. Smith, President, 6363 Main Street, Williamsville NY 14221
(Name of Officer, Title, Address)

PSC NO: 8 GAS | STATEMENT TYPE: RCC
COMPANY: NATIONAL FUEL GAS DISTRIBUTION CORPORATION | STATEMENT NO:
INITIAL EFFECTIVE DATE:

RESERVE CAPACITY COST ADJUSTMENT STATEMENT
AND
RESERVE CAPACITY COST STATEMENT

Effective With Usage During Billing Period Commencing , 2005
Applicable to Usage Under Service Classification Nos. 1, 2, 3, 5, 7, 8, 9 and Non-Large Industrial 13M and 13D
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

Daily Temperature Swing/Peaking Reserve Capacity Costs	Total NY Monthly Capacity Dth (A)	Total NY Annual Capacity Dth (B)	March Demand Rate $/Dth (C)	Total Demand Cost (D=BxC)	
NFGSC EFT Capacity Temperature Swing	158,367.0	1,900,404.0	$3.5569	$6,759,547	
NFGSC ESS Delivery Temperature Swing	92,303.2	1,107,638.4	$2.1345	$2,364,254	
NFGSC ESS Capacity Temperature Swing	646,122.7	7,753,472.4	$0.0432	$334,950	
Nexen	27,412.0	328,944.0	$5.0167	$1,650,213	
Empire Peaking	27,412.0	328,944.0	$0.7694	$253,090	
Nexen	16,000.0	192,000.0	$4.5400	$871,680	
Central NY Oil & Gas	24,264.0	291,168.0	$2.2500	$655,128	
Tennessee Lateral	24,000	288,000.0	$1.3000	$374,400	
Total Daily Temperature Swing/Peaking Reserve Capacity Costs				$13,263,073	
Peaking to classes other than TC 4.0 - %				95.359%	
Peaking to classes other than TC 4.0 - $				$12,647,589	
Total Annual Normalized Sales and Total Aggregation Volumes (Mcf)				86,435,392	
Daily Temperature Swing/Peaking Reserve Capacity Costs per Mcf				$0.1463	
Base Reserve Capacity Charge				$0.1463	
Reserve Capacity Cost Adjustment ($/Mcf) (.1463 - .1463)					$0.0000
Applicable to SC1, 2, 3, 5, 7, 8, 9 and Non-Large Industrial 13M					
DMT Factor					10.77%
Large Non-Industrial SC 13D					$0.0000

Date:, 2005

Issued by D.F. Smith, President, 6363 Main Street, Williamsville NY 14221
(Name of Officer, Title, Address)

RESERVE CAPACITY COST ADJUSTMENT STATEMENT
AND
RESERVE CAPACITY COST STATEMENT

Effective With Usage During Billing Period Commencing , 2005
Applicable to Usage Under Service Classification Nos. 13M and 13D TC 4.0
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

Daily Temperature Swing/Peaking Reserve Capacity Costs	Total NY Monthly Capacity Dth (A)	Total NY Annual Capacity Dth (B)	March Demand Rate $/Dth (C)	Total Demand Cost (D=BxC)	
NFGSC EFT Capacity Temperature Swing	158,367.0	1,900,404.0	$3.5569	$6,759,547	
NFGSC ESS Delivery Temperature Swing	92,303.2	1,107,638.4	$2.1345	$2,364,254	
NFGSC ESS Capacity Temperature Swing	646,122.7	7,753,472.4	$0.0432	$334,950	
Nexen	27,412.0	328,944.0	$5.0167	$1,650,213	
Empire Peaking	27,412.0	328,944.0	$0.7694	$253,090	
Nexen	16,000.0	192,000.0	$4.5400	$871,680	
Central NY Oil & Gas	24,264.0	291,168.0	$2.2500	$655,128	
Tennessee Lateral	24,000	288,000.0	$1.3000	$374,400	
Total Daily Temperature Swing/Peaking Reserve Capacity Costs				$13,263,073	
Peaking to SC 13 TC 4.0 - %				4.641%	
Peaking to SC 13 TC 4.0 - $				$615,484	
Total Annual Normalized Sales and Total Aggregation Volumes (Mcf)				11,543,808	
Daily Temperature Swing/Peaking Reserve Capacity Costs per Mcf				$0.0533	
Base Reserve Capacity Charge				$0.0533	
Reserve Capacity Cost Adjustment ($/Mcf) (.0533 - .0533) Applicable to SC13M TC 4.0					$0.0000
DMT Factor					13.54%
SC 13D TC 4.0					$0.0000

Date:, 2005

Issued by D.F. Smith, President, 6363 Main Street, Williamsville NY 14221
(Name of Officer, Title, Address)

PSC NO: 8 GAS
COMPANY: NATIONAL FUEL GAS DISTRIBUTION CORPORATION
INITIAL EFFECTIVE DATE:

STATEMENT TYPE: MFC
STATEMENT NO.

MERCHANT FUNCTION CHARGE

Effective With Usage During Billing Period Commencing
Applicable to Billings Under Service Classifications Nos. 1 2, 2A, and 3
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
P.S.C. No. 8 - GAS

	Residential	Non Residential
Monthly Gas Supply Charge	$ 8.01659	$ 8.01659
Merchant Function Charge Factor	2.742%	0.304%
Merchant Function Charge	$ 0.21979	$ 0.02440

Date:

Issued by D.F. Smith, President, 6363 Main Street, Williamsville, NY 14221
(Name of Officer, Title, Address)

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
MIGRATION INCENTIVE SCENARIOS

Scenario 1

Assumptions:

Migration at beginning of first year:	50,000
Migration at end of first year	75,000
Migration at end of second year	100,000
Total Migration Incentive over 2 Years	$1,900,000

Calculation of Incentive First Year			**Calculation of Incentive Second Year**		
End of Year Migration		75,000	End of Year Migration		100,000
Beginning of Year Migration		50,000	Beginning of Year Migration		75,000
Total Migration		25,000	Total Migration		25,000
Tier 1	Applicable Migration	10,000	Tier 1	Applicable Migration	10,000
	Incentive	$300,000		Incentive	$300,000
Tier 2	Applicable Migration	5,000	Tier 2	Applicable Migration	5,000
	Rate	$30		Rate	$30
		$150,000			$150,000
Tier 3	Applicable Migration	10,000	Tier 3	Applicable Migration	10,000
	Rate	$50		Rate	$50
		$500,000			$500,000
Total Migration Incentive First Year Before Limitation		$950,000	Total Migration Incentive Second Year Before Limitation		$950,000
Migration Cap Limitation		$950,000	Migration Cap Limitation		$1,900,000

Scenario 2

Assumptions:

Migration at beginning of first year:	50,000
Migration at end of first year	63,000
Migration at end of second year	65,000
Total Migration Incentive over 2 Years	$390,000

Calculation of Incentive First Year			**Calculation of Incentive Second Year**		
End of Year Migration		63,000	End of Year Migration		65,000
Beginning of Year Migration		50,000	Beginning of Year Migration		63,000
Total Migration		13,000	Total Migration		2,000
Tier 1	Applicable Migration	10,000	Tier 1	Applicable Migration	0
	Incentive	$300,000		Incentive	$0
Tier 2	Applicable Migration	3,000	Tier 2	Applicable Migration	0
	Rate	$30		Rate	$30
		$90,000			$0
Tier 3	Applicable Migration	0	Tier 3	Applicable Migration	0
	Rate	$50		Rate	$50
		$0			$0
Total Migration Incentive First Year Before Limitation		$390,000	Total Migration Incentive Second Year Before Limitation		$0
Migration Cap Limitation		$390,000	Migration Cap Limitation		$390,000

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
MIGRATION INCENTIVE SCENARIOS

Scenario 3

Assumptions:	
Migration at beginning of first year:	50,000
Migration at end of first year	45,000
Migration at end of second year	65,000
Total Migration Incentive over 2 Years	$450,000

Calculation of Incentive First Year			**Calculation of Incentive Second Year**		
End of Year Migration		45,000	End of Year Migration		65,000
Beginning of Year Migration		50,000	Beginning of Year Migration		50,000
Total Migration		(5,000)	Total Migration		15,000
Tier 1	Applicable Migration	0	Tier 1	Applicable Migration	10,000
	Incentive	$0		Incentive	$300,000
Tier 2	Applicable Migration	0	Tier 2	Applicable Migration	5,000
	Rate	$30		Rate	$30
		$0			$150,000
Tier 3	Applicable Migration	0	Tier 3	Applicable Migration	0
	Rate	$50		Rate	$50
		$0			$0
Total Migration Incentive First Year Before Limitation		$0	Total Migration Incentive Second Year Before Limitation		$450,000
Migration Cap Limitation		$0	Migration Cap Limitation		$450,000

Scenario 4

Assumptions:	
Migration at beginning of first year:	50,000
Migration at end of first year	200,000
Migration at end of second year	300,000
Total Migration Incentive over 2 Years	$2,700,000

Calculation of Incentive First Year			**Calculation of Incentive Second Year**		
End of Year Migration		200,000	End of Year Migration		300,000
Beginning of Year Migration		50,000	Beginning of Year Migration		200,000
Total Migration		150,000	Total Migration		100,000
Tier 1	Applicable Migration	10,000	Tier 1	Applicable Migration	10,000
	Incentive	$300,000		Incentive	$300,000
Tier 2	Applicable Migration	5,000	Tier 2	Applicable Migration	5,000
	Rate	$30		Rate	$30
		$150,000			$150,000
Tier 3	Applicable Migration	135,000	Tier 3	Applicable Migration	85,000
	Rate	$50		Rate	$50
		$6,750,000			$4,250,000
Total Migration Incentive First Year Before Limitation		$7,200,000	Total Migration Incentive Second Year Before Limitation		$4,700,000
Migration Cap Limitation		$2,700,000	Migration Cap Limitation		$0

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
MIGRATION INCENTIVE SCENARIOS

Scenario 5

Assumptions:

Migration at beginning of first year:	50,000
Migration at end of first year	58,000
Migration at end of second year	75,000
Total Migration Incentive over 2 Years	$950,000

Calculation of Incentive First Year			**Calculation of Incentive Second Year**		
End of Year Migration		58,000	End of Year Migration		75,000
Beginning of Year Migration		50,000	Beginning of Year Migration		50,000
Total Migration		8,000	Total Migration		25,000
Tier 1	Applicable Migration	0	Tier 1	Applicable Migration	10,000
	Incentive	$0		Incentive	$300,000
Tier 2	Applicable Migration	0	Tier 2	Applicable Migration	5,000
	Rate	$30		Rate	$30
		$0			$150,000
Tier 3	Applicable Migration	0	Tier 3	Applicable Migration	10,000
	Rate	$50		Rate	$50
		$0			$500,000
Total Migration Incentive First Year Before Limitation		$0	Total Migration Incentive Second Year Before Limitation		$950,000
Migration Cap Limitation		$0	Migration Cap Limitation		$950,000

- The following are examples of messages/information relating to competition that NFG will provide its customers:

  - Choice is available to customers in NFG territory

  - How the process of switching suppliers works; explain NFG's role of providing delivery service; how to choose and switch gas suppliers (could be linked to list of questions/considerations in bullet five below)

  - NFG will still deliver and will restore service in the event of an emergency or outage

  - List of ESCOs eligible to do business in NFG territory (For a similar example, see ESCO listing NYSEG web site at: http://www.nyseg.com/nysegweb/webcontent.nsf/doc/ESCOEligibleGas)

  - A list of questions consumers should ask the ESCO about their product, prices and other value added service (a sample list of questions is currently available on the business side of NFG's website at: http://www.nationalfuelgas.com/ForBusiness/questions_for_suppliers.htm - a similar list should be developed for residential customers and put on the residential side of the web site.

  - Make easily accessible a copy of what a bill would have looked like if they had selected a marketer over the last 12 months and the customer's bill had they stayed with the Company (and reflect any amendments if there is any change to the bill format). A sample is currently available at http://www.nationalfuelgas.com/ForHome/BillSample.htm. The sample's breakout or balloon explanation of commodity should say "This is the portion of the bill you may shop for" and list all the charges that a customer will not pay to NFG if they sign up with another supplier.

  - Explanation of customer rights and responsibilities regarding choice.

  - The Public Service Commission's Helpline is available for inquiries and complaints about your service at 1-800-342-3377. Complaints about your ESCO may be directed to the PSC's helpline, 1-888-697-7728.

  - PSC has more information on its web site, www.AskPSC.com

  - Aspects of customer choice section on current web site are less user friendly/difficult to navigate to - Staff seeks improved navigability to on the web site.

Include an FAQ to which customers may refer and call center employees may refer customers. A sample of what an FAQ might look like is located at: http://www.askpsc.com/qa/?view=naturalgas.

NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NEW YORK DIVISION
CALCULATION OF SYMMETRICAL SHARING TARGETS

Case: 04-G-1047

Transportation Service		
TC-1.1 Non Aggreation	$5,919,747	
TC-1.1 Aggreation	$6,422,467	
TC-1.1 N	$50,412	
TC-2 Non Aggreation	$4,234,897	
TC-2 Aggreation	$749,204	
TC-2 N	$239,263	
TC-3 Non Aggreation	$3,079,568	
TC-3 Aggreation	$97,310	
TC-3 N	$489,440	
TC-4	$3,392,923	
TC-4 N	$1,012,765	
TC-4.1	$1,204,145	
Service Class 15	$0	
Service Class 16	$577,296	
Service Class 17	$168,605	
Transportation Symmetrical Target		$27,638,042
Sales Service for Cogeneration Facilities		
Service Class 10 (Margin Only)	$915,575	
Sales Service for Cogeneration Symmetrical Target		$915,575
Total Transportation Symmetrical Sharing Target		$28,553,617

National Fuel Gas Distribution Corporation

April 22, 2005

Hon. Elizabeth H. Liebschutz
Administrative Law Judge
Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Jaclyn Brilling, Secretary
Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 04-G-1047, National Fuel Gas Distribution Corporation

Dear Judge Liebschutz and Secretary Brilling:

On April 15, 2005, National Fuel Gas Distribution Corporation ("Distribution" or the "Company") submitted a Joint Proposal designed to settle all outstanding issues in the above-referenced proceeding. It was discovered afterwards that due to an oversight, one item resolved by the Signatory Parties very late in negotiations was not included in the text of the Joint Proposal. Therefore, the Signatory Parties request that this letter be accepted as a supplement to the Joint Proposal and the below paragraph made a part thereof as though it were included in the text of the Joint Proposal under Section VI, subsection A., new item no. 7:

7. Anniversary Review

The Signatory Parties agree that one year following the implementation of the POR Pilot, if the number of customers migrating from sales to transportation service has not increased by 10,000, as calculated for purposes of the Migration Incentive (Section VII. C.), the Company will convene a collaborative to review the POR Pilot and other retail competition programs adopted under the terms hereof to determine (1) reasons why enrollment levels did not increase an additional 10,000 customers; and (2) if modifications to the POR Pilot, or other competition programs, should be explored.

In addition to the foregoing, further review of the Joint Proposal revealed that as a result of a word processing problem that occurred at the end of the drafting process, the section addressing the POR Pilot is missing text that identified an agreed-upon qualifying threshold for POR service. At Section VI. A., the second sentence should be revised to read as follows (new text underscored):

> Under the POR Pilot, the Company will purchase gas commodity service accounts receivable, at a discount and without recourse, on the accounts of the Company's firm transportation customers who consume less than 25,000 Mcf annually and who receive a consolidated bill from the Company that includes gas commodity service provided by the ESCOs.

Finally, at the telephonic procedural conference held on April 19, 2005, Your Honor requested that the Joint Proposal be further supplemented with a brief explanation of the Service Quality Performance Mechanism ("SQPM") (Section III. E., page 20). The following language, culled from a prior Joint Proposal, can be inserted as the first paragraph under the SQPM heading at Section III. E. of the Joint Proposal:

> Distribution has previously operated under customer service performance mechanisms of various types in successive rate plans. The objective of this kind of mechanism is to provide a means of ensuring that acceptable levels of customer service are maintained by the Company in key areas of customer service. If the delivery of customer service deteriorates by any significant degree, the Company is subject to a financial penalty.

All parties received a copy of this letter in advance of its filing. In addition to the Company's signature below, signature pages for other Signatory Parties are attached, and will be supplemented upon the receipt of additional executed pages.

Thank you for your attention to this matter.

Respectfully submitted,

Michael W. Reville

Staff of the Department of Public Service

By: [signature] Date: 4/22/2005

Consumer Protection Board

By:____________________ Date: ____________________

Multiple Intervenors

By:____________________ Date: ____________________

Public Utility Law Project

By:____________________ Date: ____________________

Small Customer Marketer Coalition

By:____________________ Date: ____________________

Crown Energy Services, Inc.

By:____________________ Date: ____________________

North American Energy, Inc.

By:____________________ Date: ____________________

Staff of the Department of Public Service

By: ______________________ Date: ______________________

Consumer Protection Board

By: ______________________ Date: ______________________

Multiple Intervenors

By: Michael B. Mager Date: April 22, 2005

Public Utility Law Project

By: ______________________ Date: ______________________

Small Customer Marketer Coalition

By: ______________________ Date: ______________________

Crown Energy Services, Inc.

By: ______________________ Date: ______________________

North American Energy, Inc.

By: ______________________ Date: ______________________

Staff of the Department of Public Service

By:______________________________ Date:

Consumer Protection Board of the State of New York

By:______________________________ Date:

Multiple Intervenors

By:______________________________ Date:

Public Utility Law Project

By: Ulur Fogel, Counsel Date: 4/21/05

Small Customer Marketer Coalition

By:______________________________ Date:

Crown Energy Services, Inc.

By:______________________________ Date:

North American Energy, Inc.

By:______________________________ Date:

Staff of the Department of Public Service

By:________________________ Date: ________________________

Consumer Protection Board

By:________________________ Date: ________________________

Multiple Intervenors

By:________________________ Date: ________________________

Public Utility Law Project

By:________________________ Date: ________________________

Small Customer Marketer Coalition

By:________________________ Date: ________________________

Crown Energy Services, Inc.

By: Robert E. H[illegible] Date: 04/22/05

North American Energy, Inc.

By:________________________ Date: ________________________

Staff of the Department of Public Service

By:________________________ Date: ________________________

Consumer Protection Board

By:________________________ Date: ________________________

Multiple Intervenors

By:________________________ Date: ________________________

Public Utility Law Project

By:________________________ Date: ________________________

Small Customer Marketer Coalition

By:________________________ Date: ________________________

Crown Energy Services, Inc.

By:________________________ Date: ________________________

North American Energy, Inc.

By:________________________ Date: 4/26/05

ATTACHMENT 2

Filing by: NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Amendments and Supplements to Schedule P.S.C. No. 8 – Gas

Original Leaves Nos. 148.7, 266.1.1
First Revised Leaves Nos. 126, 129, 130, 131, 231, 234, 235, 236, 248, 257, 282, 284, 286
Second Revised Leaves Nos. 3.1, 24, 74.2, 94, 127, 128, 151, 159, 161, 163, 179, 230, 266.3, 278, 279, 280, 281, 283, 285
Third Revised Leaves Nos. 81, 133, 148.6, 156.2, 164, 173, 174, 220, 237, 255, 258, 259, 266.1, 270.1
Fourth Revised Leaves Nos. 83, 138, 141, 148, 157, 186, 217, 218, 263, 277
Fifth Revised Leaves Nos. 74, 82, 84, 149, 155, 156.1, 190, 219, 221, 224, 262, 266
Sixth Revised Leaves Nos. 2, 152, 175, 184, 189, 206, 207, 266.4, 275
Seventh Revised Leaves Nos. 153, 187
Eighth Revised Leaves Nos. 150, 158, 165, 211, 276
Ninth Revised Leaves Nos. 154, 271
Eleventh Revised Leaf No. 222
Fourteenth Revised Leaf No. 3
Supplement No. 13
Supplement No. 16

Exhibit__(SSP-9)
Shared Services – R&D

Filed Session of February 09, 2000
Approved as Recommended
and so Ordered
By the Commission

DEBRA RENNER
Acting Secretary

Issued & Effective February 14, 2000

STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

January 31, 2000

TO: THE COMMISSION

FROM: OFFICE OF GAS AND WATER

SUBJECT: CASE 99-G-1369 - Petition of New York Gas Group for Permission to Establish a Voluntary State Funding Mechanism to Support Medium and Long Term Gas Research and Development (R&D) Programs.

SUMMARY OF RECOMMENDATION: Staff recommends that the Commission should modify a proposal by gas utilities and allow an alternative funding mechanism to replace the existing funding and research and development by the Gas Research Institute.

SUMMARY

By letter dated October 4, 1999 the New York Gas Group (NYGAS)[1/] petitioned the Commission to establish a voluntary state funding mechanism to support medium and long term gas research and development (R&D) programs. This funding mechanism would replace the Federal Energy Regulatory Commission (FERC) surcharge used to support broad-based gas related R&D conducted by the Gas Research Institute (GRI)[2/]. By agreement, between

---

[1/] The New York Gas Group (NYGAS) is a gas utility trade association comprising the 10 largest natural gas utilities in New York State, who deliver 95% of the gas used in the state.

[2/] GRI is the national gas research organization founded in 1976 with approval of the FERC. GRI's mission is to discover, develop and deploy technologies and information for the benefit of gas customers and the industry.

FERC and the interstate gas pipelines the GRI surcharge is being phased out over the next several years. Since the proposed surcharge would replace the GRI surcharge, there would be no net impact on customers' bills.

The amount collected under the NYGAS proposed funding mechanism would mirror the decrement in the FERC surcharge each year until 2004 and will be capped at $0.0174/dekatherm, thereafter.[1] Staff recommends that the petition be approved with two modifications, discussed below.

BACKGROUND

Since 1978 a significant portion of gas related R&D has been performed by GRI. This work was funded by gas consumers through a FERC approved surcharge on interstate pipeline deliveries. FERC would review GRI's program and funding request each year and approved the level of this surcharge. In 1998, FERC approved an agreement among all sectors of the natural gas industry, to gradually reduce and eliminate this surcharge by 2004. As the industry moves toward competition it was determined that mandatory funding of GRI should be replaced by voluntary support by LDCs, pipelines, producers, or others who determined that the R&D performed by GRI was beneficial to them. After 2004 GRI's funding will be entirely on a voluntary basis, by any entity that wants to participate in the R&D programs.

Historically, research funded through the GRI surcharge was broad based. GRI's work ranged from the conceptual stage through product development; projects were often long term. Internal LDC R&D programs, on the other hand, addressed specific company needs. Internal programs, funded in rate base, concentrate on projects that are near the end of the R&D cycle.

---

[1] After 2004 when this surcharge reaches the maximum amount and the GRI surcharge is gone, consideration could be given, as part of a rate case, to moving these dollars into base rates in order to eliminate the need for a separate surcharge. In the interim period, when the dollar amounts change every year, the surcharge represents the most convenient method for funding this R&D.

Internal projects are the final field testing and demonstration of appliances, and new technologies that are almost to the point of commercialization.

NYGAS states that gas R&D programs have provided significant ratepayer benefits. Benefits to costs analyses that the utilities have performed on past programs show at least $3 of benefits for every $1 invested in gas R&D. In addition, continued support for medium and longer term research programs will ultimately benefit shorter term development and demonstration projects that will continue to be funded separately under internal LDC gas research budgets. Over the past five years, due to the changes experienced throughout the gas industry, both a majority of the LDC's internally funded R&D programs and the overall level of GRI funding have been reduced.

NYGAS PROPOSAL

NYGAS proposes that the individual LDCs be allowed to impose an R&D surcharge on firm[1/] sales and transportation customers to support medium and long term gas R&D. The LDCs would be allowed to set the amount of the surcharge, up to the decrement in the FERC approved GRI surcharge. During 1998, the year used as a base for this proposal, New York gas consumers contributed roughly $15.5 million to support GRI's program. The sum of the GRI contribution plus the amount collected through NYGAS' proposed surcharge would remain constant. In the year 2004, when the proposed plan is fully implemented, the amount of funds to be used for research up to the $15.5 million would be totally under control of New York LDCs.

Upon approval of NYGAS's petition by the Commission, LDCs could file new tariff leaves that would include an R&D surcharge that would not exceed the decrement in the FERC surcharge. LDCs will use deferral accounting to insure that the

---

[1/] The surcharge will not be placed on interruptible sales or interruptible transportation. These tend to be market based transactions, and as such the addition of the surcharge could drive these customers off the system.

funds collected through the surcharge mechanism which is not spent on R&D programs will be refunded to gas consumers.

Each LCD would be responsible for planning, implementing, and managing R&D projects funded by this proposal.[1/] These projects would be tracked separately from each LDC's internal projects. The R&D projects supported by this proposal would be limited to projects that are medium to long term in nature (i.e., projects that are at least twenty-four months or more from becoming a commercially deployable product). R&D that falls into this category tends to be more in a conceptual or basic research stage; it is riskier, meaning that it is harder to find support as it is far from producing a marketable product; it also tends to be the most expensive part of project development. Internal RD&D projects, or research currently funded through rates, tend to be restricted to projects nearing commercialization. This has become necessary, of late, as limited funds dictate that results are more certain. Projects nearing the end of the R&D cycle tend to have more support from manufacturers and have a greater likelihood of demonstrating that there will be tangible benefit to both the company and the consumer.

In order to address common needs and avoid duplication, the individual LDCs will collaborate, much in the same way that they do currently, through GRI, NYGAS and other research consortia. To insure a suitable level of collaboration and maximize the benefits to NYS ratepayers, NYGAS initially proposed that at least 30% of the total dollars collected through this surcharge be used in projects having two or more cofunders. Such cofunding reduces the risks posed by long-term R&D projects. After discussions with staff, NYGAS revised its proposed cofunding level to 60%.

Attached as Appendix A is a list of program areas that NYGAS has designated as "Vital Research and Development Program

---

[1/] Some of the funding may go to support projects conducted by GRI. However, that will be discretionary by the LDCs.

Areas". NYGAS provided this list as an example of program areas to be funded through the surcharge mechanism. The program areas include: pipe installation, repair and maintenance, supply, system analysis, end-use applications, and environmental. To monitor these projects and to aid in our oversight of these funds, NYGAS would create a web-site for technical and financial reporting on funds collected and used through this mechanism. Technical information for each project would include a statement of objectives, milestones, deliverables, schedule and progress. Financial information would include expenditures and projected costs by year. In addition, periodic meetings (at least annually or more frequently if needed) between staff and the LDCs would be held to review expenditures and strategic priorities. NYGAS has also proposed that the entire process be revisited in two years to ensure that the program is meeting expectations and to determine if any revisions are necessary.

DISCUSSION

Staff supports NYGAS' proposal for a funding mechanism for continued research efforts that would be lost with the phasing out of the GRI surcharge. Staff concurs that the benefits derived from this work should be of significant value to the consumer as well as to the LDCs. Staff would, however, recommend two modifications to the NYGAS proposal: (1) increase the cofunding level to 80%, and (2) eliminate two categories of proposed research program areas.

Staff's rationale regarding setting the cofunding level at 80% is that pooled resources will assure more efficient use of the money. Most of the R&D projects conducted are already cofunded; either by several utilities or in conjunction with equipment manufacturers. Projects with several backers will mean that the dollars will be directed to places where there is more interest and need. It will also give the backers the ability to leverage funds. The remaining 20% of funds collected should give an individual LDC adequate flexibility to do company specific work as needed. If the need should arise by an LDC to direct more than 20% of its annual surcharge collection to an individually funded project it would have the opportunity to petition the Commission for permission to dedicate that level of funding to that project.

With regard to the proposed research program areas staff believes that two areas; natural gas appliances, and gas supply related storage, should not be funded through the NYGAS proposed surcharge. These areas are not part of the distribution function and thus the research should not be funded by distribution ratepayers. Rather R&D in those areas should be conducted by those segments of the industry that have a greater stake in them. Appliances are not restricted to a geographical area. Their uses are national in scope and should be funded by the appliance industry. Similar arguments apply to supply/storage projects. That work should be done by national organizations, those segments of the industry that are supply or storage related. The LDC money, in staff's opinion, would be better directed to distribution research which would have a direct effect on the cost of doing business in New York State.

NYGAS argues that R&D in those areas would benefit the LDCs' customers and would increase business, which in turn, would have the effect of lowering bills. NYGAS has expressed concern that if the distribution companies do not fund this research it may not get done. For example, it argues that in the past the appliance manufacturers have not focused on research developing new gas-fired appliances. The provision of appliances is a competitive market and there are a number of large and small appliance manufacturers serving the market. Staff is of the opinion that competitive market forces in the evolving gas industry will encourage manufacturers to conduct research into new and improved appliances.

If there were to be some unique situation where the LDC could make a compelling argument that a particular project should appropriately be funded by distribution company ratepayers, then the LDC may request an exemption for that specific project.

However, in such an instance, there would be a heavy burden on the LDC for justification.

RECOMMENDATION

It is recommended that the New York Gas Group's petition to establish a voluntary state funding mechanism to support medium and long term gas R&D programs be approved with the following modifications:

1) The required level for co-funding be set at 80% of the surcharge money collected by each LDC, and
2) Money collected via the surcharge mechanism should not be directed to fund natural gas appliance research or to supply/storage projects.
3) An LDC can petition the Commission for waiver of either of these conditions, if it believes that specific circumstances warrant.

Respectfully submitted,

RONALD O. WAGER
Associate System Planner

Reviewed by

PETER CATALANO
Office of General Counsel

Reviewed by:

SHEILA A. RAPPAZZO
Chief, Policy
Office of Gas and Water

Approved by:

Phillip S. Teumim
Director
Office of Gas and Water

Vital Research and Development Program Areas

Pipe Installation

1. Economical and widely applicable trenchless technologies
2. Low-cost and automated methods of service and main installation
3. New piping materials compatible with system upgrades and resistant to third party damage
4. Improved excavation and reinstatement materials
   - recyclable
   - minimize disruption

Repair & Maintenance

1. Improved leak pinpointing and pipe locating
2. Positive location of underground facilities
3. Robotic inspection and repair methods

Supply

1. Economical options for natural gas storage in the Northeast

Systems Analysis

1. Advanced models for decisionmaking
   - pressure and capacity optimization
   - use of existing and abandoned infrastructure

End-Use Applications

1. NG-fired appliances and prime movers capable of short term paybacks

Environmental

1. Proactive approaches to environmental issues that impact gas distribution practices

UTD IMPACT

March 2019

UTD's non-profit collaboration of utilities creates and advances products, systems and technologies that save consumers money, save energy, integrate renewable energy with natural gas, and achieve safe, reliable, resilient end-user operation with superior environmental performance.

The commercial products and technology developments shown here illustrate some of UTD's impacts and benefits for ratepayers, utilities, society, and our planet.

UTD's 15-year proven track record has directly impacted key energy and environmental issues. We thank the leading researchers, governmental agencies, and others who've partnered with UTD to make these and other exciting impacts, as UTD continues to grow and advance in 2019! Please contact us if you have any questions about UTD.

Ron Snedic (1.847.768.0572) **Rich Kooy** (1.847.768.0512)

UTD. CELEBRATING 15 YEARS

UTD's 20 member companies serve more than 47 million natural gas customers in the Americas and Europe.

UTD helps utilities create exciting new products for their customers, and maximize the impact of their energy-efficiency programs.

Together we're shaping the energy future with clean, efficient end-use technologies.

Visit www.utd-co.org for more information.

COMMERCIALIZED PRODUCTS

Yanmar 3-Pipe Engine-driven Gas Heat Pump
Yanmar's 3-pipe, 14-ton Gas Heat Pump (GHP) with variable refrigerant flow (VRF) offers an important new energy-efficiency option for the North American market by combining heat recovery with simultaneous heating and cooling. In a 2018-19 field test, UTD is validating the quantitative and qualitative performance of an instrumented installation.

YANMAR America Corp.
Mike Mehrvarz
770-877-7709
mike_mehrvarz@yanmar-es.com
www.yanmar-es.com

Sierra™ Engine-driven Gas Heat Pump

Sierra's (formerly NextAire™) 8-ton and 15-ton gas heat pumps (GHPs) include variable refrigerant flow (VRF) with multizone capabilities. They can efficiently heat and cool commercial building space (up to 1.4 COP) while reducing peak and total electric demand. More than 500 units have been sold in the U.S. UTD's analysis is supporting best practices for siting.

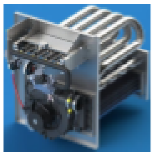
Blue Mountain Energy
Tom Young
702-339-7395
tyoung@bluemountainenergy.com
www.bluemountainenergy.com

COMMERCIALIZED PRODUCTS (continued)

Dedicated Outside Air System/Rooftop Unit

Condensing heating versions of Munters Dedicated Outside Air System (DOAS) and other rooftop unit (RTU) products increase heating efficiency from 80%-81% to 90%-93%. Multiple RTU manufacturers are now offering DOAS with 90+% efficiencies, facilitated by the availability of condensing duct furnace modules first developed with UTD support.

Munters Corporation
Larry Klekar
210-249-3883
larry.klekar@munters.com
www.munters.com



Condensing Duct Furnace Modules

High-efficiency condensing heating modules developed with UTD support are now available from Beckett Gas and other OEMs, including Heatco, and are being applied to DOAS and other products including Make-Up Air Units (MAUs) available from multiple manufacturers including RuppAir and Aaon.

Beckett Gas, Inc.
Joel Mohar
440-783-7610
jmohar@beckettcorp.com
www.beckettgas.com

Heat Sponge Economizer for Industrial/ Commercial Boilers

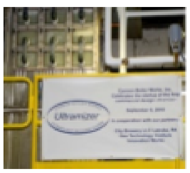
In either condensing or non-condensing configurations, this heat recovery system for commercial and industrial boilers (over 140,000-unit market in U.S.) increases boiler efficiency from 80% to a range of 85%-93% (validated by UTD lab testing). It also saves customers 5%-15% in annual energy costs. In 2018, UTD completed a field test in Utah to further validate energy savings.

Boilerroom Equipment, Inc.
866-666-8977
www.heatsponge.com

M-Trigen PowerAire

M-Trigen's PowerAire unit provides high-efficiency microCHP with integrated cooling to homeowners, small businesses, and other users. In 2019, UTD is providing technical support for a notable demonstration and also partnering with NYSERDA, NJNG, and PERC to independently validate performance.

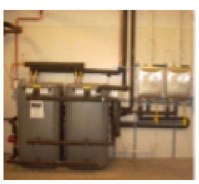
M-Trigen
Kevin Robert
713-574-4506 x1018
kevinr@mtrigen.com
www.mtrigen.com



Cannon Boiler Works Ultramizer®

The Ultramizer is an advanced heat-and-water recovery system for larger commercial and industrial boilers, of which there are more than 140,000 in the U.S. It increases boiler efficiency from 80% to 93%—saving customers 15% in energy while also reducing water demand.

Cannon Boiler Works, Inc.
Chris Giron
724-335-8541 x414
sales@cannonboilerworks.com
www.cannonboilerworks.com

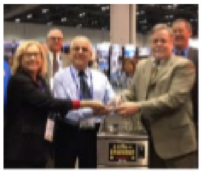


S.U.N. Equinox Solar-Assisted Heating System

The Equinox system is a combination solar/natural gas water heating system that uses an efficient evacuated tube design. It can be used in residential, commercial, or industrial locations and is capable of meeting 100% of domestic hot-water and space heating needs. UTD validated its energy performance in a field demonstration.

Solar Usage Now, LLC
Thom Blake
260-657-5605
tblake@solarusagenow.com
www.solarusagenow.com

COMMERCIALIZED PRODUCTS (continued)



ENERGY STAR® Fryer

In 2017, Royal Range's new high-efficiency RHEF-45 fryer was awarded the National Restaurant Association's Kitchen Innovation Award and GFEN's Blue Flame Product of the Year Award. Independent testing showed 63% heavy-load cooking energy efficiency. In 2019, Royal Range is introducing the high-efficiency and larger RHEF-75, building on this success.

Royal Range of California
Robert Lutz
951-360-1600
robert@royalranges.com
www.royalranges.com

Low-Oil-Volume Fryers

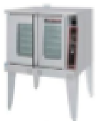
Marketed by Frymaster as Protector® fryers, this equipment increases energy efficiency while also extending cooking-oil quality and life to provide significant customer savings. Field demonstrations completed by UTD have shown an average savings of $4,800 per year per fryer.

Frymaster
Linda Brugler
318-866-2488
lbrugler@frymaster.com
www.frymaster.com

ENERGY STAR Conveyor Oven

ENERGY STAR rated conveyor ovens from Lincoln include an advanced energy-management system to reduce energy consumption up to 38%.

Lincoln, a division of Manitowoc Foodservice
260-459-8200
www.lincolnfp.com



ENERGY STAR Convection Oven
This unit showed improved efficiency and 40% energy savings compared to a standard oven during field testing and achieved an ENERGY STAR rating.

Garland
905-624-0260
www.garland-group.com

High-Efficiency Broiler

This broiler features infrared burners and an energy-saving hood that showed an average of 23% energy savings during field testing. It offers more efficient cooking as well as reducing heat gain to the kitchen.

Royal Range of California
800-769-2414
www.royalranges.com

High-Efficiency Broiler

The Montague Company commercialized a version of the advanced broiler technology using thermostatic broiler-temperature control and an energy-saving hood. It was recognized with a Kitchen Innovations Award in 2013.

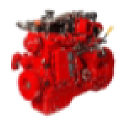
Montague
800-345-1830
www.montaguecompany.com

ENERGY STAR Countertop Steamer

A compact, gas-fired countertop steamer for commercial foodservice offers enhanced cooking rates while providing energy savings and reduced water consumption. It was the first gas-fired boilerless steamer on the market and received an ENERGY STAR rating.

Market Forge Industries Inc.
617-387-4100
866-698-3188
custserv@mfii.com
www.mfii.com

COMMERCIALIZED PRODUCTS (continued)

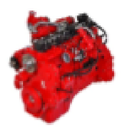


B6.7N

Cummins Westport 6.7L Medium-Duty NGV Engine

In December 2016, Cummins Westport Inc. began full commercial production of this 6.7-liter, 240-HP, medium-duty, factory-built, dedicated natural gas vehicle (NGV) engine for school bus, shuttle bus, medium-duty truck, and vocational uses. It meets U.S. 2017 EPA GHG requirements and CARB's optional more stringent low NO_x standard of 0.1 g/bhp-hr.

Cummins Westport Inc.
Stephen Ptucha
604-718-2024
sptucha@westport.com
www.cumminswestport.com

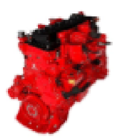


L9N

Cummins Westport 8.9L Near-Zero Emission NGV Engine

This 8.9L 320-HP NGV engine is widely used, with 50,000+ engines sold for transit, refuse-collection, and regional hauling applications since 2007. In 2016, it was advanced to become the first engine certified in North America to meet the 0.02 g/bhp-hr optional Near Zero (NZ) NO_x emissions standard (i.e. 90% lower than the current EPA NO_x limit of 0.2 g/bhp-hr).

Cummins Westport Inc.
Stephen Ptucha
604-718-2024
sptucha@westport.com
www.cumminswestport.com

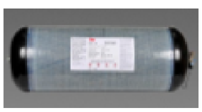


ISX12N

Cummins Westport 11.9L Near-Zero Emission NGV Engine

This 11.9L 400-HP NGV engine is used in large trucks, buses, and refuse vehicles. Engine sales since 2013 are approaching 10,000 units and 25,000+ engines will likely be sold in N.A. by 2020, yielding emissions reductions and $600+ million in annual fuel sales. In Model Year 18, it became CWI's second engine certified to meet NZ NO_x emissions standard of 0.02 g/bhp-hr.

Cummins Westport Inc.
Stephen Ptucha
604-718-2024
sptucha@westport.com
www.cumminswestport.com



HyperComp/3M NGV Cylinders

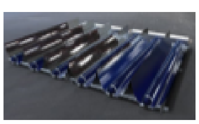
These lightweight Type IV NGV cylinders are manufactured using advanced 3M nanoparticle-enhanced matrix resin technology for high strength and durability. Three tank sizes of 30, 40, and 45 diesel gallon equivalent (DGE) are now offered in nine unique CNG Fuel System Solutions from Momentum Fuel Technologies, including roof mount, saddle mount, and back-of-cab designs.

Momentum Fuel Technologies
844-264-8265
www.momentumfueltechnologies.com

Ultimate CNG FuelMule™

The patented FuelMule™ mobile fueling solution dispenses eight diesel gallon equivalent per minute and fuels 35-50 medium-duty vehicles per delivery. It is used as a temporary starter station, station back-up, or for mobile onsite fueling. It has logged 250,000+ miles and almost 6,000 compressor hours delivering natural gas fuel to vehicles across the U.S. in five years of operation.

Ultimate CNG, LLC
Dennis Pick
703-209-4086
dpick@ultimatecng.com
www.ultimatecng.com



External Concentration Parabolic Collector

This patented, non-tracking, extremely-low-profile concentrator can achieve 200°C (392°F) solar thermal energy to economically serve commercial and industrial facilities and reduce GHG emissions. It can also be integrated with natural gas as a supplemental energy source. UTD provided technical and product development support and experimental validations over a seven-year period.

Arctic Solar Inc.
Bill Guiney
904-513-4638
bill@articsolar.com
www.articsolar.com

KEY INFORMATION & ANALYTICAL TOOLS

Reliability, Cost and Environmental Impacts of Standby Generation Systems

In 2017, Generac launched a website supported by UTD research that provides technical information on costs, emissions, and reliability for natural gas generators, including a white paper on natural gas reliability and a Total Cost of Ownership calculator that compares costs and emissions of natural gas vs. diesel-fueled standby generators. In 2018, UTD researchers also published a whitepaper that substantiated the high reliability of natural gas deliverability.

Available on-line at https://www.gti.energy/wp-content/uploads/2019/02/Assessment-of-Natural-Gas-Electric-Distribution-Service-Reliability-SummaryReport-Jul2018.pdf and https://www.generac.com/Industrial/all-about/natural-gas-fuel

Building America

Under five separate projects from 2011 to 2019, UTD has developed key information and tools to support the U.S. DOE's Building America research, development, and demonstration program, which helps accelerate use of best practices by residential builders, remodelers, installers, code officials, designers, raters, teachers, and others. Most recently a simplified combustion safety protocol was introduced.

Available on-line at https://www.gti.energy/BuildingAmerica and https://basc.pnnl.gov/library

CHP Interconnection Equipment Review Assessment

In 2016, the results of Phase 1 of UTD research project 2.15.M were made publicly available in order to build public understanding of the opportunities for wider standardization and harmonization of CHP interconnection practices. Discussions about UTD's research results were held with key decision-makers such as NARUC during 2017.

Available on-line at http://www.gastechnology.org/reports_software/Documents/CHP-Interconnection-Equipment-Analysis.pdf. For more information, contact Tim Kingston; tkingston@gti.energy

Commercial Foodservice (CFS) Equipment Calculator

Introduced in 2016, with UTD support, this website hosts CFS information and tools for the restaurant industry and others to determine the economic and environmental benefits of using new, more advanced commercial foodservice equipment. The website was showcased at several restaurant trade shows during 2017-18 and improvements are underway in 2019.

Available online at http://cfscalc.gastechnology.org. For more information, contact Frank Johnson; fjohnson@gti.energy

Virtual Test Home

A Virtual Test Home (VTH) has been created and demonstrated with UTD's support in a laboratory. The VTH can economically develop critical performance data to accelerate the adoption of advanced gas technologies (such as GHPs, combis and modulating furnaces) in U.S. DOE's EnergyPlus™ and other advanced building energy software, by incorporating experimentally-validated modeling algorithms and built-in modules that assess energy efficiency impacts on a comprehensive, seasonal basis. UTD is expanding the capabilities of the VTH in 2019.

For more information, contact Tim Kingston; tkingston@gti.energy

KEY INFORMATION & ANALYTICAL TOOLS (continued)

CSA NGV4.3 NGV Storage and Delivery Standard Technical Committee Support

CSA NGV4.3 issued in 2018 and specifies the performance requirements for temperature compensation control used to prevent compressed natural gas (CNG) dispensing systems from exceeding a safe fill level of vehicle fuel storage container(s). It contains safety performance guidelines and field evaluation methods for existing dispensing systems. UTD supported participation to lead the Technical Task Force that created the Standard.

Available online at www.csagroup.org. For more information, contact Ted Barnes; tbarnes@gti.energy

CSA NGV6.1 NGV Storage and Delivery Standard Technical Committee Support

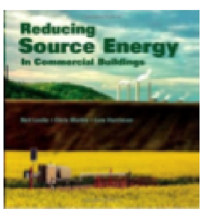
CSA NGV6.1 was introduced in 2016 and defines the requirements for the balance of systems and equipment onboard a NGV, which is not otherwise defined by NGV1 for the receptacle or NGV2 for the storage containers. UTD supported GTI's participation on the Technical Committee.

Available online at www.csagroup.org. For more information, contact Ted Barnes; tbarnes@gti.energy

CSA NGV5.1 and NGV5.2 Fueling Appliance Standard Technical Committees Support

CSA NGV5.1 was introduced in 2015 and updated in 2016, and provides mechanical, physical, and electrical requirements for residential fueling appliances (RFAs) that dispense natural gas for NGVs, including indoor and outdoor fueling appliances that connect to residential gas piping. A complimentary standard, NGV5.2 for vehicle fueling appliances (VFAs) in non-residential locations, has been developed and was published in late 2017. UTD supported participation on both of the Technical Committees.

Available online at www.csagroup.org. For more information, contact Ted Barnes; tbarnes@gti.energy



Source Energy Technical Data

Researchers are providing unbiased technical data on the benefits of source energy in reducing energy consumption and carbon emissions in buildings and transportation. Source energy is now included in the International Green Construction Code (IgCC) for high-performance commercial buildings, and in various American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) standards (e.g., Standard 100 for existing buildings, Standard 105 method for comparing building energy performance, Standard 189 for high-efficiency green buildings, and Standard 214 for building energy performance rating).

For more information, contact Neil Leslie; nleslie@gti.energy

Source Energy and Emissions Analysis Tool

The Source Energy and Emissions Analysis Tool (SEEAT) allows calculation of the source energy and greenhouse-gas emissions related to point-of-use (site) energy consumption by fuel type for each energy-consuming device. The source-energy and carbon-emission calculation methodology used accounts for primary energy consumption and related emissions for the full fuel cycle for residential and commercial buildings, industrial applications, and light-duty vehicles. SEEAT data is also used in the GTI-developed Energy Planning Analysis Tool (EPAT).

Available online at www.cmictools.com and www.epat.gastechnology.org. For more information, contact Neil Leslie; nleslie@gti.energy

TECHNOLOGY ADVANCEMENTS

Gas-fired Absorption Heat Pump Residential Water Heater

The latest generation of this efficient residential Gas-Fired Heat Pump Water Heater, with a projected Uniform Energy Factor (UEF) of 1.3 and ultra-low NO_x emissions of ≤10 ng/J, is undergoing a five-unit field test with prospective UTD manufacturing partner Rinnai in southern California, with support from CEC, UTD, SoCalGas and others. When commercially available, it will be the only residential water-heating technology with a source-energy-based EF ≥1.0.

Project Manager: Paul Glanville

Gas-fired Absorption Heat Pump for Space Heating or Commercial Water Heating

This Gas Absorption Heat Pump (GAHP) for space heating or water heating applications is undergoing a four-unit field test in Wisconsin with prospective UTD manufacturing partner Trane and support from U.S. DOE, UTD and others. The GAHP has field-demonstrated an Annual Fuel Utilization Efficiency of 140%, with 45% gas savings, an estimated financial payback period of as low as three years, and ultra-low NO_x emissions of ≤14 ng/J. The GAHP demonstrated continued operation under extreme cold weather conditions in WI during the Jan-Feb 2019 Polar Vortex.

Project Manager: Paul Glanville

Ultra-Low NO_x Burner

This innovative firetube boiler technology has more than two years of proven successful operation at a Mission Linen Supply facility in California. It improves efficiency and achieves NO_x emissions below 9 vppm, while avoiding the significant efficiency, capital cost, and/or operating cost penalties if conventional Selective Catalytic Reduction or burner enhancements such as external Flue Gas Recirculation and/or High Excess Air firing were used. UTD's partner Power Flame Inc. is helping businesses in 2019 meet NO_x emission regulations without sacrificing energy efficiency.

Project Manager: David Cygan

Low NO_x Ribbon Burner System

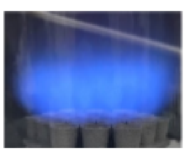
A new low NO_x combustion system reduces NO_x emissions by 50% in food processing, thermoforming, and other industrial applications. The system was evaluated in bench-scale, pilot scale, and full-scale production settings and has demonstrated transparent operation at an industrial bakery in California. In 2019, post-demo monitoring will continue at the bakery is along with commercialization activities with UTD's partner Flynn Burner Corp.

Project Manager: Yaroslav Chudnovsky

FlexCHP High-Efficiency Ultra-Clean Power and Steam Package

This innovative CHP package allows flexible steam production while meeting stringent California emission levels without a SCR system and across the full range of firing rates — achieving NO_x levels 50% below CARB limits. A 2014 installation in California operates with 84+% system efficiency and system emissions well below 9 ppm NO_x. UTD has provided long-term support, including efforts to apply the technology for broader application sizes (e.g. to 400 kW / 400 BHP).

Project Manager: David Cygan



Low NO_x Advanced 3D-Printed Nozzle Burner

A novel design for next-generation retention nozzles leverages new additive manufacturing capabilities and equipment. In 2019, UTD is evaluating technology licensing applications in boilers and air heating. Laboratory tests to date have demonstrated a robust, high-efficiency (3-6% increase), ultra-low emissions burner, and >10:1 turndown. It achieved 50%-75% reduction in NO_x emissions compared to current burners, with the potential to reach < 5 ppm NO_x.

Project Manager: Sandeep Alavandi

TECHNOLOGY ADVANCEMENTS (continued)

Gas Quality Sensor

The Gas Quality Sensor (GQS) uses solid-state infrared light absorption spectroscopy to measure Btu content and gas composition. The GQS is expected to be priced competitively to a gas chromatograph for use with natural gas and bio-methane fuels, while providing much faster response and lower maintenance costs. Successful field validation tests of pre-commercial units occurred in 2018 and continuing in 2019. Commercial introduction by UTD partner CMR Group is anticipated in 2019.

Project Manager: David Rue

Cost-Effective Small-Scale Compressor for Natural Gas Vehicles (NGVs)

A cost-effective small-scale compressor could significantly change the NGV fueling market. With UTD cost share and U.S. DOE funding, GTI and the University of Texas, Austin (using specialty materials from Argonne National Laboratory) developed a novel approach using a linear motor with only one moving piston and operated a prototype successfully in the lab. The technology is currently being scaled up to 50 SCFM capacity with UTD funding.

Project Manager: Jason Stair

On-Demand Heat and Power System

This unique new technology has received a remarkable three rounds of funding from U.S. DOE ARPA-E, along with UTD and other co-funding support. This technology captures and stores renewable energy (or other resources, including waste heat), augments it with natural gas as needed, and delivers heat and power on-demand to commercial, industrial, and other users. In 2019, the technology is moving to a pilot field scale-up demonstration in California.

Project Manager: David Cygan

CARB-Compliant Engine-Based Micro-CHP System

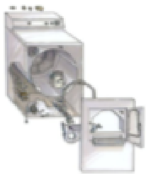
UTD researchers are collaborating with the California Energy Commission and SoCalGas to advance and commercialize the first-ever engine-based micro-CHP system that complies with California Air Resource Board requirements. A system offered by a major manufacturer in an influential market like California could spark the U.S. micro-CHP market.

Project Manager: Tim Kingston

Low-NO_x Furnace

Low-NO_x combustion systems were developed in cooperation with SCAQMD and five residential furnace manufacturers to achieve emissions levels less than 14 ng/J. Innovative burner materials, including metal mesh and metal foam, were used to achieve even heat transfer and uniform flame temperatures. UTD completed durability testing in 2017.

Project Manager: Frank Johnson



ENERGY STAR Residential Gas Dryer

UTD worked with a major manufacturer to develop one of the first commercially-available gas-fired ENERGY STAR clothes dryers (included at energystar.gov/products/appliances/clothes_dryers). UTD is currently investigating next-generation technologies and developing an early-stage prototype residential gas dryer to substantially further increase operating efficiency.

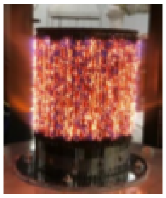
Project Manager: Shawn Scott

TECHNOLOGY ADVANCEMENTS (continued)

iGEN Self-Powered Furnace

The innovative new iGEN furnace generates its own electric power and contains an integrated battery, providing homeowners with continuous heating even during electricity outages. Initial units produce about 45 MBtu/hr and 1kW of power, with reported 95% heating system efficiency. UTD is supporting the technical refinement of this new product in 2019 with laboratory testing, validation, and recommendations.

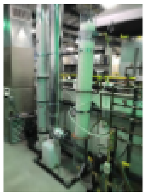
Project Manager: Tim Kingston



Ultra-High-Efficiency, Combination Heating/Cooling Vuilleumier Cycle Heat Pump

Vuilleumier cycle-based heat pumps could provide a step-change efficiency improvement over vapor absorption- or compression-based cycles, achieving cooling COP > 1 and heating COP > 2 in order to meet aggressive energy-efficiency goals. UTD is working with a leading developer to advance key system components using both computational and experimental analysis. In 2018, performance goals were achieved in alpha prototype testing funded by DOE, UTD and others.

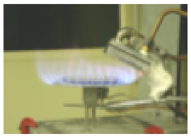
Project Manager: Paul Glanville



Next Generation Liquid Dessiccant-based, Heat-Driven HVAC System

Liquid desiccant-based systems can efficiently remove moisture from air and reduce the amount of mechanical energy and water required by conventional HVAC technologies that de-humidify, condition, and re-humidify space air. In cooperation with NYSERDA and others, UTD is testing a novel new non-corrosive, non-toxic desiccant in a gas-driven system that offers a potential 30% increase in COP on a seasonal basis over conventional HVAC technologies.

Project Manager: Doug Kosar



Self-Powered Tankless Water Heater

Tankless water heaters yield higher levels of efficiency than storage-type water heaters but require the added expense of an electrical connection and are susceptible to power outages unless a separate battery back-up system is installed. UTD researchers have assessed leading thermoelectric generator (TEG) technologies and, in 2019, are analyzing opportunities to economically integrate TEG and other technologies into a prototype water heater design.

Project Manager: Aleks Kozlov

Low NOx, High-Efficiency Burners for Commercial Food Service Equipment

UTD is helping manufacturers respond to pending new regulations on NOx emissions of CFS equipment and simultaneously improve energy efficiency by developing and demonstrating prototype equipment that uses advanced burner concepts or components. Both novel new burner configurations as well as state-of-the-art burner technologies are being evaluated.

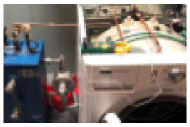
Project Manager: Frank Johnson

High-Efficiency Gas-Fired Rotary Heat Pump for Food Processing

UTD is partnering with CEC, SoCalGas, and others to demonstrate an innovative high-efficiency, thermal-vacuum, gas-fired heat pump technology for food drying applications at a commercial food processing company. The new technology has the potential to be about twice as efficient as conventional processes. A prototype system at a field host site will generate performance data during 2019.

Project Manager: Yaroslav Chudnovsky

TECHNOLOGY ADVANCEMENTS (continued)



High Efficiency Commercial Clothes Dryer

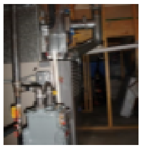
An advanced technology for a natural-gas-fired commercial clothes dryer is being created and demonstrated at laboratory scale that has the potential to save at least 50% of the energy used in the commercial clothes drying sector. It is being developed in partnership with Oak Ridge National Laboratory and others, with financial support from DOE and UTD.

Project Manager: Yaroslav Chudnovsky

Next Generation Infrared Burner

In partnership with a leading U.S.-based product manufacturer, UTD-funded researchers are testing a variety of unique metal foam materials in a laboratory to evaluate their potential performance as next-generation, high-efficiency, rapid-response, low-emission infrared burners that are directly fired with natural gas.

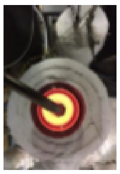
Project Manager: Sandeep Alavandi



Residential Furnace Retrofit for High-Efficiency Heating and Humidification

December 2017, results of the novel Transport Membrane Humidifier (TMH) in four homes in Minnesota demonstrated a 14% increase in furnace efficiency while providing humidification without water supply. Discussions with potential licensees are in progress.

Project Manager: Dexin Wang



Advanced Combustion System for Next Generation mCHP

An advanced combustion system with thermochemical heat recovery has been created and demonstrated with UTD's support in a laboratory. Applying the system to a Stirling-based micro-CHP system can increase fuel-to-electric efficiency from 12-15% to 30%. Testing in 2019 demonstrated low NOx and CO emissions at ≤9 ppm (at 3% O2, dry).

Project Managers: Dave Kalensky and Aleks Kozlov

WORKING WITH PARTNERS TO CO-FUND UTD INITIATIVES

In 2018, each $1.00 in new UTD funding was leveraged by $5.1 of direct funding from government and industry partners for related end-use R&D. GTI secured $21.9 million from federal and state government partners and $5.2 million in funding from manufacturing partners and other gas industry resources (outside of UTD). Manufacturing partners also provided significant, additional in-kind co-funding. Examples include:

- California Energy Commission (CEC) funding of three new projects totaling $4.4 million. Efforts include new NGV vehicle drivetrain, natural gas/renewable solar systems for industrial applications, and micro CHP systems.
- California Air Resources Board (CARB) funding of $5.1 million for advanced low-emission vehicle demonstrations.
- U.S. Department of Energy (DOE) funding of $0.8 million for advanced vehicle and power system R&D.
- U.S. Department of Defense (DOD) funding of $11 million to demonstrate new natural gas energy efficiency and resiliency technology at military facilities.
- More than $4.4 million in other gas industry funding for a range of emerging technology efforts aiming to support the evaluation of commercial readiness of new higher-efficiency natural gas technologies.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter Of

Keyspan Gas East Corporation d/b/a National Grid and
The Brooklyn Union Gas Company d/b/a National Grid NY

Cases 16-G-0058 and 16-G-0059

May 2016

Prepared Exhibits of:

Gas Policy and Supply Panel

John P. Sano
Utility Supervisor

James Lyons
Utility Consumer Program
Specialist 4

Davide Maioriello
Utility Engineer 3

Claude Semexant
Utility Engineer 1

Office of Electric, Gas and
Water

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

List of Exhibits

Exhibit GPSP-1

Table of Contents

Date of Request: March 17, 2016
Due Date: March 28, 2016

DPS Request No. DPS-305 JPS-1
KEDNY/ KEDLI Req. No. BULI-241

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, John P. Sano

TO: National Grid, Elizabeth Arangio

SUBJECT: Gas Supply Planning

Request:

Provide the following information for both KEDNY and KEDLI:

On p. 36 of Mr. Daley's testimony, he discusses the capital improvements to both Liquefied Natural Gas (LNG) facilities and he identify several important transmission projects needed for both reinforcement and growth purposes.

1. Identify the changes required in the gas supply plan required to maintain design day, as well as, colder than normal weather service during the time any portion of the LNG facilities are out of service. Include or explain the following:

    a. What is the schedule for work on LNG facilities requiring attention and what effect do these facilities have on the gas supply plan?

    b. Will more than one LNG tank be taken out of service at any given time?

    c. What will the reduction in design day deliverability when the Holtsville, Long Island tank is unavailable? Describe how the gas supply plan will accommodate or replace this supply loss?

    d. What will be the reduction in design day deliverability when either of the Greenpoint, Brooklyn tanks are unavailable? Describe how the gas supply plan will accommodate or replace this supply loss?

e. What will be the reduction in design day deliverability for any of the other LNG site work identified by the Companies in their rate filing? Describe how the gas supply plan will accommodate or replace this supply loss?

f. What contingencies are required for any schedule delays to any of the work identified above? Describe how will the gas supply plan will accommodate or replace this supply loss.

g. Describe the extent to which the Companies or other National Grid operations have previously performed similar work on its LNG facilities, for example, in New England. Describe in detail lessons learned regarding the need to modify the gas supply plan or project schedules to maintain reliability when LNG service is restricted.

2. Identify the changes required in the gas supply plan to maintain design day, as well as, colder than normal weather service during the time any portion of the transmission system is out of service due to any or the following transmission projects discussed on pp. 37-38 of Mr. Daley's testimony:

   a. Metropolitan Reliability Infrastructure Project (MRI);

   b. Northern Queens Project;

   c. Northwest Nassau Transmission Project; and

   d. Any other transmission project included in the Companies' Capital Expenditure plan.

3. How does the agreement with Transco, referenced on p. 14 of your testimony, for 115,000 dekatherms/day of incremental capacity in 2017 and a possible additional 400,000 dths/day in 2019, split between the Staten Island and Rockaway Lateral delivery points, impact the capital work for gas supply planning discussed in questions #1 and #2 above?

   a. Can this additional capacity be modified to alter the gas flows between the two delivery points, if needed, due to any concerns for reliability?

   b. Do the Companies' currently have the flexibility to alter flows between the Rockaway Lateral and Long Beach to meet fluctuating demand requirements between KEDNY and KEDLI? If there are restrictions on this flexibility describe and explain them?

   c. Explain why the Companies propose to proceed with all the capital work mentioned in your testimony instead of delaying at least a portion of the work until the additional 400,000 dekatherms a day may be available in 2019.

<u>Response</u>:

1.

a. Greenpoint Tank 2 is scheduled to be out of service for the 2020/21 winter season. Vaporization capability at Greenpoint totals 290,000 Dth/day. When Tank 2 is out of service for the 2020/21 winter season, total vaporization capability will be reduced from 290,000 Dth/day to 115,000 Dth/day, as Tank 1 will still be in operation. The Holtsville tank is scheduled to be out of service for the 2021/22 winter season. Vaporization capability at Holtsville totals 103,000 Dth/day. When the tank is out of service for the 2021/22 winter season, total vaporization capability will be reduced from 103,000 Dth/day to 0 Dth/day.

b. No. Only one tank will be taken out of service at a time.

c. The reduction in design day deliverability when the Holtsville tank is unavailable totals 103,000 Dth/day. To replace this reduction in deliverability, replacement supplies would have to flow primarily from South Commack and Transco (Floyd Bennett Field ("FBF")/Long Beach) to offset the supply loss of LNG. Prior to the 2021/22 winter season, the Company will: (1) review the latest customer requirements forecast; (2) determine whether customer requirements exceed the deliverability of existing gas supply assets; and (3) procure additional capacity and/or peaking supplies at the respective pipeline interconnects as needed.

d. The reduction in design day deliverability when Greenpoint Tank 2 is unavailable totals 175,000 Dth/day. To replace this reduction in deliverability, replacement supplies would have to flow primarily from Transco (FBF/Narrows) to offset the supply loss of LNG. Prior to the 2020/21 winter season, the Company will: (1) review the latest customer requirements forecast; (2) determine whether customer requirements exceed the deliverability of existing gas supply assets; and (3) procure additional capacity and/or peaking supplies at the respective pipeline interconnects as needed.

e. There are no additional reductions in design day deliverability for any of the other LNG site work identified by the Companies in their rate filings other than those identified in (a) and (b) above.

f. For either of the tanks to be taken out of service, Transco's New York Reliability Enhancement Project ("NYRE Project") must be in service. The NYRE Project has an expected in service date of November 2019. Additionally, the Company's on-system Metropolitan Reliability Infrastructure Project ("MRI Project") is required to be in service to allow Tank 2 at Greenpoint to come out of service for one heating season. The MRI Project has an expected in-service date of November 2020. Additionally, the Holtsville tank must be back in service before Tank 2 at Greenpoint is taken out of service. As discussed in responses (c) and (d) above, additional capacity and/or peaking supplies will be secured at the respective pipeline interconnects as needed.

To allow these tanks to come out of service for one heating season, Gas Supply Planning will secure additional incremental pipeline supplies to support system reliability in the absence of vaporization availability. The LNG facilities will continue to operate until such time as the above referenced projects are completed and gas supply is secured to replace the vaporization capacity with the tanks out of service.

g. National Grid personnel have on a number of occasions successfully removed LNG tanks from active service, performed tank entry, conducted inspections, testing, redesign and rebuild of the tanks and associated components and re-commissioned the LNG tanks back into service. In the US, National Grid LNG Operations have engaged in these activities on five occasions, most recently in 2011 and 2012 when the Tewksbury, MA LNG tank was project was completed. The supply plan was adjusted to support the execution of the Tewksbury LNG project, which included the need for securing incremental pipeline supplies to ensure reliability of the system during peak periods of demand during the winter heating season. The project schedule was closely monitored by key stakeholders, including Gas Control and Gas Supply Planning, to ensure safe system operations and supply reliability. The magnitude of these projects, including the impact to system operations, requires close coordination and planning several years in advance of the project start to ensure the basic objectives of providing safe and reliable service to customers is achieved.

2. a. – d.

Planned outages on any portion of the transmission system to accommodate transmission work, including work associated with the Metropolitan Reliability Infrastructure Project (MRI), Northern Queens, and the Northwest Nassau Transmission Project, are not permitted during design day or colder than normal weather conditions. Any transmission projects that would cause an outage on a portion of the transmission system would be scheduled between the Spring and Fall to minimize system impacts.

3. a. and b.

After submitting direct testimony, the Companies executed precedent agreements on February 29, 2016 with Transco for up to 400,000 Dth/day of incremental capacity to Rockaway. The volumes will be split between KEDNY and KEDLI. The total volume, and the exact split between KEDNY and KEDLI, is not determined at this time as this project is subject to an Open Season by Transco, expected to occur in April 2016.

The Companies currently have the flexibility to alter flows between the Rockaway Lateral and Long Beach to meet fluctuating demand requirements between KEDNY and KEDLI. The existing gate station at FBF in Rockaway has 647,000 Dth/day of takeaway capacity. With the existing Northeast Connector capacity, up to 100,000 Dth/day can flow to FBF. Transco currently provides flexibility to re-nominate gas from Long Beach and Narrows to FBF. Gas can also be re-nominated from FBF to the other Transco gates, if needed. The new upstream capacity projects in 2017 and 2019 will provide the same flexibility.

There are currently two limitations on flexibility to alter flows between Long Beach, Narrows and Rockaway:

1. Re-nominating gas from Narrows and/or Long Beach is subject to restrictions that would affect Transco's balancing pools. In some instances, the supplier would need to re-nominate gas at the receipt point before the Company would be able to process a port-cycle or retroactive nomination; and
2. The Companies must observe the New York Facility Group's Delivery Point Entitlements.

c. The MRI Project will allow the system to take additional capacity from Transco at the Rockaway Lateral delivery point and provides the flexibility to move volumes throughout the system, as well as facilitates taking an LNG outage for work at the Greenpoint LNG plant. Construction of the MRI Project is over a four year period and is currently scheduled to be in service for winter 2020/2021. Construction of the Northern Queens project is completed and awaiting a final inspection before it is placed into service to address an existing distribution system need in the northern portion of Queens. The Northwest West Nassau project addresses both integrity concerns with Gas Mains 1, 8, and 16 and existing transmission pressure issues in the line that goes through Lake Success. The capital work planned by the Companies each year is intended to match the internal forecast by the AMF group to maintain above minimum pressures.

Name of Respondent:
Elizabeth Arangio

Date of Reply:
March 28, 2016

Date of Request: March 22, 2016
Due Date: April 1, 2016

DPS Request No. DPS-329 MT-3
KEDNY/ KEDLI Req. No. BULI-286

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, Michael Tushaj

TO: National Grid, GIOP

SUBJECT: Cap Ex Non-Infrastructure

Request:

The Following questions refer to the Companies' forecasts for categories in the Non-Infrastructure Classification, as listed in the Companies' Exhibit__(GIOP-1):

1) Provide Companies' sanction papers for the following Non-Infrastructure line item accounts:
   a. AMR Installation/Replacements (KEDLI)
   b. AMR Installation (KEDNY)
   c. AMR Replacement (KEDNY)
   d. Tools & Equipment (KEDNY and KEDLI)
   e. Telecomm (KEDNY and KEDLI)

To the extent that the following information is not included in the sanction papers provided in response to the question above:

2) Provide, in Excel, a detailed breakdown of the forecasts for the "Non-Infrastructure" line item accounts "AMR Installation/Replacements" for KEDLI. Similarly, provide, in Excel, a detailed breakdown of the forecasts for "AMR Installation" and "AMR Replacement" for KEDNY.

3) Provide the experienced cost per meter and the number of meters installed over the past 3 calendar years for KEDNY and KEDLI, respectively.

4) Provide the average service life of a typical AMR meter.

5) Provide, in Excel, a breakdown for the forecasted costs in RY 1, 2 and 3 for the "Non-Infrastructure" line item account "Tools & Equipment – All" for KEDNY and KEDLI, respectively.

Response:

1.

a There is no sanction paper for this program because it less than the $1M threshold required for sanctioning.

b. Attachment 1 is the requested sanction paper.

c. Attachment 2 is the requested sanction paper.

d. Attachment 3 is the sanction paper for KEDNY. Attachment 4 is the sanction paper for KEDLI.

e. There is no sanction paper for this program because it less than the $1M threshold required for sanctioning.

2. Attachment 5 provides the requested information.

3. The table below shows the experienced cost per meter (exclusive of installation cost) and the number of meters installed over the past three calendar years for KEDNY and KEDLI. The experienced cost per meter is an average cost for all meters, both industrial and commercial. A common residential meter costs approximately $60, whereas an industrial meter could range from several hundred to over $20,000. In CY14, the Companies purchased a higher proportion of commercial rotary meters than in CY13 or CY15, which is reflected in the higher average price in that year.

	CY13	**CY14**	**CY15**
KEDNY			
Meters Installed	37,388	18,986	21,023
Experienced Cost/Meter	$205	$305	$205
KEDLI			
Meters Installed	34,626	32,292	25,759
Experienced Cost/Meter	$192	$186	$117

4. The average service life of a typical AMR meter is 20 years.

5. The "Tools & Equipment – All" line item is a blanket program. Costs are forecast based on historic levels and not at the individual unit level. The sanction papers provided in response to part 1 above provide greater detail on this program. Most tools and equipment purchases are on an as-needed basis, and these items are generally replacements for tools and equipment that are beyond repair. Some purchases are for improved or obsolete tools and equipment. The program is also used for new technology tools and equipment that will provide enhanced (employee, public and environmental) safety and improved operations. The table below provides examples of some common tools and equipment purchased through this program.

	KEDNY and KEDLI
	20 Common tools & equipment purchased within the Capital Tools & Equipment budget
1	Safety equipment (PPE, fresh air bottles, etc.)
2	Road traffic protection & public safety equipment
3	Fusing equipment
4	Electro fuse equipment
5	Water pumps
6	Welding equipment
7	Inspection tools
8	Locating devices
9	Pipe tapping equipment
10	Generators
11	Pipe cutting tools (plastic, cast iron, steel)
12	Saw cutters and pavement breakers
13	Backfilling compaction equipment
14	Pneumatic tools
15	Coring equipment
16	Lighting
17	Exterior pipe cleaning tools
18	Underground drilling tools & equipment
19	Shell cutters for tapping equipment
20	New technology tools

<u>Name of Respondent</u>:
James Thompson
Marina Perrone
Philip Di Giglio

<u>Date of Reply</u>:
March 31, 2016

nationalgrid

Short Form Sanction Paper

Title:	FY17 AMR Purchase and Installation Blanket - KEDNY	**Sanction Paper #:**	USSC-16-048
Project #:	C048384	**Sanction Type:**	Sanction
Operating Company:	The Brooklyn Union Gas Co.	**Date of Request:**	February 9, 2016
Author:	Marina Perrone	**Sponsor:**	John Stavrakas – VP Gas Asset Management
Utility Service:	Gas	**Project Manager:**	Marina Perrone

1 Executive Summary

1.1 Sanctioning Summary

This paper requests sanction of project C048384 in the amount $4.842M and a tolerance of +/- 10% for the purposes of full implementation.

This sanction amount is $4.842M broken down into:
$4.842M Capex
$0.000M Opex
$0.000M Removal

1.2 Project Summary

This project provides funding for the purchase and installation of Automatic Meter Reading Equipment for replacement of failed units, end of life units, and to support meter replacement and growth programs.

2 Project Detail

2.1 Background

The Brooklyn Union Gas Company currently has an installed AMR population of approximately 790K units. Each year a quantity of AMR units are replaced in the field by Customer Meter Service Technicians as they either fail, or have reached the end of their useful life. Recently we matched the AMR population against a battery life model supplied by the vendor to more accurately predict the number of AMR replacements which must be performed on an annual basis. Using this model, we have calculated that 35,000 AMR units will require replacement each year for the next 4 year period.

Short Form Sanction Paper

2.2 *Drivers*

The primary driver for this project is the continuation of customer meter read rate and our ability to provide timely, accurate bills.

2.3 *Project Description*

This project, and sanction request, covers material and installation costs associated with the purchase of installation of 68,500 AMR equipment units which will be used to replace failed units, to accommodate growth, and proactively replace units that are approaching their battery end of life. The FY17 budget is in line with last year's budget.

This project supports regulatory requirements for accurate meter reading and billing.

2.4 *Benefits*

This project enables the company to provide accurate, actual billing information to customers by maintaining the health and integrity of our automatic meter reading system.

2.5 *Business & Customer Issues*

There are no significant business issues beyond what has been described elsewhere.

2.6 *Alternatives*

Alternative 1: Base Case – Leave as is

This alternative is rejected as the quantity of projected AMR equipment failures resulting from age without a proactive replacement policy is expected to reach 50K units within 2 years. This failure rate will adversely impact meter read rates, customer satisfaction, and results in a less efficient use of field labor by not leveraging "tag along" process to include Proactive AMR equipment replacements

In addition, these options are rejected since AMR equipment will fail without replacement. Failures will result in the addition of over 25,000 meters to the manual meter reading routes requiring additional manpower and opex spend. In addition, this policy would adversely impact meter read rates and customer satisfaction.

Short Form Sanction Paper

Alternative 2: Revise Project Size and Scope – Partial Deferral

This alternative is rejected for the same reasons as Alternative 1

2.7 *Investment Recovery*

Investment recovery will be through standard rate recovery mechanisms

2.7.1 Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $0.995M. This is indicative only. The actual revenue requirement will differ, depending upon the timing of the next rate case and/or the timing of the next filing in which the project is included in rate base.

3 Related Projects, Scoring, Budgets

3.1 *Summary of Projects*

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
C048384		AMR Purchase	4.842
		Total	4.842

3.2 *Associated Projects*

None

3.3 *Prior Sanctioning History*

N/A

nationalgrid

Short Form Sanction Paper

3.4 ***Category***

Category	Reference to Mandate, Policy, NPV, or Other
O Mandatory ⦿ Policy- Driven O Justified NPV O Other	Support Operations thru maintaining Meter Reading Rates and delivering accurate billing to customers

3.5 ***Asset Management Risk Score***

Asset Management Risk Score: _49____

Primary Risk Score Driver: (Policy Driven Projects Only)

⦿ Reliability O Environment O Health & Safety O Not Policy Driven

3.6 ***Complexity Level***

O High Complexity O Medium Complexity ⦿ Low Complexity O N/A

Complexity Score: _15____

3.7 ***Next Planned Sanction Review***

Date (Month/Year)	Purpose of Sanction Review
June 2017	Sanction Paper Closeout

Short Form Sanction Paper

nationalgrid

4 Financial

4.1 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY17-FY21 Gas Capital Plan	⦿ Yes ○ No	○ Over ○ Under ⦿ NA	$0.000M

4.1.1 If cost > approved Business Plan how will this be funded?

N/A

4.2 CIAC / Reimbursement

N/A

4.3 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend	Prior Yrs	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
C048384	AMR Purchase	Est Lvl (e.g. +/- 10%)	CapEx	-	4.842	-	-	-	-	-	4.842
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	4.842	-	-	-	-	-	4.842
Total Project Sanction			CapEx	-	4.842	-	-	-	-	-	4.842
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	4.842	-	-	-	-	-	4.842

Short Form Sanction Paper

nationalgrid

4.4 ***Project Budget Summary Table***

Project Costs per Business Plan

$M	Prior Yrs (Actual)	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	4.842	0.000	0.000	0.000	0.000	0.000	4.842
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	4.842	0.000	0.000	0.000	0.000	0.000	4.842

Variance **(Business Plan-Project Estimate)**

$M	Prior Yrs (Actual)	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

5 ***Key Milestones***

Milestone	**Target Date: (Month/Year)**
Provide vendors with annual requirements and product delivery schedule for first half of FY16	February 2016
Provide vendors with delivery schedule for second half of FY16	July 2016
Project Closeout	June 2017

6 ***Statements of Support***

6.1.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Role	**Individual**	**Responsibilities**
Investment Planner	Roden, Thomas	Endorses relative to 5-year business plan or emergent work
Resource Planning	Buckleman, Brian	Endorses Resources, cost estimate, schedule, and Portfolio Alignment
Project Management	Fortier, Joseph Jr	Endorses Resources, cost estimate, schedule

6.1.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Reviewer List	Individual
Finance	Fowler, Keith Horowitz, Philip
Regulatory	Zschokke, Peter Gavilondo, Carlos
Jurisdictional Delegate	Brown, Laurie
Procurement	Curran, Art
Control Center	Metzdorff, Peter

6.1.3 List References

N/A

Short Form Sanction Paper

nationalgrid

7 Decisions

I:

(a) APPROVE this paper and the investment of $4.842M and a tolerance of +/- 10%

(b) NOTE that Marina Perrone is the Project Manager and has the approved financial delegation.

(c) NOTE: In the event that any Blanket/Program projects are not approved prior to the start of the FY2018 fiscal year, the FY2017 approval limits will remain in effect until such time as the FY2018 blanket/program projects are approved by USSC and/or other appropriate authority for approval.

Signature...Date 3/1/2016

Ross Turrini – SVP & Gas Process & Engineering

8 Other Appendices

8.1 Sanction Request Breakdown by Project

N/A

US Sanction Paper

Title:	KEDNY AMR Deployment	**Sanction Paper #:**	USSC-15-263
Project #:	C067854	**Sanction Type:**	Sanction
Operating Company:	The Brooklyn Union Gas Co.	**Date of Request:**	11/19/2015
Author:	Philip Di Giglio	**Sponsor:**	Johnny Johnston – VP CMS
Utility Service:	Gas	**Project Manager:**	Philip Di Giglio

1 Executive Summary

1.1 Sanctioning Summary

This paper requests sanction of C067854 in the amount $33.112 with a tolerance of +/- 10% for the purpose of completing the installation of Automatic Meter Reading (AMR) equipment in the KEDNY territory.

This sanction amount is $33.112 broken down into:

$32.062 Capex
$1.050 Opex
$0.000 Removal

1.2 Project Summary

There are currently approximately 1.3 million gas meters in the KEDNY territory of which 780K are equipped with automatic meter reading (AMR) equipment. The remainder (520K) is read bi-monthly by pedestrian meter readers.

This project provides funding for the purchase and installation of AMR equipment on the remaining 520K customers.

Installation of AMR on these sites will increase billing accuracy, reduce estimated bills by over 250K per month, and deliver an annual opex savings of over $5.8 Million when fully deployed.

Initial funding for this project was included in our recent KEDNY Deferral which was approved by the NYS PSC on 10/19/15. This funding covers the project thru the end of CY16 (3rd quarter of FY17).

CY15 - $3.75M
CY16- $12.75M
Total - $16.5M

US Sanction Paper

nationalgrid

1.3 Summary of Projects

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
C067854	N/A	KEDNY AMR Deployment	33.112
		Total	33.112

1.4 Associated Projects

N/A

1.5 Prior Sanctioning History

N/A

1.6 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
June 2018	Project Closure

1.7 Category

Category	Reference to Mandate, Policy, NPV, or Other
○ Mandatory ⊙ Policy- Driven ○ Justified NPV ○ Other	Installation of Automatic Meter Reading equipment is policy to collect monthly accurate reads for billing, reduce issuance of estimated bills, and reduce Opex costs

US Sanction Paper

nationalgrid

1.8 Asset Management Risk Score

Asset Management Risk Score: _____49_

Primary Risk Score Driver: (Policy Driven Projects Only)

◉ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven

1.9 Complexity Level

○ High Complexity ○ Medium Complexity ◉ Low Complexity ○ N/A

Complexity Score: __15___

1.10 Process Hazard Assessment

A Process Hazard Assessment (PHA) is required for this project:

○ Yes ◉ No

1.11 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan (M$)
FY16-FY20 Gas Capital Plan	◉ Yes ○ No	◉ Over ○ Under ○ NA	0.914

1.12 If cost > approved Business Plan how will this be funded?

Re-allocation of funds within the portfolio will be managed by Resource Planning to meet jurisdictional budgetary, statutory, and regulatory requirements. Funding for FY16 as provided in the recent KEDNY Deferral has been incorporated in current estimates.

1.13 Current Planning Horizon

		Current Planning Horizon						
		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	Prior Yrs	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
CapEx	0.000	6.832	16.033	9.197	0.000	0.000	0.000	32.062
OpEx	0.000	0.230	0.410	0.410	0.000	0.000	0.000	1.050
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CIAC/Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	7.062	16.443	9.607	0.000	0.000	0.000	33.112

1.14 Key Milestones

Milestone	Target Date: (Month/Year)
Sanction Approval	Nov 2015
Order Equipment	Nov 2015
Receive AMR Equipment (initial order)	Dec 2015
Begin Deployment	Jan 2016
Project Completion	Mar 2018
Project Closure	June 2018

1.15 Resources, Operations and Procurement

Resource Sourcing			
Engineering & Design Resources to be provided	☑ Internal	☐ Contractor	
Construction/Implementation Resources to be provided	☑ Internal	☐ Contractor	
Resource Delivery			
Availability of internal resources to deliver project:	○ Red	◉ Amber	○ Green
Availability of external resources to deliver project:	○ Red	○ Amber	◉ Green
Operational Impact			
Outage impact on network system:	○ Red	○ Amber	◉ Green

US Sanction Paper

Procurement Impact			
Procurement impact on network system:	○ Red	○ Amber	⊙ Green

1.16 Key Issues (include mitigation of Red or Amber Resources)

1	CMS to begin Hiring Process Immediately upon Funding Project Approval
2	IS to complete FDM interface to KEDNY Customer System
3	

1.17 Climate Change

Contribution to National Grid's 2050 80% emissions reduction target:	⊙ Neutral	○ Positive	○ Negative
Impact on adaptability of network for future climate change:	⊙ Neutral	○ Positive	○ Negative

1.18 List References

N/A

US Sanction Paper

nationalgrid

2 Decisions

The US Sanctioning Committee (USSC) at a meeting held on 11/19/2015

(a) APPROVED this paper and the investment of \$33.112M and a tolerance of +/- 10

(b) NOTED that Philip Di Giglio has the approved financial delegation.

Signature Margaret M Smyth Date 11/30/15

Margaret Smyth
US Chief Financial Officer
Chair, US Sanctioning Committee

US Sanction Paper

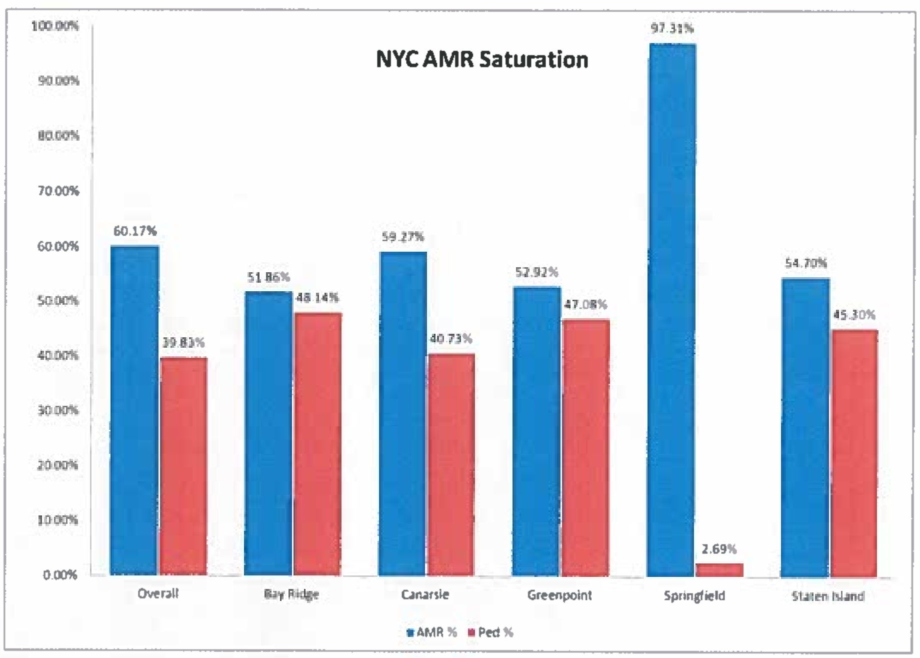
3 Sanction Paper Detail

Title:	KEDNY AMR Deployment	**Sanction Paper #:**	USSC-15-263
Project #:	C067854	**Sanction Type:**	Sanction
Operating Company:	The Brooklyn Union Gas Co.	**Date of Request:**	11/19/2015
Author:	Philip Di Giglio	**Sponsor:**	Johnny Johnston – VP CMS
Utility Service:	Gas	**Project Manager:**	Philip Di Giglio

3.1 Background

The Brooklyn Union Gas Company has approximately 1.3M gas customers of which approximately 780K are equipped with Automatic Meter Reading (AMR) equipment. The remaining meter population is read using pedestrian meter readers.

While the overall saturation of AMR equipment is just over 60%, the saturation of AMR varies by individual yard within the territory



US Sanction Paper

Originally, AMR equipment was deployed primarily in the "Springfield" area over 25 years ago as a mass installation project. Over the past 25 years, AMR deployment has expanded as a result of targeted "hard to access" areas, or as part of our meter exchange program resulting in a slow expansion of the technology.

Over the past year, AMR expansion has been positive but slow. While this expansion has been positive for customer satisfaction and increasing the accuracy of customer bills, the scattered expansion approach has an adverse impact on the pedestrian meter reading process whereby we have noted increasing distances between pedestrian read customers, and reduced meter counts on pedestrian route.

NYC AMR Meter Saturation FY2016

nationalgrid
HERE WITH YOU. HERE FOR YOU.

Choose Month: September 2015

	Pedestrian	Ped Variance vs April	Pedestrian %	AMR	AMR Variance vs April	AMR %	Total
Bay Ridge	171,274	-2,516	48.14%	184,520	2,206	51.86%	355,794
Canarsie	96,884	-1,524	40.73%	140,976	1,453	59.27%	237,860
Greenpoint	175,753	-4,358	47.08%	197,592	4,340	52.92%	373,345
Springfield	4,870	-384	2.69%	176,387	304	97.31%	181,257
Staten Island	71,116	-1,845	45.30%	85,863	1,888	54.70%	156,979
Grand Total	519,897	-10,627	39.83%	785,338	10,191	60.17%	1,305,235

This project allows for the addition of AMR equipment on the remaining 520K accounts over a 24 month period.

3.2 Drivers

Mobile AMR is currently near 100% deployed throughout all other National Grid regions. Once completed in KEDNY, AMR technology will improve the gas actual read rate from the current overall level of 93.75% to above 98% and provide monthly, rather than bi-monthly actual reads for billing for the 520K customers without AMR. As a result, we anticipate a monthly reduction over 250K estimated bills being issued to customers.

This transformational improvement in customer service coupled with a projected annual reduction in opex costs of over $5.8M is the primary driver.

3.3 Project Description

This project provides funding for the completion of the installation of a Mobile (Drive By) AMR System for all gas meters on the KEDNY Gas Distribution System. The AMR endpoint which will be installed is planned to be the ITRON 100G device which is the latest version of the ITRON Gas AMR endpoint already in use in all other National Grid US Gas Distribution service territories.

This endpoint has increased range over the prior version (40G) and is planned to be compatible with the ITRON IPV6 Smart Grid Fixed Network System in the coming year.

The project includes the purchase of 2 additional mobile collectors, AMR Endpoints, installation labor, supervision, and clerical support. We have also included IS costs of $.5M, to support the creation of an interface between the KEDNY customer system and the ITRON Field Deployment System (FDM) currently in use in the KEDLI AMR Project.

3.4 Benefits Summary

- Improved meter reading actual read from an overall rate of 93.75% to 98%
- Decrease in FTE resources required to perform off cycle "Special Read" requests due to a higher actual read rate and monthly versus bi-monthly read schedule.
- Overall reduction in FTE resources required to perform meter reading function
- Projected Annual Opex savings of > $5.8M when fully Deployed
- Overall reduction in chronic long term estimate (LTE) accounts
- Increased ability to track advance consumption on inactive accounts
- Improved customer satisfaction due to a reduction in read to bill errors.
- Avoidance & reduction of OSHA recordables, LTIs and RTCs and associated workers compensation costs.
- Provides ability to capture hourly consumption data with 100G AMR device to support Load Research etc. programs with little or no added cost.

3.5 Business and Customer Issues

There are no significant business issues beyond what has been described elsewhere.

3.6 Alternatives

Alternative 1:

Continue Pedestrian Meter Reading

- Continued opex spend of over $5.8M per year for pedestrian meter reading
- Continued 250K estimated bills generated per month
- Continued overall read rate of 83% for pedestrian read meters (vs projected 99%)
- Continued, non-targeted AMR expansion reduces pedestrian route efficiency

This alternative is rejected as it increases Opex spend indefinitely, and provides no operational or customer benefits

Alternative 2:

Defer project

- Deferring project delays realization of potential opex savings and customer benefits detailed above

3.7 Safety, Environmental and Project Planning Issues

Project planning issues are mostly centered on deployment strategy. Deployment strategy is currently being developed with the goal of having the IS work to interface our Field Deployment Manager (FDM) system with the KEDNY customer system in place to begin deployment in the fourth quarter of FY16.

In addition, we are developing a staffing plan which will support the installation project within the specified timeline (24 months) while beginning to achieve our opex reduction targets.
For the purposes of the development of this strategy, we have considered the current budgeted Gas resources will remain and are currently developing a roll out strategy which will allow that workforce to continue manual reads for all meters not fitted with

US Sanction Paper

nationalgrid

AMR technology during deployment. We believe this is achievable if the project is approved within the time frame indicated in Section 1.6 (Key Milestones) of this paper.

3.8 Execution Risk Appraisal

Number	Detailed Description of Risk / Opportunity	Probability	Impact		Score		Strategy	Pre-Trigger Mitigation Plan	Residual Risk	Post Trigger Mitigation Plan
			Cost	Schedule	Cost	Schedule				
1	Purchase Orders for project not issued in accordance with project timeline	1	1	1	1	1	Accept			
2	Qty of installed AMR equipment falls short of 2018 Target	2	3	2	6	[illegible]	Mitigate	Develop Strategy to minimize/optimize installation plan	Monitor Installation progress during project	Adjust In-house resources as needed to meet targeted installation
3	Customer rejection of AMR Technology	3	3	5	9	15	Mitigate	Develop Customer Outreach Program to socialize benefits of AMR Program	Develop communications plan for Call Center to communicate positives of the project with concerned customers	Work with Regulatory to develop "Opt Out" option for next KEDNY Rate Case
4										
5										
6										
7										
8										
9										
10										

3.9 Permitting

N/A

3.10 Investment Recovery

3.10.1 Investment Recovery and Regulatory Implications

Investment recovery will be through standard rate recovery mechanisms approved by appropriate regulatory agencies.

3.10.2 Customer Impact

AMR technology will improve the gas actual read rate for the 520K pedestrian read meters from the current level of 83% to above 99% and provide monthly, rather than bi-monthly actual reads for billing.

US Sanction Paper

nationalgrid

The 100G ERT technology will position KEDNY to deploy advanced fixed network technologies thus enabling the creation of beneficial rate structures.

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $6.59M. This is indicative only. The actual revenue requirement will differ depending upon the timing of the next rate case and/or the timing of the next filing in which the project is included in rate base.

3.10.3 CIAC / Reimbursement

		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	Prior Yrs	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	Total
CIAC/Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

3.11 Financial Impact to National Grid

3.11.1 Cost Summary Table

					Current Planning Horizon						
					Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
C067854	KEDNY AMR Deployment	Est Lvl (e.g. +/- 10%)	CapEx	0.000	6.832	16.033	9.197	0.000	0.000	0.000	32.062
			OpEx	0.000	0.230	0.410	0.410	0.000	0.000	0.000	1.050
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	7.062	16.443	9.607	0.000	0.000	0.000	33.112
Total Project Sanction			CapEx	0.000	6.832	16.033	9.197	0.000	0.000	0.000	32.062
			OpEx	0.000	0.230	0.410	0.410	0.000	0.000	0.000	1.050
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	7.062	16.443	9.607	0.000	0.000	0.000	33.112

US Sanction Paper

nationalgrid

3.11.2 Project Budget Summary Table

Project Costs per Business Plan

$M	Prior Yrs (Actual)	Current Planning Horizon Yr. 1 2015/16	Yr. 2 2016/17	Yr. 3 2017/18	Yr. 4 2018/19	Yr. 5 2019/20	Yr. 6 + 2020/21	Total
CapEx	0.000	0.000	0.000	10.245	17.563	4.390	0.000	32.198
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	0.000	0.000	10.245	17.563	4.390	0.000	32.198

Variance (Business Plan-Project Estimate)

$M	Prior Yrs (Actual)	Current Planning Horizon Yr. 1 2015/16	Yr. 2 2016/17	Yr. 3 2017/18	Yr. 4 2018/19	Yr. 5 2019/20	Yr. 6 + 2020/21	Total
CapEx	0.000	(6.832)	(16.033)	1.048	17.563	4.390	0.000	0.136
OpEx	0.000	(0.230)	(0.410)	(0.410)	0.000	0.000	0.000	(1.050)
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	(7.062)	(16.443)	0.638	17.563	4.390	0.000	(0.914)

3.11.3 Cost Assumptions

- AMR Equipment costs per current contracts
- FTE Labor Costs per FY16 Actuals including loadings
- Future FTE Costs include inflation for current GWI (2.5%)
- Additional requirements are estimated using historical manual meter reading data
- Incremental back office costs to support project have been projected based on similar historical values

3.11.4 Net Present Value / Cost Benefit Analysis

3.11.4.1 NPV Summary Table

This is not an NPV Project

3.11.4.2 NPV Assumptions and Calculations

This is not an NPV Project

US Sanction Paper

nationalgrid

3.11.5 Additional Impacts

None

3.12 Statements of Support

3.12.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Department	Individual	Responsibilities
Investment Planner	Roden, Thomas	Endorses relative to 5-year business plan or emergent work
Resource Planning	Buckleman, Brian	Endorses Resources, cost estimate, schedule, and Portfolio Alignment
Project Management	Fortier, Joseph Jr.	Endorses Resources, cost estimate, schedule

3.12.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Function	Individual
Finance	Fowler, Keith Horowitz, Philip
Regulatory	Zschokke, Peter Gavilondo, Carlos
Jurisdictional Delegate	Brown, Laurie
Procurement	Curran, Art
Control Center	Metzdorff, Peter

4 Appendices

4.1 Sanction Request Breakdown by Project

N/A

4.2 Other Appendices

None

US Sanction Paper

4.3 NPV Summary

N/A

4.4 Customer Outreach Plan

Appropriate plans will be developed to communicate how NGRID services will be changing and what KEDNY customers can expect from the transition to AMR. Benefits of AMR will include the elimination of estimated bills and the need to provide premise access every cycle in order to obtain an actual read. Communications also will include information on the proven safety and reliability of AMR.

Initially communication channels will include bill messages and inserts, website updates, and news media articles and possibly first class mailings. As deployment begins, more targeted proactive communications will be delivered to customers selected for conversion in specific neighborhoods. Roll out plans and progress updates will be shared with the call center so telephone agents are kept informed in order to respond to customer questions.

It is recommended that at the conclusion of deployment, the Company place news briefings in popular media outlets to recap the ongoing benefits of AMR to customers

The communication plan will be developed in coordination with CMS, Customer Relations, Public Affairs and the NYS Jurisdictional team.

Short Form Sanction Paper

nationalgrid

Title:	FY17 Purchase Misc Capital Tools & Equipment - KEDNY	**Sanction Paper #:**	USSC-16-042
Project #:	CNCC501, CNSC501, CNNC501, CNFC501	**Sanction Type:**	Sanction
Operating Company:	The Brooklyn Union Gas Co.	**Date of Request:**	February 9, 2016
Author:	James Thompson	**Sponsor:**	Robert De Marinis – VP Maintenance & Construction NY
Utility Service:	Gas	**Project Manager:**	James Thompson

1 Executive Summary

1.1 Sanctioning Summary

This paper requests sanction of project numbers CNCC501, CNSC501, CNNC501 and CNFC501 in the amount $ 3.168M and a tolerance of +/- 10% for the purposes of full implementation.

This sanction amount of $3.168M is broken down as follows:
- $3.168M Capex
- $0.000M Opex
- $0.000M Removal

1.2 Project Summary

Purchase Miscellaneous Capital Tools and Equipment in FY17 that are not used for specific projects. These items support the safe, efficient and on-going day-to-day operations of the gas business unit.

2 Project Detail

2.1 Background

Current Company policy capitalizes general tool and/or equipment purchases subject to predetermined minimum dollar thresholds ($500 for The Brooklyn Union Gas Company). Such general equipment includes tooling (hand, power, pneumatic, hydraulic, etc.), specialty equipment, PPE, office machines, electronic data processing equipment and software applications, shop and garage equipment and communications. The Purchase Miscellaneous Capital Tools and Equipment line item captures the above mentioned items that are not used for specific projects but rather support the safe, efficient and on-going day-to-day operations of the gas business unit.

Short Form Sanction Paper

nationalgrid

Purchase of miscellaneous Capital Tools and Equipment are blanket project numbers that are budgeted based on historical funding due to the inability to associate this equipment with any one specific project.

2.2 Drivers

Maintenance of on-going operations to ensure safety, compliance and commitments to customer needs and expectations are the primary drivers. This budget item is typically used to assure that process related initiatives and subsequent goals are achieved. Funds from this budget line item support significant tasks that support the entire Gas organization. These items relate to safety (e.g. mechanized maintenance of traffic devices, worker safety enhancements etc.), climate change (e.g. apparatus to minimize emissions through natural gas drawdown operations), support of new, emerging and on-going technologies (e.g. capital spares and parts for trenchless and keyhole technologies) and initiation of innovative applications of core technologies that will lead to improved operations.

2.3 Project Description

Purchase Miscellaneous Capital Tools and Equipment that are not used for specific projects but rather support the safe, efficient and on-going day-to-day operations of the gas business unit.

2.4 Benefits

The budget line items support our on-going ability to provide timely service to Customers.

2.5 Business & Customer Issues

There are no significant business and customers issues beyond what has been described elsewhere

2.6 Alternatives

Alternative 1: Reduce Request – not recommended
Reducing the budget line item is not recommended because funds allocated here drive process changes that support new initiatives and productivity improvements throughout Gas distribution organization.

Short Form Sanction Paper

nationalgrid

2.7 Investment Recovery

Investment recovery will be through standard rate recovery mechanisms.

2.7.1 Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $0.651M. This is indicative only. The actual revenue requirement will differ, depending upon the timing of the next rate case and/or the timing of the next filing in which the project is included in rate base.

3 Related Projects, Scoring, Budgets

3.1 Summary of Projects

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
CNCC501, CNSC501, CNNC501, CNFC501		Purchase Misc. Capital Tools & Equipment	3.168
		Total	3.168

3.2 Associated Projects

N/A

3.3 Prior Sanctioning History

N/A

3.4 Category

Category	Reference to Mandate, Policy, NPV, or Other
○ Mandatory ⦿ Policy- Driven ○ Justified NPV ○ Other	

Short Form Sanction Paper

3.5 Asset Management Risk Score

Asset Management Risk Score: 36

Primary Risk Score Driver: (Policy Driven Projects Only)

⦿ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven

3.6 Complexity Level

○ High Complexity ○ Medium Complexity ⦿ Low Complexity ○ N/A

Complexity Score: 15

3.7 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
June 2017	Project closure

4 Financial

4.1 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY17 – FY21 Capital Plan - Gas	⦿ Yes ○ No	○ Over ○ Under ⦿ NA	$0.000 M

4.1.1 If cost > approved Business Plan how will this be funded?

N/A

4.2 CIAC / Reimbursement

Short Form Sanction Paper

nationalgrid

N/A

4.3 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend	Prior Yrs	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CLCC501	Purchase Misc Capital Tools & Equipment	+/- 10%	CapEx	-	3.168	-	-	-	-	-	3.168
CLSC501			OpEx	-	-	-	-	-	-	-	-
CLNC501			Removal	-	-	-	-	-	-	-	-
CLFC501			Total	-	3.168	-	-	-	-	-	3.168

4.4 Project Budget Summary Table

Project Costs Per Business Plan

$M	Prior Yrs (Actual)	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	3.168	0.000	0.000	0.000	0.000	0.000	3.168
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	3.168	0.000	0.000	0.000	0.000	0.000	3.168

Variance (Business Plan-Project Estimate)

$M	Prior Yrs (Actual)	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

5 Key Milestones

Milestone	Target Date: (Month/Year)
Project Sanction	February 2016
Project Close	June 2017

6 Statements of Support

6.1.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Role	Individual	Responsibilities
Investment Planner	Roden, Thomas	Endorse relative to 5 yr business plan or emergent work
Resource Planning	Buckleman, Brian	Endorses Resources, cost estimate, schedule, and Portfolio Alignment
Project Management	Fortier, Joseph Jr	Endorses Resources, cost estimate, schedule

6.1.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Reviewer List	Individual
Finance	Keith Fowler, Philip Horowitz
Regulatory	Peter Zschokke, Carlos Gavilondo
Jurisdictional Delegate Gas - NY	Laurie Brown
Procurement	Arthur Curran
Control Center	Peter Metzdorff

6.1.3 List References

N/A

Short Form Sanction Paper

nationalgrid

7 Decisions

(a) APPROVE this paper and the investment of $3.168M and a tolerance of +/-10%

(b) NOTE that James Thompson is the Project Manager and has the approved financial delegation.

(c) NOTE: In the event that any Blanket projects are not approved prior to the start of the FY2018 fiscal year, the FY2017 approval limits will remain in effect until such time as the FY2018 blanket projects are approved by USSC and/or other appropriate authority for approval.

Signature..Date. 3/16/2016

Executive Sponsor – Ross Turrini, SVP, Gas Process & Engineering

7

8 Other Appendices

N/A

8.1 Sanction Request Breakdown by Project

N/A

Short Form Sanction Paper

nationalgrid

Title:	FY17 Purchase Misc Capital Tools & Equipment - KEDLI	**Sanction Paper #:**	USSC-16-041
Project #:	CLCC501, CLSC501, CLNC501, CLFC501	**Sanction Type:**	Sanction
Operating Company:	KeySpan Gas East Corp.	**Date of Request:**	February 9, 2016
Author:	James Thompson	**Sponsor:**	Robert De Marinis – VP Maintenance & Construction NY
Utility Service:	Gas	**Project Manager:**	James Thompson

1 Executive Summary

1.1 Sanctioning Summary

This paper requests sanction of project numbers CLCC501, CLSC501, CLNC501 and CLFC501 in the amount $1.7M and a tolerance of +/- 10% for the purposes of full implementation.

This sanction amount of $1.700M is broken down as follows:
- $1.700M Capex
- $0.000M Opex
- $0.000M Removal

1.2 Project Summary

Purchase Miscellaneous Capital Tools and Equipment in FY17 that are not used for specific projects. These items support the safe, efficient and on-going day-to-day operations of the gas business unit.

2 Project Detail

2.1 Background

Current Company policy capitalizes general tool and/or equipment purchases subject to predetermined minimum dollar thresholds ($500 for Keyspan Energy East Corp). Such general equipment includes tooling (hand, power, pneumatic, hydraulic, etc.), specialty equipment, PPE, office machines, electronic data processing equipment and software applications, shop and garage equipment and communications. The Purchase Miscellaneous Capital Tools and Equipment line item captures the above mentioned items that are not used for specific projects but rather support the safe, efficient and on-going day-to-day operations of the gas business unit. Purchase of miscellaneous

Short Form Sanction Paper

nationalgrid

Capital Tools and Equipment are blanket project numbers that are budgeted based on historical funding due to the inability to associate this equipment with any one specific project.

2.2 Drivers

Maintenance of on-going operations to ensure safety, compliance and commitments to customer needs and expectations are the primary drivers. This budget item is typically used to assure that process related initiatives and subsequent goals are achieved. Funds from this budget line item support significant tasks that support the entire Gas organization. These items relate to safety (e.g. mechanized maintenance of traffic devices, worker safety enhancements etc.), climate change (e.g. apparatus to minimize emissions through natural gas drawdown operations), support of new, emerging and on-going technologies (e.g. capital spares and parts for trenchless and keyhole technologies) and initiation of innovative applications of core technologies that will lead to improved operations.

2.3 Project Description

Purchase Miscellaneous Capital Tools and Equipment that are not used for specific projects but rather support the safe, efficient and on-going day-to-day operations of the gas business unit.

2.4 Benefits

The budget line items support our on-going ability to provide timely service to Customers.

2.5 Business & Customer Issues

There are no significant business and customers issues beyond what has been described elsewhere

2.6 Alternatives

Alternative 1: Reduce Request – not recommended
Reducing the budget line item is not recommended because funds allocated here drive process changes that support new initiatives and productivity improvements throughout Gas distribution organization.

Short Form Sanction Paper

nationalgrid

2.7 Investment Recovery

Investment recovery will be through standard rate recovery mechanisms.

2.7.1 Customer Impact

This project results in an indicative first full year revenue requirement when the asset is placed in service equal to approximately $0.349M. This is indicative only. The actual revenue requirement will differ, depending upon the timing of the next rate case and/or the timing of the next filing in which the project is included in rate base.

3 Related Projects, Scoring, Budgets

3.1 Summary of Projects

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
CLCC501, CLSC501, CLNC501, CLFC501		Purchase Misc Capital Tools & Equipment	1.700
		$	1.700

3.2 Associated Projects

N/A

3.3 Prior Sanctioning History

N/A

3.4 Category

Category	Reference to Mandate, Policy, NPV, or Other
O Mandatory ⦿ Policy- Driven O Justified NPV O Other	

Short Form Sanction Paper

nationalgrid

3.5 Asset Management Risk Score

Asset Management Risk Score: 36

Primary Risk Score Driver: (Policy Driven Projects Only)

⦿ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven

3.6 Complexity Level

○ High Complexity ○ Medium Complexity ⦿ Low Complexity ○ N/A

Complexity Score: 15

3.7 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
June 2017	Project closure

4 Financial

4.1 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
FY17 – FY21 Capital Plan - Gas	⦿ Yes ○ No	○ Over ○ Under ⦿ NA	$0.000 M

4.1.1 If cost > approved Business Plan how will this be funded?

N/A

4.2 CIAC / Reimbursement

Short Form Sanction Paper

N/A

4.3 Cost Summary Table

Project Number	Project Title	Project Estimate Level (%)	Spend	Prior Yrs	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CLCC501 CLSC501 CLNC501 CLFC501	Purchase Misc Capital Tools & Equipment	+/- 10%	CapEx	-	1.700	-	-	-	-	-	1.700
			OpEx	-	-	-	-	-	-	-	-
			Removal	-	-	-	-	-	-	-	-
			Total	-	1.700	-	-	-	-	-	1.700

4.4 Project Budget Summary Table

Project Costs Per Business Plan

$M	Prior Yrs (Actual)	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	1.700	0.000	0.000	0.000	0.000	0.000	1.700
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	1.700	0.000	0.000	0.000	0.000	0.000	1.700

Variance (Business Plan-Project Estimate)

$M	Prior Yrs (Actual)	Current Planning Horizon ($M) Yr. 1 2016/17	Yr. 2 2017/18	Yr. 3 2018/19	Yr. 4 2019/20	Yr. 5 2020/21	Yr. 6 + 2021/22	Total
CapEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

5 Key Milestones

Milestone	Target Date: (Month/Year)
Project Sanction	February 2016
Project Close	June 2017

Short Form Sanction Paper

nationalgrid

6 Statements of Support

6.1.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Role	Individual	Responsibilities
Investment Planner	Roden, Thomas	Endorse relative to 5 yr business plan or emergent work
Resource Planning	Buckleman, Brian	Endorses Resources, cost estimate, schedule, and Portfolio Alignment
Project Management	Fortier, Joseph Jr	Endorses Resources, cost estimate, schedule

6.1.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Reviewer List	Individual
Finance	Keith Fowler, Philip Horowitz
Regulatory	Peter Zschokke, Carlos Gavilondo
Jurisdictional Delegate Gas - NY	Laurie Brown
Procurement	Arthur Curran
Control Center	Keith Rooney

6.1.3 List References

N/A

Short Form Sanction Paper

nationalgrid

7 Decisions

(a) APPROVE this paper and the investment of $1.700M and a tolerance of +/-10%

(b) NOTE that James Thompson is the Project Manager and has the approved financial delegation.

(c) NOTE: In the event that any Blanket projects are not approved prior to the start of the FY2018 fiscal year, the FY2017 approval limits will remain in effect until such time as the FY2018 blanket projects are approved by USSC and/or other appropriate authority for approval.

Signature..Date...3/15/2016.........

Executive Sponsor – Ross Turrini, SVP, Gas Process & Engineering

Short Form Sanction Paper

nationalgrid

8 <u>Other Appendices</u>

N/A

8.1 Sanction Request Breakdown by Project

N/A

KeySpan Gas East Corporation
d/b/a National Grid
The Brooklyn Union Gas Company
d/b/a/ National Grid NY
16-G-0058 16-G-0059
Attachment 5 to DPS-329 MT-3 BULI-286

KEDNY AMR INSTALLATION (NON-INFRASTRUCTURE)			
Category	**CY'17 Capital Plan**	**CY'18 Capital Plan**	**CY'19 Capital Plan**
AMR Installation	$ 15,821	$ 7,065	$ 600
Number of Units	259,000	115000	9800
Material	$ 10,360,000	$ 4,600,000	$ 392,000
Labor	$ 5,459,720	$ 2,424,200	$ 206,584
Total	$ 15,819,720	$ 7,024,200	$ 598,584

KEDNY AMR REPLACEMENT			
Category	**CY'17 Capital Plan**	**CY'18 Capital Plan**	**CY'19 Capital Plan**
AMR Installation	$ 5,078	$ 5,225	$ 5,330
Material	$ 3,234,000	$ 3,314,850	$ 3,397,721
Labor	$ 1,844,000	$ 1,890,100	$ 1,937,353
Total	$ 5,078,000	$ 5,204,950	$ 5,335,074

KEDLI AMR INSTALLATION / REPLACEMENT (NON-INFRASTRUCTURE)			
Category	**CY'17 Capital Plan**	**CY'18 Capital Plan**	**CY'19 Capital Plan**
AMR Installation/Replacements	$ 835	$ 855	$ 873
Material (12000 units)	$ 475,000	$ 486,875	$ 496,613
Labor (field replacments of new or damaged units included above)	$ 360,000	$ 369,000	$ 376,380
Total	$ 835,000	$ 855,875	$ 872,993

Date of Request: March 22, 2016 DPS Request No. DPS-332 JS-1
Due Date: April 1, 2016 KEDNY/ KEDLI Req. No. BULI-289

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, John Sano

TO: National Grid, GIOP

SUBJECT: Renewable Gas Interconnections

Request:

1. Do the Companies have gas quality standards that the Companies provide to local producers of natural gas like anaerobic digester projects, landfills or other in territory gas sources? If so, provide a copy of the gas quality standards that are required.

2. Do the Companies have a standard interconnection process in place for local gas producers? If so, provide a copy of the interconnection process or agreement used.

3. What type of equipment is installed at the interconnection with local gas producers to measure gas quality?

4. What capability does such equipment have to deter gas of inferior quality from entering the distribution system?

5. Describe the process for filtering in place at an interconnection with a typical landfill gas producer.

6. How do the Companies measure heat content of gas entering its distribution system from a local gas producer?

7. Are there operational limits to how much gas can be accepted from local gas producers? If so, provide a list of and detailed explanation of the operational limits.

Response:

1. Yes, National Grid maintains gas quality guidelines for renewable natural gas ("RNG") projects (see Attachment 1). These guidelines provide developers of RNG projects with a framework in which to consider design options based on the nature of the biomass feedstock and resulting digester gas. National Grid is currently leading a collaborative in New York through the Northeast Gas Association to develop a standardized approach for LDCs to consider introduction of RNG into gas distribution systems. The collaborative will work with developer representatives to address technical gas quality and interchangeability issues.

2. The Companies have two standard agreements that cover the interconnection process. Pursuant to an Engineering Services Agreement, National Grid will perform a technical evaluation for the RNG connection requests (see Attachment 2). A separate Gas Sales Agreement defines the commercial/operational arrangement for accepting gas into the distribution system (see Attachment 3). Together, these agreements provide criteria for RNG interconnection.

3. The equipment that is required for continuous quality monitoring of biomethane derived from raw biogas includes:

   - Moisture measurement equipment
   - A gas chromatograph to measure and analyze hydrocarbon and non-hydrocarbon gases, based on constituent measurement, calculated parameters such as heating value, interchangeability indices, specific gravity, hydrocarbon dew point
   - Automated sampling devices to capture samples of gas for measurement and analysis of trace constituents and other components identified in the site specific sampling/monitoring plan
   - Gas temperature, pressure monitoring equipment

4. Critical gas quality variables are monitored in real-time and process control measures (as specified in the Engineering Service Agreement and corresponding Gas Supply Agreement) are in place to facilitate remote isolation of the RNG facility from the gas distribution system. The Companies monitor these critical variables through the SCADA System and reserve the right to isolate the facility from the system upon discovery of unacceptable gas quality conditions. Site specific procedures are developed collaboratively with the RNG project developers to ensure optimized production, acceptance of the gas into the distribution system and to address safety concerns.

5. A variety of biogas clean-up technologies exist; however, these technologies must be evaluated for appropriate application at each RNG project based on a number of site specific variables, including raw gas treatment constituents and facility interconnection physical limitations (pressure and acceptable flow rates into the distribution system). These treatment systems include:

a. Solid phase absorption (raw gas is passed over the solid material to absorb constituents of concern).
b. Membrane systems utilizing selective constituent semi-permeable membrane materials that filter constituents of concern from the raw gas stream followed by regeneration once the membrane become saturated.
c. Solvent based absorption processes, which include contacting raw gas with an appropriate solvent that is capable of absorbing constituents of concern.

Most treatment systems incorporate a combination of technologies depending on the constituents of concern to be removed to meet the gas quality specifications of the LDC and are designed based of detailed raw gas analysis.

6. The Companies monitor the heating value of gas entering its system through gas chromatographs. Hydrocarbon and non-hydrocarbon constituents are identified, and a software program is used to calculate heating value consistent with ASTM standards.

7. The Companies evaluate site specific interconnection variables to ensure the anticipated production volumes can be accommodated within the distribution system. It is the Companies' policy not to offer pairing services (commercial blending services) for these facilities as dilution of non-conforming gases cannot be relied on to ensure system safety. Gas entering the distribution system is expected to be pre-treated such that processed gas is similar in composition and characteristics of pipeline gas at the specified connection point within the distribution system. National Grid's gas quality guidelines are included in Attachment 1.

<u>Name of Respondent</u>: Robert Wilson

<u>Date of Reply</u>: March 31, 2016

RNG DEVELOPMENT & ACCEPTANCE GUIDELINES FOR PIPELINE QUALITY GAS

Raw biogas shall be appropriately treated utilizing industry acceptable practices and treatment systems acceptable to National Grid to ensure reliability in meeting the following gas quality guidelines:

(1) Gas shall be of composition and quality to ensure safe, reliable operation of the distribution system and be capable of direct utilization by distribution system customers without further treatment or blending/aggregation by National Grid, and,

(2) Commercially free of objectionable matter as defined in latest edition of **AGA Report 4A - Natural Gas Contract Measurement and Quality Clauses** including, but not limited to, trace constituents such as bacteria and other particulate matter, liquids, dust, gums, tars, volatile metals, siloxanes, VOC's, SVOC's, PCB's and other hazardous constituents that interfere with merchantability of pipeline natural gas, and

(3) Completely interchangeable with flowing pipeline gas common to the National Grid distribution system.

In addition, it shall meet the specifications set forth below.

Value	**Minimum Acceptable**	**Preferred (Normal Operations)**
HHV (dry @ 14.73 psia)	975 Btu/Scf	980 Btu/Scf
Wobbe Number	1280	1290
Constituent	**Maximum**	**Preferred**
CO_2	2%	As low as practical
N_2	2.50%	As low as practical
Total Inerts ($N_2 + CO_2$)	4%	As low as practical
Total Sulfur (Incl. contributions from naturally occurring mercaptans)	< 1 ppm	As low as practical
H_2S	< 0.25 grains/100cf (4 ppm)	As low as practical
O_2	< 0.2%	As low as practical
Moisture Content	< 7 lbs/mmcf	As low as practical
Temperature	100 ^{O}F	-

Draft 6/18/15

SAMPLE
ENGINEERING SERVICES REIMBURSEMENT AGREEMENT

THIS ENGINEERING SERVICES REIMBURSEMENT AGREEMENT ("*Agreement*"), effective as of this [____] day of [________] ("*Effective Date*"), is by and between [____________] ("*Customer*"), a [____________] organized and existing under the laws of [____________], and KeySpan Gas East Corporation d/b/a National Grid ("*Company*"), a corporation organized and existing under the laws of the State of New York.

WHEREAS, Customer is proposing to build an anaerobic digester within a landfill located in [____], New York that will recover methane gas from organic food waste to be burned on site to generate electricity, with excess gas to be sent to Company's natural gas distribution system (the "*Project*"); and

WHEREAS, Customer desires to have Company perform certain engineering services (as specified below) in connection with the Project, and Company has agreed to perform such services upon the terms and conditions set forth below;

NOW, THEREFORE, in consideration of the mutual promises and covenants contained herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties entering into this Agreement (each a "*Party*", and collectively, the "*Parties*"), with the intent to be bound, agree as follows:

ARTICLE I – SERVICES

Section 1 - Scope of Services

Company will perform those services specified in Exhibit A attached hereto and hereby incorporated herein ("*Services*"). No goods, equipment, or materials will be provided under this Agreement.

This Agreement does not provide for generation interconnection service, procurement of equipment, installation or construction, or transmission service.

Section 2 - Customer's Responsibilities

Customer shall provide:

1. Complete and accurate information regarding requirements for Services, including, without limitation, constraints, space requirements and relationships, special equipment, systems, site requirements, underground or hidden facilities and structures, and all applicable drawings and specifications;

2. If and to the extent applicable, Company access to the site where Services will be performed;

3. A project manager who will be given the authority to coordinate all aspects of the Project between Customer and Company;

4. If and to the extent applicable, adequate parking for the vehicles of Company personnel performing the Services; and

5. Other responsibilities and access deemed necessary by, and in the sole discretion of, Company to facilitate performance of the Services.

Customer shall reasonably cooperate with Company as required to facilitate Company's performance of the Services. Other express Customer responsibilities, if any, shall be as specified in Exhibit A attached hereto.

Anything in this Agreement to the contrary notwithstanding, Company shall have no responsibility or liability under this Agreement for any defective performance or nonperformance to the extent such defective performance or nonperformance is caused by the inability or failure of (i) Customer to cooperate or to perform any of the tasks or responsibilities contemplated to be performed or undertaken by Customer in Exhibit A or elsewhere in this Agreement, or (ii) Customer and Company to reach agreement on any matter requiring their mutual agreement as contemplated in Exhibit A or elsewhere in this Agreement.

Section 3 - Unknown Conditions

Customer represents, warrants and covenants that all information provided by Customer is accurate and complete and acknowledges and agrees that Company may and will rely on this representation, warranty and covenant in performing under this Agreement. If, as a result of additional, different, or previously unknown information, any changes in Services are required that will result in an increase or decrease in the cost or time of performance under the Agreement, the Price, schedule and other affected provisions of this Agreement shall be equitably adjusted and this Agreement shall be amended in writing to memorialize such changes.

Section 4 - Changes and Extras

Customer may request changes in Services in writing. If any such changes will result in an increase or decrease in the cost or time of performance under this Agreement, the Price, schedule and other affected provisions of the Agreement shall be equitably adjusted and this Agreement shall be amended in writing to memorialize such changes. Company may make changes in Services with the prior written approval of Customer (which approval shall not be unreasonably withheld, conditioned, or delayed).

Section 5 - Governmental Requirements

Changes in Services may be necessary in order to meet the requirements of governmental authorities, laws, regulations, ordinances, Good Utility Practice (as such term is defined in

Article V, Section 1, below) and/or codes. After Customer's approval (which shall not be unreasonably withheld, conditioned, or delayed), Company will make changes in Services as it deems necessary, in its sole discretion, to conform to such requirements. If any such changes will result in an increase or decrease in the cost or time of performance under this Agreement, the Price, schedule and other affected provisions of this Agreement shall be equitably adjusted and this Agreement shall be amended in writing to memorialize such changes. If Customer withholds its approval, and in Company's sole and exclusive judgment the withholding of approval by Customer is not reasonable, then, at Company's election, this Agreement may be immediately terminated upon written notice to Customer. Nothing in this Agreement shall relieve Customer of the responsibility to comply with requirements of ISO-NE or other utilities with regard to the Project and the Services.

ARTICLE II – PRICE, TAXES, AND PAYMENT

Section 1 - Price

The price for the Services to be paid by Customer shall be the actual costs and expenses incurred by the Company and its affiliates in connection with performance of the Services or otherwise incurred by Company in connection with this Agreement, and shall include, without limitation, any such costs that may have been incurred by Company prior to the Effective Date (the "*Price*").

The Price shall include, without limitation, the actual costs and expenses for the following to the extent incurred in connection with performance of the Services: labor (including, without limitation, internal labor); materials; subcontracts; equipment; travel, lodging, and per diem paid in accordance with Company policy; copying and reproduction of materials, overnight delivery charges, certified mailing charges, first class mailing charges and similar types of incidental charges; transportation; carrying charges and surcharges; all applicable overheads including an Administrative and General (A&G) expense charge at Company's current rate at the time of invoicing; all federal, state and local taxes incurred; all costs and fees of outside experts, consultants, counsel and contractors; all other third-party fees and costs; and all costs of obtaining any required consents, releases, approvals, or authorizations. All invoiced sums will include applicable expenses, surcharges, and federal, state and local taxes.

If Customer claims exemption from sales tax, Customer agrees to provide Company with an appropriate, current and valid tax exemption certificate, in form and substance satisfactory to Company, relieving Company from any obligation to collect sales taxes from Customer ("*Sales Tax Exemption Certificate*"). During the term of this Agreement, Customer shall promptly provide Company with any modifications, revisions or updates to the Sales Tax Exemption Certificate or to Customer's exemption status. If Customer fails to provide an acceptable Sales Tax Exemption Certificate for a particular transaction, Company shall add the sales tax to the applicable invoice to be paid by Customer.

Draft 6/18/15

Section 2 – Payment

Customer shall provide Company with an initial prepayment in the amount of twenty thousand US dollars ($20,000.00) ("*Initial Prepayment*"). Company shall not be obligated to commence performance of Services until it has received the Initial Prepayment. If, during the performance of the Services, Company determines that one or more additional prepayments are required before completing the Services, Company may, but is not required to, request additional prepayment from Customer; any such requests will be in writing. If an additional prepayment is requested and is not received from Customer on or before the date specified in each such request, or if no date is specified, within 30 days of receipt of the written request, Company may cease work upon the depletion of the Initial Prepayment and any other prepayments made by Customer to date, as applicable. Upon Company's receipt of the additional requested prepayment from Customer (such prepayment to be additional to the Initial Prepayment and any other prepayments made by Customer to date), Company will continue to perform the Services. The Initial Prepayment and the additional prepayments (if any) represent estimates only.

Company is not required to request additional prepayments from Customer and may elect, in its sole discretion, to continue performing Services hereunder after the depletion of the Initial Prepayment, or any other prepayments made by Customer to date, as applicable, without additional prepayments and invoice Customer for such Services at a later date. Customer shall be responsible to pay Company the total Price for completing the Services actually performed by Company whether or not any additional prepayments were made at Company's request. Any election by Company to seek or defer additional prepayments in one instance shall not obligate the Company to seek or defer additional prepayments in any other instance.

Company will invoice Customer for all sums owed under this Agreement. With the exception of additional prepayments required under the first paragraph of this Section 2 of Article II, in which case the due date provided in such paragraph shall apply, payment shall be due in full within thirty (30) days of Company's submittal of an invoice, without regard to claims or off-sets. Payment shall be made in immediately available funds transmitted by the method specified in the invoice. A continuing late payment charge of 1.5% per month will be applied on any late payments.

If Company's Price for completing the Services is less than the Initial Prepayment plus any such additional prepayments paid by Customer under this Article ("*Total Prepayment*"), Company will refund the remaining unused portion of the Total Prepayment to Customer.

ARTICLE III - SCHEDULE, DELAYS, AND FORCE MAJEURE

Company will use reasonable efforts to commence the Services promptly following its receipt of all of the following: a fully executed Agreement, the Initial Prepayment, and all information required by this Agreement to be supplied by Customer prior to commencement of the Services.

If Company's performance of the Agreement is delayed by Customer, an equitable adjustment shall be made for any increase in the cost and/or time of performance caused by the delay.

Any delays in, or failure of, performance by Customer or Company, other than payment of monies, shall not constitute default and shall be excused hereunder, if and to the extent such delays or failures of performance are caused by occurrences beyond the reasonable control of Customer or Company, as applicable, including, but not limited to, acts of God, Federal and/or state law or regulation, sabotage, explosions, acts of terrorism, unavailability of personnel, equipment, supplies, or other resources for utility-related duties, delays by governmental authorities in granting licenses, permits or other approvals necessary in connection with Services, compliance with any order or request of any governmental or judicial authority, compliance with Company's public service obligations, storms, fires, inclement or adverse weather, floods, riots or strikes or other concerted acts of workers, and accidents.

ARTICLE IV – INTELLECTUAL PROPERTY

Any drawings, specifications or other documents (i) prepared or used by Company, or (ii) prepared by Customer for Company in connection with this Agreement, shall be the proprietary, confidential information and sole property of Company at no cost to Company (collectively "*Materials*").

Excluding third-party owned documents and software, Customer is granted an irrevocable, nontransferable, and non-assignable license to use such Materials solely in connection with the Project. No commercialization of such Materials by Customer is authorized. Customer shall not disclose any of the Materials to any third party, in whole or in part, without the prior written consent of Company.

The obligations imposed by this Article IV shall survive the completion, cancellation, or termination of this Agreement.

ARTICLE V – PERFORMANCE

Section 1 -- Performance.

Company shall perform the Services in a manner consistent with "Good Utility Practice" (as such term is defined below); provided, however, that Company shall have no responsibility or liability in connection with (i) any items or services provided by Customer or its third party contractors or representatives whether or not such items or services are incorporated in the Services, (ii) any items or services provided, manufactured or licensed by third parties whether or not such items or services are incorporated in the Services, or (iii) any defects in Services that result from the acts or omissions of persons other than Company or accidents not caused by Company.

Draft 6/18/15

"*Good Utility Practice*" shall mean the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any practices, methods and acts which, in the exercise of good judgment in light of the facts known at the time the decision was made**,** would have been reasonably expected to accomplish the desired result consistent with good business practices, safety, and law. Good Utility Practice is not intended to require or contemplate the optimum practice, method or act, to the exclusion of all others, but rather to be reasonably acceptable practices, methods, or acts generally accepted in the region in which the Services are to be performed.

Prior to the expiration of one (1) year following the date of completion of a Service, Customer shall have the right to give Company written notice that some or all of such Service was not performed in compliance with the first paragraph of this Section 1, and the Company shall, at the option of Company, either (i) re-perform or repair the defective portion of such Service, or (ii) refund the amount of money paid by the Customer to Company attributable to the defective portion of such Service. The remedy set forth in this Section 1 of Article V is the sole and exclusive remedy granted to Customer for any failure of Company to meet the performance standards or requirements set forth in this Agreement.

ARTICLE VI – INSURANCE

From the commencement of the Agreement through its expiration, each Party shall provide and maintain, at its own expense, insurance policies issued by reputable insurance companies with an A. M. Best rating of at least B+ (collectively, the "*Required Insurance Policies*"). The Required Insurance Policies shall, at a minimum, include the following coverages and limitations:

Workers' Compensation and Employers Liability Insurance, as required by the State in which the work activities under this Agreement will be performed. If applicable, coverage will include the U.S. Longshoremen's & Harbor Workers' Compensation Act, and the Jones Act. If a Party is a qualified self-insurer by the State, Excess Workers' Compensation coverage shall be maintained in lieu of the Workers' Compensation coverage.

Public Liability, including Contractual Liability and Products/Completed Operations coverage, covering all operations to be performed under this Agreement, with minimum limits of:

Bodily Injury	-	$1,000,000 per occurrence
Property Damage	-	$1,000,000 per occurrence

Automobile Liability, covering all owned, non-owned and hired vehicles used under or in connection with this Agreement, with minimum limits of:

Bodily Injury	- $500,000 per occurrence
Property Damage	- $500,000 per occurrence
OR	
Combined Single Limit	- $1,000,000 per occurrence

If requested, each Party will provide evidence to the other Party that it maintains the Required Insurance Policies required under this Article.

Either Party may elect to self-insure to the extent authorized or licensed to do so under the applicable laws of the State of New York, provided, that, the electing Party provides written notice of any such election to the other Party. Company hereby notifies Customer that it is a qualified self-insurer under the applicable laws of the State of New York and that it elects to self-insure to satisfy its obligations under this Article.

ARTICLE VII – TERM AND TERMINATION

The term of this Agreement shall expire one (1) year from the Effective Date. As of the expiration of this Agreement or, if earlier, its termination, the Parties shall no longer be bound by the terms and provisions hereof, except (a) to the extent necessary to enforce the rights and obligations of the Parties arising under this Agreement before such expiration or termination (including, without limitation, with respect to payment of all amounts due and payable hereunder), and (b) such terms and provisions that expressly or by their operation survive the termination or expiration of this Agreement.

Either Party may terminate this Agreement for convenience by delivery of written notice to the other Party, such termination to be effective on the tenth (10th) day following delivery of such written notice, or upon payment in full of all amounts due and payable hereunder, whichever is later. On or before the effective termination date of this Agreement, Customer shall pay Company all amounts due and payable as the Price for that portion of the Services performed to the effective date of termination ("*Amount Outstanding*"), including, without limitation, all costs and expenses incurred, less the Total Prepayment. In the event that the Total Prepayment exceeds the Amount Outstanding, Company shall remit the balance to Customer.

ARTICLE VIII – MISCELLANEOUS PROVISIONS

Section 1 - Assignment and Subcontracting

Customer agrees that Company has the right, but not the obligation, to (i) use the services of its affiliated companies in connection with the performance of Services, and (ii) issue contracts to third parties for, or in connection with, the performance of Services hereunder, without the prior consent of Customer, and that the costs and expenses of such affiliated companies or third parties charged or chargeable to Company shall be paid by Customer as part of the Price.

Section 2 – No Third-Party Beneficiary

Nothing in this Agreement is intended to confer on any person, other than the Parties, any rights or remedies under or by reason of this Agreement.

Draft 6/18/15

Section 3 – Amendment; Equitable Adjustments

This Agreement shall not be amended, superseded or modified, except in a writing signed by both Parties. In any circumstance in which this Agreement contemplates an equitable adjustment to Price, schedule or any other term of this Agreement, Company shall have no obligation to continue performance hereunder until and unless such equitable adjustment has been mutually agreed to by both Parties in writing.

Section 4 – Notices

Any notice given under this Agreement shall be in writing and shall be hand delivered, sent by registered or certified mail, delivered by a reputable overnight courier, or sent by facsimile with electronic confirmation of receipt, to the party's representatives as follows:

Customer:

[____________________]
Attn: [ ]
[________________]
[________________]
Phone: [_____________]
Facsimile: [__________]

Company:

KeySpan Gas East Corporation d/b/a National Grid
Attn: [ ]
[__________________]
[__________________]
Phone: [_______________]
Email: [____________________]

Section 5 - Waiver

No term of this Agreement may be waived except in a writing signed by an authorized representative of the Party against whom the amendment, modification, or waiver is sought to be enforced. Waiver of any provision herein shall not be deemed a waiver of any other provision herein, nor shall waiver of any breach of this Agreement be construed as a continuing waiver of other breaches of the same or other provisions of this Agreement.

Section 6 - Approvals

It is understood that Company may be required to obtain, regulatory, and other third-party approvals and releases in connection with the provision of the Services. If so, this

Agreement shall be effective subject to the receipt of any such approvals and releases, in form and substance satisfactory to Company in its sole discretion, and to the terms thereof.

Section 7 - Laws

This Agreement shall be interpreted and enforced according to the laws of the State of New York and not those laws determined by application of the State of New York's conflicts of law principles. Venue in any action with respect to this Agreement shall be in the State of New York; each Party agrees to submit to the personal jurisdiction of courts in the State of New York with respect to any such actions.

Section 8 - Severability

To the extent that any provision of this Agreement shall be held to be invalid, illegal or unenforceable, it shall be modified so as to give as much effect to the original intent of such provision as is consistent with applicable law and without affecting the validity, legality or enforceability of the remaining provisions of the Agreement.

Section 9 - Integration and Merger; Entire Agreement

Customer and Company each agree that there are no understandings, agreements, or representations, expressed or implied, with respect to the subject matter hereof other than those expressed herein. This Agreement supersedes and merges all prior discussions and understandings with respect to the subject matter hereof, and constitutes the entire agreement between the Parties with respect to such subject matter.

Section 10 – Authority

Each Party represents to the other that the signatory identified beneath its name below has full authority to execute this Agreement on its behalf.

Section 11 – Information and Coordination Contact

[__name, contact information________________________________], or such other representative as Company may designate, will be the point of contact for Customer to submit the information required for Company to perform the Services stated in this Agreement. [____________] or such other representative as Customer may designate, will be the point of contact for Company to request additional information from Customer, if required.

Section 12 – Counterparts

This Agreement may be executed in multiple counterparts, each of which shall be considered an original, and all of which together shall constitute one and the same agreement. The exchange of copies of this Agreement and of signature pages by facsimile or other electronic transmission (including, without limitation, by e-mailed PDF) shall constitute effective execution and delivery of this Agreement as to the Parties and may be used in lieu of the original

Agreement for all purposes. Signatures of the Parties transmitted by facsimile or other electronic means (including, without limitation, by e-mailed PDF) shall be deemed to be their original signatures for all purposes.

[Signatures are on following page.]

Draft 6/18/15

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the Effective Date.

KeySpan Gas East Corporation d/b/a National Grid

By: ______________________________________
Name:
Title:

Company Name

By: ______________________________________
Name:
Title:

Draft 6/18/15

EXHIBIT A

Scope of Services

Company's scope of Services shall be:

- Assign a Project Engineer and Project Manager to provide technical support for the Project;

- Arrange and schedule periodic Project meetings;

- Provide standards for Customer to follow in order to design metering equipment in accordance with Company specifications;

- Provide the specifications for the meters to be installed and determine the size and quantity of meters required;

- Provide technical assistance as needed by Customer in reviewing the design and layout for analytical equipment to be installed by Customer in accordance with manufacturer's recommendations;

- Provide technical assistance as needed by Customer in reviewing the design and layout for odorant equipment to be installed by Customer in accordance with applicable health and safety codes for the storage of odorant, including DEC, DEP, and Suffolk County Department of Health;

- Review drawings and specifications created by Customer for the equipment set forth below. Company reserves the right to make changes to the design in order to meet National Grid standards; and

- Provide engineering services to assist Customer in design and development of specifications for the work to purchase and install the equipment and facilities set forth below.

Equipment and Facilities Required for Project (to be provided by Customer):

- Gas service and associated metering equipment for back up supply from Company
- Gas outlet system tie-in and associated metering equipment for gas produced on site
- Remote Terminal Unit (RTU) to transmit gas quality and flow data to Company's Gas Control Room
- Gas Chromatograph (10 component) to measure BTU, inerts (CO_2, N_2), Oxygen of digester gas
- Odorant Chromatograph to measure mercaptans, total sulfur, and H_2S in the digester gas
- Moisture Meter to measure amount of H_2O in the digester gas
- Remote control valve to enable remote shut-in of Customer's outlet in cases where gas from the plant is out of specification as listed in Table below.
- Odorant injection system with sight glass diffusion probe, storage tank(s) with dike
- Gas filters with differential gages on plant outlet line

Draft 6/18/15

- Analyzer Building – prefab concrete building to house RTU and all analytical equipment with electric service and Power Conditioning, and Battery Back Up system, gas detector(s)
- Odorant Building – negative pressure concreted building to house odorant equipment with electric service and gas detector(s), charcoal filter, blower, fire suppression and monitoring equipment (as required by Town of Brookhaven Fire Marshall).

Assumptions and Conditions:

Any dates, schedules or cost estimates resulting from the Services are preliminary projections/estimates only and shall not become or give rise to any binding commitment.

The Services contemplated by this Exhibit and this Agreement do not include any construction, relocations, alterations, modifications, or upgrades with respect to any facilities ("Construction"), nor does Company make any commitment to undertake such Construction. If the Parties elect, in their respective sole discretion, to proceed with any Construction: (i) such Construction would be performed pursuant to a separate, detailed, written, and mutually acceptable Cost Reimbursement Agreement to be entered into by the Parties prior to the commencement of any such Construction, and (ii) payment of all actual costs incurred by Company or its Affiliates in connection with or related to such Construction shall be the responsibility of Customer and Customer shall reimburse Company for all such costs.

For the avoidance of doubt: This Agreement does not provide for generation interconnection service, procurement of equipment, installation or construction. The Company shall not have any responsibility for seeking or acquiring any real property rights in connection with the Services or the Project including, without limitation, licenses, consents, permissions, certificates, approvals, or authorizations, or fee, easement or right of way interests. Neither this Agreement nor the Services include securing or arranging for Customer or any third party to have access rights in, through, over or under any real property owned or controlled by the Company.

Draft 7/15/15

Sample
DIGESTER GAS SALES AGREEMENT

This Digester Gas Sales Agreement ("Agreement"), dated as of the __ day of _____, 201_ by and between KeySpan Gas East Corporation d/b/a National Grid (hereinafter referred to as "Buyer" or "Company"), a New York corporation with offices at 100 East Old Country Road, Hicksville, NY 11801 and Company Name (hereinafter referred to as "Seller"), a ____________[state] [corporation] with offices at [address] and each hereinafter referred to as a "Party" or collectively as the "Parties".

WHEREAS, Seller owns an anaerobic digester situated within a landfill located in [ ], New York that recovers digester methane gas from organic food waste exclusive of other gases from Landfill operations; and

WHEREAS, Buyer is a regulated natural gas distribution company which owns and operates a natural gas distribution system in Nassau and Suffolk counties; and

WHEREAS, Seller desires to sell and deliver Pipeline Quality Processed Digester Gas to Buyer, and Buyer desires to purchase and accept such Processed Digester Gas from Seller; and

WHEREAS, Buyer has agreed to operate and maintain certain of the facilities required in connection with the delivery of Processed Digester Gas, and Seller has agreed to reimburse Buyer for performing such operation and maintenance services; and

NOW THEREFORE, in consideration of the foregoing premises and of the mutual covenants and agreements contained herein, the Parties hereby agree as follows:

ARTICLE 1
DEFINITIONS

1.1 The term "Btu" means British Thermal unit, and shall be the quantity of heat required to raise the temperature of one (1) pound of water one degree Fahrenheit at sixty (60) degrees Fahrenheit at a pressure of 14.73 psia.

1 .2 The term "Day" means a period of twenty-four (24) consecutive hours beginning and ending at 9:00 AM Central Standard Time.

1 .3 The term "Delivery Point" shall mean the point of interconnection between the facilities of Seller and Buyer at or near the Landfill where Processed Digester Gas will be sold and delivered by Seller to Buyer under this Agreement, as shown on Exhibit "A" hereto. [Schematic drawing]

1.4 "Facilities"' means those facilities that will be maintained by the Company pursuant to this Agreement and other facilities utilized in connection with the delivery of Processed Digester Gas.

Draft 7/15/15

1.5 “Landfill” means the existing Customer Address.

1.6 The term "Maximum Daily Quantity" (or "MDQ')is the maximum amount of Processed Digester Gas that Buyer is obligated to purchase on any Day during the term of this Agreement.

1.7 The term "MMbtu" means one million Btu.

1.8 The term "Month" means a period beginning at 9:00 AM Central Standard Time on the first Day of any calendar month and ending at 9:00 AM Central Time on the first Day of the next succeeding calendar month.

1.9 The term Plant" means the digester and processing facilities operated by Seller located at the Landfill.

1.10 The term "Processed Digester Gas" means natural gas produced by Seller at the Plant.

1.11 "Services" has the meaning set forth in Article 8 of this Agreement.

1.12 “Pipeline Quality” has the meaning defined in latest version of AGA Report 4a.

ARTICLE 2
EFFECTIVE DATE AND TERM

2.1 The term of the Agreement shall commence as of the date first written above and shall remain in effect through _____________, 20__, and from month to month thereafter unless terminated by either Party on no less than thirty (30) days prior written notice to the other.

2.2 Upon the termination of this Agreement for any reason, any monies due and owing Seller or Buyer shall be paid pursuant to the terms hereof, and any corrections or adjustments to payments previously made shall be determined and made at the earliest possible time. The provisions of this Agreement shall remain in effect until the obligations under this paragraph have been fulfilled.

ARTICLE 3
SALE AND PURCHASE OBLIGATIONS

3.1 Subject to the terms and conditions of this Agreement, Seller agrees to sell and deliver, and Buyer agrees to purchase and receive, each Day during the term of this Agreement, at the Delivery Point, a quantity of Pipeline Quality Processed Digester Gas equal to the lesser of (a) the quantity of Processed Digester Gas produced by the Plant on such Day or (b) the MDQ for such Day.

3.2 As of the effective date of this Agreement, the MDQ shall be __________MMBtu.

3.3 Seller shall tender Pipeline Quality Processed Digester Gas for delivery at a substantially uniform rate of flow throughout each Day, at a minimum of 0 mdth/day and a maximum of ___ mdth/day, except that if Seller becomes aware that the rate of delivery or the total quantity of Pipeline Quality Processed Digester Gas, Seller will deliver for any Day will differ by more than twenty-five percent (25%) (positive or negative) from that achieved the previous Day, Seller shall so notify Buyer's Gas Control Center at the contact set forth in Section 13.10 below. Seller also shall notify Buyer's Gas Control Center at least twenty-four (24) hours in advance of any suspension of Processed Digester Gas deliveries under this Agreement necessitated by Seller's maintenance of its Plant.

ARTICLE 4
PRICE OF GAS

4.1 The price paid for each MMBtu of Processed Digester Gas sold and purchased under this Agreement in any Month shall be equal to the New York Mercantile Exchange (NYMEX) natural gas futures contract last day settle price for such Month.

ARTICLE 5
TITLE TO GAS

5.1 Seller hereby warrants good and merchantable title to all Pipeline Quality Processed Digester Gas delivered hereunder, free and clear of all liens, encumbrances and claims whatsoever. Seller will indemnify Buyer and hold it harmless from any and all suits, actions, debts, accounts, damages, costs, losses, and expenses arising from or out of adverse title claims of any and all persons to said Pipeline Quality Processed Digester Gas.

5.2 Title to all Pipeline Quality Processed Digester Gas received by Buyer shall pass to Buyer at the Delivery Point. As between the Parties hereto, Seller shall be deemed to be in exclusive control and possession of the Processed Digester Gas deliverable hereunder and responsible for any damage or injury caused thereby until the same shall have been delivered to Buyer at the Delivery Point; thereafter Buyer shall be deemed to be in exclusive control and possession of such gas and responsible for any damage or injury caused thereby.

ARTICLE 6
GAS PRESSURE, TEMPERATURE AND QUALITY

6.1 Seller shall tender Pipeline Quality Processed Digester Gas for delivery to Buyer under this Agreement at the Delivery Point at pressures sufficient for such Pipeline Quality Processed Digester Gas to enter Buyer's facilities at such point, but in no event in excess of the maximum allowable operating pressure on Buyer’s system which, at the time of execution of this Agreement, is 124 psig. Buyer shall promptly notify Seller of any changes in the maximum operating pressure of the Buyer's system.

6.2 Seller shall tender Pipeline Quality Processed Digester Gas for delivery to Buyer under this Agreement at the Delivery Point at a temperature no less than 40 degrees Fahrenheit and no greater than 100 degrees Fahrenheit. Should Seller tender Processed Digester Gas to Buyer at the Delivery Point at a temperature colder or warmer than such range and Buyer's meter is damaged as a result, then in addition to and without limitation of any other remedy Buyer may have, Buyer shall be entitled to receive from Seller an amount equal to Buyer's cost to repair or replace such meter and any other related equipment affected.

6.3 Seller agrees that it will exercise reasonable care and diligence in tendering Pipeline Quality Processed Digester Gas for delivery to Buyer under this Agreement, and warrants that all Pipeline Quality Processed Digester Gas when tendered for delivery to Buyer hereunder at the Delivery Point shall:

a. be compatible and interchangeable with pipeline gas as defined in 16 NYCRR 229;

b. be within the limits set forth below:

Table 1: Gas Quality Specifications

Gas Quality Specification	Low	High
BTU Content (Heat Content) [BTU/scf]	980	1100
Wobbe Number (capped @ 1400 w/ BTU of 1100)	1290	1390
Relative Density	0.56	0.60
Water Vapor Content [lb/MMscf]	-	6.5
Mercaptans (as Odorant) [lb/MMscf]	0.35	0.75
Hydrocarbon Dew Point, [°F] CHDP	-	12°F
Hydrogen Sulfide (H_2S)	-	0.5 ppmv
Total Sulfur		<1.0 ppmv
Diluent Gases	-	
Carbon Dioxide (CO_2)		2.0%
Nitrogen (N_2)		2.5%
Oxygen (O_2)		0.15%
Total Diluents		**Not to exceed 4.0%**
Hydrogen	-	0.04 vol%
Total Bacteria	-	Not Detectable
Mercury	-	Not Detectable
Other Volatile Metals (including arsenic)	-	Not Detectable
Siloxanes (D4)	-	Not Detectable
Ammonia	-	Not Detectable
Non-Halogenated Semi-Volatile and Volatile Compounds	-	Not Detectable
Halocarbons	-	Not Detectable

Draft 7/15/15

Aldehyde/Ketones	-	Not Detectable
Radon	-	<1 pci/L
PCBs	-	Not Detectable
Pesticides	-	Not Detectable

NOTES:

1. *Not-detectable for purposes of this specification is defined as a value less than the lowest detectable level for a mutually agreeable standard industry analytical test method*
2. *BTU = commonly referred to as Higher Heating Value (HHV)*
3. *Wobbe = Interchangeability parameter; ratio of BTU content to specific gravity*
4. *In addition to the specified limits above, gas received into Buyer's pipeline system shall be pipeline quality and as such remain commercially free of objectionable materials and merchantable as defined in latest edition of AGA Report 4A "Natural Gas Contract Measurement and Quality Clauses"*

c. be monitored as to conformity with all of the foregoing criteria by manual test or by mutually acceptable continuous monitoring equipment; and Buyer will require quarterly random grab sampling to ensure gas is free of objectionable materials with analytical costs to be reimbursed by the Seller.

6.4 Seller shall maintain in good working order its facilities at the Plant that enable it to ensure that the pressure, temperature and quality of the Pipeline Quality Processed Digester Gas it tenders for delivery under this Agreement fully conform with the criteria set forth in this Agreement.

6.5 In addition to any and all other remedies that it may have, Buyer shall have the right to reject as non-conforming any Processed Digester Gas Seller tenders for delivery under this Agreement that fails to comply with the pressure, temperature or quality specifications set forth in this Agreement, and will maintain suitable equipment at Seller's premise in order to remotely monitor and shut off Seller's supply should it not meet such specifications.

6.6 The Parties shall develop a facility start-up gas quality sampling and testing plan (the "Plan") to ensure all equipment is functioning as and intended in order to provide Pipeline Quality Processed Digester Gas conforming to the quality specifications set forth in Table 1 above. The Plan shall include provisions regarding frequency of initial testing.

ARTICLE 7
GAS MEASUREMENT

7.1 The quantity of Processed Digester Gas delivered hereunder shall be measured according, to Boyle's and Charles' Laws for the measurement of gas under varying temperatures and pressures and shall be determined as follows:

a. the sales unit of the Processed Digester Gas delivered shall be one (1) MMBtu of gas measured as HHV on a real, dry, basis at standard temperature and pressure;

b. the unit of weight for the purpose of measurement shall be one (1) pound mass of gas;

c. the average absolute atmospheric pressure shall be assumed to be 14.73 pounds per square inch; and

d. the temperature of gas passing through the meter shall be determined by the continuous use of a temperature measuring device; the arithmetic averages of the temperature recorded each twenty-four (24) hour Day shall be used in computing gas volumes or continuous instantaneous temperature measurements may be applied to metering instruments to provide the volume computation.

7.2 The metering equipment shall be sealed and the seals shall be broken only upon occasions when the meters are to be inspected, tested or adjusted, and representatives of Seller shall be afforded at least twenty-four (24) hour notice and reasonable opportunity to be present upon such occasions. Buyer shall use reasonable efforts to give Seller more than twenty-four (24) hour notice of such inspections, tests or adjustments.

7.3 Periodic tests of such metering equipment, at intervals not to exceed two times per year, will be made at any reasonable time upon request there for by Seller. If, as a result of any such additional test, the metering equipment is found to be defective or inaccurate, it will be restored to a condition of accuracy or replaced. If an additional test of the metering equipment is made at the request of Seller with the result that said metering equipment is found to be registering correctly or within two percent (2%) plus or minus of one hundred percent (100%) accuracy, Seller shall bear the expense of such additional test. If such additional test shows an error greater than two percent (2%) plus or minus of one hundred percent (100%) accuracy, then Buyer shall bear the expense of such additional test and any necessary repair or replacement.

7.4 All meters shall be adjusted as close as practical to one hundred percent (100%) accuracy at time of installation and testing. If any of the metering equipment tests provided for herein disclose that the error for such equipment exceeds two percent (2%) plus or minus of one hundred percent (100%) accuracy, and the period of inaccuracy cannot be reasonably ascertained, then the period of inaccuracy will be assumed to have begun at the midpoint in time between the discovery of the inaccuracy and the previous meter test.

7.5 Any correction in billing resulting from such correction in meter records shall be made in the next monthly invoice rendered by Buyer after the inaccuracy is discovered. Should any metering equipment fail to register the gas delivered or received during any period of time, the amount of Processed Digester Gas delivered or received during such period will be estimated by the Parties according to the amounts previously delivered or received during similar periods under substantially similar conditions, and upon mutual agreement of the Parties shall be used as the basis for billing for that period.

Draft 7/15/15

ARTICLE 8
OPERATION and MAINTENANCE SERVICES, EQUIPMENT REPLACEMENT COSTS

8.1 SCOPE - During the term of this Agreement the Company will perform, or cause to be performed, in a prudent and workman like manner the Services set forth in Section 8.2 below. Upon the mutual agreement of the Parties, the Company may perform additional Services (the "Unscheduled Services") in connection with the Facilities. In the case of emergencies that render the Facilities unsafe, the Company may perform emergency services that it deems necessary to make the Facilities safe (the "Emergency Services"), including shutting off gas supply and the gas delivery. The Company shall attempt to notify Seller prior to commencing any such Emergency Services, however if prior notification is impractical, the Company shall have the right to commence the Emergency Services immediately and to notify Seller within 24 hours thereafter.

8.2 SERVICES - During the term of this Agreement, the Company shall provide the labor and materials necessary to operate and maintain the gas meters, gas regulators, odorant system, gas chromatographs, telephone lines and other ancillary equipment required by the Company in connection with the delivery of Processed Digester Gas pursuant to this Agreement (the "Services"). The Services do not include repairs for damages, malfunctions or failures caused by or occurring as the result of: (a) repairs, adjustments or any other actions performed by persons other than the Company's authorized representatives; (b) failure of components not serviced by the Company's authorized representatives; (c) abuse, misuse or negligent acts of Seller or others; or (d) an event of force majeure as defined in Article 11 hereof. Installation of the equipment described above is the Seller's responsibility.

8.3 COST OF SERVICES - Seller shall reimburse the Company for the fully loaded cost incurred by the Company in performing the Services, Unscheduled Services and/or Emergency Services.

8.4 EQUIPMENT REPLACEMENT AT END OF LIFE – Seller shall reimburse the Company for the fully loaded cost to replace gas meters, gas regulators, odorant system, gas chromatographs, telephone lines and other ancillary equipment when such equipment reaches the end of its service life.

ARTICLE 9
BILLING AND PAYMENT

9.1 On or before the fifth (5th) day of each Month, Buyer shall notify Seller of the quantity of Processed Digester Gas delivered by Seller to Buyer during the preceding Month. Seller shall render a written statement to Buyer on or before the fifteenth (15th) day of such succeeding Month which, upon verification by Buyer, shall be paid by Buyer by the twenty-fifth (25th) day of such Month. If the twenty-fifth (25th) day of any Month falls on a weekend or bank holiday, payment by Buyer shall be due on the next succeeding business day.

9.2 The fully loaded costs incurred by the Company in performing any Services,

Draft 7/15/15

Unscheduled Services and/or Emergency Services will be applied as an offset to the amount invoiced by Seller pursuant to Section 9.1 above.

9.3 AUDITS. Each Party shall have the right at its own expense to examine and audit at a reasonable time and upon reasonable prior notice the books, records and charts of the other Party relevant to this Agreement. Each Party shall use reasonable efforts to make available such records as may be necessary to verify the accuracy of any statements or charges made under or pursuant to any of the provisions of this Agreement. A formal audit of accounts shall not be made more than once each calendar year.

ARTICLE 10
ACCESS TO PREMISES

10.1 Seller agrees during the term of this Agreement that it will provide access as may be required by the Company's authorized representatives for the performance of its obligations hereunder. Upon 24 hours' notice, Seller shall grant access to, or obtain access for, the Company's authorized representatives for performance of the Services and the Unscheduled Services. Furthermore, Seller shall grant or obtain immediate access for the Company's authorized representatives for the performance of Emergency Services.

ARTICLE 11
FORCE MAJEURE

11.1 The term force majeure as employed herein shall mean acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning earthquakes, fires, storms, floods, washouts, arrests, the order of any court of governmental authority having jurisdiction while the same is in force and effect, civil disturbances, explosions, breakage, accidents to machinery or lines or pipe, freezing of or damage to facilities, ·inability to obtain or unavoidable delay in obtaining material, equipment, and any other cause whether of the kind herein enumerated or otherwise, not reasonably within the control of the Party claiming suspension and which by the exercise of due diligence such Party is unable to prevent or overcome.

11.2 In the event of either Party being rendered unable, wholly or in part, by force majeure to carry out its obligations (other than the continuing obligation set forth herein below), it is agreed that on such Party's giving notice and full particulars of such force majeure in writing or by telegraph or telecopy to the other Party within a reasonable time (not to exceed five (5) days) after occurrence of the cause relied on, the obligations of both Parties, so far as they are affected by such force majeure, shall be suspended during such period of force majeure, but for no longer period, and such cause shall so far as possible be remedied with all reasonable dispatch.

11.3 Neither Party shall be liable in damages to the other for any act, omission or circumstance occasioned by, or in consequence of, force majeure, as herein defined. Such causes or contingencies affecting the performance by either Party, however, shall not relieve it of liability unless such Party shall give notice and full particulars of such cause or contingency in writing, to the other Party at the address set forth in Section 13.10 within a reasonable time after the occurrence relied upon, nor shall such causes or contingencies affecting the performance by either Party relieve it of liability in the event of its failure to use due diligence to remedy the situation and remove the cause with all reasonable dispatch, nor shall such causes or contingencies affecting the performance relieve Buyer from its obligation to make payments of amounts in respect of Pipeline Quality Processed Digester Gas delivered.

11.4 To the extent that, in Buyer's sole judgment. Buyer's ability to receive, measure monitor and/or odorize pipeline quality Processed Digester Gas is impaired by conditions on its system including, but not limited to, the performance of routine maintenance or repairs, then Buyer's obligation to purchase and receive such Processed Digester Gas shall be suspended for the duration of such condition.

ARTICLE 12
EVENTS OF DEFAULT

12.1 EVENTS OF DEFAULT - The occurrence of anyone or more of the following shall be an "Event of Default” under this Agreement:

(a) Failure by a party to pay/reimburse any amount when due and payable that is required to be paid by the terms of this Agreement.

(b) Failure by a party to perform any covenant, condition or agreement required to be performed by it by the terms of this Agreement that continues for a period of ten (10) days after the required date of performance.

12.2 REMEDIES ON DEFAULT.

(a) The non-defaulting party shall have the right, upon written notice to the defaulting party, to terminate this Agreement upon any Event of Default.

(b) Upon any Event of Default by the Company, Seller, or a designee of Seller, may cure any breach or default of the Company under this Agreement that resulted in an Event of Default (including the failure to perform Services), in which case the full cost thereof shall be reimbursed to Seller by the Company.

ARTICLE 13
MISCELLANEOUS

13.1 Except as provided hereinafter, neither this Agreement nor any rights or obligations hereunder may be assigned or transferred, by operation of law or otherwise by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Notwithstanding the foregoing, Buyer may assign this Agreement and all of its rights and obligations to an affiliate of Buyer at any time upon 30 days prior written notice to Seller.

13.2 Seller shall provide, at no cost to Buyer, all of the electricity and compressed air required for Buyer to operate the facilities that will measure, regulate and odorize the Processed Digester gas delivered by Buyer to Seller under this Agreement at Buyer's facilities for such purposes located at or near the Delivery Point.

13.3 The sale and delivery of Processed Digester Gas by Seller and the purchase and receipt thereof by Buyer are subject to all valid legislation with respect to the subject matter hereof and to all valid present and future orders, rules and regulations of duly constituted authorities having jurisdiction. Neither Buyer nor Seller shall be liable to the other for failure to perform any obligation hereunder where such failure is due to compliance with such valid laws, orders, rules or regulations. If any statute, order, rule, or regulation of a duly constituted authority having jurisdiction over a Party or the performance of this Agreement prevents Seller from charging or collecting the price or prices payable hereunder or prevents Buyer from recovering costs representing the price or prices payable hereunder, the following shall apply notwithstanding any other provision of this Agreement:

a. If Buyer is prevented from recovering any costs representing all or a portion of the price or prices payable hereunder, or Buyer’s recovery of such costs is made subject to refund, Buyer may, at its option, terminate this Agreement by written notice to Seller, effective not less than sixty (60) days after delivery thereof;

b. If Seller is prevented from charging or collecting all or any part of the price or prices payable hereunder, or Seller's collection of such prices is made subject to refund, Seller may, at its option, terminate this Agreement by written notice to Buyer, effective not less than sixty (60) days after delivery thereof.

13.4 This Agreement sets forth all understandings between the Parties respecting the terms and conditions of this transaction. All other agreements, understandings and representations by and between the Parties hereto prior to this Agreement, whether consistent or inconsistent, oral or written, concerning this transaction are merged into and superseded by this written Agreement.

13.5 All headings appearing herein are for convenience only and shall not be considered a part of this Agreement for any purpose.

13.6 The Parties may, by mutual agreement, waive any provision herein; however, a waiver shall not be construed to constitute a continuing waiver hereunder and furthermore, a waiver by either Party of any one or more defaults by the other Party in performance of any provision of this Agreement shall not operate or be construed as a waiver of future default or defaults, whether of a like or different character.

13.7 Seller hereby agrees to indemnify and hold harmless Buyer from damage to Buyer's or third parties' property or injury to persons (including death) to the extent resulting from the negligence of Seller, its servants, agents or employees, while engaged in activities under this Agreement. Buyer shall indemnify and hold harmless Seller from damage to Seller's or third parties’ property or injury to persons (including death) to the extent resulting from the negligence of Buyer, its servants, agents or employees while engaged in activities under this Agreement except to the extent Buyer's Schedule for Gas Service (as filed with and approved by the Public Service

Draft 7/15/15

Commission of the State of New York), limits Buyer's liability. The obligations under this Section shall survive termination of this Agreement.

13.8 THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO ANY RULES GOVERNING CONFLICTS OF LAWS THAT WOULD REQUIRE APPLICATION OF THE LAWS OF ANOTHER JURISDICTION.

13.9 This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument.

13.10 Unless otherwise specified, any notice, reque.st, demand, statement, bill or other payment provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be considered duly delivered as of the earlier of the date of the receipt by the addressee or three (3) business days after the postmark date when mailed by ordinary mail or given to the addressee at the addresses listed below:

BUYER:

Notices:

KeySpan Gas East Corporation d/b/a National Grid
100 East Old Country Road
Hicksville, NY 11801

Attention:
Gas Contracting and Compliance

Billings:

KeySpan Gas East Corporation d/b/a National Grid
100 East Old Country Road, 2nd floor
Hicksville, New York 11801
Attn: Comptroller

Gas Control Center:

SELLER:

NOTICES and BILLINGS
(Original)

Draft 7/15/15

(Copy Submitted to)

Draft 7/15/15

IN WITNESS WHEREOF, The Parties have duly executed this Agreement as of the day and year first above written.

KeySpan Gas East Corporation d/b/a National Grid

By:____

Company Name

By:____

Date of Request: April 11, 2016 DPS Request No. DPS-418 JL-1
Due Date: April 21, 2016 KEDNY/ KEDLI Req. No. BULI-435

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, GIOP

SUBJECT: Automated Meter Reading - KEDLI

Request:

Provide the following:

1. Referring to p. 84 of the Gas Infrastructure and Operations Panel (GIOP), identify the percent of AMR deployment in KEDLI's service territory that is complete and what deployment KEDLI expects to have completed in Calendar Year (CY) 2016.

2. Table 11 GIOP testimony shows costs associated with Automated Meter Reading for CY 2017, CY 2018 and CY 2019. Enumerate the specific activities and the associated costs, by activity, for AMR for each calendar year shown.

3. Table 11 does not provide costs associated with AMR Replacement; explain why there are no cost projected for AMR replacement for CY 2017, 2018, and 2019? Also, identify when the Company anticipates that it will incur such costs.

4. Identify KEDLIs estimated useful life for these installed AMR devices. If there are different classes of meters and the useful life varies by class, please explain the differences that exists between classes.

5. Provide a chart showing the numbers AMR meters installed by year and projected replacement timeframe.

6. Provide any Cost/Benefit Analyses performed by the Company to support its meter replacement program.

7. The Company identified that these AMR meters are compatible with an AMI upgrade going forward, if such a decision were made by the Company. Describe the activities necessary to upgrade these meters to be AMI compatible and the associated costs. For example, will physical changes need to be made to these meters? If so, what changes will be needed and the anticipated costs (capital/labor/etc.)? What communications infrastructure will be necessary to support such a changeover and the anticipated costs (capital/labor/etc.)? What software changes will be required to support the change from an AMR infrastructure to an AMI infrastructure and the estimated costs for each such software application?

Response:

1. KEDLI's AMR deployment is now 97.5% (580,000 meters) complete. The remaining 15,000 customer meters are expected be completed in CY 2016 (assuming the Company is afforded access to install AMR).

2. The requested information was previously provided in Attachment 5 to DPS 329.

3. As indicated in the Company's response to DPS 329, the forecast AMR costs presented in Table 11 include new installations and replacements.

4. As indicated in the Company's response to DPS 329, the average service life of a typical AMR meter is 20 years. There is no difference between meter classes.

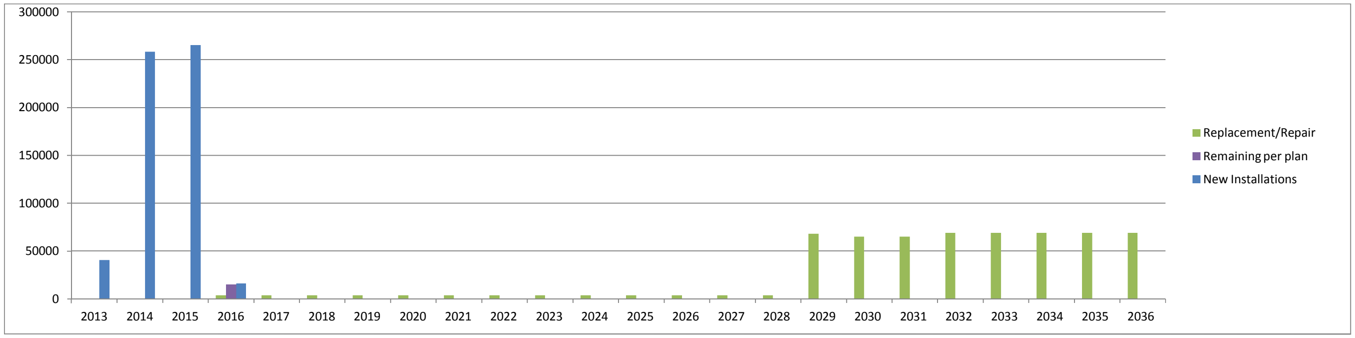
5. Attachment 1 is a chart showing the number of AMR meters installed by year and projected replacement timeframe. The work schedule provides for all AMR installations to be complete in CY 2016, a small number of replacements each year thereafter through 2028, followed by a ramp-up in replacements beginning in 2029 as the meters begin to near the end of their useful lives.

6. As stated in Exhibit __ (GIOP-4) at page 23, the primary driver for the Company's meter replacement program is compliance with state regulatory requirements. There is no available cost/benefit analysis for the mandated meter replacement program.

7. The ITRON 100G ERT endpoint is compatible with the ITRON Fixed Network AMI System with no required changes to the meter endpoint. Fixed network systems require the installation of a communications network compatible with the meter endpoints to be purchased and installed. This network is only available from ITRON, the manufacturer of the AMR endpoints being used. The Company has not developed a cost estimate for an upgrade to AMI.

Name of Respondent:	Date of Reply:
Phillip DiGiglio	April 21, 2016

LI AMR Installations	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
New Installations	40,542	258,291	265,167	16,118	[redacted]																			
Replacement/Repair	[redacted]			4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	68,000	65,000	65,000	69,000	69,000	69,000	69,000	69,000
Remaining per plan	[redacted]			14,882	[redacted]																			



Date of Request: April 11, 2016 DPS Request No. DPS-419 JL-2
Due Date: April 21, 2016 KEDNY/ KEDLI Req. No. BULI-436

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, GIOP

SUBJECT: Automated Meter Reading - KEDNY

Request:

Provide the following:

1. Table 11 of the Gas Infrastructure and Operations Panel (GIOP) testimony shows AMR Installation and Replacement Costs for Calendar Year (CY) 2017, CY 2018 and CY 2019. Enumerate the specific activities and the associated costs, by activity, for these two AMR categories for each calendar year shown.

2. Referring to p. 89 of the GIOP testimony, identify what AMR deployment in KEDNY's service territory will be complete in CY 2108. Explain why there are no costs shown for AMR deployment for CY 2018 in Table 11 Table 11 shows AMR Replacement Costs in excess of $5 million for CY 2017, CY 2018 and CY 2019. Explain how these cost estimates were developed.

3. The panel on p. 89 indicates that AMR has been in KEDNY's service territory for nearly twenty years, thus a significant number of existing AMR units are at or near the end of their useful lives. Identify KEDNY's estimated useful life for these devices. If there are different classes of meters and the useful life varies by class, explain the differences that exists between classes.

4. Provide a chart showing the number of AMR meters to be installed by year and projected replacement timeframe for the period 2016 to 2036.

5. Provide any Cost/Benefit Analyses performed by the Company to support its meter replacement program.

6. The Company identified that these AMR meters are compatible with an AMI upgrade going forward, if such a decision were made by the Company. Describe the activities necessary to upgrade these meters to be AMI compatible and the associated costs. For example, will physical changes need to be made to these meters? If so, what changes will be needed and the anticipated costs (capital/labor/etc.)? What communications infrastructure will be necessary to support such a changeover and what are the anticipated costs (capital/labor/etc.)? What software changes will be required to support the change from an AMR infrastructure to an AMI infrastructure and what are the estimated costs for each such software application?

Response:

1. The requested information was previously provided in Attachment 5 to DPS-329.

2. The KEDNY AMR project was initially expected to be completed in early CY 2018. However, as discussed in the Company's April 4, 2016 Corrections and Updates testimony at page 7, the work plan has been extended. The revised schedule is reflected in Attachment 5 to DPS-329. The AMR replacement project includes both material and labor costs associated with the annual replacement of approximately 57,000 AMR units per year; both proactive (units > 16 years old) and reactive (units that have failed due to end of life). Attachment 5 to DPS-329 provides a breakdown of the forecast AMR costs for CY 2017 through CY 2019.

3. As indicated in the Company's response to DPS-329, the average service life of a typical AMR meter is 20 years. There is no difference between meter classes.

4. Attachment 1 is a chart showing the number of AMR meters to be installed by year and projected replacement timeframe for the period 2016 to 2036.

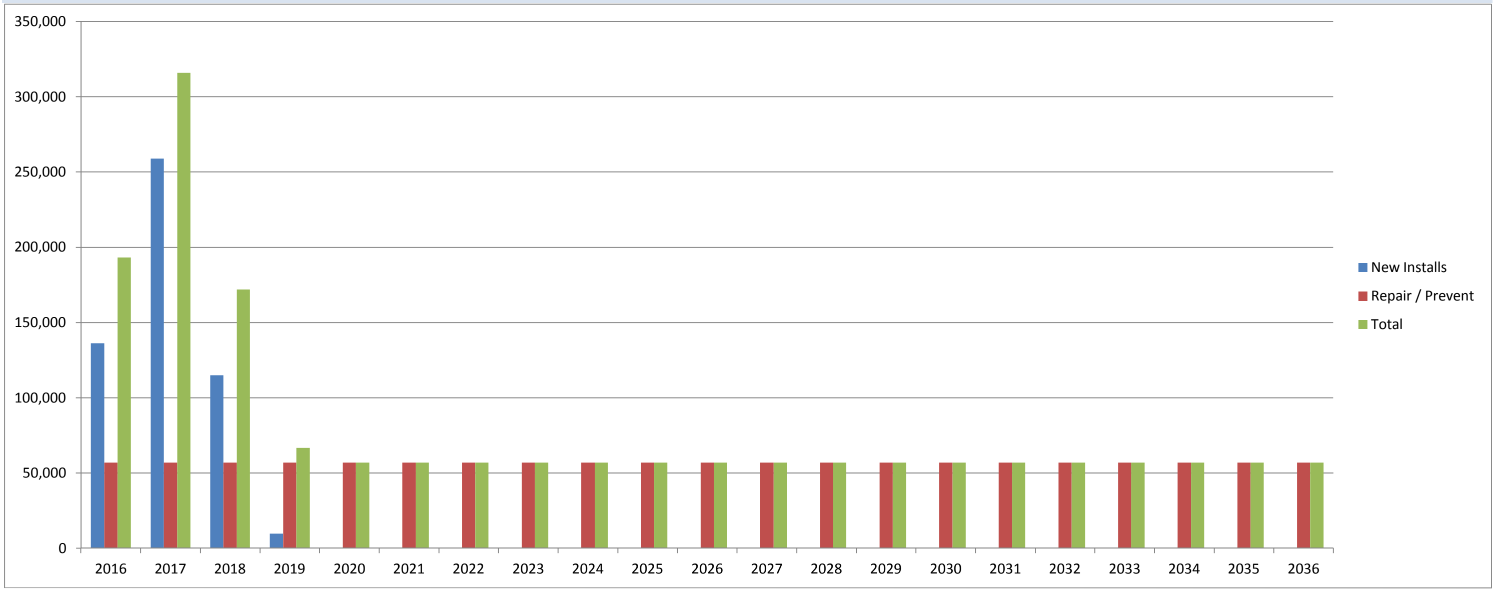
5. As stated in Exhibit __ (GIOP-4) at page 39, the primary driver for the Company's meter replacement program is compliance with state regulatory requirements. There is no available cost/benefit analysis for the mandated meter replacement program.

6. For meters installed in 2016 or later, the ITRON 100G ERT endpoint is compatible with the ITRON Fixed Network AMI System with no required changes to the meter endpoint. Meters installed prior to 2016 would need to be replaced to be AMI compatible; there is no upgrade option. In addition, fixed network systems require the installation of a communications network compatible with the meter endpoints to be purchased and installed. This network is only available from ITRON, the manufacturer of the AMR endpoints being used. The Company has not developed a cost estimate for an upgrade to AMI.

Name of Respondent:
Philip DiGiglio

Date of Reply:
April 20, 2016

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
New Installs	136,200	259,000	115,000	9,800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Repair / Prevent	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57000	57000	57000	57000
Total	193,200	316,000	172,000	66,800	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57,000	57000	57000	57000	57000



Date of Request: April 11, 2016 DPS Request No. DPS-420 JL-3
Due Date: April 21, 2016 KEDNY/ KEDLI Req. No. BULI-437

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, Sean Mongan

SUBJECT: Research and Development Costs - KEDLI

Request:

Provide the following:

1. Using the table below, provide five (5) years of data (one table for each year, 2011-2015, showing the annual planned budget, program revenues (surcharges/base rates) collected from customers, actual program expenditures, and reconciled accrued program dollars for each of the three major R&D program areas (KEDLI Internal, NYSERDA, and Millennium). If the amount is $0 for any cell, indicate the $0 amount and explain why the amount is zero.

2. For 2016, provide the same data as requested in question 1, showing the projected/estimated program expenditures, program revenues to be collected during 2016, actual program expenditures to-date, and accrued program dollars for each of the three major R&D program areas ((KEDLI Internal, NYSERDA, and Millennium).

KEDLI Research and Development 2010 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs				
NYSERDA				
Millennium				
Total				

3. On pp. 19-20, you indicate that Utilization Technology Development (UTD) is currently engaged with more than 60 active end-use technologies. Provide a list of those technologies.

4. To the extent that the company currently engages in internal research and development, identify how these projects differ from those end-use technologies that will be developed by UTD.

5. On pp. 21-22 you show planned cost associated with UTD of $250,000 annually and identify flexibility for the KEDLI to determine which projects they wish to support. Explain where the program dollars will come from that KEDLI plans to direct to projects that have the greatest potential to benefit its customers. For example, will these expenditures come from the $250,000 planned annual expenditures for this program or another source? If these expenditures will come from the $250,000, How much of these dollars will be under the control of the company? If they will come from another source, explain where they originate from.

Response:

1. Please see below:

KEDLI Research and Development 2011 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$64,085	$0	$64,085	$0
NYSERDA	$1,165,393	$1,034,456	$1,165,393	$0
Millennium	$850,000	$849,019	$858,517	$9,498
Total	$2,079,478	$1,883,475	$2,087,995	$9,498

KEDLI Research and Development 2012 Revenues and Expenditures				
	Program Budget	Revenues Collected	Actual Expenditures	Total Program Accruals
Internal Programs	$40,780	$0	$40,780	$0
NYSERDA	$950,213	$1,056,054	$950,213	$0
Millennium		$784,575	$790,257	$5,6820
Total	$990,993	$1,840,629	$1,781,250	$5,682

KEDLI Research and Development 2013 Revenues and Expenditures				
	Program Budget	Revenues Collected	Actual Expenditures	Total Program Accruals
Internal Programs	$90,084	$0	$90,084	$0
NYSERDA	$933,271	$1,056,054	$933,271	$0
Millennium		$1,096,906	$175,000	($921,906)
Total	$1,023,355	$2,152,960	$1,198,355	($921,906)

KEDLI Research and Development 2014 Revenues and Expenditures				
	Program Budget	Revenues Collected	Actual Expenditures	Total Program Accruals
Internal Programs	$131,131	$0	$131,131	$0
NYSERDA	$542,324	$1,056,054	$542,324	$0
Millennium		$1,226,719	$422,418	($804,301)
Total	$673,455	$2,282,773	$1,095,873	($804,301)

KEDLI Research and Development 2015 Revenues and Expenditures				
	Program Budget	Revenues Collected	Actual Expenditures	Total Program Accruals
Internal Programs	$245,988	$0	$245,988	$0
NYSERDA	$1,063,547	$1,056,054	$1,063,547	$0
Millennium		$19,973	$324,509	$304,536
Total	$1,309,535	$1,076,026	$1,634,045	$304,536

Total Program Accruals" are $0 for "Internal Programs" and "NYSERDA" as these are not subject to true-up.

2. Please see below:

KEDLI Research and Development 2016 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$618,246	$0	$0	$0
NYSERDA	$1,063,547	$1,056,054	$269,915	$0
Millennium	$657,228	$6	$221,146	$221,140
Total	$1,275,474	$1,056,060	$221,146	$221,140

Total Program Accruals" are $0 for "Internal Programs" and "NYSERDA" as these are not subject to true-up.

3. Attachment 1 is a list of the 58 active projects in the Utilization Technology Development (UTD) program (as of April 2016). These projects are currently supported by UTD's membership without participation by National Grid. Additional information about technologies, projects and categories is available at http://www.utd-co.org/.

4. Current internal R&D is focused on short term research (work expected to be 24 months and less duration) and technology to improve gas distribution operations in terms of safety, cost-effective operations, damage prevention, reliability and environmental performance. As such, this research almost exclusively supports the development of technologies for deployment on the Company's side of the meter (*e.g.*, threat risk model improvements, cured-in place liners technology transfer and trenchless service replacement prototype) not end-use utilization. National Grid's Three Year Research, Development, and Demonstration Report (Attachment 2) discusses these programs in more detail.

   The UTD program is focused on supporting the development of technologies for application on the customer side of the meter that utilize natural gas, including technologies to improve the energy performance of customers' buildings or processes with natural gas in terms of life-cycle costs, reliability and environmental performance. The technologies are of interest to National Grid because they support the expanded use of natural gas, including advanced residential applications, distributed generation, commercial HVAC applications such as thermal air conditioning, natural gas vehicles, commercial processes such as foodservice, and renewable technologies. For example, there are more than 7,200 foodservice businesses in the KEDLI service area. Attachment 3 is a 2010 GTI assessment of the energy challenges and technology opportunities in the foodservice industry in areas served by National Grid.

5. The $250,000 to participate in the UTD program is proposed to be included in KEDLI's revenue requirement as an annual operating expense. This is the only funding for gas end-use R&D (other than the internal labor to manage National Grid's participation).

   The UTD program is managed by the Gas Technology Institute (GTI). Each member company appoints a representative to the Board of Directors and a member of the technical program committee.

   Individual project proposals are initially developed by the GTI staff based on their review of relevant technological opportunities and needs. In some cases, projects are conceived by the member companies. For each project identified, the members of the program committee allocate a portion of their company's dues to the projects of interest to their company. A member's funds can only be allocated by a member's vote. Projects that receive sufficient interest, by virtue of the total funding allocated, proceed and those that do not achieve the required minimum funding do not proceed and those funds are available for re-allocation. National Grid's representatives will be responsible for allocating funds to projects that have the greatest potential benefit to KEDLI's customers or for proposing projects if none are sufficiently relevant.

   One of the benefits of the UTD program is the ability, on a project-by-project basis, to leverage the funds of other companies with similar customer benefits and also to leverage external funding from federal or state research programs, such as the US Department of Energy or NYSERDA. Co-funding is usually a requirement or a factor in scoring for DOE or NYSERDA funding and, by pooling funds, the UTD program makes it easier to achieve the minimum required co-funding.

Name of Respondent:	Date of Reply:
Chris Cavanagh/Mary Holzmann	April 21, 2016

Keyspan Gas East Corporation d/b/a National Grid
Brooklyn Union Gas Company d/b/a National Grid NY
Case 16-G-0058 and 16-G-0059
Attachment 1 to DPS Request No. DPS-420 JL-3 BULI-437

UTD Project Titles

Project No	Description	Status
Group 1		
1.10.A	Web Program Upkeep	Active
1.10.W	Development of an End Use New Technology Roadmap	Active
1.11.D	Gas Fired Conveyor Warewasher	Active
1.11.G.2	Low Cost Condensing Prototype Phase 2	Active
1.11.H.3	Gas Heat Pump Water Heater Reliability Phase 3	Active
1.11.M.5	Building America Whole House Retrofit Program (Phase 5)	Active
1.12.P.3	Air Handler Enhancements for Condensing Combis Phase 3	Active
1.12.Q.3	Unplugged Energy Star Water Heater Phase 3	Active
1.12.U.2	Gas Heat Pump Modeling	Active
1.13.B.3	CFS Information and Calculators - Phase 3	Active
1.13.D.3	Codes & Standards for Advanced Gas Technologies (Phase 3)	Active
1.13.F	Application of Innovative Gas Heat Pump Design to Space Conditioning	Active
1.13.I.3	Gas Appliances in Tight Houses (Phase 3)	Active
1.13.L.2	Validation of mCHP Test Standard ASHRAE SPC204 Phase 2	Active
1.13.M	Field Demonstration of Model E NextAire Gas Engine-driven Heat Pump	Active
1.14.A.2	Next Generation CFS Burners - Phase 2	Active
1.14.B.2	2015 CFS Demonstrations	Active
1.14.C.2	Demonstration of Next Gen Low Oil Volume Fryer	Active
1.14.D	Conveyor Broiler Improvements	Active
1.14.E.2	Heating System Competitive Performance Phase 2	Active
1.14.G	Thermally Driven Ground Source Heat Pump	Active
1.14.I	Cold Climate Field Demonstration of the NextAire GHP	Active
1.14.J	Multifamily Infrastructure Challenges	Active
1.14.K	Advanced Systems for Self Powered Water Heating	Active
1.14.M	Enbridge Analysis	Active
1.15.A	CFS Quick Response Project	Active
1.15.B	Demonstration of Demand Control Kitchen Ventilation System	Active
1.15.C	Next Generation Advanced Gas Dryer Development	Active
1.15.D	Low NOx Metal Foam Burner Durability Testing	Active
1.15.E	Gas-fired High-Efficient Liquid Desiccant Air Conditioning and Humidity Control – Commercial	Active
1.15.G	Residential Kitchen Cooking Ventilation Effectiveness	Active
1.15.H	Water Quality Impacts on Compact HXs	Active
1.15.I	TMH Field Evaluations for High Efficiency Residential Heating and Humidification	Active
Group 2		
2.11.D	Design and Development of Timed Fill CNG Metering System and Controls	Active
2.12.F.3	Reliability Assessment of Natural Gas vs. Diesel for Standby Generation Phase 3	Active
2.12.T.3	Free Piston Linear Motor Compressor Phase 3	Active
2.12.U	Gas Quality Sensor (GQS) for Natural Gas and Renewable Gas Fueled Engines	Active
2.13.G.2	CWI 6.7 liter MD Natural Gas Engine Field Trials Phase 2	Active
2.14.A	High-Efficiency Gas Fired Rotary Dryer with Heat Pump	Active
2.14.B	Low Cost Low NOx Sensor for Industrial Applications	Active
2.14.D.2	HeatSponge Evaluation Phase 2	Active

2.14.F	Free Piston Linear Motor Compressor Scale Up	Active
2.14.H.2	CSA Standards Development for Home Refueling Appliances Phase 2	Active
2.14.I	CNG Fuel Station Safety, Performance, and Best Practices Audit Kit	Active
2.14.K	CNG Composition Impacts on New Generation Engine and Fuel Delivery Systems	Active
2.14.O	Field Validation of Gas Quality Sensor for Natural Gas	Active
2.15.A	On-site Electrical Generation	Active
2.15.B	Valuable Products From Natural Gas	Active
2.15.D	Advanced Retention Nozzle	Active
2.15.H	Modular CNG Storage System Investigation	Active
2.15.I	High Volume Off-road CNG Applications Analysis	Active
2.15.J	Truck Transport Refrigeration Units	Active
2.15.M	CHP Interconnection Equipment Review	Active
2.15.O	FlexCHP Power and Steam	Active

nationalgrid

Tae Kim
Associate Counsel
Legal Department

April 5, 2016

VIA ELECTRONIC DELIVERY
Honorable Kathleen H. Burgess, Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223

Re: Case No. 98-G-1304 - National Grid's Three Year Research, Development, and Demonstration Report

Dear Secretary Burgess:

The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, and Niagara Mohawk Power Corporation d/b/a National Grid hereby submit for filing their Three Year Research, Development, and Demonstration Report.

Please direct any questions regarding the enclosed report to Mary Holzmann, Principal Engineer – Gas Research, Development & Deployment at (631) 770-3449 or mary.holzmann@nationalgrid.com.

Respectfully submitted,

/s/ Tae Kim
Tae Kim

Enc.

One Metrotech Center, Brooklyn, NY 11201
T: 929-324-4550 ■ F: 917-310-0132 ■ Tae.Kim@nationalgrid.com ■ www.nationalgrid.com

National Grid

Three Year RD&D Report

Prepared for

New York State
Public Service Commission

Albany, NY

Prepared by

Mary Holzmann
Principal Engineer
Gas RD&D

April 2016

Introduction

National Grid distributes natural gas to 2.5 million customers in Nassau and Suffolk Counties on Long Island and in Brooklyn, Staten Island and parts of Queens in New York City, and large portions of Upstate New York, including the cities of Albany and Syracuse. National Grid also distributes natural gas to 1.2 million customers in Massachusetts and Rhode Island.

In addition to its gas distribution business, National Grid owns and operates electric generation in Nassau and Suffolk Counties of New York State and also distributes electricity to customers in Upstate New York, Massachusetts and Rhode Island.

Goals of the RD&D Program

National Grid's Gas Research, Development & Demonstration (RD&D) program is designed to improve distribution operations. Targeted operations improvements involve enhanced public safety, cost reductions, improved worker safety, environmental and regulatory compliance. Within these broad areas, National Grid's ongoing research program focuses on the following technical categories:

- Damage Prevention. Technologies that allow the accurate detection of hard-to-find underground facilities such as plastic pipe with inoperable tracer wire, sewer laterals, or joints on cast iron systems. Technologies that warn of impending damage to underground gas facilities, or detect obstacles in the path of directional drilling machines
- Leak Location. Technologies that allow quicker, more accurate and less costly detection of leaks.
- Integrity Management. Various technologies to facilitate National Grid's compliance with the Pipeline Safety Improvement Act of 2002 and subsequent pipeline safety regulations which includes robotics, cased-pipe, material verification and integrity, improvements in asset tracking and traceability, TIMP and DIMP, crack detection, plastic pipe, and other risk and pipeline integrity management challenges.
- Live Maintenance and Repair. Live Repair technologies eliminate customer downtime by allowing repairs with gas mains in the live, operating condition.
- Trenchless Technology. Techniques that allow pipelines to be rehabilitated with minimal excavation.
- Gas Quality. The Company is engaged in various research projects to help prepare us for the expected changing picture in gas supply. The research is focused on the potential impacts that new supplies may have on our infrastructure and our customers.
- Environmental Technologies. New technologies that could be brought to bear on methane and advanced leak detection methods, residential methane sensors, manufactured gas plant (MGP) site remediation, monitoring, and other projects related to climate change.

- Infrastructure Support. Various projects targeted in improving infrastructure operations, corrosion control, construction and the tracking and traceability of underground assets.
- General Operations Improvement. Various projects targeted at improving operational safety, efficiency and/or worker ergonomics.
- Metallurgy, Welding, and Joining Process Improvements.

Projects active during the past three years within these categories, are described in the body of this report.

Execution of the Program

Most RD&D projects within these program areas are performed with a high degree of collaboration via the following research consortia:

NYSEARCH
NYSEARCH, whose members consist of 19 local distribution companies (LDCs) and one Pipeline Company in North America, is the research sub organization of the Northeast Gas Association (NGA). The NGA is a regional trade association focusing on education, training, research and development, operations planning and increased public awareness on natural gas in the Northeast US. NGA member companies collectively serve 9.5 million customers in eight states. NYSEARCH was originally created as a committee within the former New York Gas Group but has since become national in scope. In addition to the Northeast, NYSEARCH membership comes from the Middle Atlantic States, Mid-West and the West Coast and Canada. NYSEARCH focuses primarily on Operations projects. The NYSEARCH Staff of four project managers manage an active portfolio of projects within the program areas above. Member LDCs join projects at their discretion, commit funds according to their size, act as project advisors, and may host field demonstrations. For the NYSEARCH program, the Company's budget is set by first analyzing the projects that are approved. The project schedules are then established and a spending forecast is developed jointly with NYSEARCH. The company may contribute "in-kind" expenses towards a project in the form of field demonstrations and those costs are also considered. If a new project is still awaiting approval, a forecast is made of projected spending, again in conjunction with NYSEARCH.

Operations Technology Development (OTD)
OTD consists of 25 LDCs throughout North America and is an Illinois based not-for-profit (NFP) company administered by the Gas Technology Institute (GTI). GTI also performs project management services and researches about half the project portfolio. OTD focuses on operations projects. OTD Member LDCs join projects at their discretion, commit funds as they deem appropriate, act as project advisors, and may host field demonstrations. The OTD business model calls for an up-front pre-determined (based on company size) payment of annual dues each calendar year. For the OTD program the Company's annual dues are $750,000. As projects are approved they are funded by the annual dues. Unused funds can be used to offset the following year's dues. The company exercised this option for 2012.

A sub-program within OTD, the Sustaining Membership Program (SMP) is a longer term GTI program focusing on basic science, which usually results in a proof of concept that which is further developed in the OTD program. National Grid terminated its participation in the SMP program effective January 2013.

In some cases, National Grid may choose to enter into development contracts with research providers jointly with other LDCs or by ourselves.

NYSERDA

The Company is currently assessed an annual amount of approximately $4.9 Million for the NY State Energy Research and Development Authority (NYSERDA). The assessed rate is based upon NYS Intrastate Revenue – (Sales for Resale and Transmission for Others). The Company has no say in which projects are funded through the NYSERDA program. However, the company monitors the various NYSERDA Project Opportunity Notices (PONS) and may elect to submit a proposal to NYSERDA for cofunding a Company RD&D project.

Funding

Part of National Grid's ongoing RD&D program is funded via the "Millennium" Fund and surcharge, authorized by the New York Public Service Commission's February 14, 2000 Order in Case 99-G-1369 (the "Millennium Order") to replace the mandatory FERC pipeline research surcharge. A maximum allowable collection rate of $0.0174/dekatherm on firm transportation and sales is the source of funding for the program. National Grid currently collects $0.0067/dekatherm from its KEDNY operations and $0.0000/dekatherm from its Long Island and Upstate Operations. The winter of 2014-15 was unusually cold with extended periods below freezing. This caused the collection rates, which are tied to dekatherm usage, above the current spending levels for a period of time. Additionally, a great deal of R&D focus has been on residential methane detectors which is not being funded through Millennium but is being funded via company funds through the Long Island Settlement Agreement instead. So we have decreased the collection rates in KEDLI and NMPC in order to levelize balances with current R&D commitments. Since the last report, the changes in spending levels are in part due to National Grid Downstate has been funding the majority of the development of the Explorer 16/18 inch internal inspection robot for un-piggable pipelines in this range of larger diameter transmission piping. While this project benefits our Upstate territory, the larger share has been funded through the Downstate surcharge due to the larger inventory of 16 inch un-piggable pipe there. More recently, projects looking into the use of drones in gas operations will be of greater potential use in our Upstate NY area which will shift R&D investment dollars to Upstate as that work progresses.

Unlike the phased-out Federal Energy Regulatory Commission (FERC) surcharge, the Millennium fund is controlled by National Grid and spent on eligible projects via NYSEARCH, OTD, GTI or other research providers at National Grid's discretion. As specified in the Commission's Millennium Order, in order to qualify for Millennium funding a project must be medium to long term in nature (i.e., projects that are at least twenty-four months or more from becoming a commercially deployable product); 80% of Millennium funds must be spent on co-funded projects and cannot be directed to fund natural gas appliance research or supply/storage projects. The projected budget for the next three years averages $2.7 Million. The Company realizes a high degree of cofunding from other participating LDCs, and from the US Department of Transportation (DOT) Pipeline Safety Research Program. Because of this, the Company's leverage is about 7:1, meaning for every RD&D dollar we spend we realize seven dollars of overall RD&D funding.

National Grid maintains an internal budget to fund projects that do not meet the criteria set forth in the Millennium Order. The budget is $183,000 and typically funds short term "quick hit" RD&D efforts, association (NYSEARCH) dues, and patent protection fees.

Attachment 1 shows actual and projected spending for the Company's Gas RD&D program, Internal, External (NYSEARCH and OTD) and the NYSERDA Assessment.

Program Management

The management and administration of the operations program is by National Grid's Gas Materials and Standards, group within the Gas Engineering/Network Strategy organization. Subject matter experts throughout the company are used as needed when specific technical expertise is required on projects.

Selection of Projects

The Company uses four criteria to judge the merits of RD&D projects. The first is safety. Some projects are undertaken to enhance the safety of workers in the field, or the general public.

The second criterion is compliance with regulations. An excellent example of this is the transmission pipeline safety regulations. In the Pipeline Safety Improvement Act of 2002, Congress directed the US Department of Transportation to establish and promote a research partnership with industry to develop tools and techniques to improve pipeline safety. Ensuring the highest level of pipeline safety requires tools and techniques that have been developed over the last 10 years, such as the robotics program for internal inspection of unpiggable pipelines.

The third is increased knowledge about gas operations which can lead to increased efficiencies, material improvements and or better techniques for conducting daily operations.

The fourth criterion is financial benefit. The R&D budget is looked at based upon historical spending levels and is adjusted depending upon if there is an increase or decrease in current challenges being addressed and priorities that require research investment are funded. The Company may use a benefit/cost (B/C) ratio test to determine whether RD&D projects should be adopted into our operations. Benefits are the net savings in operational costs that are realized via implementation of new technology. Costs are the project costs to fund and implement the new technology. In some cases R&D studies can also lead to operational savings and the same B/C test applies. However, not all studies have a definitive cost benefit. Studies may lead to increased safety measures or process improvements.

Most projects have multiple benefits, for example, projects undertaken for worker safety can lower injuries and reduce sick time (thereby providing a financial benefit), and compliance with regulations can improve safety of the gas system and the public. A project with a marginal financial benefit may also be approved if it meets one or more of the other criteria.

Benefits

National Grid, in collaboration with other funders, has been involved with bringing the following products or increased knowledge to market over the past few years:

- Keyhole Tools and Methods
- Pipe Splitter
- PFT Chromatograph for Leak Detection
- No-Interrupt Service Transfer (NIST) Tee
- Cured in Place Liner Improvements
- Butt Fusion Repair Sleeve (BFRS)
- 4” and 6” Variable Length PE Repair Sleeve
- Remote Methane Leak Detector (RMLD)
- Studies on Plastic Pipe Performance
- A Full Suite of Live Internal Gas Main Video Inspection Devices
- NYSEARCH/Kiefner Interacting Threats Modeling Software
- Cased Pipe Integrity Assurance Model
- Explosion Proof Light Fixture
- Guidance Document on Biomethane
- Explorer Suite of Inspection Robots for the Inspection of Unpiggable Pipelines – Pipetel Technologies, Inc. EXP 6/8, EXP 10/14, EXP 16/18, EXP 20/26, EXP 30/36, Supporting Technologies and enhancements in detection capabilities
- Cased Pipe Annular Space Inspection Robot
- CISBOT
- Acoustic Pipe Locator
- Metallic Joint Locator

<u>Active Project Discussion</u>

<u>Internal Budget – Non-Millennium – NYSEARCH Projects</u>

Projects that do not meet the criteria set forth in the Millennium Order (i.e., medium to long term and no end use or appliance funding) are funded via National Grid's internal budget. Internal projects (also referred to as Non-Millennium or Traditional R&D) are research that is of short term duration (work that is expected to be completed in less than 2 years) or work that is appliance or storage related.

T759 - Ergonomic Study to Develop and Test a New Design Needle Bar. A needle bar is a manually operated tool used to make small diameter holes, called barholes, in paved or unpaved areas over gas mains to allow pinpointing of leaks. During a typical leak investigation as many as 15-25 such holes may be required. The repetitive up-down motion required when using the tool is often a source of soft tissue injury if the user fails to maintain an upright position when using the tool. An ergonomic needle bar with a ratcheting handle was developed. This tool allows the operator to remain in an upright position for the duration of time it takes to create a barhole. The drawback is that the tool is heavier. Field trials were conducted throughout the National Grid territory and the tool failed to gain universal user acceptance. However, these efforts have stimulated manufacturers to continue working independently working towards more ergonomic tool design. The benefit of this work is a reduction in soft tissue injuries.

T763 - PE Rock Impingement Study. A study was undertaken to determine whether the requirement for clean backfill around polyethylene (PE) pipe could be relaxed given the high resistance to slow crack growth demonstrated by modern PE materials. In many situations, a common practice is to truck in clean, screened backfill in lieu of using native materials, at an increased cost. Testing performed in Europe has demonstrated that modern PE materials have such superior resistance to point loadings that use of select backfill is no longer required. No such testing had been undertaken in the US so, through NYSEARCH, Jana Labs was commissioned to perform the tests. Medium density and high density PE pipe, which is representative of the PE pipe installed now at the Company, were subjected to extreme point loading to simulate contact with rocks which could be present in native backfill. (Test loadings were so severe that the indentation was visible at the interior pipe wall.) The sample pipes were then pressurized and hot tank tested (standard testing protocol – which compresses many years of testing into a relatively short time period). Tests have shown no harmful effects from extreme simulated rock impingement loading and the projected time-to-failure in normal operating conditions is well in excess of 100 years. This work is an excellent validation of the superior toughness of modern PE materials. Significant cost savings have already been experienced in the Company's New York City Operation.

T764 - Auto Gas Lamp Field Evaluation. Working through NYSEARCH, the Company undertook an evaluation of a gas lamp for street lighting that was equipped with an igniter and a photo sensor which would shut off during daylight hours and reignite in the evening. Independent testing confirmed that the lamp and igniter system performed well in lab testing and several lamps were deployed in funders' territory. The benefit of the project is a savings of natural gas during daylight hours, a corresponding reduction of CO2 emissions, and improved customer relations and satisfaction.

T765 - Gas Interchangeability Study for Installed Residential Appliances. The addition of new gas supplies (imported LNG, unconventional gas) is expected to accelerate, leading to wider ranges of natural gas compositions. While the industry is expanding supply sources, to date there has been no standardized approach for evaluating the impacts of varying gas compositions on in-service residential gas appliances. The benefits of such a study are to determine the extent to which potentially sensitive appliances exist and to identify which specific appliances are affected based on type, vintage, adjustment practices, and maintenance characteristics. With that information, better decisions can be made about whether adjustments are necessary to those appliances in order to successfully accommodate varying gas compositions. The project consists of two phases; in Phase I, over 2400 appliances were visited in the field and firing rate, percent excess air, CO and NOx formation were measured and flame quality was observed. In Phase II, lab testing was performed on selected appliances (about 20) subjecting them to a wide range of future expected gas compositions to determine their performance. This phase of the study yielded important information about how typical appliances will perform over a wide range of gas compositions and benefits the company by allowing it to more effectively negotiate future tariffs and plan for remedial actions for more sensitive appliance types. This work is nationally recognized. Project results have been shared with the American Gas Association (AGA) and key findings will be incorporated into the next revision of “Bulletin 36,” which addresses gas interchangeability concerns. Based on the results of this work an appliance assessment software tool is now available on the NYSEARCH website. NYSEARCH RANGE™ is one of the deliverables of the NYSEARCH Gas Interchangeability for Appliances project which studied and modeled how changing gas composition can impact the performance of in-service residential appliances. This risk assessment model is available to purchase for on-line use.

T766 - Technology Transfer Improvements. An ongoing study to investigate specific member lessons learned with successes and failures of technology transfer and to share procedures so that more companies can be successful with a process for cultivating company support and longevity in implementing new technology

T768 - NYSEARCH/Kiefner Interactive Threats Project. The project defined and prioritized interacting threats that impact pipeline integrity. A more robust treatment of interacting threats was incorporated in risk models. To ensure that the NYSEARCH/Kiefner Interacting Threats model stays current, PHMSA's annual incident and Kiefner's forensic failure databases are being checked and incorporated into annual software version upgrades.

T769 – Test Program for Picarro Leak Surveyor. In early 2012 the Company became aware of a new technology for leak survey manufactured and marketed by Picarro Corp. The technology is vehicle mounted laser based sensing of methane at sensitivity levels never achieved before by standard leak detection technology. Methane at 30 parts per billion (PPB) above background concentrations can be detected. Along with methane sensing, this vehicle based technology also records atmospheric conditions such as wind speed and direction, temperature, humidity and cloud cover. When methane is detected

the Picarro technology plots out an area that should be investigated and pinpointed. The area to be investigated is based on the methane concentration that was detected, and the atmospheric conditions, such as wind speed and direction. This gives operators a good idea from which direction the methane is coming.
Through the NYSEARCH consortium, the company and others wanted to do a side-by-side comparison of Picarro technology to existing distribution leak survey methods in use at the Company. A double blind test protocol was established and for two days the standard company leak survey procedure – which is a walking survey using Bascom Turner "Rover" leak detector – was run on the same days on the same streets as the Picarro mobile survey technology. Results of the comparative surveys for the Company and other project participants have been compiled. No report can be released due to legal agreements with Picarro. This project was completed in Nov. 2014.

T-770 - Technology Transfer, Demonstration & Post Mortem Testing of Cast Iron & Steel Pipe Lined with Cured-in-place Pipe Liners. See details under Live Inspection, Maintenance and Repair section.

T-773 - Trenchless Replacement of Small Diameter Steel Gas Service Lines. See details under Trenchless Technology section.

T-774 - Impact of Gasoline/Oil on PE Pipe. The objective of the project is to understand the impact of external contaminated soil conditions on the external surfaces of PE pipe and develop a practical engineering and operator's guideline that provides specific instructions for evaluating in-service PE pipe exposed to contaminated soils.

National Grid Study on Risks Associated With Natural Gas Appliances Immersed In Water. Flooding and flood damage are not unusual events in the United States (U.S.). According to the National Oceanic and Atmospheric Administration (NOAA) and the National Weather Service (NWS) data, annual flooded property losses exceed $7.8 billion on average during the past thirty years. Major episodic events such as Hurricanes Katrina and Sandy can substantially raise losses and place substantial strain on natural gas and electric utility operations due to the extensive damage done to delivery infrastructure and customer equipment. This study was undertaken to help qualitatively assess the failure modes and potential risks associated with natural gas appliances immersed in water for extended periods. Survey questions were used to facilitate interaction with several natural gas furnace, boiler, and water heater manufacturers.

In general, funding for "internal projects" is used to pilot new products and technology—e.g. keyhole, live main insertion, leak sealants, or to perform short term studies. Any appliance related work would also be internally funded.

<u>Millennium Program</u>

NYSEARCH and OTD Projects

Damage Prevention and Pipe Location

According to the US Department of Transportation (DOT), third party damage is the primary cause of pipeline incidents on LDC distribution systems, accounting for over one third of all reportable incidents. Repair costs due to Third Party Damage are estimated at $10 Million annually, and often result in loss of service to customers. National Grid is funding the following efforts:

M2001-005 – Handheld Pipe Locator using Ground Penetrating Radar (GPR). GPR is high frequency electromagnetic radiation that has proven capabilities to detect underground features but no hand held GPR device existed. The goal of the project is to develop a user friendly GPR device that can be deployed by field crews when standard locating technology cannot precisely locate suspected underground facilities. A portable, light-weight free scanning plastic pipe locator for use by LDCs and construction crews to identify the lateral position of hard-to-find plastic pipe (can also locate other metallic pipe). The target application for this technology is plastic pipe with inoperable tracer wire. Such pipe cannot be located by standard “clip-on” locating technology. The product has been designed, developed and tested. NYSEARCH worked with Pipehawk LLC, a UK company, to develop the technology but attempts to commercialize it in 2006 were unsuccessful. Difficulties arose when attempting to transfer this product to a commercializer for engineering improvements (such as ergonomics) and preproduction testing. Another potential commercial partner, Sensors and Software, a recognized leader in both development and manufacture of GPR locating equipment, had been engaged to explore potential commercialization. This contractor is now assessing the feasibility and potential market for this technology. A successful device would provide company crews with the ability to quickly locate plastic pipe without tracer wire. After multiple attempts with a selected contractor who had interest in commercializing, no additional work or funding was promoted.

M2002-011 PhIII - FFT Damage Prev Monitoring - Advances with Aura. Damage Prevention and particularly proactive monitoring for third party intrusion near transmission and distribution pipelines is a high priority for many gas companies. Due to interest expressed by members in revisiting the FFT’s fiber optic intrusion detection system, and in particular its advanced system known as Aura™, NYSEARCH renewed this project (renewing the former FFT project that worked with the Secure Pipe product) to test this higher resolution distributed sensor product as it applies to two different test sites with different conditions; one at Woodbridge NJ in PSEG's territory and one in Ontario in Enbridge's territory. Tests and results are finalized. Final Reports for PSEG complete; final report for Enbridge work pending.

M2002-018 - Proactive Infrasonic Sensor This system consists of seismic sensors that can be installed near critical gas mains or other facilities and can sense activity near those facilities and send a warning to a control center or other company facility. The system is “trained” to distinguish benign threats (truck traffic, etc) from real threats. Comparable systems on the market now differ in one important distinction; they all require physical contact with the sensor, this system will detect activity as far away as 300 ft. Benefits of this project are reduced incidences of third party damage and associated repairs.

M2007-007 Advanced Video Surveillance (A-Gas) System. This project uses a video image approach to detect possible third party damage. Standard video cameras are trained on an area of concern and proprietary software is used to "learn" the scene so that normal activity can be discounted but abnormal activity alarmed. The A-Gas system is available for security applications. The research component of this project is to adapt the technology to the new concept of advanced warning to LDC operators of potential third party damage. In a second phase of the project we are working with the vendor to develop an environmentally hardened version of the camera/software system which can be mounted outdoors without any special environmental enclosures. The benefits of this project are reduced incidences of third party damage and associated repairs.

M2008-001 – Advanced Development of PipeGuard™ – Proactive Pipeline Damage Prevention. This system by Magal/Senstar is technically similar to the Proactive Infrasonic Sensor system but is a commercially available system that is used for security applications. The goal of this project is to adapt this security based technology for use in the natural gas industry to be utilized in an underground surveillance mode to detect occurrences at or near the surface to alert the operator of third party activity, presumably excavation, in the vicinity of the installed sensors. This project includes the evaluation of a geophone-based pipeline monitoring capability that will warn an LDC of impending damage to pipeline facilities. Following the initial technical feasibility assessment, through NYSEARCH, the Company is hosting a demonstration site on Long Island to test this technology adaptation. The target goal for detection alarms for backhoe, pneumatic piercing tools, and pavement breakers is 250 feet from the sensing units. This will provide total monitoring coverage of 1000 feet along the pipeline run when two sensing units are installed. It is expected that detection distances for shovels and manual post-hole digging tools will be significantly lessened. Benefits of this project are reduced incidences of third party damage and associated repairs through proactive monitoring in advance of actual work performed by a third party.

M2011-005 – Fiber Sen System Development and Testing In the last 10 years advanced damage prevention technologies using fiber optic cable have been marketed. Most of these technologies are suitable for extremely long lengths of transmission piping and one system even uses satellite transmission of data to a central monitoring site in Europe. Systems such as this do not meet the needs of the Company. Through NYSEARCH, the Company became aware of Fiber SenSys Inc., who is interested in developing a shorter version of existing technology which would be more applicable to the needs of distribution companies.

Fiber SenSys proposed to develop a fiber optic cable which can be installed parallel to an existing gas transmission main, or alternately the cable can be incorporated into a new main installation. The system functions by detecting vibrations in the soil around the pipeline. The vibrations alter the characteristics of the laser light in the cable and can be detected and alarmed. Requirements are that the system be able to detect presence of commonly used excavation equipment, while recognizing and filtering out other acoustic signals that would be generated by benign threats such as truck or rail traffic. The system must perform in all types of soil that can commonly be encountered in the Company's territory. A NYSEARCH member company has offered a test site where a prototype system can be installed and tested. The target cost of the system, depending on length monitored, would be as low as $3000 per mile. The benefit to the Company is enhanced damage prevention and potential avoidance of a major pipeline accident due to third party damage. This project expanded on lessons learned from a prior project related to proactive monitoring for third party damage using fiber optic sensors. The project developed a system for shorter runs of pipe based on the contractor's (Fiber Sensys's) system for longer runs of pipe. The 'short ranger' system was tested and evaluated for gas distribution applications and its technical and economic feasibility was studied.

M2011-008 – BioBall Test Program. A NYSEARCH member company has worked with a technology company to develop a simple technical approach to accurately locate sewer laterals. The technical approach is to simply wind a length of copper wire on to a biodegradable "spool" which can be flushed down a commode in a residence. The wire will unspool and standard locating equipment can be connected to it and the location of the sewer lateral can be determined. NYSEARCH member companies want to determine whether the idea is feasible and have funded a test program. The Company has conducted a week long field test program on this technology. Results were mixed; in many cases gaining access to the residence was problematic. In those cases access to the sewer lateral was through an outside cleanout. Where the bioball did deploy successfully, location of the lateral was determined within +/- 2 ft. Interest in this project is high because of a concern with "crossbores," in which pipe installed via directional drilling inadvertently punctures a sewer lateral. The situation may not be detected for years until the sewer line clogs and a plumber is called by the homeowner, with potentially disastrous results.
The benefit of this technology is accurate location of sewer laterals and subsequent avoidance of a crossbore.

OTD 1.8.a - GPS-Based Excavation Encroachment Notification This project focuses on linking Global Position System (GPS) technology with digging operations to provide a warning system to prevent excavation damages to underground facilities. The objective is to develop and demonstrate a system to ensure that excavation activities are occurring within a valid "One-Call Ticket" area (which authorizes excavation) and are not encroaching upon underground pipes and facilities. The Company and other project funders are partnering with Virginia Utility Protection Service (VUPS), a "one-call" center for utility locates, that has been conducting pilot programs to demonstrate the feasibility of using GPS-enabled cell phones (Phase 1) and GPS-enabled locators (Phase 2), and excavating equipment (Phase 3) to call in excavation projects, access information, and prevent unauthorized excavations. The benefits of this project are more accurate and smaller "white-line" (areas needing markout) areas, more accurate locating, and warnings to excavators if they are excavating in unmarked areas. All of this reduces the threat of third party damage. The company is participating in a follow on project to implement a similar pilot program in upstate NY.

OTD 1.h and 1.10.c – Hand Held Acoustic Pipe Locator. Plastic pipe without tracer wire remains a vexing problem for LDC locating crews because standard electromagnetic locating techniques will not detect plastic pipe. Ultrasonic waves are ideally suited for this application because they will travel well through solid mediums (soil) but are reflected off of voids, air pockets or lighter density materials. The acoustic locator has shown that it can reliably detect plastic pipe. A follow on to this project (described next) will target location of sewer laterals, an important issue lately as more LDCs are using directional drilling to install gas mains. Accurate location of our buried facilities is the main benefit of this project. Completed 2013.

OTD 1.10.e – Enhancing Damage Prevention in New York. The objective is to conduct a pilot project to demonstrate the procedures and technologies for implementing an electronic as-built process and radio frequency (RF) tag based asset locating system. The proposed technology will automate the as-built process by using new high-accuracy GPS technology and aerial photography to document the location of newly installed facilities. RF tags will be used to enhance the locating and mark-out process by providing field personnel with additional asset location information. Phase 3 will develop a prototype system that allows the collection of highly accurate spatial data in urban canyons where traditional GPS technology is ineffective.

OTD 1.11.e - Crossbore National Database and Risk Model. As crossbores, where a natural gas line installed via trenchless construction methods, has penetrated a sewer main/lateral. For example, homes with sloping front yards and no basements may have sewer laterals that are close to the surface and therefore more likely to be intersected by a horizontal directional drilling operation. The objective of this project is to gather as many parameters as possible associated with crossbores actually identified in the field. In addition to the Company, other LDCs are gathering data on crossbores. There has not been a unified effort nationally to collect this data. By combining this data into national database users can identify those situations and field conditions where crossbores are more likely to occur in its own territory, and can prioritize and focus remedial action on the highest risk areas. The purpose of the database is to collect information on crossbores root causes, environmental and situational factors, and compile incident reports to facilitate the sharing of lessons learned and increase public safety.

OTD 1.12.b – Crossbore Detection Using Mechanical Spring Attachment
In the concluding phase of OTD 1.11.a, “Evaluation of Chemical Detection Methods for Detecting Sewer Lateral Crossbores,” one of the project funders suggested a brainstorming session for innovative ideas to detect crossbores. The leading idea is to use a simple spring loaded sensor on a drillhead that would “snap open” upon encountering a void, such as would happen if the drillhead suddenly penetrated a sewer lateral.
GTI engineers will design and test a prototype tool that will detect a hit to sewer laterals during the HDD or mole installation of PE gas pipe. The tool utilizes a low-cost and easy to use mechanical system that is attached to the HDD/mole head during drilling or to the PE pipe during pullback. The mechanical system is activated inside the sewer pipe void; thus locating the lateral and providing a real-time alarm identifying a hit. At the conclusion of the project, commercialization activities will begin. A simple yet accurate

method for detecting a crossbore in this fashion is a tremendous benefit to the company because crews are present to immediately rectify the situation.

Leak Detection and Methane Emissions

Rapid and more accurate leak detection and location (pinpointing) has always been a research focus for the industry and for National Grid in particular. We are funding the following efforts:

M2010-002/T-776 – Methane MR Sensor/ new Residential Methane Detector Development Program. NYSEARCH/NGA has been developing a small, reliable, intrinsically safe, line and/or battery powered, miniature methane (natural gas) sensor based on micro-resonator technology that measures the viscosity of a gas mixture. The sensor would be used in detecting natural gas leaks and other applications. The instrument is being developed for two applications; an analytical sensor for measurement with data output, and as an improved safety sensor for use in residential applications. Due to the high reliability and resistance to false alarms, this program has shifted its focus entirely to the residential sensing application. Following extensive testing of advanced prototypes, precommercial prototypes are being tested by UL and a pilot test program is being implemented following completion of UL testing. This project has produced a novel type of methane sensor using the principle of micro-resonance. The theory behind the sensor is that micro-size tuning forks will vibrate at different frequencies when exposed to a methane/air environment than it would in free air. This concept was uncovered during a technology search undertaken as part of the “Oracle” project. After extensive testing it has been found that this methane sensing device does not exhibit false positives in the presence of many household chemicals which is makes it superior as safety device over currently commercialized devices. It has not demonstrated any false positives.

The sensor is capable of measuring the methane concentration from 0% to 100% in air at different pressures, relative humidity levels and in a wide temperature range. The measurement range of primary interest corresponds to 0-100% Lower Explosive Limit (LEL) with the ability to measure gas concentrations up to 100%. [LEL for methane corresponds to approximately 5% methane/natural-gas concentration in air.] The sensor has a detection limit and an accuracy of 0.25% natural gas concentration in air. The sensor is capable of operating at various gas gauge pressures ranging from 30 to 110 kPa and temperatures of -20°C to 50°C. The response time of the sensor is targeted at 1 second or less. To verify and validate the performance of the MR Methane detector (safety sensor/alarm monitor) a pilot testing program will be implemented. Detectors will be deployed in residential settings to test them under real life conditions under a variety of operational conditions and environments. The following issues will be addressed: (a) having a sufficient number of installations, (b) covering a wide range of housing types, (c) evaluating different detector locations within the homes, (d) selecting locations that expose units to possible interfering chemicals (e.g., masking, false positive) and potentially damaging conditions (e.g., humidity, temperature, chemicals, insects), (e) considering the impacts of ventilation rates and air flow patterns in homes, (f) monitoring performance in all seasons, (g) monitoring performance at various elevations, and (h) validating detector performance before, during, and after the field trial.

M2014-002 - Leak Pinpointing Inside Pipe. The overall program goal is clear to design, develop and test an innovative system that can precisely locate gas leaks from inside the pipe. The selected technology needs to apply to a range pipe sizes, 2” – 12” in diameter. During testing the experienced JD7 operator inserted the instrument into the flow loop through an ALH/WASK valve fitting after the simulated leak was created and covered. The first round of testing was designed to determine if the JD7 could detect leaks of various sizes and pressures. This initial round of testing was performed without air flow (fans were off). The JD7 proved capable of detecting leaks as low as 6” water column pressure leaking at the rate of 0.12 scf/hr. and at our top simulated pressure of 40 psig with a leak rate of 52.5 scf/hr. The JD7 was also capable of detecting leaks at various pressures and leak rates in between these upper and lower tested limits. A second round of testing was performed. The JD7 was manually inserted down the test pipe and located the leak without knowledge of the leak location. This testing was conducted without air flow and with air velocities of 2.5 mph (one fan) and 12 mph (both fans). The JD7 located leaks at no flow as small as; 1) 0.70 scf/hr. at 12” water column and 20 psig, 2) between 5.23 and 8.33 scf/hr. at 2.5 mph air velocities at both 5 psig and 40 psig, and 3) at 12 mph air velocity with a leak rate of 52.5 scf/hr. at 40 psig. Although initial flow loop testing of the JD7 at Heath was a success, improvements should be made to the JD7 Gas Investigator in a proposed Phase II of this project in order to improve its efficiency of operational performance. These improvements should subsequently be blind tested in a buried flow loop containing simulated leaks with the capability of varying pressures and flows.

M2014-004 - Technology Evaluation and Test Program for Quantifying Methane Emissions. The overall objective of the project is to identify, test and validate what technology or technologies are available that can be applied from a mobile platform in an urban environment to quantify methane emissions rates.

M2015-002 - SRI Standoff Gas Flow Imaging and Analysis System. The overall objective of the approved program is to quantify the flow rate from gas distribution leaks using the schlerien optical imaging technique as applied on a portable, field-usable system.

OTD 1.9.a – GPS Based Leak Survey. The objective of this project is to develop and utilize a software application that automates leak surveying with GPS. Using standard GPS receivers a leak surveyor’s route is automatically uploaded to company maps and a permanent record of the actual route surveyed is created and preserved. The application attaches GPS coordinates to survey routes and leaks while electronically documenting work to demonstrate compliance. The application also allows the user to create and populate an electronic leak form that can be directly transferred to a back-office leak management system or a Geographic Information System (GIS). New leak detection equipment that is on the market will be linked via software to company maps or images to automatically track routes of leak surveyors, thereby creating a traceable record of survey routes walked. The benefits of this project are reduced time for documentation and more accurate record keeping.

National Grid funded an additional phase of the project to conduct an actual field trial of the technology in a select area in New York City. Due to Hurricane Sandy, the pilot was delayed until April 2013 and was completed in August 2013.

OTD 1.11.c - Methane Sensor The goal of this project is a low cost reliable methane sensor for in-home use or use in company facilities (gate stations etc.) to detect and alarm on the presence of methane in air. Instruments are available to do this but typically can be set off by non-methane hydrocarbons which could be present in a house basement, paint thinner or hairspray for example. The testing protocol was designed to test the accuracy and stability of the six KWJ MEMS sensors by testing them at various methane concentrations, different temperatures, different relative humidities, and different interfering gases. In order to execute the testing protocol a testing chamber was designed to monitor and control all of the different conditions. After the completion of several basic testing conditions, the project team concluded that further testing should be terminated. Termination of the testing was recommended for several reasons. Because of our concerns on the path forward of this project, National Grid elected not to continue this effort.

OTD 1.14.d - Field Measurement of Leak Flow Rate. The goal of this project is to develop an inexpensive and repeatable device that can provide a measurement of the gas-leakage rates in the field from Class 2 and 3 non-hazardous pipe leaks. The current phase of the project involves improvements on an alpha prototype and upgrading the technology to provide increased accuracy, precision, lower cost, and ease of use. In 2015, an enhanced prototype was placed in a test chamber and subjected to varying levels of methane at constant temperature and humidity. The prototype is Wi-Fi enabled and presents an access point that the user can log into. A web page is presented that displays the parameters being measured by the prototype and allows control of the sampling fan. This allows access to the prototype through a device that supports Wi-Fi and a web-browser. Additional work was performed in the area of calibrating the Figaro methane sensor that is used in the prototype. The goal is to develop an accurate calibration curve that relates the raw sensor output voltage to % LEL with corrections for temperature variation. The current version of the prototype measures the flow through the device accurately but is somewhat limited in the range of flows achievable. The flow sensor represents a constriction in the measurement path of the prototype. At this time a high-powered fan is required to draw samples through the system. GTI is currently considering replacing the thermal flow sensor with a rotating vane type that would lower the requirement on the fan and consequently on the overall power consumption.
The alpha prototype was demonstrated to OTD at the fall 2015 meeting. — A basic demonstration of the Phase 2 beta prototype is planned for the fall 2016 OTD meeting.

OTD 1.14.g - Residential Methane Detectors Program. In this program, several discrete initiatives are being addressed as tasks, with the initial work being a consumer behavior study to better understand how customers react to potential leaks and the development of a “Fit-for-Purpose” standard for residential methane detectors. This program also includes a comprehensive pilot program to evaluate commercially available detectors that performed well during laboratory evaluations. — A pilot testing program is currently under way, with detectors being placed in residential homes throughout the U.S.

OTD 1.15.e - Triple+ Shutoff Valve Pilot Program. Triple Plus Ltd. has made available the Triple+ NGL™ version 4.0 of its gas leak management system, a product capable of detecting gas leaks and automatically shutting off the gas supply and stopping the leak. The objective for this project is to perform controlled testing of the valve portion of the product. Researchers are collaborating with Triple Plus to evaluate a technology that combines a methane detector with an automatic shutoff valve as a safety solution to prevent risks due to leaks and other events (e.g., hurricanes, earth-quakes, floods). This unit is assembled in-line with existing gas systems. If a gas ball valve is installed, there is no need to cut, replace, or remove existing pipelines or valves. — Plans are being made for a testing program with OTD sponsors.

OTD 5.14.j - Residual Gas Removal - Identify Technologies, Limitations & Best Practices. This effort reviews current and new venting equipment and strategies utilized by gas operators to effect safe and timely extraction of in-ground residual gas. The presence of residual in-ground gas poses hazards to the public and nearby infrastructure, complicates leak pinpointing efforts and obfuscates effectiveness of performed leak repairs. A lingering presence of odorized gas can also generate secondary leak reports by the public for extended periods after a leak repair has been completed. Numerous equipment and strategies for venting and dispersing residual in-ground gas exist. A number of field visits to residual gas mitigation job sites were made to evaluate current practices and provide best practice guidance to the industry. In light of findings from industry surveys and sponsor discussions, the frequency of residual gas mitigations requiring more than natural venting strategies such as that provided from barholing, trenching or the use of vented manhole covers, was significantly lower than anticipated. Other traditionally employed devices such as aerators and air movers, that utilize pneumatic power to generate suction via the Venturi principle, are highly effective in the bulk of residual gas extraction scenarios. Though ultimately dictated by local soil and site conditions, the need to utilize dedicated or higher flow capacity vacuum extraction approaches is minimal and reflected by slow market uptake of specialty equipment such as Vapor Extraction Unit (VEU). Safety aspects and some factors dictating how best to elevate extraction efforts in dealing with persistent in-ground gas indications at the site of repaired leaks are summarized in the project report. Due to the low frequency of this issue and demonstrated effectiveness of the most simple, low cost strategies in the majority of residual gas removal scenarios faced by operators, it was agreed that there is no need to propose follow-on quantitative evaluation of techniques as of Q1 2015.

OTD 5.14.w - Testing Program for Valve with Water Sensor for Storm Hardening. In this project, researchers are evaluating a valve integrated with a water sensor to assist with storm hardening. Phase 1 testing was completed in 2015. Additional phases will be addressed based on development status and needs of the project sponsors. Evaluations involve a battery of tests, including: visual tests, pressure tests, debris tests, water-intrusion tests, corrosion tests, humidity testing, drop tests, and others. — A Phase 1

Final Report was issued in August 2015. Additional work continues in the development and addition of methane sensor to couple with the valve actuator.

OTD 7.15.b - Remote Gas Sensing and Monitoring for First Responders. The safety of workers, first responders, and the general public will be greatly increased by being able to monitor the atmosphere of buildings and other structures remotely. In addition, continuous remote monitoring of various gas levels during known gas leak situations will allow for better and quicker analysis of the situation. The remote sensors can be placed and/or operated in multiple buildings, sewers, and other structures in the area of the known gas leak. The remote device can wirelessly provide real-time information back to first responders, gas company personnel and others in charge of monitoring and assessing the gas levels in the structures. The objective of this project is to create a device to remotely monitor the level of gases during emergency situations. The device will provide critical information to first responders and gas company personnel, allowing them to determine the concentration of methane, CO, and possibly other key indicators inside buildings, sewers, and other structures from a safe distance.

Integrity Management

The passage of the 2002 Pipeline Safety Improvement Act – which required detailed assessments of all pipelines operating at 20% or higher of specified minimum yield strength (SMYS) - is the driver for this research for National Grid. National Grid is funding innovative research in the areas of wall loss sensing for unpiggable pipelines and novel methods to assess the condition of cased pipe. These challenges have resulted in the Integrity Management area being the largest R&D spending area for National Grid. Within the overall category of Integrity Management there are three project areas:

Robotics: In line Inspection (ILI) using smart pigs is considered the most desirable method of pipeline inspection among the three methods (In line inspection, Direct Assessment, Hydrostatic Test) specified by the US DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA), yet many of National Grid's older transmission lines are not piggable. To meet this challenge we participate in the NYSEARCH Robotics program which is developing robotic, self powered sensors for 6" through 36" transmission pipe. These inspection tools are battery powered and are launched "live" into the pipeline and communicate via wireless signal. Pipe wall thickness measurements are either remote field eddy current (RFEC) sensing or magnetic flux leakage (MFL) sensing. The robotics program has received significant support and cofunding from the USDOT and other industry outside NYSEARCH; to date about $8 million has been received from the USDOT alone. The benefits of this technology investment is pipeline safety, ILI, as mentioned, is the most desirable of the three mandated inspection methods, and savings can be considerable, though highly site specific. In this reporting period the Company has funded the following projects:

M2001-014 - Explorer 2026 Robotic Inspection System for Unpiggable Pipelines using Magnetic Flux Leakage (MFL) Sensing. Explorer 2026 is a live entry, battery powered untethered robot designed to enter and inspect transmission pipelines 20 in. through 26 in. diameter at pressures up to 750 psi. Wall loss measurements are by industry standard MFL sensing. The design of the robot and sensor specifically overcomes the restrictions that cause a pipeline to be designated “unpiggable.” These restrictions include short radius or back to back elbows, mitered bends, presence of plug valves (these are valves that do not have a full diameter opening and won’t allow a typical pig to pass through) or no/low flow conditions. The robot is launched “live” into a pipeline and travels under its own power along the pipeline taking wall thickness measurements along the way. Explorer 2026 is fully developed and has completed two of three field demonstrations at host LDC sites. It will be in full commercial operation later in 2013.

M2003-009 - Explorer 6/8 (Explorer II) Robotic Inspection System for Unpiggable Pipelines using Remote Field Eddy Current Sensing (RFEC). Explorer 6/8 is a live entry, battery powered, untethered robot designed to enter and inspect 6 in and 8 in diameter pipelines operating at pressures up to 750 psi. Wall loss sensing is through a novel sensor called “Remote Field Eddy Current” (RFEC) sensing. Development of this sensor was itself a separate R&D effort and the sensor represents advancement over state-of-the-art magnetic flux leakage (MFL) sensing. The reason this new sensing technique was developed is that traditional MFL sensing creates high strength magnetic fields and given the small diameter of these pipelines not enough robot power could be developed to overcome these forces and move the robot down the pipeline. The robot is specifically designed to overcome obstacles that traditionally cause a pipeline to be classified unpiggable, such as mitered bends, back to back elbows, and low or no flow conditions. The robot consists of drive modules, steering modules, cameras on front and back, and the RFEC sensing module in the middle. The robot is placed in a specially designed launch tube which is mounted on standard hot tapping equipment affixed to the pipeline. The robot is then launched into the pipeline under live gas conditions and travels down the pipeline under its battery power at about 15-20 feet per minute, collecting wall thickness measurements. After the conclusion of the “pig run,” data is analyzed and a report on anomalies found, if any, is made.

An important part of any R&D project is a serious and robust field demonstration phase. For this project, the Company served as a field demo site at its 6 in dia 473 psi gas transmission pipeline in Oneida, NY. During this 3 day demo, the Explorer 6/8 robot scanned over 4900 ft. of this pipeline and found no anomalies. This scan provided the company with added insurance that there is in fact no corrosion defects present in this high pressure gas main. This robot and its supporting technology has been licensed to Pipetel Inc, a robotic inspection services company in Buffalo NY, and is now in full commercial operation.

M2011-006 – Robotics Supporting Technologies. Modifications are being designed that will allow in-line battery recharging (to extend the range), new sensors to detect cracks, and a “rescue tool” that will allow a disabled robot to be retrieved.
In testing conducted to date, battery life is the factor most limiting the range of the robots. It was realized by the company and others that a more efficient way was needed to recharge the batteries than removal of the entire robot from the pipeline. The technology developer, Invodane Engineering Inc. conceived of an innovative method of recharging

the robot via an “in-line” charging system. A charging cable will be inserted through a small tap on the main and the robot can remain in the pipe while being recharged overnight. Based on recent industry pipeline accidents there is increased focus on sensors that can detect cracks. Although less of a threat than corrosion wall loss, crack sensing is the focus of new development efforts. The benefit of this technology is increased assurance of the integrity of the company’s transmission system.

A rescue tool” will be developed that will assist in the retrieval of a failed robot. This will give the company greater assurance that the robots can reliably be placed inside its piping network. On some critical pipelines this may be a requirement before the robot is placed in the pipeline. The project is designing, developing and testing additional sensors to add to NYSEARCH’s inspection platform for unpiggable mains. Supporting technologies that are being addressed under this project include mechanical damage sensor/ovality sensor, crack sensor, MFL sensor for 6/8, bend sensor, methods for cleaning the pipe at the launch point and ahead of the tool and methods for in-line active charging as well as a rescue tool for the commercial system. We are also developing and testing a hardness test module to add to the Explorer series of robotic platforms for internal testing of material hardness and yield strength.

M2011-009 – Explorer 30/36 Robotic Inspection System for Unpiggable Pipelines using Magnetic Flux Leakage (MFL) Sensing. The Company and two other LDCs are funding Explorer 3036 which addresses larger size transmission piping inspections in 30” through 36” pipelines. This project is still in the development phase and will incorporate all the features of the existing suite of robotic inspection tools such as live launching, plug valve and short radius bend negotiation, all in pipelines up to 750 psi operating pressure.

M2013-001- Explorer 16/18 - Inspection of Unpiggable Pipelines. This Special Project was an Accelerated Development effort cofunded by Invodane to design, manufacture, integrate sensors and supporting technologies and test prior to commercialization.

M2013-002 - RMD Crack Sensor using Eddy Current Technology. RMD has developed a new eddy current sensor that in early studies has shown promise for detecting crack defects. The new sensor is different from existing eddy current sensors in two regards: (a) it uses solid state technology instead of the traditional coils (which have inherent limitations in providing high accuracy and detectability), and (b) it is easily and inexpensively fabricated in inflexible and flexible substrates using mass production techniques. The combination of these two factors results in an inexpensive sensor with resolution and sensitivity superior to traditional eddy current sensors. This project first proved the feasibility of using their EC technology for the detection of cracks in natural gas pipelines and is now advancing to development and testing as well as integration onto the EXP series of robotic platforms.

Cased Piping: Research into cased pipe assessments is an important part of the transmission pipe integrity management program. Transmission piping placed concentrically within a larger "casing" is a common practice when pipelines pass under major highways, railroads or bodies of water. Assessing the condition of these "carrier" pipes within casings can be difficult if the pipeline is not piggable. The company is involved in several research efforts to address this important issue. The efforts consist of software tools to evaluate casings, and inspection hardware to perform inspections. A very promising technology is "Guided Wave," in which an ultrasonic signal is propagated along a pipeline from a remote location revealing flaws in inaccessible areas of the pipeline.

M2001-003 - Cased Pipe Risk Assessment Model. This project involved the construction of a software tool program that prioritizes casings in terms of relative risk. The program considers inputs including, but not limited to corrosion rate, degree of cathodic protection, presence of moisture and wall thickness of the pipe and categorizes casings in terms of probability of failure. Casings with higher risk scores can be scheduled for further follow up inspections while those with lower scores can be monitored. Consequence of failure can also be added to the model, thereby producing a total risk score, which is the product of probability of failure and consequence of failure. Depending on the degree and accuracy of the data that is input into the model, the model can also calculate time to failure in years. A follow on to this project involved lab and field analysis of corrosion rates in various environments. With this information, a corrosion rate can be entered into the model which would be most representative of actual corrosion expected in the field, and not theoretical (overly conservative) rates. This project benefits the company by allowing it to prioritize inspections of riskier casings first and perform remedial actions, if required, on those riskier casings.

M2007-001 - Mini-camera for cased pipe inspections. This is a crawler camera magnetically attached to the casing. It can navigate down the length of the carrier pipe returning video image of the pipe. The camera has been deployed successfully at several sites and a follow on phase to the project will incorporate ultrasonic sensors for wall thickness readings and humidity gauges to assess the presence of moisture (a key ingredient that can accelerate corrosion). The mini-camera does not, by itself, provide a complete assessment of the carrier pipe condition but is rather another "tool in the toolbox" when used with other assessment methods such as Guided Wave technology.

M2007-003 - Multi Technology Validation Testing for Cased Pipe Applications. This is a testing program for various technologies, which may have promise for inspecting wall loss and other defects on carrier pipes within casings. Technologies tested were guided wave, magnetostrictive sensors (an in-situ type of guided wave), the casing camera, and Time Domain Reflectometry (TDR). Some of the technologies tested are commercially available and some are still in the development phase. The results of this test program gave the company valuable information on to the effectiveness of these various inspection techniques. The two most promising are guided wave and the casing inspection camera. The magnetostrictive sensors were not as sensitive as traditional guided wave, and TDR, although promising, will not be seriously pursued at this time. A new phase of this project has recently been authorized which will focus on more detailed testing of guided wave. All tests are conducted at the NYSEARCH test bed, which is a network of above ground and buried pipe containing machined defects. This is an effective way to compare technologies as all tests are on the same piping components, and defect locations are known only to NYSEARCH staff. However, the company took an additional step and developed a test program for guided wave on its own in-service piping. This project is more fully discussed later in this report.

M2011-007 – Cased Pipe Inspection via Vents. National Grid has had success in its downstate territory with the mini-camera for cased crossings, described above, but the drawback to this technology is the requirement for costly excavations to gain access to the casing annular space at the end seal. An alternate approach is to gain access to the annular space from above ground, through small diameter vent piping which is present on casings. Technology to provide this visual inspection does not exist. The technical approach on this project is to use commercially available camera technology and adapt it to travelling down through the vent piping until it reaches the casing annular space. Through a technology search for new technology providers, NYSEARCH has qualified a small robotics company, Honeybee Robotics, to perform robotics work, and they will perform on this project in a two- phased approach with a go – no/go decision point after Phase 1. Phase 1 will demonstrate the feasibility of adapting existing technology to the task of negotiating the vent piping to gain access to the casing annular space. Such access will be constrained by the small diameter and sharp ninety degree bends that are normally present in casing vent piping. Cleanliness of these vent pipes may also be an issue. If the testing reveals that access to most typical casings can be gained, then the project will proceed to development of a prototype system that can enter the annular space and obtain meaningful information. The benefit is compliance with pipeline integrity management regulations at a significantly lesser cost than traditional means of gaining access to a casing. This project is focused on developing and testing concepts of a compact tethered robotic camera. The successful robotic camera is intended to provide the operator with insight about a cased pipe by gaining access to the annular space through a typical casing vent without requiring excavation.

Other Integrity Management Research

Included here are various projects that contribute to our understanding of, or help us meet, transmission or distribution integrity management requirements.

M2005-003 - Design, Construction & Operation of Regional Test Bed. An above ground and below ground pipe network that has been built specifically for testing new inspection technologies by member gas engineers. This 1200 foot network features different coatings, known anomalies of different sizes, varying soil types, varying welds with good and bad weld practices, different joints and other features for future use on other gas operations purposes. The test bed site is a NYSEARCH/NGA site that is leased from New York State Electric & Gas in upstate New York (Johnson City near Binghamton).

M2007-005 - TransKor Remote Inspection Testing (Magnetic Tomography). The magnetic tomography method (MTM) is a commercial, non-intrusive, above ground method of pipeline inspection developed in Russia by TransKor. Through NYSEARCH, the Company became interested in this technology as an additional “tool in the toolbox” for transmission pipeline assessment. Although other above ground assessment techniques are in use today, they rely primarily on detection of coating failures. MTM measures the inherent magnetic field surrounding a metallic pipeline and detects stress risers in the pipeline by analysis of the pipeline’s magnetic field. Stress risers are indicative of wall loss, welds, manufacturing defects, or mechanical damage such as dents or gouges. A test program is underway by the Company and other LDCs who are members of NYSEARCH to thoroughly test the capabilities and accuracy of the MTM. The ultimate goal of the test program is to evaluate the performance of MTM and have it recognized by PHMSA as an “other technology” suitable for transmission pipeline assessment. MTM could provide a significant benefit to the company’s Integrity Management plan by providing a much less expensive and more thorough assessment method which requires only a simple walk-over of the transmission pipeline being assessed.

M2009-001 - Holistic Review of Distribution Integrity Management Plan (DIMP) Risk Practices and Models. In 2010 the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued regulations requiring operators of natural gas distribution systems to implement a formal distribution integrity management program. The regulations are not prescriptive and don’t require specific types of inspections and assessments as do the transmission integrity regulations, but they require operators to risk rank their distribution system. The Company undertook this project to more fully understand exactly what type of risk modeling may be best suited to analysis of a gas distribution system. Some of the projects’ findings suggest that age of the distribution piping alone is not a complete indicator of risk, but other factors such as material type, location, and potential for operator error all factor into a relative risk ranking. Availability of data on the distribution system is also key to developing a reasonable and useful risk model. (For example, although age, material type and location of pipeline segments are certainly known, various component types or specific installation practices are not always known with the same certainty.) Conversely, overloading a risk model with too much specific data does not result in a useful risk tool either.
The final report on the project provides suggestions on a risk management approach and guidelines on making decisions on purchase or development of a specific risk model. The benefit is information and guidance to the company regarding the best method to risk rank its distribution network.

M2012-003 – Enterprise Level Assessment of Data Management Systems. This project addresses a relatively new requirement for gas distribution operations, namely to establish traceability – from initial manufacture to installation – of gas system piping components, and a means to track the location and installation parameters of these components, and integrate this information into existing company data management systems. The best methods of doing this, both from a hardware and software perspective, are being explored in this project. The company is funding this project to gain important information about this new industry initiative, but because we are conducting active field demonstrations via a similar OTD project (OTD 5.11.m) we will only be observers for this project.

OTD 2.11.d - RSD X-Ray. This non-destructive examination (NDE) method has advantages over traditional X-Ray. For example, radiation levels are reported to be lower, and resolution can potentially be higher. Additionally, images can be displayed in real time. As opposed to traditional X-Ray, which requires through-the-wall penetration from the radiation source to a film on the back side of the weld, RSD X-Ray works on the principle of backscatter, or reflection of the X-Ray signal. The detector can be outside the pipe, co-located with the source. Before such a new technique is adopted it needs to be tested to demonstrate that it is capable of identifying flaws in welds with the same sensitivity and accuracy as traditional X-Ray. GTI will work with the vendor of this equipment to perform blind tests to demonstrate this. The results of the blind tests will indicate whether the project should proceed and whether equipment and techniques should be developed for practical applications in the gas industry. If successful, this method of non-destructive examination (NDE) could also be applied to pipeline integrity assessments of existing transmission pipeline segments via incorporation on to a pipeline pig, or a robotic internal inspection device.

Using Nucsafe's Scatter X-ray Imaging (SXI) technology, the first iteration of this investigation utilized standardized PE disks with precisely measured defects placed in the fusion interface. The objective was to develop a repeatable methodology of introducing specific defects into the fusion interface and to scan a sufficient number of replicates that would allow probability of detection statistics to be calculated. A set of calibration specimens was prepared at GTI and sent to Nucsafe for scanning. The scan results showed that while the disks were detectable the interfaces between the disks and the pipe dominated the signal and masked the included defects in many instances. The initial approach was abandoned in favor of that utilized in OTD Project Number 2.6.e which was more successful.

OTD 4.7.g - Yield Strength Determination. Operators with incomplete records need a better way to determine the yield strength of their pipeline segments if it is unknown. Current regulations require that operators either take a full size cutout of the pipeline and subject it to laboratory testing, or assume a low value of 20,000 psi. Obtaining full size cutouts is disruptive to pipeline operations as it would require a full shutdown of the pipeline. Assuming 20,000 psi could result in the pipeline being in an (assumed) over pressure condition when in fact it may not be. GTI developed a method to determine the yield strength of a pipeline through lab testing of "sub-size" samples. The samples can be obtained easily by using standard hot tapping equipment without shutting down the pipeline. A follow on phase to the project will utilize sophisticated statistical techniques to possibly lower the number of sub-size coupons required for given lengths of pipeline. The benefit to the company is a less expensive and less disruptive method for positive determination of yield strength, should any of the company's records be incomplete.

OTD 4.8.a - Guided Wave Equivalent to Hydrotest. The objective of this project was to perform a validation effort to allow the use of GWUT as an acceptable inspection technique by demonstrating the ability of GWUT to perform equal to, or better than, a hydrotest. The specific objectives of this project were to perform the following: Compile data from GWUT inspections that have been validated by design, ILI, or direct measurement, Demonstrate that GWUT finds defects that would pass a hydrotest (therefore substantiating that GWUT will find all larger defects), and Provide a validated methodology for a new standard. Data collection involved gathering all available and acceptable data from prior GWUT inspections and the associated dig records (defect geometry, pipe diameter, wall thickness and grade). Data was only accepted and reported in this study if the GWUT could be verified through direct inspection. The collected data was used to calculate the failure pressure for rupture using the most conservative federally approved methodology, i.e., ASME B31G for all validated data points. The validation calculations were undertaken to confirm or substantiate the following hypothesis: GWUT misses no defects that would fail a hydrotest, and GWUT misses no defects that were found in the direct examination (i.e., determine the False Call Rate). The percentage wall loss vs. anomaly length diagrams plotted to B31G confirmed that GWUT is equivalent to hydrotesting. The GWUT methodology found all those anomalies that would have been found by the hydrostatic testing and GWUT also found anomalies that were too small to have been detected and would survive in a hydrostatic test to a pressure equivalent to the pipe's Specified Minimum Yield Strength (SMYS).

OTD 4.8.i - Extended Reassessment via Wax Fill of Casings. A proper wax fill of a casing eliminates the threat of external corrosion on the carrier pipe by removing any electrolytes in the annular space between the casing and the carrier pipe and replacing it with a dielectric medium (the wax fill). Although techniques for filling casings with wax are well known, there has been no known technique for validating the effectiveness of the wax fill operation so that assessment intervals could be extended. For this project, corrosion monitoring techniques and techniques to determine the completeness of the initial wax fill operation have been developed. Casings were filled with wax and monitored to determine the extent, if any, of corrosion. To simulate actual field conditions, water was left in some of the test sections prior to filling the annular space with wax as well as through ports made through the casing wall and water forced into created voids. Such testing conditions were extreme. Upon post examination, after 1 year of service, extremely low corrosion growth rates were found, at a much lower rate than would be expected. Longer term testing could provide additional data to verify if the corrosion rate drops, stabilizes or does neither over time. More work would be required to quantify actual corrosion rates over a longer time period

OTD 4.9.a - Leak vs. Rupture Boundary. The current Pipeline Integrity rule requires that all pipelines operating at 20% or higher of the specified minimum yield strength (SMYS) are subject to the more stringent transmission integrity assessments. (20% is thought to be the lower limit of pipeline stress at which pipelines fail by rupture). However, there remained questions as to whether 20% is a realistic lower limit. With the support of the USDOT, investigations of past failures coupled with detailed mathematical modeling can confirm that the 20% limit is overly conservative and a more realistic lower limit may be 30%. The Company may then elect to designate certain pipeline segments as covered under the new Distribution Integrity Management rules. GTI investigated over 20,000 pipeline failures worldwide and was able to draw conclusions as to the parameters that cause pipes to fail via leakage vs. rupture. Not only yield strength but also diameter, pressure, and toughness are factors that determine whether pipes fail by rupture or leakage. The project results showed that for most modern pipeline materials the leak-rupture boundary is more like 30%. Using the results of the project, operators can – with proper regulatory approval – place their pipeline segments in the appropriate integrity management program. The benefit would be that company resources can be directed to assessing the more vulnerable pipeline segments.

OTD 4.11.f and T 768 (non-Millennium Project) - Understanding Threat Interactions. Part of an operator's Transmission Integrity Management program is a relative risk assessment of the various threats that could impact a pipeline. There are various risk models in use that can quantify the relative risk of pipeline failure via the threats that are present. What is not so well developed is a ranking methodology that accounts for threats that can interact, or occur simultaneously on a pipeline segment. For example, what is the additional risk to a segment if external corrosion occurs on a manufacturing defect, or if earth movement occurs in an area with a defective weld? This project will examine a realistic combination of multiple threats that can reasonably be expected and will calculate the additional risk of failure to a pipe segment due to the presence of these interacting threats. This is timely work since the Company and others have been questioned during safety audits by regulators on their methodology for addressing interactive threats. This benefits the company by allowing the most accurate risk ranking and subsequent assessment of the integrity of those segments. Because this is an important issue the Company funded two parallel projects. The first is a short term effort through NYSEARCH that focuses on (but is not limited to) evaluating interacting threats through the existing Kiefner Model, which many LDCs use today. This effort took far longer than expected but an algorithm is now available (Nov. 2015) for use in determination of the risk associated with interactive pipeline threats. Yearly updates will be made to this model as incident data is reported and updated through the DOT under a 5-year contract with the developer. The second is a longer term more theoretical approach by GTI which could provide more overall flexibility.

OTD 4.12.b – Correlating Pipeline Operation to Potential Crack Initiation and Growth. Based on recent industry events coupled with new or proposed regulations, the gas industry is expected to increase the amount of pressure, or "hydrostatic" testing on existing pipelines. In addition to a standard pressure test (in which the pipeline is pressure tested to 1.5 times its operating pressure) there is the possibility that operators would be required to perform a "spike test" in which the pipeline is raised to 90% of yield strength (which could be significantly higher than a normal hydrostatic pressure test).
Such pressure testing, while having advantages over other integrity assessments, can cause cracks to initiate and/or grow. This has been observed in other industries (boiler tubes) but is not well understood in the gas industry. The Company is aware of the advantages of pressure testing but wants to understand the risks that could present themselves due to pressure and spike testing. GTI will leverage previous work done in

the boiler tube industry to develop a model to predict crack growth due to pressure testing. Validity of the model will be tested by subjecting actual pipe specimens to laboratory pressure cycling which can simulate years of pressure testing and/or pressure excursions in a matter of hours. The deliverable of the project will be a model that will relate historical and planned pipeline operations to potential crack initiation, growth and arrest. This benefits the company by insuring that pressure testing does not degrade the pipe segment being tested, with the associated possibility that the pipe could fail while in service.

OTD 4.13.a - DIMP Consequence Model. The objective of this project was to develop a model that quantifies the consequence of failure for distribution systems and DIMP based factors such as population density, proximity of critical infrastructure and business districts, failure mode based on material properties, gas migration patterns, soil and surface conditions, pressure and potential energy. The deliverable of this project is a DIMP consequence model that operators and software vendors can incorporate into existing risk modeling tools.

OTD 4.13.b - Demonstration of 3D Scanners for Anomaly Assessment. A validated tool that eliminates manual data collection of in-the-ditch anomaly measurements using a pit gauge will improve data quality and increase operational efficiency. Automating the process of measuring anomalies found through ECDA and ILI runs could be achieved through various 3D scanning devices. This project’s goals are to validate and demonstrate the performance of 3D scanners for automated in-the-ditch anomaly measurement and assessment of corrosion, dents and gouges. The two 3D scanners that were tested demonstrated the ability to provide more accurate and reliable anomaly assessments compared to manual pit-gauge measurements. Recommendations for further assessment include: 1) Evaluate the cost of the products in relation to the value that they provide in terms of improved data accuracy and reliability and time savings during data collection and management. 2) Ensure that 3D scanners are compliant with federal and state regulations.

OTD - 4.13.c EMAT Sensor for Small Diameter and Unpiggable Pipe. This project goal is to develop a bi-directional electromagnetic acoustic transducer (EMAT) sensor that can be used to assess small diameter and unpiggable pipelines containing reduced diameter fittings and other restricting features. Phase 2 focuses on constructing and testing a field-ready prototype based on the success of the bench-scale prototype sensor developed in Phase 1. This research will enable natural gas pipeline operators to identify defects that are traditionally difficult to find and assess and therefore improve system integrity and public safety. The EMAT sensor will be designed to find and characterize cracks in welds and pipe walls. PHMSA is co-funding phase 2 effort with industry funders of this project.

OTD - 4.13.d.3 - Hydrotest Alternative Ph 3. The third phase of this program is to identify and validate inspection and assessment technologies that are equivalent to a 1.25x Maximum Allowable Operating Pressure (MAOP) hydro-test for Integrity Verification Process (IVP) compliance. Phase 2 created the Finite Element Analysis

(FEA) critical flaw data and collected Probability of Detection (POD) data for Electromagnetic Acoustic Transducer (EMAT) and Acoustic Resonance Technology (ART) sensors. Phase 3 will create the critical flaw curves that will allow a comparison to In-Line Inspection (ILI) tool detection capabilities. The deliverable of Phase 3 will be a tool that operators can potentially use to demonstrate equivalence to a hydrotest for a specific pipe segment. The ability to use internal and/or external inspection tools to perform an integrity assessment as a regulatory acceptable alternative to hydro-testing would ensure the operator of the safety of the pipeline and provide significant cost savings in complying with new regulations. It would also provide operators an integrity assessment solution for those critical pipelines that cannot be taken out of service. Furthermore, hydro-testing may increase risk by introducing water that cannot be removed and may accelerate crack growth for certain susceptible pipeline materials. Acceptable alternative methods to hydrotesting are a critical need.

OTD - 4.14.a Fitting and Component Catalogue for IVP. The goal of this project is to develop a catalogue of legacy fittings and components to assist operators in identifying and characterizing assets to comply with PHMSA's Integrity Verification Process (IVP). The envisioned catalogue will contain pictures, descriptions, strength class ranges, and material and mechanical properties. A catalogue of legacy fittings and their characteristics will assist operators in complying with pending federal regulations, specifically the new IVP requirements. An industry catalogue will reduce the cost of gathering and compiling this information and provide support for strength requirements and assumptions when a fitting can be positively identified. This project has encountered issues with obtaining suitable documentation of data for inclusion in the catalog. Initially critical documentation had been located via the internet (only 2 copies existed) and one copy was ordered but the shipment never arrived. The other copy is not for sale and is owned by Chinese interests. Securing composite catalogs of vendor products and parts from the desired pre-1970 era are actively being worked and GTI is in the process of obtaining a paper copy of a large document from Gulf Publishing via loan that may include useful information. Digitizing and collating the potentially thousands of relevant vendor catalog pages from Gulf documents could ultimately lead to generation of a searchable online tool for LDC use. This effort would likely require significant resources outside the scope and budget of this project.

OTD 4.14.c - Surface Indentation for Material Characterization Correlation of Surface Properties Based on Vintage. There is a need to develop correlation factors to relate surface properties to actual material properties to allow surface indentation techniques to be used for material property validation for pipelines. These correlation factors will be based on pipe vintage by decade. Past research has proven the ability of surface indentation techniques such as stress-strain microprobes and hardness testing to accurately determine material properties of pipes within a localized area, but variations in material properties through the wall are problematic for local interrogation techniques. GTI will develop probabilistic confidence intervals that will allow operators to use surface indentation techniques by applying correlation factors to pipe materials that may have through-wall variability. The ability to characterize material properties, particularly yield strength, of in-service pipelines without taking the line out of service or removing samples will significantly reduce the cost of complying with existing and pending federal regulations. Backfilling records with material property information such as yield strength and toughness also improves integrity management through system knowledge that allows enhanced modeling and analysis. It is anticipated that the results of this research will facilitate the regulatory approval of stress-strain microprobes and hardness testing to characterize material properties of in-service pipe. It will also empower internal inspection tools (such as PRCI's signature pig under development or TDW's MFL tool that may be able to detect signatures) to use surface readings from the inside of the pipe to be applied to the entire pipe wall.

OTD 5.8.e - Tracking and Traceability. One of the requirements of a Distribution Integrity Management program is to "know your system." But there is no industry standard for manufacturers to mark gas piping and appurtenances with critical manufacturing information nor is there a standard for LDCs to record data when installing permanent additions to their gas systems. On the manufacturing side, date of manufacture and lot number need to be recorded in a standard fashion across industry, and installers need a standard way to record location of the installation and identify the crew doing the work. For this project, GTI and a subcontractor formed a steering committee to identify which commonly used materials should be identified, and what pertinent information should be recorded. The steering committee consisted of manufacturers and LDCs. An ASTM F2897 standard was developed to which capture the results of the Steering Committee's decisions and a bar coding protocol was agreed upon. A future phase of the project will develop methods to record, store, and retrieve, if necessary, data on installed components.

OTD 5.9.j - Gas Distribution Model. With Distribution Integrity Management Program (DIMP) regulations now in place, operators will be developing data collection strategies to ensure compliance. One tool that could help operators in this process is a non-proprietary, industry standard data model for distribution assets and operations. A standard data model, the Pipeline Open Data Standard (PODS) model was developed to assist transmission operators in managing their data and ensuring regulatory compliance. The PODS model is an open, industry-standard data model that has successfully been used for over ten years to reduce the cost of implementing software and improve interoperability for the pipeline industry.

Now with DIMP there is a similar need for an industry-standard data model for distribution assets and operations. Gas Technology Institute (GTI) initiated a program to develop the Gas Distribution Model (GDM) to meet this need with three specific purposes. First, the model will be used as a data exchange function between operator data models and vendor's software products to reduce the need for customization. Second, the model can store both transmission and distribution data and will facilitate vertical data integration. Third, GDM could be used as the primary data model for operators to avoid the need for internally developing a model. The Company engineers and IS personnel felt that such a data model would benefit the business and also would facilitate transition to the new SAP system. The GDM initiative brought together a diverse group of operators, vendors, and industry experts to collaboratively develop a GIS-neutral model that holds promise to reduce the cost of software implementation and improve interoperability. GDM is a flexible model that will grow and expand with continued use and development.

OTD 5.11.m – Intelligent Utility Installation Process (Asset Tracking and Traceability). This project will develop methodology and suggest field processes for capturing data during new installations. It is a logical follow on to the requirements of recently enacted DIMP regulations which require operators to "know their systems." It also will provide the means to implement the results of the "Tracking and Traceability" project which created an industry standard for manufacturers to mark their products with manufacturing data. A key component of the Intelligent Utility Installation project is to achieve standardization across industry. When this project is implemented the company will benefit by knowing precise attributes of its distribution system and will be able to quickly react to reports of possible defective pipe material or fittings.

OTD 5.15.b - Roadmap for an Enterprise Decision Support System (EDSS). By striking the proper balance between competing influences, operators will maximize business health. There is a growing realization among operators and regulators that ad hoc decision making, based on the latest crisis, is not the optimal method for enterprise management and ultimately system reliability, safety, and efficiency. The objective of this project to develop an Enterprise Decision Support System (EDSS) technology roadmap. The EDSS will allow LDC operators to integrate all data and business knowledge sources into a decision support system that will optimize policies related to: risk mitigation, safety, code compliance, customer satisfaction, environmental stewardship, efficient operations and future growth. It is increasingly necessary to optimize various operational decisions based on predefined rationale coupled with comprehensive knowledge of data/system inputs and a methodical risk analysis. Enterprise decisions and risk analysis that will be supported through this process include repair vs. replace vs. rehabilitate, predictive threat interactions and consequence of failure, risk based prioritization of O&M activities, scenario analysis for various risk mitigation strategies, economic analysis, amongst others. Additionally, new asset-based data streams are continually being developed as directed by distribution and pipeline integrity programs as well as the relative ease in which large volumes of system data can be collected. The EDSS will integrate these disparate data streams into a logical system capable of rationalizing the inputs to enable sound decision making. The deliverable of this project will be a well formulated roadmap that provides guidance on how to realize an EDSS. This roadmap will be used to execute a series of stage-gate linked projects that progressively move us towards the goal of a fully functional EDSS.

Plastic Pipe Research

The bulk of piping added to LDCs' networks each year is medium or high density polyethylene (PE), or plastic pipe. Last year alone, the Company added over 500 miles of such pipe to our system. Working with NYSEARCH and GTI, the Company is involved in several research projects designed to improve our understanding of PE performance and develop new products.

M2000-001 - PE Repair Sleeves for Damaged PE Pipe. As an alternative to squeeze off and cutout of minor defects on PE pipe, the Company and others are developing, through NYSEARCH, repair sleeves to reinforce PE pipe in the area of the butt fusion joint, or along the length of the pipe. During routine operations such as new service additions or main extension, minor damage – not causing leakage - can be noticed on the existing PE pipe that is uncovered. The substandard conditions noticed can be either a scratch or gouge on the pipe itself, or a questionable appearing butt fusion joint. The solution, up to now, is removal of the defective pipe segment. Removal is usually accomplished by first "squeezing off" ahead of and behind the pipe segment in question, then cutting it out and replacing it. As an alternative, the PE repair sleeve can be fitted over the defective area in question and fused on to it. The fitting is designed to withstand line pressures up to 124 psi but will not be installed if an active leak is present. The benefit of this technology is lowered repair costs and improved reliability of PE piping systems by reducing the amount of "squeeze-offs" made. These repairs can also be made without causing an outage, whereas a squeeze-off may require a short outage if the pipe is a one way feed.

M2006-002 – Butt Fusion Integrity. This project examines current butt fusion parameters such as pressure and temperature at the joint interface with an aim towards optimizing them. Through a novel test method, the "whole pipe creep rupture test" several test fusions are made and subject to this laboratory destructive test. This test more accurately simulates stresses that actual in-service pipe experiences, and results of these tests can serve to further refine butt fusion parameters and associated procedures.

M2008-010 – UV Degradation of PE Pipe. The Company wants to understand, through testing, what the real time limit for PE pipe to withstand UV exposure without a harmful effect would be. Current USDOT regulations specify two years but the current version of ASTM D2513 (the industry standard for manufacture and use of PE pipe) specifies an outdoor storage limit of 3 years for medium density PE pipe and 10 years for high density PE pipe. But this current standard has not been accepted by the USDOT, who recognize the previous version which limits outdoor storage to 2 years. This project was undertaken to demonstrate, through testing, that pipe stored outdoors longer than 2 years is still suitable for use. Both non-destructive and destructive tests have demonstrated that pipe stored outdoors for three years is suitable for use. The work now is to present the information to the USDOT and request a rule change. The benefit to the Company will be immediate; National Grid recently discarded over $300,000 worth of PE pipe that exceeded the 2 year requirement.

M2009-008 – Ultrasonic Inspection Device for PE Butt Fusions. The aim of this project is to develop a field instrument to rapidly and easily examine butt fusions in the field, providing on-the-spot assurance of the integrity of a newly made butt fusion joint. A low cost user friendly butt fusion inspection device has been a goal of gas industry research for quite some time. Such a device gives greater assurance of butt fusion quality by allowing "on-the-spot" inspections by field crews or supervisors actually doing the work. The Welding Institute (TWI), located in the UK, is a leader in plastic pipe research and was selected to carry out this work in a phased approach. In the first phase, an instrument was configured to examine and return information on the presence or absence of flaws in the butt fusion. The next phase of the project is to determine which flaws can be accepted and which will cause the pipe to fail. This is done via destructive testing; fusions with varying degrees of flaws are subjected to testing and a “library” of flaws is developed and flaws are categorized as either “causes failure” or “does not cause failure.” Based on similar European technology for metric sizes, the objective is to develop and test a nondestructive tool for examination of butt fusion joints (particularly for use with advanced PE materials). This project has taken advantage of significant research already performed by The Welding Institute (TWI) for the European gas and PE piping industries. Extended long term testing is being performed because the test protocols/data from Europe showed that U.S. failures do not occur as rapidly and to test to failure, different conditions needed to be imparted. The significance of this extensive testing is that NYSEARCH and TWI are developing acceptance criteria for use in a tool that does not require a trained technician. Other phased array NDE tools are either not state-of-the-art OR they require a trained technician. In its final form, the instrument will examine field fusions and compare them to fusions in the “library” and be able to give a simple “good fusion” or “bad fusion” reading. The benefit of this work is greater assurance of the quality of a butt fusion and increased safety and reliability of the gas distribution network.

OTD 5.13.c - PE Pipe Splitting—Technology Evaluations, Enhancements, and Standardization of Tool Kits A research team is evaluating and refining existing PE pipe-splitting equipment and developing guidelines. In October 2015, manufacturers performed various pipe-splitting activities with plastic-pipe-replacement construction techniques. — Researchers are seeking additional field sites for this project.

.

Live Inspection, Maintenance and Repair

The Company is always looking to minimize customer downtime or gas main shutdown during routine maintenance activities. The following projects help us meet this goal.

M2001-006 - Development/Testing/Commercialization of Real Time Gas Distribution Sensor Network - Phase I-V. This distribution sensing system is intended to provide network sensor data acquisition, robust wireless communication and encrypted data accessible for pipeline monitoring and assessment. Data from these real-time sensors will include pressure, temperature, humidity, flow volume, and direction. The objective of the program is to complete development and testing to the point where Enetics/Telog can commercialize the technology.

M2008-003 - Evaluation of Rapid Crack Propagation. A study to model and test the existing ISO correlation formulas used to determine rapid crack propagation in PE pipe. Through this project, it has been determined that existing formulas are overly conservative and need to be changed.

M2014-001 - sUAS Technology - Regulatory & Technology Assessment. The objective of the project is to evaluate regulatory issues and technology of small unmanned aerial systems (sUAS) devices as applied to gas industry inspections and surveys. Further, NYSEARCH has been investigating development of methane leak detection module and control system capable of using at tree-top level for leak survey and methane emissions measurement on a sUAS.

M2014-005 - Critical Valve Operability. The objective of the project is to develop a method of confirming valve position and provide validation of a critical valve operability test.

M2016-001 (Millennium); T-770 and T-776 (non-Millennium) - Cured In-Place Composite Liners projects and Technology Transfer, Demonstration & Post Mortem Testing of Cast Iron & Steel Pipe Lined with Cured-in-place Pipe Liners. The objectives of the project were to: 1) gain understanding and support from regulators using Cured-in-Place Pipe (CIPP) Liners as a rehabilitation technique for cast iron and steel pipe, 2) provide an engineering assessment to advance the understanding of liner/host pipe interaction and demonstrate structural equivalence towards repair/remediation of lined pipe/appurtenances, and 3) validate the effectiveness of CIPP-lined cast iron and steel pipe through examination of past studies & further demonstration and lab testing.

M2016-001 (Millennium) - Chemical Longevity & Post Mortem Slow Thermal Cooling Testing of Field Aged Cured-In-Place Lined (CIPL) Cast Iron and Mechanically Joined Steel Pipe. The primary objective of this proposed Phase II project is to further address regulatory concerns by testing field aged extracted cured-in-place segments as they interact with host steel or cast iron pipe to demonstrate the actual impact of slow thermal cooling and perform chemical aging longevity evaluation tests to (100) years. Six test segments of CIPL pipe, three steel (12”-16” diameter) with a mechanical coupling, and three for cast iron (12”-16” diameter) are proposed to be extracted after years of gas service and will be further tested using a solid foundation of protocols by scientists at Cornell University. The cast iron pipe will be flexed to create a circumferential crack prior to testing. Project goals include: 1) performing thermal testing to simulate actual slow cooling in the field, and, 2) conducting independent tests to examine the chemical longevity of a new CIPL pipe to a (100) year life cycle equivalent, 3) completing a workshop with funding member SME’s and Cornell professional staff on “best practices” for evaluating corrosion and structural limitations of host steel and cast iron pipe segments, and, 4) providing a platform that encourages industry and regulatory dialogue regarding the use of CIPL pipe as an option for the renewal of our aging pipeline infrastructure. This will involve preparing information so that the gas industry sponsors develop a unified approach to addressing levels of host pipe corrosion acceptable for CIPL use in field aged CI or steel pipelines.

OTD 2.11.a - Above Ground Leak Repair Systems Testing. The Company and other LDCs desire to qualify various repair products that are sold for repair of above ground leaks on natural gas piping as a permanent repair system. The application is for above ground meter piping on distribution systems. No use of these products on below ground piping is contemplated. Two available products are being tested. Initial tests will be short term testing to establish the proof, or “burst” pressure of the repair system. These tests

are complete with burst pressures found to be well above (by an order of magnitude) normal operating pressures. Plans for long term testing are now underway.
A successful outcome of this project would be that these repair systems would qualify as a permanent repair thus repairs can be made more inexpensively than a shutdown and rebuild of meter piping, with the associated inconvenience to the customer.

OTD 2.12.e - Selection of Liners Composites for the Rehabilitation of Distribution and Transmission Lines. This project is an evaluation of the use of composite pipes and cured-in-place (CIP) liners in the rehabilitation of gas distribution and high-pressure lines. The replacement and rehabilitation of these pipeline systems in congested, urban areas with very limited right of way space is particularly problematic. This project investigates the trenchless rehabilitation options of these pipes.

OTD 2.13.b - Guidelines for Special Permits for Structural Composite Rehabilitations. The objective of this project is to develop guidelines for submitting special permits to state and federal regulators to request approval to use composite materials for structural pipe rehabilitation. The need for new techniques to repair and replace pipe will continue to increase as infrastructure continues to age. While open trench replacement will be the most cost effective technique for many applications, some situations will require the use of trenchless or alternative techniques that use the host pipe as a conduit for installing a new pipe. Composite materials hold much promise for rehabilitating aging infrastructure, including high pressure pipes. Composite materials can have properties that are superior to steel and can be installed in flexible configurations. Guidelines for submitting special permit requests will reduce the cost and time associated with filing the application. Guidelines will also improve the likelihood of obtaining approval through a special permit by ensuring that permit applications are complete and address the issues that are of interest to state and federal regulators. Other means are being explored for regulatory acceptance, as such; this project is temporarily on hold.

OTD 2.13.c - Long-Term Evaluation of Liners and Composite Pipe Materials. An engineering assessment was conducted to improve testing methods for predicting the long-term performance of liners and composites used in the rehabilitation of aging gas distribution and transmission lines. The focus was on high-pressure (up to 350 psig) composites and liners installed using trenchless technology. — A Final Report containing guidelines is being prepared.

OTD 2.14.a - Composite Repair Wrap for Polyethylene Systems
Researchers are evaluating a new composite pipe-wrap system for the repair of damaged PE gas pipe. Efforts are under way to establish the correct combination of adhesive and wrapping material. — Repaired specimens are being monitored under long-term hydrostatic pressure testing.

OTD 2.14.b - Steel-Pipe-System Repair Technique
A novel repair method for live leaking steel-infrastructure applications was developed and tested. The method uses a mold, resin, and composite wrap to provide safe,

permanent repairs. The goal is to have the technique applicable to steel couplings, threaded joints, cast-iron bell joints, and service tees. Testing is complete and a patent for the technology was filed. — A Final Report is being prepared. Discussions with potential manufacturers are under way.

Trenchless Technology

The Company's primary research effort in this program area is to find ways to complete maintenance with minimal excavation. These technologies will lower cost and result in less disruption to the customer.

M2010-001 – Service Tee Renewal The purpose of this project is to develop a means to renew a service tee under live conditions without an excavation. Gas mains can be rehabilitated via cured in place lining with minimal excavations. Steel service lines are routinely renewed by inserting plastic tubing, with no need to shut the main down. An alternate process, called "Renu" seals the interior of a steel service line with access gained at the meter. The weak link in this process is the service tee, usually made of carbon steel, which is not routinely replaced during the above mentioned gas main and service rehabilitation projects. The Trenchless Technology Center, retained by NYSEARCH to conduct this research, focused first on an appropriate sealant that would effectively seal the interior of the service tee. Spray coatings, liners, and mechanical seals were investigated. A hybrid mechanical seal concept was judged the best of the three alternatives but significant design challenges existed, mostly related to delivery of the sealing system down the length of the service line to the tee (up to 100 ft in some cases). Because of the uncertainties associated with these approaches the Company and the other funders will request proposals for alternate solutions.

T 773 (non-Millennium) - Trenchless Replacement of Small Diameter Steel Gas Service Lines. The objective of the project is to design, develop and test a new system for extracting small steel services, bare or wrapped in the size range of ¾" – 1 ¼" diameter to replace them with same size or larger size PE pipe. If successful for the smaller steel services, the contractor and cofounder also envisions a Phase II to address steel services with diameters of 1 ½" and larger.

OTD 2.8.e - Structural Liners – Technology Search. Large diameter cast iron mains can be effectively rehabilitated by lining them and Ngrid has been using this technology successfully since 2003. The current approved liner for use on gas systems relies on the structural integrity of the host pipe. For this reason, lining is generally limited to cast iron or protected steel pipelines. If a liner could be developed that had structural properties (meaning it would resist external loads such as traffic loading) more pipelines could be candidates for lining.

Four liner manufacturers who make structural liners for other industries (water) were contacted and their products' capabilities were discussed. One manufacturer seems to have a product that may meet the requirements for gas service and further evaluations will be required. This project would benefit the Company by expanding the available pipelines that could be rehabilitated by lining as opposed to replacement, resulting in lower cost and less disruption to the community and customers.

OTD 5.10.f – Cold Assisted Pipe Splitting One of the methods to renew deteriorated steel pipe is to split it by pulling a tool with cutters through it. A new length of PE pipe is attached to the rear of the cutter. When the cutter emerges from the pipe, the new length of PE pipe remains as the new gas carrier. This can be a cost effective rehabilitation method but many times the splitting operation is difficult because of the ductility of steel pipe. This project investigated whether liquid nitrogen or some other cryogenic liquid could lower the temperature of a steel pipeline to a level at which the pipe would transition into the "brittle" zone and be easier to split.
GTI Engineers determined that the quantities of cryogenic liquid required would be excessive, and further found that during testing; the cooling effect was not uniform through the length of the pipe. Since the project had reached a go / no-go milestone the Company decided not to continue further funding.

Gas Quality

The gas supply picture for the Company's service territory – and indeed for much of the nation – is evolving, and unconventional supplies such as LNG, shale gas, biogas, and gas from other geographic regions will soon be a part of our supply picture. While research into supply itself is outside the scope of the Millennium funding mechanism, the effect that these diverse supplies may have on our existing infrastructure is a new and growing R&D area for us.

M2005-005 – Gas Interchangeability for Installed Components A multi-phase study investigating LDC coupling components and associated materials and whether varying gas compositions in a range of temperatures and pressures can create leakage in the couplings. This project studies the effect that a wide range of future expected gas supplies from non-traditional sources may have on installed infrastructure components such as gaskets, O-rings, seals, and diaphragms. Anecdotal evidence exists that suggests that gas supplies outside of normal expected limits may have been the cause of component failure in two east coast LDC distribution systems, but no definite conclusions can be reached, and no similar studies have ever been undertaken. This test program is designed to determine, through controlled laboratory testing at GTI test facilities, whether gas composition changes affect the performance of elastomer components mentioned above. Baseline and test gasses were agreed upon and procured, and infrastructure components were removed from the field and sent to the GTI lab for testing. Components are cycled through a "baseline" gas (the gas normally expected) and then cycled through several "test" gases (representing future expected supplies). During this cycling, pressure and temperature are also varied. The results of this test program will allow the Company to take action by removing and replacing components determined to be "at risk" or set new supply tariff limits with a scientific basis for setting them.

M2011-002 - Storage Effects on Gas Quality - A portion of the gas entering the Company's system comes from underground storage in geological formations. There is anecdotal evidence that gas leaving storage can have different properties than gas entering storage, for several reasons. These reasons can include presence of water or other substances in the storage formation, temperature variations in the formation (which could affect dew point), blending (or lack of blending) and others. None of this is well understood or modeled. The Company would like to understand this better from the perspective of the ultimate effect on our distribution system. This would help us better negotiate tariffs for gas delivered that would not have harmful effects on pipe materials as well as gaskets, seals and diaphragms. NYSEARCH commissioned a subcontractor for a two phase effort; the first phase is a literature search which will identify the key parameters that affect gas quality in storage. Assuming a successful outcome of the first phase, a second phase would develop a predictive model so that ultimate gas qualities can be more accurately projected. This benefits the company by enabling it to better predict quality, set tariff limits that recognize the potential for change in the quality of the gas in storage, and ultimately insure the integrity of our infrastructure.

M2011-003 – Odor Masking. Odor Masking is a phenomenon recently observed in gas distribution systems in which the odorant, although present in the required concentrations, is not perceptible to the human sense of smell. It is manifested by no odor or a markedly different odor than is usually associated with natural gas. This is different from Odor Fade, in which the concentration of odorant is lowered due to its being absorbed by the pipe (common in new piping systems) or by trace constituents in the gas stream. The Company is concerned about this issue because absence of the characteristic gas odor will prevent recognition of gas leaks or other hazardous situations.
Odor Masking is not well understood but the Company and other NYSEARCH members are working with Cardiff University in the UK and a professor there who has done some research in this area.

It is known that pairs of compounds, called “antagonistic pairs” can act together to change the perception or intensity of an odor and that this reaction actually occurs in the human nose or brain. In Phase I of this project, researchers at Cardiff University have demonstrated that certain chemicals that can be present in a natural gas stream can mask the odor of some sulfur compounds that are commonly used in odorant. This was shown by actual tests involving volunteers at the university who ranked the intensity and pleasantness of these chemicals before and after mixing. The Phase 1 work will attempt to identify as many of these antagonistic pairs as possible. In Phase II, just beginning now, researchers will attempt to identify where this human response is taking place. This is important because it will lead to certain mitigative strategies depending on where the response takes place.

The ultimate goal and benefit of the project is a practical pipeline operator guideline on how best to mitigate this phenomenon. For example, the guideline could call for tariff limits on certain trace constituents be set at a lower level, or it could recommend the use of certain odorant types that are more resistant to masking. A successful project outcome would eliminate the situation where a gas leak goes undetected with potentially catastrophic results, such as the Texas school explosion in 1937. The project identified the causes and mechanisms associated with a phenomena that is not fully understood, odor masking. The overall goal was to develop guidelines to mitigate odor masking and anticipate issues that arise from variations in gas quality. While the mechanisms were identified and confirmed, the program did not move to distinct measures for mitigation due to results that unveiled more issues to resolve in terms of human variability in terms of concentration sensitivity. Status is "Complete" until parallel work determines need

M2013-003 - WKU Advanced Chemical Sensor. Through the TecFusion/Oracle program, NYSEARCH identified the smart nose technology of Western Kentucky University (WKU). This technology uses nanosensors to develop a smart nose that is rather sensitive and can be used to also detect a certain gas signature. The Western Kentucky University (WKU) project first completed a feasibility study for using an "artificial nose" system to detect a series of analytes of interest to the natural gas industry. The nanosensor technology leads itself very well to small, low power instruments, ideal for field deployment. This project is now advanced to development and testing of advanced prototypes.

OTD 7.8.a – Pipeline Quality Biomethane: Guidance Document for Landfill and Water Treatment Conversion. This is a national study and sampling program to determine acceptable gas quality for introduction of landfill and wastewater-derived biomethane into Ngrid's distribution system. No such standard exists in the US today. Information was assembled on landfill and wastewater biogas production, treatment, gas quality standards, and test protocols surrounding biogas production and use. A lab test program was executed testing raw and processed biogas samples for over 400 chemical species. A guidance document was prepared for safe interchangeable use of landfill and wastewater treatment biomethane in LDC networks. The results of this project show that these biomethane sources can be safely introduced into LDC networks.

OTD 7.9.c – Assessing Acceptable Siloxane Concentrations in Biomethane
Siloxanes are a class of compounds that are silica-based and found in many personal hygiene and health care products. As such, they enter waste streams and can be found in biomethane produced from landfill or wastewater biogas cleanup systems. There is evidence that siloxanes, when combusted, can result in excessive deposits of silicon dioxide on boiler tubes or gas turbine blades. The Company is also concerned because the effect of siloxane on standard infrastructure components is unknown. GTI is assessing industry data and attempting to determine what levels of siloxanes in biomethane would lead to issues with end use equipment or pose indoor air quality issues. In addition to the acceptable concentration of siloxane, other unknowns must be understood, such as where, and at what ratio, the biomethane enters the LDCs' distribution systems, and what flows and velocities can occur at the end use equipment. This project fills an important knowledge gap and allows the company to prepare for the introduction of another non-traditional supply into our existing infrastructure.

OTD 7.10.a – Trace Constituents in Natural Gas. Significant research to identify the complete range of trace constituents in natural gas has not taken place in 20 years. In that time span, non-conventional supplies are entering LDC systems and these supplies are expected to have trace constituents in them. The objective of this project is to build a database of trace constituents specific to current supplies of gas flowing into LDC systems. The Company will use this database to assess new gas supplies from unconventional sources such as shale gas to see whether these new supplies are compatible with existing supplies. Routine analysis of natural gas supplies is an established practice. Heating value, specific gravity, hydrocarbon content, and some inerts such as nitrogen are measured periodically, but trace constituent analysis is not routinely done. A partial list of trace constituents of concern would include halocarbons, volatile organic compounds (VOCs), siloxanes, ammonia, trace metals, and bacteria. Comprehensive knowledge of the presence and amount of these constituents would allow intelligence to be placed on setting limits for these constituents in future supplies.

OTD 7.10.b - Odor Fade. Odorants used in the gas industry in North America all contain sulfur, carbon, and hydrogen and belong to a category of chemicals known as organosulfurs. The most common odorants used are alkyl mercaptans such as t-butyl mercaptan, alkyl sulfides such as dimethyl sulfide (added to lower the freezing point of the mixture), and tetrahydrothiophene (a cyclic odorant). This project was designed to investigate causes of odor fade in natural gas distribution systems. A preliminary literature survey reviewed the availability of current and historical data. It concluded that the primary causes of odorant fading include: 1) surface interactions of odorants with different pipe materials, 2) scrubbing or dissolution by condensates or cleaning fluids, 3) chemical reaction/oxidation of odorant with other components in the gas stream, and 4) other system state variables. Thermodynamic prescreening was one tool used to look at the possible reactions involving more common blend stock odorants. In addition to forming (mainly) disulfides and iron sulfides, mercaptans might also decompose or react with trace gas processing constituents (e.g., methanol). Analysis of data collected by funders over the study period indicated that: most odor fade events were reported to have been prompted by weak sniff test results and most respondents reported performing follow-up quantitative analyses. No instances of solvent odors were reported. Two odor fade events were reported with plastic (PE) pipe, the others with steel pipe. Ambient temperature ranged from 20-90°F. All events involved a single source of natural gas. No pipe cleaning was mentioned as having been employed by any of the respondents. Odorants involved were t-butyl mercaptan mixtures with either dimethyl sulfide, i-propyl mercaptan, or tetrahydrothiophene; no odorizer operational issues were noted. Supplementary odorant injection was employed to increase odorant levels by all but one of the respondents. Findings include: analysis of TBM loss in plastic pipe with respect to temperatures. THT loss with respect to temperature, TBM reactivity with steel pipe vs. plastic pipe material, and steel pipe and odorant levels of TBM and THT in relation to presence of rust. When water was introduced into the steel reactor, the rate of loss increased further. Water by itself had no effect (as seen in the inerted reactor tests), but had a significant effect when iron was present. Initial modeling of the 1-step versus multi-step reaction mechanism showed the multistep mechanism to be more robust. The information gained in this project was used to prepare a suggested revision to Chapter 7 of the current edition of the AGA Odorization Manual, last revised in 2000. This study was completed end of 2014

OTD 7.11.a – Gas Quality Resource Center. The Gas Quality Resource Center is intended to provide technical support necessary to identify and fill knowledge gaps regarding potential industry issues associated with changes in gas composition profiles in North America. The Resource Center will provide a centralized "clearing house" for information related to gas quality, analysis of current flowing gas supplies in North America, identification of constituent trends across identified regions, analysis of current technical regulatory trends associated with pipeline tariff negotiations and identification of research needed to help fill information gaps ultimately aimed at maximizing supplies while balancing the needs of pipeline integrity and end use concerns. The resource center would maintain information on gas compositions and pipeline tariffs, and would serve to identify and launch research as appropriate related to gas quality issues. Issues such as odor masking or siloxane levels are examples of the types of research that could result from the Company's participation in the Gas Quality Resource Center.

OTD 7.11.b – Trace Constituents Sensors This project will identify candidate sensors or sensor technologies for measuring, perhaps in real-time, trace constituents in new gas supplies, such as landfill gas, biomethane derived from a variety of biomass sources, and unconventional supplies such as shales, tight sands and coal bed methane. The Company is aware that its future fuel mix will include renewable and unconventional gas. The need to understand the composition of a new gas supply and to monitor its components is increasing as the number and variety of sources grows along with their frequency of introduction into the natural gas pipeline network. The project will proceed on a phased approach, future supplies must be identified, and constituents of concern present in these supplies also need to be identified. For some new supplies such as landfill gas, research into gas trace constituents had already taken place, for others for example shale gas, less information exists. Once the constituents have been identified, instruments that can sense these constituents will be identified and assessed. The benefit of this work is the ability to monitor the composition of new gas supplies and the associated capability of protecting our distribution assets.

OTD 7.15.a - Real-Time Gas Quality Sensor. The introduction of shale gas and upgraded biogas into the gas transmission network is increasing the importance of accurate and regular monitoring of the natural gas heating value and composition. Currently used gas chromatographs (GC) are expensive and slow. The project objective is to demonstrate development of a practical, reliable, and real-time gas quality sensor (GQS) that can detect changes in gas quality (heating value, and concentrations of methane, ethane, propane, butane and carbon dioxide concentrations) in real time and can provide this data to the operators of an LNG plant or other facility.

Environment

Projects in this area are focused on new technologies to more easily and cost effectively remediate MGP sites. A more recent focus in the Environment area is related to Climate Change Concerns.

M2001-002 – Management of Impacted Sediments. The company formed and led this project, which was funded by other NYSEARCH members as well as a national consortium of industry and the US Navy. This project studied the correlation between polycyclic aromatic hydrocarbon (PAH) concentrations in manufactured gas plant (MGP) sites and the actual bioavailability of these compounds to living organisms, with the goal being more realistic guidelines for site remediation. Not all PAHs at MGP sites are actually bioavailable, and therefore harmful, to organisms and the environment. This project developed a new analytical method to determine actual bioavailability. Benefits include the potential of a greatly reduced remediation area. A final report has been submitted and accepted by the project funders as well as the USEPA, the NY State DEC and the NY State Department of Health. In February 2012 the NY State DEC issued a remedy decision based on the new analytical method for the city of Hudson NY (Water Street) company site. Savings realized for this one remediation are approximately $26M.

M2008-006 – Expanding the function of No Blow Tools. Tools to make “live” taps into gas mains are commercially available but during certain operations small amounts of blowing, or escaping gas are present. A set of innovative tooling was developed to enable plug insertion or removal, or insertion of stoppers. This benefits the environment by reducing the amount of methane (a greenhouse gas 21 times more potent than carbon dioxide) released into the atmosphere, and also contributes to worker safety. A second phase of the project developed an innovative method to reinject gas into an adjacent main segment rather than blow it off to atmosphere during a special test called a “flow test.” This method reduced greenhouse gas emissions and lessens customer concerns and complaints.

M2009-003 – Adaptation to Climate Change. The company and others recognize that there are two aspects to climate change, how we, through our methane and CO2 emissions, affect climate change, and how we, as LDCs, adapt to climate change effects and impacts that are certain to occur in the future. To meet this latter goal the Company and others commissioned a study that investigated a range of future climate models, predicted maximum and average expected temperatures and sea level rise, and developed a framework for estimating risk and remedial action to address those climate changes. Phase II examined more detailed flood risks at the local level for sponsoring companies. The benefits of this project will be the development of a gas-industry specific risk-based framework for addressing the impacts of climate change on a broad geographic level to give LDCs quantitative information on which climate effects and impacts to focus on and which portions of our natural gas infrastructure are most susceptible to those climate impacts. A final report has been issued and sea level rise has been identified as the main threat to a natural gas distribution system.

M2010-002/ T 776 – Methane MR Sensor/Residential Methane Sensor Pilot Testing Program. See details under Leak Detection and Methane Emission section of this report.
M2010-004 – Soil Vapor Intrusion The work in this project involves characterizing manufactured gas plant (MGP) coal tar vapors so that volatile organic compounds (VOCs) can be conclusively identified as either coming from an MGP or from some other source. For example, benzene, a constituent in coal tar, could also be present in a dwelling from common household sources. If compounds such as benzene are identified near a dwelling, current regulations require extensive sub-slab (below the basement or slab of a dwelling) sampling at a cost of $10,000 per dwelling. However, if MGP coal tar can be ruled out as the source of the contamination, less expensive investigations would be warranted.

M2011-004 – Carbon Calculator. The Company has been voluntarily reporting fugitive methane emissions since the mid-nineties and is committed to reducing its carbon footprint. One component of that carbon footprint is carbon dioxide emissions resulting from normal construction activities. The intent of this project is to quantify the emission reduction that would result from choosing a less energy intensive method of construction. For example, there are two alternatives to installing a new gas main. The first is traditional open trench, where a trench 18 in wide by 3 ft deep is excavated along the proposed length of the installation. In an alternate method, the pipe may be installed via directional drilling. This latter method is quicker, uses less equipment for a shorter time, and eliminates the bulk of new paving that must be applied. But up until now there has been no way to quantify the reduction in emissions. This project involves quantifying the emissions that result from each step of the construction process.

NYSEARCH, together with the North American Society for Trenchless Technology (NASTT) is working with ETA/Environ, to develop the spreadsheet tool. In the first phase of the project, subject matter experts from the participating companies are quantifying types and time on the jobsite of various pieces of construction equipment used on various construction activities. Then, ETA/Environ will use the latest EPA "non-road" emission factors to compile emission rates for the various pieces of equipment. In the final step, ETA/Environ will create a robust, user friendly spreadsheet tool to enable gas company managers to compare the carbon impact of alternative constriction practices.

There are several benefits from this project; determining the construction methods with the least environmental impact, validating the additional (environmental) benefit to public authorities who may be skeptical about the use of a newer or non-traditional construction technique; and it could allow the Company to be proactive in tracking and reporting (if required) these emissions.

OTD 6.8.a - Carbon Management Information Center.
The Carbon Management Information Center (CMIC) was established in 2007 to serve as an on-line clearinghouse for relevant carbon management information. The CMIC serves the gas industry, its customers, and other stakeholders by developing resources and analytical tools to provide clear, concise, and technically-sound information on issues related to reducing the nation's energy consumption, source energy codes and standards, and carbon emissions.

OTD 7.9.d and 7.10.c – Improving Methane Emission Estimates for Natural Gas Distribution Companies. The Company and other LDCs have been voluntarily reporting fugitive methane emissions from their distribution systems under the US Environmental Protection Agency (EPA) "Star" Program since the 1990s. With the recent passage of EPA "Subpart W" LDCs are now required to report these emissions.
To report emissions from its piping network, which account for over 80% of the Company's fugitive emissions from its gas distribution system, the EPA allows the use of emissions factors, expressed in terms of cubic feet of methane per mile of pipe per year.

Different pipe materials have different emissions factors. The factor is simply applied to the mileage of pipe in the system and total emissions are reported.

These emissions factors were developed in the early nineties via a testing and measurement program sponsored by the USEPA and conducted by the Gas Research Institute and subcontractors. The factors have never been updated and the Company and industry in general, are aware that the factor for plastic (PE) pipe is unrealistically high. For example, a similar study in the UK conducted in the early 2000s resulted in a leakage factor for PE pipe that is one half the value used in the US. PE piping systems are fabricated with improved materials and installed under better quality control than in the nineties, and the emissions testing program for PE pipe done then only contained six data points – for the entire nation!

Working through GTI and subcontractors, and with the knowledge of the USEPA, the Company and others are replicating the test methods from the previous study and attempting to develop a more realistic emission factor. Project funders (there are 18 LDCs participating) are identifying leaks in the field and the GTI team measures them. In parallel with conducting the leakage measurement (which involves exposing the leaking pipe segment) an alternate measurement technique is being applied which involves only surface measurement of leakage. If the two separate techniques agree, more field measurements can be taken with the less expensive surface measurement technique. Several field tests have taken place so far with others scheduled. After the PE leakage factor is revised, a second phase of this project will revise the factors for cast iron and bare steel pipe materials. The benefit of this project is more accurate reporting and a better representation of the company's contribution to greenhouse gas emissions.

Infrastructure Support

The following projects benefit overall company operations in areas such as safety, sensing and measurement, advanced material research, community and customer concerns, and general operations improvements.

M2009-002 - Mercaptan Sensor Development. To insure proper odorant levels in natural gas, LDCs are required to perform a periodic "sniff test." The human nose can detect odorant levels in the ppb range and if the gas is properly odorized this provides adequate warning to the public that gas is present at levels well below the "lower explosive limit" (LEL). However, sniffing by humans is subjective and technicians performing these tests can sometimes be desensitized to the odor of mercaptan. Also, the recently identified phenomenon called "odor masking" can cause the characteristic odor of mercaptan to change or disappear. This project aims to develop a portable sensor that can detect mercaptan in the ppb range. It would not replace the sniff test – which is required by code – but would supplement those tests, and would also be installed in areas where odor fade or masking is suspected, to verify that proper odorant levels are present. The technical approach is a unique combination of standard gas chromatography and a relatively new technology called differential mass spectroscopy. This technology was discovered via the NYSEARCH "Oracle" project mentioned above. Feasibility testing has been successfully completed and a prototype instrument is being built. Due to an instability issue, re-design work was attempted by the first contractor in place of additional field tests. With that work not solving the problem, NYSEARCH sought additional expertise and is now working with UC Davis to resolve the engineering issue associated with instability before going to advanced prototyping and testing. The benefit is advanced warning of possible odorant deficiencies.

M2010-002/T-776 – Methane MR Sensor. See details under Leak Detection and Methane Emission section of this report.

M2010-003 – PCB Absorption in PE Piping. Every year the Company discards quantities of polyethylene (PE) pipe that have been removed from service because they have been damaged by third parties, or for other miscellaneous reasons. The Company ships such pipe to a special landfill that accepts PCB-contaminated pipe because there is no EPA-approved method for decontaminating PE pipe potentially exposed to PCBs. The Company determined that the same approved procedures used to clean and decontaminate steel pipe may be applicable to PE pipe, if it can be proven that PCBs are not absorbed into the wall of PE pipe. Such testing has never been conducted for PE pipe. This is a Material Science Study to evaluate whether there are particular PE pipe characteristics that interact with PCBs. Address decontamination issues so that abandoned PE pipe can potentially be left in place. The Company, through NYSEARCH, engaged Jana Labs – a respected plastic pipe research and testing laboratory – to conduct this testing. The tests are underway with Jana. Pending a successful outcome of the test program, the Company will work with the USEPA to create a standard for cleaning and decontaminating PE pipe so it may be discarded in a normal fashion.

M2011-001 – Self Healing Pipe. Through the NYSEARCH "Oracle" Program, the Company has become aware of advances in material science through nanotechnology. Several concepts related to advanced materials were addressed and the two most promising were self locating pipe (pipe containing materials that would respond to conventional above ground locators, thereby solving the problem of broken or malfunctioning tracer wire) and self healing pipe. (Self locating pipe was discussed among NYSEARCH members and the group, after careful consideration, decided not to pursue that technology at this time.) The Company and other NYSEARCH members want to explore further the concept of self healing pipe so this project was authorized. Our investigations indicated that the addition of different types of nanoparticles into polyethylene (PE) material can enhance its mechanical or electrical properties. One type of adder can actually induce self-healing capabilities in the base PE material. A crack in the material will release a bonding agent and lab experiments conducted by others show recovery of up to 75% of tensile strength of the base material. The Company wants to pursue this further and feasibility discussions with manufacturers will commence. This is a long term project with ultimate benefits realized perhaps 25 years into the future. The project will be carefully monitored and will proceed in phases. Reduction in distribution pipeline incidents due to damage is the benefit of this research. The objective of the program is to develop a new generation of PE based pipes with self-healing properties for use in the natural gas industry. Following completion of the feasibility study, additional work was completed to prove that the PE pipe when altered for the self-healing nanomaterial would retain its required strength properties and at those conditions, still provide self-healing capability. It has been proved that the strength properties are maintained. Additional research is necessary as to evaluation of all conditions and development of various PE piping appurtenances. NYSEARCH is reframing the program to move from feasibility testing to more advanced development.

OTD 1.12.b - Cross-Bores Detection Using Mechanical Spring Attachment. Research is under way to develop a tool that will detect a hit to a sewer pipe during the installation of a gas pipe. A prototype for field testing was built that uses a mechanical spring system that is activated inside the sewer pipe void to provide a real-time alarm identifying a hit. Laboratory and field tests were conducted in 2013-2014 and a patent application for the technology was filed. In testing, the tool was able to successfully indicate the voids in pipes which were hit (i.e., providing positive indications). Several modifications of the proto-type may be performed with future commercializers. — A report on the results of field-test activities is being prepared.

OTD 1.13.a - Real-Time, Multiple Utility Detection During Pipe Installation Using HDD Systems. Research and testing is being conducted on an acoustic-based technology to detect obstacles during horizontal directional drilling (HDD) operations. The ultimate goal is to develop a system that can automatically and rapidly detect buried pipes/obstacles in front of and adjacent to the drill-head of HDD machines. The system was tested with seismic/noise sources and under differing attack angles to pipes. Post-processing data showed that the acoustic system was able to achieve the average pipe detection accuracy of ± 2.1' during the trials. — New and improved noise sources are being developed for further evaluation.

OTD 1.14.e - Plastic Pipe Locating—Alternatives to Traditional Tracer Wire. OTD along with GTI and 3M submitted a White Paper to DOE/PHMSA for a project that would have a very similar work scope as this current OTD project. The proposal resulted in an award from PHMSA with work expected to begin in the fourth quarter. The revised scope of the project is to develop an electronic marking system that will provide locatability on various-diameter HDPE and MDPE pipes. The project will also assess the technology capabilities versus pipe diameter, burial depth, and pipe-burial methods (horizontal directional drilling, open trench, etc.) —The contract for the new PHMSA-supported project is being finalized.

OTD 1.15.a - Cross Bores—Sewer System Cleanout Safeguard Device. This project focuses on the development of a safety device that provides the ability to seal the sewer-system cleanout opening in the event a natural gas line (inadvertently installed in a sewer) is struck by a power auger or other mechanical tool. The project team finalized a prototype cap design. Based on evaluations, 35 split caps were manufactured and shipped to sponsors for evaluation. — The project team has been in discussions with a manufacturer regarding commercialization of the split-cap safety device.

OTD 1.15.d - Improved Camera Imaging to Identify Cross Bores. The objective of this project is to provide an evaluation of imaging systems with the potential to work in conjunction with various types of trenchless pipe-installation technologies (including the use of horizontal directional drilling equipment with drilling mud) and still be able to positively identify a cross bore. An initial patent/literature search produced no new information on sewer camera technology. This, along with discussions with experts in the industry, indicated that there is little that can be done to improve this technology without additional technology platforms. Subsequently, several potential alternative platforms were identified. — Communications are being arranged with project sponsors to discuss the technologies identified and deter-mine future plans.

OTD 2.7.d - Cold Adhesive Repair and Joining of Polyethylene Pipes with Minimal Surface Preparation. In this project, researchers tested a cold-adhesive repair technique in an effort to develop an economical, reliable, and safe technology to quickly and effectively repair damaged plastic gas pipes. Long-term test results of PE pipes patched with the repair method found that the patching system can be effective. Testing also resulted in additional information about the effective application of the adhesive. — A Final Report on the project is being prepared.

OTD 2.10.b - In-Service Field Evaluation of Polyurea Coating Systems.
As a follow-up to a previous project, research into field-applied polyurea coatings for gas industry use is being conducted on promising coatings. Long-term field trials will be performed to evaluate these coatings and determine a cost-effective coating-application method and process for structural liners. — Installation and evaluation of the coating was successfully completed at a sponsor site in November 2015.

OTD 2.11.a - Development of a System for Repair of Aboveground Leaks.
Researchers are conducting a thorough evaluation of repair methods for leaks on aboveground piping in an effort to establish a basis for choosing the right repair method for a specific leak, establishing levels of adequate preparation, and providing the proper installation for increased reliability. Prototype test samples were constructed to simulate aboveground leaks from varying levels of corrosion (pin holes) and from threaded joints. Test samples were fabricated, fitted with the corresponding repair systems, and hydrostatically tested to failure. — Testing is ongoing.

OTD 2.12.a - Integrated Expert Monitoring and Training System for Butt Fusion.
A set of critical fusion variables is being developed to provide an integrated technology package for use in pipe-fusion training and field operations. The goal is to produce a system capable of flagging marginal fusions in all operating conditions. In the third quarter of 2015, all butt-fusions and low-temperature high-speed tensile tests were completed and creep testing initiated. A significant amount of test data post-processing was completed and correlation of the test data to butt-fusion conditions initiated. — A Final Report is being prepared.

OTD 2.14.c - Assessment of Squeeze-Off Location for Small-Diameter Polyethylene (PE) Pipe and Tubing. Researchers developed a model for predicting the effects of squeeze-off on small-diameter PE pipes. Mechanical testing was tailored specifically for the squeeze-off mod-el to capture the application's conditions. Technicians prepared a total of 230 specimens for testing. The results from the squeeze-off FEA model indicate that a squeeze-off can be performed at a distance three pipe diameters from a fitting with any size pipe. The project team initiated efforts to revise ASTM F1041; however, feedback received from ASTM indicates the project needs to address squeeze-off near mechanical fittings as well. This additional scope of work is to be submitted to the project sponsors for consideration.

OTD 2.14.e - Guidelines/Best Practices for Scraping PE Pipe and Fittings
Research is focused on the development of a functional set of improved, up-to-date guidelines for PE pipe and fittings that take into account current tooling and practices (e.g., scraping) while addressing the variables associated with fusion execution. Information from survey results was combined with data from previous projects and a test matrix for the pertinent tools was developed.

OTD 3.8.a - Addressing Jackhammer Noise Abatement. In urban areas of the Company's territory there is increasing pressure from city officials to lower the noise of commonly used construction equipment. Evening and weekend work, such as is required for emergency response work, only amplifies this need. Pneumatic jackhammers are among the noisiest of commonly used construction equipment. National Grid, in New York City, experimented with insulated fabric jackets that are placed around the jackhammer and while these helped to reduce noise levels, a more permanent solution is desired. The Company and others are working through GTI to try to engage jackhammer manufacturers to examine the design of a typical jackhammer to see if there is any opportunity to reduce the noise produced. It is recognized that noise from a jackhammer is produced from three distinct sources, the internal piston operating inside the cylinder, the air exhaust, and the bit striking the pavement.

The objective of the project is to engage manufacturers and determine whether they are open to a basic redesign effort of their tools to make them less noisy. GTI identified several manufacturers but only one was willing to attend a meeting to discuss the intent of the project. As a result, the project will most likely not proceed to Phase 2, which would have involved detailed noise analysis and would have served as the basis for a redesigned jackhammer.

OTD 3.14.a - MBW Soil Compaction Survey Enhancements. The SCS fills a need to verify soil compaction levels during field operations (excavation back-filling). The memory media that was used in the previous version of the SCS is cumbersome to use and has become obsolete. The industry practices in field data collection have also evolved considerably since the SCS was first introduced. The objective of this project is to upgrade the capabilities of the Soil Compaction Supervisor (SCS) to make it compatible with modern Geographic Information System (GIS) data capture practices as well as more user friendly through better data logging and reporting capabilities. Initial efforts will also be investigated to determine the SCS's ability to be correlated to a standard proctor value or range. The ability to attach metadata such as GPS coordinates and photos to compaction data is now wanted for entry into a GIS. Transferring compaction data from a mobile device to a GIS with the additional capabilities available on mobile devices (GPS, camera, etc.) will be incorporated into the data acquisition for the compaction record. By redesigning the SCS, a useful tool will continue to be available and the data generated can be directly imported into utility GIS or other data systems. Capturing and archiving the soil compaction data will help ensure that compaction is being performed properly (quality control) and will enable a utility to validate proper compaction to jurisdictional and/or regulatory authorities. The testing portion of the project seeks to better understand the correlation of the SCS data with that from a nuclear densitometer to provide a lower cost alternative.

OTD 3.14.b - Update ASTM Standard of DCP Compaction Control. Through this project, interactions were made with ASTM to update its current standard on the five-pound Dynamic Cone Penetrometer (DCP) compaction control device. The ASTM standard D7380-08 (Test Method for Soil Compaction Determination at Shallow Depths Using 5- lb. DCP), which was developed in an earlier OTD project, completed the balloting process of its standards in September 2015. The OTD-developed standard passed both the sub-committee ballots with no negatives. —The project team is following up with the ASTM Publications Committee to complete the process of adding the new version to the ASTM 2016 standards publication.

OTD 5.6.e – Portable Propane Air Temporary Residential Supply, Phase II
Many routine gas operations require temporary disruption of service to customers. Replacement of aging gas mains requires a brief interruption while the service is transferred from the old main to the new main. Meter change activities also require a brief shutdown. Rehabilitation techniques such as cured-in-place lining can require an outage lasting 12 hours or more. In such cases compressed natural gas (CNG) bottles can be used but they are heavy and cumbersome. The propane air mixer has been under development since 2006. It mixes propane from a standard gas barbecue tank with air and delivers the mix at the proper heating value. A prototype was built by GTI engineers and subjected to extensive operational and end use testing, including local field testing in Chicago. Tests were successful with the exception of results with one particular brand of water heater, which shut down on high flame temperature. Phase II of this project will redesign the unit to produce a cooler flame and the testing will be repeated on a mix of appliances. Firing rate, flame temperature and emissions will be recorded. If the testing is successful (meaning all appliances performed within spec on all tests) then a new phase of the project will investigate commercialization of the unit. The benefit is better customer service using a more efficient and ergonomic method.

OTD 5.7.p - GPS/GNSS Consortium. The project objective is to facilitate the sharing of information related to the use of GPS, Global Position System [US reference] and GNSS, Global Navigation Satellite Systems (International reference) technology for utility operations. The GPS/GNSS Consortium is a cost effective way for utilities to better understand this rapidly growing technology field and how GPS technology can best be applied to daily operations to create operational efficiencies, enhance regulatory compliance, and improve the quality of field collected data. The program activities include technology development and integration, workshops, pilot projects, demonstrations, best practices/standards development and general information sharing. Over the last two years, the GPS Consortium has focused on technology development that will reduce the cost and complexity of deploying GPS for routine construction and O&M activities. A Real Time Kinematic (RTK) base station has been installed, on GTI's main campus. This base station was built using GNSS Consortium funds in 2014 and continues to be an important asset for GNSS and GIS research at GTI. The following emerging technologies were selected for evaluation; Garmin GLO, Swift Navigation Piksi RTK Kit, uBlox Neo-7P & EVK-7P. Additionally, the following well known legacy units were tested to provide base-line comparisons; Trimble GeoExplorer XH, Navcom SF-3040, Geneq SxBlue III. GTI has completed testing and results are currently being compiled.

OTD 5.8.a - Automated Welding. This project will identify and select an automation manufacturing partner, develop a beta prototype automated welding unit, and create procedures to perform the welds on various types of tees and nipples. Throughout the project, the project team will work with the selected manufacturer(s) to assist with the implementation of the unit as a commercially viable product for the industry. A final report will document these efforts.

OTD 5.8.d - Tool for the External Classification of Pipe Contents
Research is being conducted to develop a practical tool that can detect "live" three-phase electrical cable in pipe without breaching the pipe wall. The ultimate objective is to develop an affordable tool that could be carried in each crew truck. The current project phase involves the construction and demonstration of a pre-production proto-type tool. Recently, the main focus was to debug the software required to perform the Fast Fourier Transform (FFT) on the vibrations detected on a pipe. The hardware platform was demonstrated to run the FFT library functions correctly; however, the signal level captured was somewhat low. This will need to be corrected in the hard-ware by adding amplification between the vibration sensor and the processor. The project is behind schedule and potentially will require additional time. — Software and hardware modifications are under way.

OTD 5.08.e.2ab - Enhanced Material Tracking and Traceability-Development of Standardized Protocols/Identifiers for Meters, Regulators, and Transmission Pipelines, Phase 2 (TEJ). The objective of the program is to utilize the previously established base-62 di encoding system methodology and develop a series of unique identifiers and format to characterize pertinent information for meters and regulators conforming to ANSI B109 requirements. TEJ continued its work related to proposed changes to ASTM F2897 to incorporate key data related to transmission pipeline components (pipe / appurtenances). The initial ballot for the F17.60 subcommittee ballot was submitted in December 2013 (one negative and five comments were received). The negative has been resolved and proposed ballot has been revised accordingly. The revised amendments were submitted for concurrent main and subcommittee voting. Provided that the ballot is approved, all the necessary identifiers required to produce a 16-character code schema to mark transmission pipeline components should be in place. It is important to emphasize, even with the proposed changes in place, this simply provides all the elements needed to develop a similar 16-character code for transmission components and satisfy the objective of this phase of the program. Additional work will need to be incorporate these requirements within applicable API 5L standards and resolve underlying procurement practices and supply chain considerations within utility companies.

OTD 5.9.h - North American Outreach Manufacturer Outreach Program
Research was conducted to identify promising technologies that are under consideration but not currently under development by qualified North American manufacturers. The focus was on prospective products or technologies and that have sufficient commercial value to natural gas utilities to justify submission of a funding proposal to OTD. — A Final Report detailing project results is being prepared.

OTD 5.10.d - Remote QA QC. Development of a remote monitoring program with map based application for smartphones and tablets for field data capture and documentation will advance utility operations and quality inspections. The goal of this project will develop a mobile application with a supporting step-by-step field procedure for its use including guidelines. The focus is to develop technologies and protocols to allow operators to remotely monitor and record the quality of various operations. The quality of field work can then be monitored in real-time using a step-by-step procedure, GPS-enabled cameras, and a web-repository to capture, store, and share photos and create permanent records. Using smartphones to capture time-stamped photographic documentation during field operations improves quality and enhances quality control, particularly for new installations. Field crews, both in-house and contractors are encouraged to follow specifications and procedures because pictures are used to document important steps. Using remote QA/QC methods allows 100% of new installations to be monitored by a quality inspector or office manager and support staff, no matter where they are, they will be able to view pictures of all new installations in real-time and share information. Further, pictures are captured in a GIS environment and can be stored for long-term usage such as validating regulatory compliance, future locating, and engineering operations.

OTD 5.11.a – Dewatering System for Mains. Excessive amounts of water in gas mains can cause service outages. This “water intrusion” is particularly prevalent in low pressure areas where groundwater can enter into a gas main through leaky joints in high water table areas. The normal solution is to locate the area of water intrusion and pump the water out. This project is investigating novel methods to remove residual moisture that can be present even after water is pumped out. Two methods that have been investigated are desiccant and molecular sieve technologies that can more permanently dry out the interior of a gas main, and chemical additives such as methanol foam which can allow moisture to flow out of low points and not collect there. Once the feasibility of such methods is evaluated, the next step in the project will be to decide whether the successful technology can be adapted to installation on a gas distribution system. This project will decrease the amount of customer outages in areas prone to water intrusion. Completed June 2015.

OTD 5.12.b – Development of a Portable Flash Fire Suppression System. During live gas operations the potential for rapid ignition of natural gas (a flash fire) is present. Although workers follow strict safety procedures and are protected with fire retardant clothing and breathing air apparatus, bodily harm can occur within milliseconds if an ignition were to occur. A true industry need exists for a system that can rapidly detect and extinguish flash fires. The project was initiated in GTI's Sustaining Membership Program (SMP). Two separate and distinct challenges were investigated, the ability of a sensor to detect a flash fire in less than ½ second, and the ability of a fire suppression system to limit injury as low as is reasonably achievable. In testing at GTI facilities both concepts were proven; a UV detector reliably detected fires within 30 milliseconds, and two separate suppression systems, high velocity air, and nitrogen extinguished the fire but each had some drawbacks needing further investigation. The Company is extremely interested in this project and Safety Dept. personnel will act as advisors to the GTI project team. A successful outcome of the project will be a portable flash fire suppression system that will effectively detect and extinguish flash fires should they occur and be simple to deploy. Enhanced worker safety and avoidance of serious or even fatal injuries is the obvious benefit of this research.

OTD 5.12.g – Evaluation and Adaptation of Kleiss Inflatable Stoppers for the US Natural Gas Industry. Current line stopping equipment in the natural gas industry has been used since inception (~ 50 years) in the same trim without substantial re-design. This equipment certainly works but is heavy, costly to maintain, and is somewhat time consuming and labor intensive when the installation of the necessary components required are taken into account. New line stopping equipment that may reduce these problematic issues, while providing the same assurance of safety and performance, could contribute to substantial time and money savings when incorporated into day-to-day operations. Through a technology search such equipment was sourced. This apparatus is produced by a European Vendor, Kleiss and Co., and has shown promising performance. The objective of this effort is to evaluate these existing medium and high pressure inflatable stoppers as an alternative to currently employed stopping equipment for use on US natural gas distribution systems. GTI will test and evaluate this inflatable stopper suite of tools (capable of stopping off line pressures of 60 psig at pipe diameters up to 24-inches). Deliverables include the development of testing criteria and a program to evaluate the current offering. In addition, it will identify the necessary modifications to the bagging system(s) and identify deployment fittings required to meet the US natural gas industry standards so that the system may be introduced and deployed for use in the US.

OTD 5.12.o and 1.14.h – Guidelines for Cast Iron Winter Operations and Cast Iron Winter Patrols study. The Company and others want to know the best methods for determining when to initiate winter frost patrols on their cast iron (CI) piping systems. Simply starting the patrols when the ground temperature or air temperature reaches a certain limit may not be optimum. There are other factors, in addition to temperature, which may influence the propensity of CI piping to break in frost conditions. Some of these factors are diameter and pressure of the main, age, soil type, and presence of other adjacent underground facilities. The ultimate deliverable of the project is a practical guideline for operators as to when to initiate frost patrols. GTI was selected to perform the study and is investigating – through examination of LDCs' records - the frequency of breaks in the presence or absence of the potential breakage factors. The study is not complete but has already determined that diameter is a key variable and that most breaks take place on smaller diameter piping and, at least for one LDC, there is no record of breakage for pipelines larger than 18" diameter. As more data is accumulated and analyzed patterns like this should emerge. The end result should be a fact-based guideline, based on the above parameters that affect breakage, stating exactly when, and for which segments, winter frost patrols should begin.

Under OTD 1.14.h, the company did an evaluation with GTI using Picarro's CRDS and some of Picarro's latest algorithms to evaluate if this advanced leak detection system and methodology could improve our winter patrols and identify CI breaks more rapidly. The frost conditions were extreme during the course of the investigation which was ideal for the study. However, it was found that numerous passes are required and the processing of the data took a great deal of time. GTI is evaluating the data to determine if there was significant improvement in detection, however to date, this has not translated into cost savings with this approach for CI winter patrols.

OTD 5.13.d - Transmission Cut In Valve. The development of proposed cut-in valve system will give operators options for the placement of valves without the need to shut off the flow of gas along with the benefit of greatly reducing the cost of installation. This valve concept can lead to: faster installation times especially in urban environments, no need for flow control and/or bypass of gas, single excavations with no need to stop off the flow in the pipe and no need to install a bypass, enhanced safety, and lower cost of installation. This system will be a unique design that meets all material and performance expectations while delivering a compact and fast alternative to traditional valve installation methods. It will be developed to provide important performance and installation benefits to pipeline operators working under difficult conditions and with critical needs. Initially, a concept transmission EZ Valve will be developed for sizes up to 12-inches with working pressures up to 300 psig. After initial proof of concept, a 6 inch prototype valve will be constructed.

OTD 5.13.f - Low-Cost Collision-Avoidance System

Efforts are under way to develop a low-cost, low-speed, collision-avoidance system that would provide gas industry utility vehicles the ability to provide driver alerts and, when necessary, automatic braking. A complete set of laboratory-based testing scenarios was conducted using an experimental test apparatus to generate datasets that represent typical driving maneuvers. Field tests of a wireless tablet PC user interface were completed. For testing, a video system was successfully integrated with the test hardware. — A video is being prepared to demonstrate the capabilities of the system.

OTD 5.13.g - Post Disaster Risk Assessment with LiDAR and GIS. The project objective is to develop pipeline risk assessment tool to identify high risk pipe segments after post-disaster events to prioritize repair and restoration activities. This work is performed along with a DOT-funded project with Rutgers, the State University of New Jersey, to develop a mobile mapping platform that harnesses commercially available technologies to provide remote sensing data collection capabilities and to implement a GIS-based platform for data management and pipeline risk assessment. Progress thus far: the risk assessment approach and model is completed, the Bayesian Network has been integrated into a web-based computer model, and a case study is being entered into this model to estimate damage potential of pipe segments at Ortley Beach, NJ after hurricane Sandy.
The results are pending at this time.

OTD 5.14.a - RFID Testing Program. A testing program is being conducted to compare the performance and features of multiple radio frequency identification (RFID) and related technology solutions for locating and tracking gas utility assets. RFID tag installations were completed for the 3M Marker Ball, the Berntsen Infra Marker, and the Eliot Marker System. Programming of tags, along with user experience and impressions, were recorded. Assets targeted for RFID tagging included a mix of steel and PE systems from existing pipe test beds in addition to available utility hook-ups (gas, electric, and water). — The project team is in the process of locating, reading, and testing all installed above- and below-ground tags.

OTD 5.14.b - Smart Leak Repair Form. A smart leak repair form will improve the quality of data collected during the leak repair process and will lead to improved threat identification and risk assessment for DIMP. The objective is to develop a system to capture more detailed information to allow for more granular analysis to be performed, such as the identification of leak trends. Development of a Fault Tree Analysis and Decision Tree logic will be employed in this framework to resolve issues concerning proper identification of root causes and categorization of failures. The objective of the sponsors is to define an appropriate logic for electronic data collection forms.

OTD 5.14.d 2a – Tracking &Traceability for Transmission Phase 2a: Standards for MTR and Coating Reports and Phase 2b: Data Collection Technology. The goal of this project is to develop standards, guidelines, and technology for tracking and traceability of transmission pipe and components. The ability to automate the process of capturing and storing tracking and traceability information for transmission pipe will improve data quality and reduce risk. Data quality will be improved by using electronic records and barcode scanning to capture data essential for MAOP calculations and integrity management. Eliminating manual, paper-based data collection will reduce the occurrence of human errors when capturing and transferring data into the asset management system. In addition to data quality, operators will have access to pipe and coating data that can be used for threat identification and risk modeling as part of integrity management. The results of this project will provide the industry with a standardized approach for capturing pipe, appurtenance, welding and coating data. Phase 1 identified data collection requirements, developed barcode labeling specifications, and created a design document for field data collection software. Phase 2a will create standardized forms for Mill Test Reports (MTR) and factory applied coating information. Phase 2b will create technology to capture manufacturer information using standardized barcodes and develop and test the technology in a proof-of-concept project. Phase 3 (future) will create standardized forms and technology to capture field welding and field applied coating data. GTI will propose a Phase 3 to develop standards and technology for data collection of field applied coatings and field welding operations.

OTD 5.14.f - Battery and Electric Powered Tool Evaluation, phase 1. The use of battery-powered power tools in Class 1 Division 2 environments is limited by most LDC's best practice policies; however, this project aims to investigate this topic to propose alternative ways to improve safety of these highly useful devices.

OTD 5.14.n - Construction Compliance Monitoring System. The goal of this project is to develop a risk-based Construction Compliance Monitoring (CCM) system to assist operators in ensuring and quantifying the compliance of new construction. The CCM system will be composed of a model and software. The system will assess new construction work from a system-risk perspective and will deploy audit resources based on the probability and consequence of failure for specific job sites. It will identify high risk construction activities, generate prioritized audit schedules, provide electronic audit forms on tablet computers, collect audit results, and quantify the level of compliance using industry-standard statistical methods. This project will create the CCM model and a proof-of-concept system that will be tested with one operator. Full commercialization will be pursued in a second phase, if desired by OTD. The deliverable of this project will be a model and software sufficient to prove the concept and demonstrate the value of a compliance monitoring system. Provide documentation of compliance that can be used in communicating with regulators, insurance providers, or in the event of potential litigation. The benefits of the project: Maximize the efficiency of resources devoted to ensuring compliance. Implementations of this methodology may reduce the number of field inspectors required to achieve the desired level of confidence by targeting and optimizing the deployment of audit resources, improve construction performance and efficiency, and continuously improve risk management efforts by better understanding the sources and frequency of installation error.

OTD 5.14.p - Developing Devices to Use with the Jameson Directional Insertion Tool
The objective for this project was to evaluate and modify devices or attachments for use with the Jameson insertion tool to increase the use and capabilities of live in-pipe inspection. A survey was conducted to obtain information on the current tooling and practices for live camera insertion, water removal, and digital mapping. Tests were performed to evaluate the ability of a camera to be inserted into a two-inch PE pipe through various access fittings. Tasks related to water removal and mapping-device insertion have not moved forward as survey results did not identify any devices that sponsors are currently using. — A Final Report is being prepared.

OTD 5.14.t - Methods to Detect Inserted Plastic in Steel Mains. This is an investigation into the feasibility of techniques for detecting inserted PE pipe. Three methods were considered as the most promising from an ease of field application perspective: 1) flow noise, 2) rate of cooling, and 3) modal analysis. Measurement of flow noise and/or cooling rate should work for large volume flows and the results are a function of flow rate, becoming ambiguous when volume flow decreases to zero. Using a combination of the two requires developing a method relating flow noise to cooling rate that is different for pipes with an insert and no insert. Because gas flow in a main varies greatly (including zero flow), a method independent of gas flow would be preferable for this application. An impulse modal analysis, being independent of gas flow, was seen as the most promising for identifying inserts across the largest range of flow conditions. Practical, reproducible, and easy to apply methods for generating and detecting the acoustic waveforms were identified. This technique can be used on the crown of the pipe. Measurements were performed indoors on bare, 2-inch diameter steel pipe found a large number of acoustic vibration modes. The amplitudes of the frequencies are different and depend on the insert diameter and the separation distance between the impact point and transducer location. Although the spectra are complex and additional work is required, the indoor results suggest it should be possible to distinguish among no insert and various insert diameters. Similar measurements were made in the GTI’s pipe farm. The 2 and 4-inch diameter steel pipes were longer, coated with fusion bonded epoxy, and buried at both ends beneath raised earthen berms. The frequency range was greatly reduced and any differences between inserted and non-inserted pipe were small at best. It is unclear whether the reduced spectral content of the signals is due to earth and/or pipe coating attenuation, or variations in the method of attachment for the accelerometer to the external pipe surface. Additional work would be required to determine if any of the three techniques are feasible. The work performed to date has been on the impact modal analysis technique. As noted above, promising results from the indoor work did not translate to the outdoor setup with soil and coating interactions. This work was completed in 2015.

OTD 5.14.u - Evaluation of Geospatial Technologies. The purpose of this project is to evaluate two new geospatial technologies that could have engineering and operations applications for operators. The technologies to be evaluated could include wearable augmented reality devices (such as Google Glass) and handheld 3D mapping tools (such as Google’s Project Tango). This project will test select technologies at GTI and local utility sites and develop recommendations for applications such as leak survey guidance, facility location and attributes, equipment repair, mapping of new and existing facilities, and emergency response. There are many advancements being made in the consumer hardware space and that the hardware and devices being developed can hold a lot of potential for the gas industry. Through efforts such as this project, research on new technologies can identify applications for the gas industry. Not every technology is going to provide the benefits that are intended, but through testing and identification of these technologies, ongoing research can bring new technologies to the gas industry. Microsoft HoloLens and other successful technologies such as Google Project Tango were identified in this project as technologies showing potential for further gas applications from which the company and the entire gas industry may benefit.

OTD 6.6.a - Keyhole Consortium. This GTI program develops continuous improvements and innovations to small hole (keyhole) technology. Keyhole excavations involve 18” diameter road openings to perform many routine operations that would traditionally require a 4 ft. x 4 ft. opening. Soil is vacuumed out and work takes place from street level using special long handled tools. This reduces paving costs and in many cases the 18” core is reused – set back in the excavation so there are no paving costs associated with the work. The Keyhole Consortium meets twice yearly; Company representatives attend with other LDCs and manufacturers. At the meeting common issues and needs are discussed and new research ideas are generated.

OTD 7.14.a - Next Generation Water Clean-up Technology. The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) has proposed IVP regulations that will require operators to verify the integrity of transmission pipes without pressure test records. These regulations could potentially require the industry to hydrotest up to 90,000 miles of in-service pipe. Cleaning and disposing of the hydrotest water is a significant component of the overall cost of hydrotesting. The objective of Phase I of this project is to conduct a technology review and business case to quantify the cost of disposing of water using current methods and the potential savings that could be achieved with new technologies. It is anticipated that development and implementation costs will be significant, thereby warranting a formal business case prior to pursuing technology development or technology transfer. Results of the industry survey taken in this project indicates that conventional management of pipeline discharge waters most often includes either hauling of the water to a publicly owned treatment works (POTW) for disposal or field-based filtering of the water through a ring of hay bales. The POTW alternative requires significant expense in transportation and in discharge fees; all costs connected with this option often exceed $0.50/gallon (2014 dollars). The hay bale alternative (whereby water is forced through a ring of hay bales) is sometimes used in the field, but the method only seems to work for the control of oils and greases and suspended solids but is not effective in removing many soluble organic compounds of concern such as benzene. Clearly, a second generation treatment system is needed that allows low cost field based treatment that is reliably compliant with water quality criteria specified in permits for water reuse and discharge to surface waters. Primary treatment systems used by industry in the past such as sedimentation and dissolved air flotation have been effective in control of suspended solids and free oil and grease. Granular activated carbon (GAC) is effective in removal of soluble organics, but becomes expensive when treating waters that are greater than 1-5 mg/l of total organic carbon (TOC). Biological treatment can be used to remove soluble organics, but the process requires too much of a footprint to be practical. Chemical oxidation, however, can be used for oxidizing most of the soluble organics while taking up a very small footprint. What is needed, however, is a chemical oxidant that is easy to handle and use in the field as a part of the integrated mobile treatment system. A review of commercial chemicals indicates that many of them are not suitable for implementation in a highly mobile, treatment system applied to 1-2 day processing of hydrostatic test waters. A list of information gaps is described in the report; these gaps can be resolved with research and development concentrated on the oxidation step of the advanced treatment flowsheet.

On the basis of this technical evaluation, it is recommended that the industry consider development and optimization of the manganese dioxide oxidative process for the conditioning of pipeline discharge wastewaters. This development work should be pursued in the context of an integrated prototype that includes all of the treatment steps that preceded and follow the oxidation process.

Cathodic Protection, Coatings and Corrosion Related

M2012-001 - Development of a Corrosion Sensor Array. This project will attempt to develop a novel method of monitoring for external corrosion on a gas pipeline by installing an "array" of sensors on a pipeline. If successful, pipeline operators will have another "tool in the toolbox" for monitoring critical pipelines for external corrosion. This project utilizes an existing microsensor-based system to provide corrosion monitoring of full sections of gas pipelines. The project will initially modify the system and then assess its suitability for the natural gas industry through lab testing. The core technology employed is the micro-linear polarization resistance sensor developed originally for aerospace applications.

OTD 2.9.c - Field Applied Pipeline Coatings. Modern pipe materials are factory coated and these coatings stand up very well as long as they are not damaged by external forces. However, in locations where field welds or other field installed fittings are present, the necessary pipeline coating needs to be field applied. Field applied coatings vary in quality and are not always installed under ideal environmental conditions such as would be present in a pipe coating factory. This project tested the performance of several different types of coatings on buried pipe at Gas Technology Facilities in Chicago.
Throughout the world, a variety of generic coating systems are commonly applied to field girth welds, including the following: (1) fusion bonded epoxy (FBE), (2) heat shrink sleeves (HSS), (3) liquid applied coatings, (4) composite systems, and (5) tapes/wraps. Eighteen (18) manufacturers supplied seventy-five (75) different coating systems for the test program. The coatings were installed by the manufacturers on a network of 8" and 24" steel piping buried in rocky, sandy, and clay-like soils. Coating systems were unearthed and examined at 2, 5, and 7 year intervals. Some coatings exhibited no rust on any of the pipes in any soil, and other coatings exhibited rust on pipe in all soil. A key conclusion of the test program is that strict adherence to the manufacturers' recommended installation procedures is absolutely necessary. A final report on project results has been prepared. The benefit is improved pipeline safety and assurance that superior products, from a long term performance point of view, are installed on company facilities.

OTD 5.9.c - Mitigating Electrical Interference on Cathodic Protection Systems. Electrical interference can impair or negate the effect of cathodic protection systems. The objective of this project is to understand the types of interference that can be present near pipeline systems and make recommendations to mitigate the effect of these interferences. Interferences can be steady state, such as would be present from adjacent high voltage power lines or transient, caused by a lightning strike or power line surge.
To implement the project, GTI selected three host sites and installed data logging instrumentation on cathodic protection systems there. Transient events and steady state

interference data is being gathered. The results of the data gathering exercise will be recommendations for enhanced equipment or better surveillance of cathodic protection systems to better protect them. Enhanced integrity of piping systems protected by cathodic protection is the benefit of this research.

OTD 5.9.f – Cathodic Protection Monitor. The objective is to develop and deploy a Cathodic Protection Monitor prototype that stores monthly CP readings. GTI has partnered with 3M to develop a completely encapsulated, direct burial monitoring device. A 3M handheld locator/reader is used to retrieve the readings electronically from above ground without requiring a direct connection. The data, consisting of 12 sets of monthly readings, can be downloaded from the handheld devices as tabular data. The first version of the CP Monitor has been successfully tested; as a result of testing additional product requirements were identified. The objective of Phase 2 is to develop and test a modified CP Monitor prototype with some or all of the following features: ability to record AC potential readings to detect stray currents, increased data storage, improved range with the ability to capture readings from a moving vehicle, programmable data recording intervals, and ability to transfer data to other handheld devices via Bluetooth for direct GIS integration. The benefit is improved monitoring of CP performance on protected piping, with the potential cost savings of making mobile readings

OTD 5.11.n – Quality Control Procedure for High Potential Anodes. The Company recently has been experiencing quality problems with magnesium anodes as delivered from manufacturers. Anodes that appear – upon visual inspection – to be sound have been experiencing premature failures in the field. Quick and simple voltage tests may initially reveal that the anode is generating the required voltage potential but this may be indicative of good quality of the surface layer of the anode only. If the entire anode is not of the same quality and purity the anode will deteriorate prematurely. The standard industry test for measuring anode purity, ASTM G97, is expensive and time consuming and it is not practical to conduct this test for all new anodes received. Therefore, there is an industry need for a quicker test that can validate the requisite quality and purity of anodes. GTI has received anodes from project participants and is currently evaluating alternate methods of testing them that can give results similar to the G97 test. As an indication of the need for this project, GTI reports that the project has experienced delays due to the time consuming nature of the G97 test, which is being performed in parallel as a control. The benefit is better assurance of the quality of materials received and installed in the company's gas system.

OTD 5.12.n – Advanced Tools for Improved AC Corrosion Prevention and Mitigation. Alternating Current (AC) corrosion is not common but can occur if gas mains are in proximity to railroads or overhead electric transmission lines. When it does occur, the corrosion rates can be rapid, thus the need for the Company to quickly identify and mitigate the occurrence of AC corrosion. The company is working with GTI on this project and they have proposed a two part solution, a model to predict rates of AC corrosion, and a calculator to determine the most effective mitigation measure. The project will draw heavily on existing work done by the National Association of Corrosion Engineers (NACE) and the Company's and other funders' experience. The final deliverable of the project will be the model and calculator, which can be used to prioritize inspections and gauge the impact of various mitigating measures on both new and existing gas pipelines.

OTD 5.14.x - Risk-Based Atmospheric Corrosion/Leak Survey Considerations
A study reviews historical and current data on atmospheric corrosion of indoor service piping. A detailed review of the published, peer-reviewed literature related to field data on indoor corrosion was made. A comparison of the fundamental principles of indoor and outdoor atmospheric corrosion was made. The research conducted compares and contrasts indoor atmospheric corrosion to outdoor corrosion for iron and steel piping materials. In addition, thousands of recent inspections in NY and New England States were completed on outdoor and indoor services by operators the data was collected and statistically analyzed to determine the trends and drivers behind the observed corrosion rates. A similar analysis was completed on exclusively indoor leak survey data from LDC operators. Finally, all the findings were summarized and related to risk-based considerations for setting appropriate inspection intervals for indoor service piping. This art of the study was completed in late 2014.

General and Other Areas Not Covered Elsewhere

M2001-013 - Millennium Website Development. A project for maintenance and upgrading of NYSEARCH's website and for use by the NY LDCs who utilize NYSEARCH as a clearinghouse for reporting to the NY PSC on the use of the Millennium R & D funds

M2002-008 - Oracle Technology Concept Investigation. Through the NYSEARCH research consortium, the Company and others fund a concept known as “Oracle.” The purpose of this program is to look outside the gas industry for novel technology solutions to gas industry needs. In the past, technologies from the military, biomedical, and telecommunications industries have been tracked. More recently, our focus has been sensor technologies using fiber optics or nanotechnology, and material science advances. Applications from these industries, when identified, will be funded as separate projects. An example of that is a current effort to take nanocomposite particles used in plastic in other industries and create self-healing PE pipe. Another example that came from this is the methane sensor using tuning fork technology.

OTD 5.14.c - Improving Cybersecurity for LDCs - Needs Identification & OTD 5.15.a Cybersecurity Collaborative. Initiated in February 2014 an initiative to review and to provide information on the status of cybersecurity R&D activities for LDCs and identify the short and long-range needs for cybersecurity capability improvement for LDCs. A workshop was conducted on April 16-17, 2014 at GTI facilities in Des Plaines, IL. Day 1 included presentations by representatives from GTI, AGA, DHS and SRI to orient the attendees to cyber related activities focused on the energy sector and natural gas specifically. Day 2 was dedicated to sharing lessons learned and identifying technology needs and gaps, and prioritizing project ideas. A summary report was prepared which identifies the industry need and business value of addressing cybersecurity issues, and summarizes the cybersecurity lessons learned for the participating utilities, A follow on effort under OTD 5.15.a continues as a multi-year collaborative program between natural gas distribution companies and the Department of Homeland Security (DHS) to address the high priority cybersecurity issues of participating members through a focused outreach and education process and a technology evaluation and transfer initiative.

OTD 6.14.a - Quality Audit Program for Natural Gas Utility Suppliers. Distribution Integrity Management regulations encourage utility companies to place a new focus on supplier and supply chain quality. Identifying threats and mitigating risks starts with the manufacturing process. Reducing supply chain risk requires a comprehensive and well-coordinated supplier audit program to ensure that the integrity of the supply chain is controlled and that the supplier is following policies and procedures required by customers and regulators. The purpose of this effort is to develop an audit program and provide natural gas utility operators with a mechanism to collaboratively audit supplier's quality management systems. The program will conduct an independent and unbiased assessment on behalf of participating operators to provide a reliable and standardized approach for monitoring suppliers. Participating operators will benefit from a collaborative program by creating efficiencies and promoting information sharing. Supplier audits identify non-conformances in manufacturing, shipping, engineering change, invoicing, and quality processes. After the audit, the supplier and auditors jointly identify corrective actions which must be implemented by the supplier within an agreed-upon timeframe. A future audit ensures that these corrective actions have been successfully implemented. While the need for enhanced quality audits and monitoring programs is increasing, the availability of resources to conduct these programs is decreasing due to operator's focus on operations and efficiencies. Therefore, there is a need for a coordinated collaborative audit program to allow gas utilities to efficiently monitor supplier processes. Participation in the collaborative program will provide value in the following ways: create efficiencies and cost savings by consolidating audits into one program, increase the number of audits performed, create leverage and increase influence with suppliers, utilize RAB/IRCA certified auditors with extensive experience, provide a high quality audit due to consistency and standardization of audit methodology and allow internal resources to focus on the core business rather than auditing. National Grid has participated in the development and pilot which has helped us review and improve our own auditing process but we are currently evaluating if we will continue in this GTI program.

Joint Industry Projects

The following three projects have been are jointly funded and managed between DET NORSKE VERITAS, DNV, and various industry co-funders:

Development of Industry Best Practices for Hot Tap Branch Connections Joint Industry Project (JIP) – a welding procedure is being developed and draft sent out to the group for comments, particularly for preheat. Concerns for maintaining preheat on a flowing pipeline are to be addressed.

Development of Industry Best Practices for Girth Weld Repair The objective of this JIP is to develop industry best practice for repair of pipeline girth welds during new construction activities, which will include the development and qualification of a suite of repair welding procedures in accordance with Section 10 of the Twenty-first Edition of API 1104. A guideline for selecting an appropriate procedure for a given application will also be developed. The scope will also include the development of guidance pertaining to other technical aspects of girth weld repair and repair welder qualification (e.g., preheating requirements, inspection requirements, time delay prior to inspection, minimum-required and maximum-allowable repair length, practical limits on wall thickness, etc.) that will be used to develop a generic company specification for repair of pipeline girth welds during new construction.

Validation of the ASME Procedure for Estimating Lower Bound Yield Strength of Pipe from Hardness Data. Forty-nine pipe samples representing a wide range of age, size, grade, composition, and manufacturing method were tested to demonstrate the validity of using hardness test data to estimate lower bound yield strength (YS) of steel pipe. Three different types of field portable hardness testers were used on each pipe sample. The hardness testing was performed in accordance with ASME CRTD-Vol. 91. The hardness test results were converted to estimated lower bound YS values using the correlations described in ASME CRTD-Vol. 57. The estimated lower bound YS was compared to the results of standard API 5L tensile tests. In addition, the metallurgical attributes of each pipe were characterized to determine if certain subsets of pipes produced better (or worse) correlations of estimated lower bound YS to YS determined from tensile tests. The results showed that hardness data can be used to estimate conservative values of lower bound YS using a range of different confidence levels.

National Grid Managed Projects

National Grid funds projects outside the NYSEARCH and OTD consortia and manages them ourselves or jointly with other LDCs. The following two projects are jointly funded and managed between National Grid Downstate and Consolidated Edison Co (Con Ed)

M2001-009 - Construction Interference Cost Reduction (CONCORD) Program. National Grid and Con Edison, along with the Urban Utility Center of Polytechnic Institute of New York, are working with New York City to introduce trenchless technologies to the city’s construction program. Trenchless technology – as compared to traditional “open cut” construction – can save National Grid and Con Edison significant dollars by eliminating the need to relocate our gas facilities if they interfere with the city’s new construction. We have introduced new trenchless technologies to the city’s engineers, conducted training programs, performed lab testing, and these efforts have culminated in New York City’s decision to rehabilitate two miles of a major water main in Manhattan via a trenchless method. This method involves insertion of a plastic liner into the existing cast iron water main and few adjacent gas facilities will need to be relocated. Con Ed estimates significant savings. If this program is successful and NY

City adopts trenchless technology for future construction, the savings to National Grid and Con Ed could be significant for years to come.

M2002-015 Cast Iron Sealing Robot (CISBOT): National Grid and Con Edison jointly fund and manage this project to design, construct and test a live, tethered robot that will internally seal cast iron joints. National Grid has the highest inventory of cast iron pipe in the nation, over 6000 miles, with over 2600 miles in the State of New York alone (Source, US DOT report). Cast iron is a very durable material but over time the joints – mechanical connections packed with jute and lead – can dry out and are the source of leakage. National Grid's predecessor company, KeySpan, partnered with Con Edison of New York to jointly fund the development of CISBOT. The robot was built by ESI Corp of Toronto, Canada. Upon completion of the robot Con Ed and National Grid entered into an agreement with ULC Robotics, a small high tech firm located on Long Island, to 'commercialize' the device and ultimately become the service provider for the CISBOT services. This is a typical business plan for high tech deployment in the gas distribution sector; ULC Robotics performs this type of work as their main line of business. To date, National Grid has spent over $2.2 Million on the project, with a similar amount funded by Con Edison. CISBOT is designed to seal joints in 16" through 36" diameter cast iron gas mains operating at pressures up to 25 psi. An excavation will be dug at a convenient point along the gas main and a special fitting is installed on the main which allows a 12" opening to be cut into the main in "live" conditions with no shutdown required and no blowing gas. (This is a fairly common procedure in the gas industry.) The CISBOT robot is then inserted into a launch tube and the launch tube is attached to the fitting on the main. The launch tube is purged of air with nitrogen and then a valve is opened and natural gas fills the launch tube. The robot is then lowered into the gas main. A tether connects the robot with external power and communication, and a small tube in the tether contains the anaerobic sealant which is used to seal the joints. An operator drives the robot using onboard cameras as a guide and stops at the first joint. A small hole is then drilled into the joint at a predetermined spot. Once the hole is drilled, a nozzle is inserted up into the drilled hole and anaerobic sealant is pumped into the hole, saturating the joint. Cameras on the robot are positioned to view the wicking action of the anaerobic fluid and pumping is stopped when the operator judges that a particular section of the joint is filled with sealant. The robot is then repositioned to a different "clock position" around the circumference of the joint and the drilling and sealing operation is repeated. Once the operator judges that the joint is sealed the robot will travel down to the next joint and the process is repeated.

CISBOT is undergoing an extensive program of field demonstrations over the past three years in New York City and Boston. Costs for the demonstrations outside NY State are borne by the area conducting the demonstration. In parallel with the demonstrations, the Company and Con Edison are negotiating a Commercial License with ULC Robotics. The cost of the service will be determined by ULC Robotics prior to their offering the service as a commercial business. National Grid NY and Con Ed will receive a discount from the stated list pricing. Because the final cost of the service has not yet been determined, it is difficult to accurately predict savings but assumptions can be made.

The basis for our assumed savings of $2.5M annually is to assume that CISBOT is deployed to a main segment where 50% of the joints are or will soon be leaking. Per job that's about 15 joints at an estimated cost of $3000 per joint to repair, total cost $45,000. This figure can vary depending on the final pricing structure set by ULC Robotics. Standard repair including a tight sheeted pit is estimated at $20,000 per repair for total repair cost of $300,000. Actual costs for tight sheeted pits in congested urban areas have been reported as much higher but this is a conservative estimate. Based on these assumptions the net savings is about $255,000 per job. Assuming full successful deployment of CISBOT, 10 such jobs per year could be performed, resulting in annual savings of $2,550,000.

National Grid expects to deploy this technology in its large diameter cast iron mains in New York State and Massachusetts. Any royalties received will be returned to NY ratepayers through the Millennium Fund.

Attachment 2 shows spending for these projects described above.

National Grid Gas R&D Spending

Includes Ngrid Downstate (KeySpan) and Ngrid Upstate (NMPC)

Calendar Year Expenditures ($)

	Actual		Projected		
Year	**2014**	**2015**	**2016**	**2017**	**2018**
National Grid Internal Program					
Utilization	$ 104,800	$ 211,426	$ 758,574	$ 170,000	$ 170,000
Operations	$ 57,708	$ 28,476	$ 200,000	$ 263,000	$ 263,000
Ngrid Labor and Expenses	$ 229,692	$ 184,741	$ 201,640	$ 207,689	$ 228,094
TOTAL INTERNAL	**$ 392,200**	**$ 424,643**	**$ 1,160,214**	**$ 640,689**	**$ 661,094**
National Grid Millennium Program					
NYSEARCH Projects	$ 2,265,234	$ 1,311,235	$ 1,571,000	$ 1,687,000	$ 1,150,000
OTD Projects	$ 750,000	$ 870,279	$ 750,000	$ 750,000	$ 750,000
National Grid Projects	$ 40,000	$ 103,502	$ 352,000	$ 400,000	$ 450,000
TOTAL MILLENNIUM	**$ 3,055,234**	**$ 2,285,016**	**$ 2,673,000**	**$ 2,837,000**	**$ 2,350,000**
TOTAL MILLENNIUM AND INTERNAL	**$ 3,447,434**	**$ 2,709,659**	**$ 3,833,214**	**$ 3,477,689**	**$ 3,011,094**
NYSERDA Assessment	$ 3,565,124	$ 4,906,042	$ 5,000,000	$ 5,250,000	$ 5,550,000
TOTAL R&D PROGRAM	**$ 7,012,558**	**$ 7,615,701**	**$ 8,833,214**	**$ 8,727,689**	**$ 8,561,094**

Note: Total spend, from books of Company

PROJECT NUMBER	PROJECT	START DATE	END DATE	TOTAL NGRID COMMITMENT	TOTAL SPEND 2013	TOTAL SPEND 2014	TOTAL SPEND 2015	TOTAL NGRID SPEND Joe YEARS
M-2000-001	Variable length sleeve - NYSEARCH	2000	2013	$ 147,356		$ 29,586.33		$ 111,970.00
M-2000-004	Explorer Commercialization, Phase I	2000	2006	$ 341,239		$ 14,906.96		
M-2001-002	Mgmt of Impacted Sediments - NYSEARCH	2001	2011	$ 430,061				$ 430,061.00
M-2001-003	Cased Pipe Risk Assessment Model	2001	2011	$ 274,472		$ 4,007.04		$ 184,501.00
M-2001-005	PipeHawk Hand-Held Pipe Locator - NYSEARCH	2001	2013	$ 435,090		$ 23,892.72		$ 392,895.00
M-2001-006G	Development / Testing / Commercialization of GASNET(tm) - Phase V	2001	open	$ 392,485			$ 31,593.94	
M-2001-009	Interference Avoidance/UUC Technology Demo Lab	2001	2010	$ 475,000				$ 446,000.00
M-2001-013	Millennium Web Development	2001	ongoing	$ 37,998		$ 5,751.81	$ 1,612.19	
M-2001-014	InspectionTool for Unpiggable Facilities - Automatika (TIGRE)	2001	2011	$ 967,261	$ (9,098.34)			$ 959,781.00
M-2002-008	Technical Expert (Oracle) to ID Quantum Leap Technologies	2002	ongoing	$ 53,931		$ 13,585.11	$ 179.87	$ 29,396.00
M-2002-011	FFT AUra Damage Prevention Systems - Testing Program - Phase III	2002	open	$ 202,380		$ 109,480.05	$ 43,194.73	
M-2002-015	CISBOT-Live IP CI Joint Sealing (KSE/ConED/ESI/ULC)	2002	2013	$ 2,356,825				$ 2,219,476.00
M2002-018	Infrasonic Sensor for Remote Pipeline Monotoring - NYSEARCH	2002	2010	$ 129,711				$ 104,858.00
M2003-009	Explorer II	2003	2012	$ 483,030		$ 24,727.35		$ 451,452.00
M2005-003	Test Bed Maintenance and Improvements	2005	ongoing	$ 110,108		$ 518.11	$ 1,225.31	
M2005-005	Gas Interchangeability for LDC Infrastructure	2005	2014	$ 753,336		$ 96,150.43	$ 25,514.42	$ 644,948.00
M2006-002	Butt Fusion Joint Integrity	2006	2011	$ 70,198		$ 9,776.81		$ 53,213.00
M2007-001	Mini-camera for Cased Crossings	2007	2012	$ 150,952		$ 10,491.88		$ 228,563.00
M2007-003	Multi Technology Validation Testing for Cased Pipe Applications	2007	2013	$ 73,315		$ 897.85	$ 2,952.00	$ 49,676.00
M2007-005	Testing Program for Remote Inspection-Transkor	2007	2012	$ 133,080		$ 15,387.64	$ 1,803.50	$ 75,901.00
M2007-007	Technology Advancement in Damage Prevention Tools and Communications	2007	2011	$ 91,973		$ 7,268.87		$ 64,243.00
M2008-001	Third Party Detection - Magal	2008	2013	$ 58,297		$ 5,522.13	$ 4,202.49	$ 29,419.00
M-2008-005	Developing Platelet Technology for use in Gas Transmission and Distribution Centers	2008	open	$ 23,280		$ 23,279.52		
M2008-006	Expand Function of No Blow Tools to Reduce GHG	2008	2012	$ 122,329		$ 6,055.00		$ 82,078.00
M2008-010	UV Degradation of PE Pipe	2010	2013	$ 14,125				$ 8,070.00
M2009-001	Holistic Review of DIMP Practices and Models	2009	2012	$ 48,750		$ 3,995.78		$ 44,409.00
M2009-002	Mercaptan Sensor Development	2009	open	$ 330,462		$ 60,282.16		$ 266,030.00
M2009-003	Adaptation Study	2009	2012	$ 23,500				$ 23,500.00
M2009-007	Particulate Dispersion Study	2009	2011	$ 75,000				$ 60,516.00
M2009-008	Ultrasonic Evaluation System for PE Butt Fusion	2009	open	$ 133,700		$ 20,632.90		$ 2,079.00
M2010-001	Service Tee Renewal	2010	open	$ 73,170		$ 27,692.85		$ 20,118.00
M2010-002	Methane MR Sensor Development	2010	open	$ 126,730		$ 12,318.70	$ 41,955.00	$ 23,265.00
M2010-003	PCB Absorption in PE Piping	2010	2013	$ 194,000		$ 60,613.68		$ 121,228.00
M2010-004	Soil Vapor Intrusion	2010	2012	$ 83,100		$ 39,199.82		$ 43,877.00
M2010-005	Guided Wave Test Program	2010	2012	$ 175,000				$ 95,082.00
M2011-001	Self Healing Pipe	2011	open	$ 232,442		$ 123,440.62	$ 45,986.48	$ 7,397.00
M2011-002	Storage Effects on Gas Quality	2011	2013	$ 26,555		$ 9,470.17		$ 12,628.00
M2011-003	Odor Masking	2011	open	$ 126,695		$ 89,198.22		$ 23,158.00
M2011-004	Carbon Calculator	2011	open	$ 24,450		$ 1,156.83		$ 12,234.00
M2011-005	Fiber Sen System Development and Testing	2011	open	$ 71,248		$ 32,464.79	$ 28,342.19	$ 6,316.00
M2011-006	Robotics Supporting Technologies	2011	open	$ 1,020,009		$ 411,841.51	$ 169,306.28	$ 152,941.00
M2011-007	Cased Pipe Inspection via Vents	2011	open	$ 386,760		$ 168,393.96	$ 94,646.85	$ 41,630.00
M2011-008	BioBall Test Program	2011	2013	$ 37,630		$ 37,630		$ -
M2011-009	Explorer 30 - 36"	2011	2013	$ 500,000	$ 64,500			$ 435,000
M2012-001	Development of Corrosion Sensor Array	2012	open	$ 72,310		$ 20,811	$ 49,013	$ -
M2012-003	Enterprise Level Assessment of Data Management Systems	2012	2014	$ 33,900		$ 33,900		$ -
M-2013-001	Explorer 16/18 - Inspection of Unpiggable Pipelines	2013	2015	$ 1,230,915	$ 307,730	$ 615,460	$ 307,725	$ 1,230,915
M-2013-002	Non-Destructive Inspection of Gas Pipes Using AMR Sensors for Eddy Current Testing (ECT)	2013	open	$ 342,668		$ 2,883	$ 45,940	
M-2013-003	Integrated Nanosensors for Analysis of Chemical Compounds in Natural Gas Applications (WKU Advanced Chemical Sensor)	2013	open	$ 189,885		$ 4,563	$ 152,422	
M-2014-001	Aeryon sUAS Technology - Regulatory & Technology Assessment	2014	open	$ 131,880			$ 10,396	
M-2014-002	Leak pinpointing inside pipe	2014	open	$ 27,380			$ 8,717	
M-2014-003	Picarro Methane Emissions Analyzer System	2014	open	$ 129,748			$ 129,748	
M-2014-004	Technology Evaluation & Test Program for Quantifying Methane Emissions Related to Non-Hazardous Leaks	2014	open	$ 54,210			$ 14,825	
M-2014-005	Critical Valve Operability	2014	open	$ 18,155			$ 7,033	
				$ 14,248,084	$ 363,132	$ 2,177,234	$ 1,218,335	$ 9,188,824
Keyspan dues					$ 55,000	$ 55,000	$ 60,000	
NMPC dues					$ 33,000	$ 33,000	$ 33,000	
					$ 451,132	**$ 2,265,234**	**$ 1,311,335**	
OTD 1.08.a	GPS-Based Excavation Encroachment Notification	2008	open	$ 134,269	$ 19,176			$ 134,269
OTD 1.08.a.CA	GPS Based Excavation Encroachment Notification for ROW Monitoring- CA (GTI)	2008	open	$ 33,142	$ 33,142			
OTD 1.08.c	GPS-Enabled Leak Surveying and Pinpointing (see 1.9.a)	2008	open	$ 50,000				
OTD 1.8.f	Electromagnetic and Acoustic Obstacle Detection Refund	2004	2011	$ 24,599	$ (12)			$ 24,599
OTD 1.8g	Acoustic Sewer Lateral Locator	2008	2012	$ 80,289	$ 7,300			$ 72,989
OTD 1.09.a	GPS Leaks - Phase 2 (from 1.8.c)	2009	2013	$ 129,080	$ (437)			$ 121,780
OTD 1.h and 1.10.c	Hand Held Acoustic Pipe Detector and tech transfer	2003	2013	$ 287,260				$ 287,260
OTD 1.10.e	Enhancing Damage Prevention in New York	2010	2015	$ 16,500				
OTD 1.11.a	Chemical Methods to detect crossbores	2011	2011	$ 2,870				$ 2,870
OTD 1.11.c	Low-Cost MEMS Methane Sensor Platform Phase 1	2011	2015	$ 30,000				$ 30,000
OTD 1.11.e	Cross Bores - National Database and Risk Model	2011	open	$ 35,000	$ 3,000			$ 35,000
OTD 1.12.b	Cross-Bores Detection Using Mechanical Spring Attachment	2012	2014	$ 10,000	$ 5,314			$ 10,000

PROJECT NUMBER	PROJECT	START DATE	END DATE	TOTAL NGRID COMMITMENT	TOTAL SPEND 2013	TOTAL SPEND 2014	TOTAL SPEND 2015	TOTAL NGRID SPEND Joe YEARS
OTD 1.14.d	Field Measurement of Leak Flow Rate	2014	open	$ 9,994		$ 5,000	$ 4,994	
OTD 1.14.g	Evaluation of Residential Methane Detectors	2014	open	$ 85,000		$ 85,000		
OTD 1.14.g.2	Evaluation of Residential Methane Detectors-Phase 2	2014	open	$ 32,097		$ 15,446	$ 10,000	
OTD 1.14.g.2a	Evaluation of Residential Methane Detectors-Phase 2 Pilot	2014	open	$ 175,000				
OTD 1.14.h	Picarro Surveyor Winter Patrol Implementation	2013	2015	$ 572,500		$ 25,000	$ 547,500	
OTD 2.07.a	2.7.a Refund				$ (9,014)			
OTD 2.8.e	Structural Liners and Sleeves - Technology Search	2008	2013	$ 12,132				$ 12,132
OTD 2.9c	Field Applied Coatings	2009	2012	$ 67,000				$ 67,000
OTD 2.11.a	Development of a System for Repair of Above Ground Leaks	2011	open	$ 44,611	$ 4,375			$ 40,236
OTD 2.11.d	RSD X-Ray for Metallic Pipe Assessment - Testing and Validation	2011	2012	$ 20,000				$ 20,000
OTD 2.11.d Refund	2.11.d Refund						$ (2,737)	
OTD 2.12.e	Selection of Liners Composites for the Rehabilitation of Distribution and Transmission Lines	2012	2015	$ 15,000	$ 15,000			
OTD 2.13.b	Guidelines for Special Permits for Structural Composite Rehabilitations	2013	open	$ 38,000	$ 38,000			
OTD 2.13.c	PHMSA Accelerated Dynamic Testing for Long Term Evaluation of Liners and Composite Pipe Materials add (PHMSA-21501)	2013	open	$ 39,063	$ 25,000	$ 14,063		
OTD 2.14.a	Composite Repair Wrap for Polyethylene (PE) Systems	2014	open	$ 5,000		$ 5,000		
OTD 2.14.b	Pipe System Repair Technique	2014	open	$ 40,000		$ 20,000	$ 20,000	
OTD 2.14.c	Assessment of Squeeze off Location for Small Diameter Polyethylene (PE) Pipe and Tubing	2014	open	$ 8,190		$ 5,000	$ 3,190	
OTD 2.14.d Refund	2.14.d Refund	2014		$ (17,964)		$ (17,964)		
OTD 2.14.d	Universal PE Entry Fitting	2014	cancelled	$ 20,000		$ 20,000		
OTD 2.14.e	Guidelines/Best Practices for Scraping PE Pipe and Fittings	2014	open	$ 1,251		$ 1,000	$ 251	
OTD 2.b	Service Applied Main Stopper			$ 152,078				
OTD 3.8a	Jackhammer Noise Abatement Issues	2008	2010	$ 20,000				$ 36,463
OTD 3.9a	Backfill Evaluation & Ecoroads	2009	2012	$ 24,295				$ 30,869
OTD 3.14.a	Soil Compaction Supervisor Enhancements	2014	open	$ 36,355		$ 25,000	$ 8,934	
OTD 3.14.b	Update ASTM Standard of DCP Compaction Control	2014	open	$ 1,000		$ 1,000		
OTD 4.7.g	Yield Strength	2007	2012	$ 27,672	$ 2,500			$ 25,172
OTD 4.08.a	Guided Wave Validation as Hydro Equivalent	2008	2015	$ 52,843				
OTD 4.8.i	Extended Reassessment Interval Validation Through Dielectric Wax Casing Fill	2008	2012	$ 58,929				$ 58,929
OTD 4.9a	Leak vs. Rupture Boundary	2009	2012	$ 68,048				$ 68,048
OTD 4.9.a Refund	4.9.a Refund			$ (99)			$ (99)	
OTD 4.11.f	Understanding Threat Interactions for Risk Analysis (GTI)	2011	2013	$ 30,000				$ 30,000
OTD 4.12.b	Correlating Pipeline Operations to Potential Crack Initiation Growth Arrest (GTI)	2012	open	$ 74,678	$ 30,000	$ 14,678		$ 30,000
OTD 4.13.a	DIMP Consequence Model	2013	2015	$ 55,200	$ 30,000	$ 25,200		
OTD 4.13.b	Validation of 3D Scanners for Anomaly Assessment	2013	2013	$ 25,000	$ 25,000			
OTD 4.13.c.2	PHMSA EMAT Sensor for Small Diameter and Unpiggable Pipe Phase 2 Construct and test field ready prototype	2013	open	$ 10,000			$ 5,000	
OTD 4.13.d.3	Hydro-testing Alternative Program - Phase 3	2013	open	$ 8,658		$ 5,000	$ 3,658	
OTD 4.14.a	Fitting and Component Catalogue for IVP	2014	open	$ 5,000		$ 5,000		
OTD 4.14.c	Surface Indentation for Material Characterization Correlation of Surface Properties Based on Vintage	2014	open	$ 58,301		$ 30,000	$ 28,301	
OTD 4.e	Inspection Platforms for Unpiggable Pipelines (NYSEARCH)			$ 303,963				
OTD 5.06.e	Portable Propane Air Residential Temporary Gas Supply	2006	open	$ 90,062	$ 14,851			
OTD 5.07.f	Automated Meter Shut-Off Device (AMS)	2007		$ 47,596				
OTD 5.07.p	5.07.p (GTI) GPS Consortium	2007	open	$ 15,000				
OTD 5.08.a.2	5.08.a.2 Development of Automated Welding Unit for Installing Laterals – Phase 2 (GTI)	2008	open	$ 42,500	$ 20,000	$ 22,500		
OTD 5.08.d.3	5.08.d.3 Tool for External Classification of Pipe Contents, Phase 3	2008	open	$ 1,000		$ 1,000		
OTD 5.8e	Gas Material Traceability	2008	2012	$ 77,008	$ 4,020			$ 72,988
OTD 5.08.e.b (b)	5.08.e.2ab Enhanced Material Tracking and Traceability-Development of Standardized Protocols/Identifiers for Meters, Regulators, and Transmission Pipelines, Phase 2 (TEJ)	2008	open	$ 6,749		$ 5,000	$ 1,749	
OTD 5.08.e.a (a)	5.08.e.a (a)Enhanced Material Tracking and Traceability Development of Standardized Protocols Identifiers For Meters and Regulators	2008	open	$ 5,000				
OTD 5.08.e.b (b)	5.08.e.b (b) Enhanced Material Tracking and Traceability Development of Standardized Protocols Identifiers For Transmission Pipeline	2008	open	$ 30,916	$ 7,916			$ 30,916
OTD 5.08.k Refund	5.08.k Refund				$ (287)			
OTD 5.08.l Refund	5.08.l Refund				$ (271)			
OTD 5.9c	Mitigating Elec. Interference on Cathodic Protection Systems	2009	2012	$ 80,522				$ 80,522
OTD 5.09.f	CP Monitor Prototype Modification and Field Trials Phase 2	2009	2015	$ 46,739	$ 15,326	$ 6,413		$ 25,000
OTD 5.09.f Refund	5.09.f Refund						$ (546)	
OTD 5.09.h	5.09.h North American Manufacturer Outreach			$ 1,893				$ 1,893
OTD 5.9j	Gas Distribution Model	2009	2012	$ 103,600				$ 103,600
OTD 5.9k	Low Impact Marking Study	2009	2012	$ 50,261				$ 50,261
OTD 5.10.d.2	5.10.d.2 Remote Field QA/QC Phase 2	2010	open	$ 73,450		$ 40,000	$ 33,450	
OTD 5.10.f Refund	5.10.f Refund			$ (21,616)	$ (21,616)			
OTD 5.10.f	Cold Assisted Pipe Splitting (CAPS), Phase 1	2010	2012	$ 46,615				$ 46,615
OTD 5.10.g	Indoor Air Quality and Safety Issues	2010	open	$ 25,000				$ 25,000
OTD 5.11.a	Dewatering Systems for Mains	2011	2013	$ 66,927			$ 2,000	$ 66,927
5.11.a Refund	5.11.a Refund						$ (229)	
OTD 5.11.m	Intelligent Utility Installation Process	2011	2014	$ 278,297	$ 191,000	$ 18,344		$ 68,953
OTD 5.11.n	Quality Control Procedure for High Protential Anodes	2011	2013	$ 44,929	$ 4,045			$ 40,884
OTD 5.11.n.2	5.11.n.2 Quality Control Procedure for High Potential Anodes – Phase 2	2011	2015	$ 20,000	$ 20,000			
OTD 5.12.b	Development of a Portable Flash Fire Suppression System (PFFSS)	2012	2014	$ 34,430	$ 14,430			$ 20,000
OTD 5.12.b.2	5.12.b.2 Development of a Portable Flash Fire Suppression System (PFFSS) Phase 2	2012	open	$ 10,000		$ 10,000		
OTD 5.12.g	Large Diameter Medium Pressure Inflatable Stoppers Evaluation of Kleiss System for the U.S. Natural Gas Industry	2012	2014	$ 20,000	$ 8,007			$ 20,000

PROJECT NUMBER	PROJECT	START DATE	END DATE	TOTAL NGRID COMMITMENT	TOTAL SPEND 2013	TOTAL SPEND 2014	TOTAL SPEND 2015	TOTAL NGRID SPEND Joe YEARS
OTD 5.12.n	Advanced Tools for Improved AC Corrosion Prevention and Mitigation	2012	2013	$ 70,000	$ 35,000			$ 35,000
OTD 5.12.o	Guidelines for Cast-Iron (CI) Winter Operations	2012	2013	$ 108,000	$ 48,000			$ 60,000
OTD 5.12.o.2	Assessment of Frost Impact on Cast Iron Pipes Phase 2	2012	2015	$ 37,410		$ 37,410		
OTD 5.12.p	NG Appliance Immersion Study	2012	2015	$ 104,606	$ 104,606			
5.12.p refund	5.12.p Refund	2012					$ (5,722)	
OTD 5.13.c	PE Pipe Splitting Technical Evaluations, Enhancements, and Standardization of Tool Kits	2013	open	$ 30,000	$ 30,000			
OTD 5.13.d.2	Transmission Cut In Valve Phase 2	2013	open	$ 50,000		$ 25,000		
OTD 5.13.f	Low Cost Collision Avoidance System	2013	open	$ 18,338	$ 10,000	$ 8,338		
OTD 5.13.g	Post Disaster Risk Assessment with LiDAR and GIS	2013	open	$ 50,000	$ 25,000	$ 25,000		
OTD 5.14.a	RFID Testing Program	2014	open	$ 25,277		$ 15,000	$ 10,277	
OTD 5.14.b refund	5.14.b Refund	2014		$ (829)			$ (829)	
OTD 5.14.b	Smart Leak Repair Form	2014	open	$ 18,500		$ 18,500		
OTD 5.14.c	Improving Cybersecurity for LDCs-Needs Identification Workshop	2014	open	$ 5,000		$ 5,000		
OTD 5.14.d	Tracking and Traceability for Transmission Pipe Materials	2014	open	$ 15,000		$ 15,000		
OTD 5.14.d.2a	Tracking and Treaceability for Transmission-Phase 2a Standards for MTR and Coating Reports, Rev	2014	open	$ 19,141		$ 10,000	$ 9,141	
OTD 5.14.d.2b	Tracking and Treaceability for Transmission-Phase 2b Data Collection Technology, Rev	2014	open	$ 23,725		$ 10,000	$ 9,091	
OTD 5.14.f	Battery and Electric Powered Tool Evaluation Phase 1	2014	2015	$ 20,000		$ 20,000		
OTD 5.14.j	Residual Gas Removal Identify Technologies Limitations Best Practices	2014	open	$ 15,000		$ 15,000		
OTD 5.14.n	Construction Compliance Monitoring System	2014	open	$ 29,234		$ 15,000	$ 14,234	
OTD 5.14.p	Pipe Insertion Technologies - Develop Devices to Use with Jameson Directional Insertion Tool	2014	open	$ 1,663		$ 1,000	$ 663	
OTD 5.14.t	Methods to Detect Inserted Plastic in Steel Mains	2014	2015	$ 11,909		$ 11,298	$ 611	
OTD 5.14.t Refund	5.14.t Refund	2014		$ (27)			$ (27)	
OTD 5.14.u	Evaluation of New Geospatial Technologies	2014	2015	$ 5,125		$ 5,000	$ 125	
OTD 5.14.u Refund	5.14.u Refund	2014		$ (1,221)			$ (1,221)	
OTD 5.14.w	Testing Program for Valve with Water Sensor for Storm Hardening	2014	open	$ 21,625		$ 21,625		
OTD 5.14.x	Atmospheric Corrosion / Leak Survey Considerations	2014	2014	$ 35,000		$ 35,000		
OTD 5.15.b	Roadmap for Enterprise Decision Support System	2015	open	$ 2,778			$ 2,500	
OTD 5.16.b	Alternative Caps for PE Service Tees Fusible Caps	2016	open	$ 5,620				
OTD 5.16.c	Piercing Tool Redevelopment Enhancement to Remove "Mole" from Small Excavations (12mo)	2016	open	$ 22,150				
OTD 5.16.d	Stopping Off LP Mains with No Excavation	2016	open	$ 19,982				
OTD 5.16.f	Improved Safe Excavation Productivity for Locating Buried Utilities	2016	open	$ 5,274				
OTD 5.16.g	Enhancement of the Dynamic Cone Penetrometer (DCP) Compaction Device	2016	open	$ 53,033				
OTD 6.a	Sustaining Membership Program - GTI (discontinued)	2003	2012	$ 152,000				$ 152,000
OTD 6.6.a	Keyhole Consortium - GTI	2006	2012	$ 100,000	$ 20,000		$ 20,000	$ 60,000
OTD 6.08.a	(GTI) Carbon Management Information Center	2008	ongoing	$ 65,000		$ 25,000	$ 25,000	
OTD 6.11.a	PRCI Membership	2011	2015	$ 10,000		$ 10,000		
OTD 6.13.a	Quantitative Risk Assessment Methodology Protocol for LNG Facilities Siting (AGA)	2013	open	$ -	$ (10,000)	$ 10,000		
OTD 6.14.a	Quality Audit Program	2014	open	$ 40,000		$ 20,000	$ 20,000	
OTD 7.8.a	Pipeline Quality Biomethane: Guidance Document for Landfill and Water Treatment Conversion	2008	2012	$ 65,990				$ 65,990
OTD 7.9.c	Assessing Acceptable Siloxane Concentrations in Boimethane	2009	2012	$ 52,972				$ 52,972
OTD 7.9.d and 7.10.c	Improving Methane Emission Estimates for NG Distribution Companies, Phase 1 and 2	2009	2014	$ 67,674				$ 67,674
OTD 7.10a	Trace Constituents in Natural Gas	2010	2013	$ 78,205				$ 78,205
OTD 7.10.b	Odor Fade (GTI)	2010	2014	$ 36,940				$ 36,940
OTD 7.10.b Refund	7.10.b Refund	2010		$ (1,570)			$ (1,570)	
OTD 7.10.b.2	Odor Fade Phase 2 (GTI)	2010	2014	$ -		$ (10,000)	$ 10,000	
OTD 7.10.c Refund	7.10.c Refund	2010					$ (43)	
OTD 7.10.c.2	Improving Methane Emission Estimates for NG Distribution Companies, Phase 2	2010	2014	$ 67,674				$ 67,674
OTD 7.10.c.3	Improving Methane Emission Estimates Phase III - Cast Iron and Unprotected Steel Pipes	2010	2014	$ 99,839	$ 50,000	$ 49,839		
OTD 7.10.c.4	Improving Methane Emission Estimates for Natural Gas Distribution Companies Phase IV	2010	2014	$ 6,880		$ 5,000	$ 1,880	
OTD 7.11.a	Gas Quality Resource Center	2011	2013	$ 65,000	$ 20,000	$ 20,000		$ 25,000
OTD 7.11.a.2	Gas Quality Resource Center	2011	2013	$ 20,000			$ 20,000	
OTD 7.11.b	Trace Constituents Sensors	2011	2014	$ 27,610				$ 27,610
OTD 7.14.a	Next Generation Water Clean-up Technology Phase 1	2014	open	$ 25,000		$ 25,000		
OTD 7.15.a	Real Time Gas Quality Sensor	2015	open	$ 4,981			$ 2,500	
OTD 7.15.b.2	Remote Gas Sensing and Monitoring Phase 2	2015	open	3000				
OTD 7.16.a	Leak Repair Prioritization	2016	open	20110				
OTD 7.16.b	Evaluate Gas Imaging Technologies for LDC Applications	2016	open	30000				
OTD 7.16.c	Secure Communication for Networked Gas Sensors	2016	open	21302				
OTD 8.16.a	Intelligent Field Data Collection Platforms	2016	open	19956				
OTD 8.16.b	Remote QA/QC: Fusion Inspection and Reporting	2016	open	39441				
OTD 9.16.a	Determining Data Quality Implication	2016	open	56224				
OTD 9.16.b	Establishing Risk Tolerance	2016	open	25358				
				$ 6,229,580	$ 838,371	$ 834,690	$ 802,024	$ 2,520,240

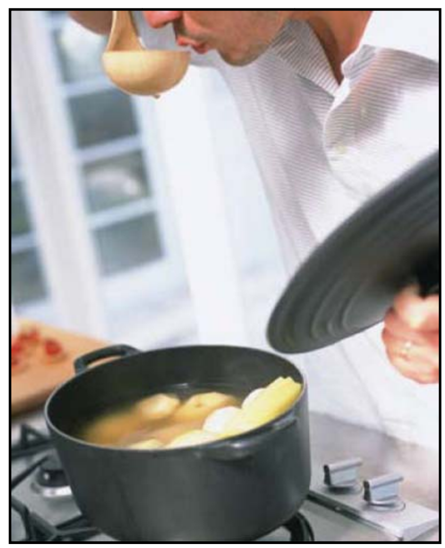
T759	Ergonomic Study to Develop New Needle Bar	2005	2012	$ 29,889		$ 557		$ 25,366
T763	Rock Impingement	2007	2011	$ 19,250				$ 21,100
T764	Auto Gas Lamp Evaluation	2009	2012	$ 27,500		$ 10,443		$ 10,314

the Energy to Lead

TOPICAL REPORT

GTI PROJECT NUMBER 20733

National Grid Foodservice Market Assessment



Report Issued:
March, 2010

Prepared For:
National Grid

GTI Technical Contact:
Dr. Frank Johnson
Senior Engineer
End Use Solutions
847-768-0670
Fax: 847-768-0501
frank.johnson@gastechnology.org

Gas Technology Institute

1700 S. Mount Prospect Rd.
Des Plaines, Illinois 60018
www.gastechnology.org

Disclaimer

This information was prepared by Gas Technology Institute ("GTI") for National Grid.

Neither GTI, the members of GTI, National Grid, nor any person acting on behalf of any of them:

a. Makes any warranty or representation, express or implied with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately-owned rights. Inasmuch as this project is experimental in nature, the technical information, results, or conclusions cannot be predicted. Conclusions and analysis of results by GTI represent GTI's opinion based on inferences from measurements and empirical relationships, which inferences and assumptions are not infallible, and with respect to which competent specialists may differ.

b. Assumes any liability with respect to the use of, or for any and all damages resulting from the use of, any information, apparatus, method, or process disclosed in this report; any other use of, or reliance on, this report by any third party is at the third party's sole risk.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

National Grid Foodservice Market Assessment

Executive Summary

The commercial and institutional food service sector represents an important – **and growing** – market for the natural gas industry. According to the National Restaurant Association (NRA), there are approximately 525,000 commercial food service establishments nationwide with annual sales of $580 billion. Remarkably, nearly one in ten workers in the U.S. is a restaurant employee. The NRA indicates total U.S. commercial foodservice employment is 11.2 million – a substantial figure that is projected to grow to 14 million by 2020 (25 percent growth).

There are approximately 37,400 restaurants in New York with gross sales of $27.8 billion and over 672,000 employees. In Massachusetts, there are over 14,000 restaurants with annual sales of $11.8 billion and 304,000 employees. Rhode Island has nearly 2,700 restaurants with $1.8 billion in sales while New Hampshire has over 2,800 restaurants with annual sales of $2.1 billion. Together, this totals nearly 57,000 establishments with annual sales in excess of $43 billion. Using a nominal value of 3.4 percent of sales, commercial food service annual utility cost (electricity, natural gas, water, etc) exceed $1.4 billion in these four states and approach $20 billion nationally.

According to Energy Information Agency (EIA) survey data, commercial foodservice customers have 2.2 times the energy intensity (Btu/ft^2) of the average commercial customer. Audits conducted by Southern California Gas and Piedmont Gas found that natural gas sales to commercial foodservice customers account for 12 percent of the volume of gas sold, but comprise a healthy 19 percent of their profits.

In terms of new equipment, the estimated annual sales of new commercial foodservice equipment totaled about $1.2 billion in 2006. Of this, about 69 percent was natural gas-based products – indicating a strong market position for natural gas relative to electricity. The report provides further analysis of sales by product category and, an important consideration, the limited availability of Energy Star-rated natural gas products.

While a significant and growing market, there are continual threats and opportunities to assess within the commercial food service market segment. This project was undertaken to generate insights on the current gas foodservice market in National Grid's Northeastern United States market territory, with findings intended to guide a course of action for future RD&D and marketing initiatives within the foodservice arena. In addition to market and technology insights from GTI's experience and literature review, interviews were conducted with six foodservice consulting firms and equipment dealers within National Grid territories.

From this, the following observations, trends, opportunities, and threats are identified for the natural gas industry in the commercial foodservice marketplace:

- Natural gas market share is currently strong and holding against electric market share. New electric products; perceptions of electric as clean, simple, and reliable; and growing electric energy efficiency programs represent potential threats. There is also a market perception that electric equipment is more advanced or higher end than gas equipment, posing a significant threat.

- Natural gas is perceived as more cost-effective by users, with current electric-to-natural gas price ratios of 4.5:1 or higher. A typical restaurant is paying over twice as much annually for electricity than natural gas – underscoring the perception of natural gas as being cost effective.
- Rising labor, food, and energy costs are motivating foodservice providers to seek new and innovative equipment designs that could save operating costs through productivity improvements and speedier delivery.
- **Labor issues are a dominant factor in this sector** – major issues are obtaining and retaining quality workers, labor costs, and productivity. Increased labor turnover motivates foodservice providers to seek methods or equipment to improve the working environment for employees in terms of comfort, ease of equipment usage, and cleaning.
- Key purchase factors for new equipment include price, efficiency (operating costs), after-sales support, and productivity improvement. Equipment obsolescence and deterioration is typically the main reason to buy new equipment. With older gas equipment lasting for many years, added effort is required to convince users to purchase new equipment. Getting information to users about the cost and energy saving associated with new equipment is needed along with meaningful incentives from energy efficiency programs.
- There is a paucity of Energy Star recognized standards and, subsequently, natural gas products in the commercial foodservice sector. This can impact the ability to use utility energy efficiency program funds to incentivize the shift to higher-efficiency equipment.
- More investment is needed to develop advanced, energy efficient natural gas appliances that would satisfy current or future Energy Star labeling requirements.
- Trends toward healthier and/or more environmentally responsible eating habits can influence the market, but the economic benefits/effects are not fully understood by the industry.
- The industry is concerned about lower emissions standards (including NO_x and particulates) – especially where such requirements have been imposed on residential appliances.
- Ventilation advancements represent an opportunity to increase energy efficiency and kitchen comfort and indoor air quality for workers. Improvements include demand ventilation systems.
- The green movement is a threat to natural gas. Consumer surveys show that electric is perceived as being more green, possibly due to the site-based efficiency claims. There is an opportunity to position new gas equipment as green through consumer education - identifying the financial, source energy, and environmental benefits.

Food Service Industry Market Characterization

The food service industry is a growing and diverse segment of the commercial market. Figure 1 shows the major segments of this estimated $580 billion industry, including "eating places" (i.e., various types of restaurants), vending & recreation, non-commercial (i.e., institutional), managed services, lodging, as well as bars & taverns.

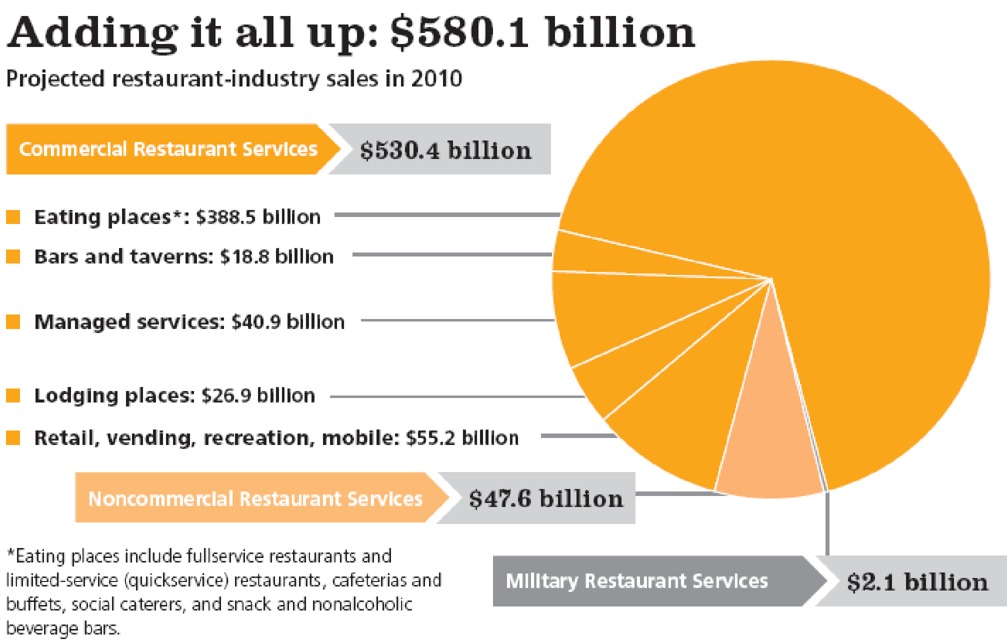


Figure 1: Foodservice Market Segmentation

(Source: NRA 2010 Restaurant Industry Forecast)

There are approximately 525,000 foodservice establishments across the country. State-level characteristics on four key states – New York, Massachusetts, Rhode Island, and New Hampshire – are shown in Table 1, with additional state profile data from the National Restaurant Association included in the appendix to this report. These four states include 56,900 commercial foodservice locations with annual sales in excess of $43 billion.

Table 1: Selected State Foodservice Data (2009)

Sales Volume	Foodservice Establishments	Annual Sales ($Million)	Employment
New York	37,400	$27,800	672,000
Massachusetts	14,000	$11,800	304,000
New Hampshire	2,800	$2,100	61,200
Rhode Island	2,700	$1,800	51,900

Source: National Restaurant Association

The foodservice market can be further broken down into major and niche segments (Table 2). Eating places are dominated by full-service restaurants – around $184 billion -- and limited-service (or quick-service) restaurants at over $165 billion. Together, these two groupings comprise 60 percent of the foodservice market. Beyond this are a number of smaller market niches, including institutions such as hospitals, schools, and universities.

Table 2: 2010 Restaurant Sales and Segmentation ($Billions)

GROUP I COMMERCIAL RESTAURANT SERVICES	2010 Sales	Growth?
EATING PLACES		
Full-service restaurants	$184.176	
Limited-service (quick-service) restaurants	$164.837	☑
Cafeterias, grill-buffets and buffets	$7.671	
Social caterers	$7.090	☑
Snack and nonalcoholic beverage bars	$24.736	
TOTAL EATING PLACES	**$388.510**	
Bars and taverns	$18.844	
TOTAL EATING-AND-DRINKING PLACES	**$407.354**	
MANAGED SERVICES		
Manufacturing and commercial offices	$9.218	
Hospitals and nursing homes	$5.053	☑
Colleges and universities	$13.649	☑
Primary and secondary schools	$5.863	☑
In-transit restaurant services (airlines)	$2.061	
Recreation and sports centers	$5.025	☑
TOTAL MANAGED SERVICES	**$40.869**	
Lodging Places	$26.943	☑
Retail-host restaurants	$30.936	☑
Recreation and sports	$12.518	
Mobile caterers	$0.635	
Vending and Non-store retailers	$11.097	
TOTAL — GROUP I	**$530.352**	
GROUP II NONCOMMERCIAL RESTAURANT SERVICES		
Employee restaurant services	$0.426	
Public and parochial elementary, secondary schools	$6.144	
Colleges and universities	$6.083	
Transportation	$1.830	☑
Hospitals	$15.225	☑
Nursing homes, homes for orphans, disabled	$7.145	☑
Clubs, sporting, recreational camps, community centers	$10.694	
TOTAL — GROUP II	**$47.547**	
GROUP III MILITARY RESTAURANT SERVICES	$2.161	☑
GRAND TOTAL	**$580.060**	

Source: NRA 2010 Restaurant Industry Forecast

Schools, universities, hospitals are addressed using either in-house foodservice (non-commercial) and by "managed services" such as foodservice contractors. For example, the total university segment includes a non-commercial component of over $6.1 billion and a managed services component of about $13.6 billion (which is growing faster than the non-commercial segment). Managed service providers could be an attractive point for targeted marketing by National Grid.

Restaurants have a wide level of variability in their size and operations. Table 3 shows a breakdown of annual sales volumes based on average check cost. More than half of restaurants do more than $1 million annually in sales, with nearly one quarter being greater than $2 million. Not surprisingly, sales volume tends upward with higher average check businesses.

Table 3: Restaurant Annual Sales Data (% of restaurants)

Sales Volume	Average Check <$15	Average Check $15-25	Average Check >$25
<$500K	19.3%	9.6%	12.3%
$500K-$1000K	25.5%	30.7%	15.8%
$1000-$2000K	31.7%	33.3%	31.0%
>$2000K	23.5%	26.4%	40.9%

Source: NRA and Deloitte, Restaurant Industry Operations Report (2006/2007 Edition)

Most restaurants are either owned by a private corporation (around 60-65 percent), sole proprietorship, or partnership (the latter two each being about 15-20 percent of the market). This ownership structure is true of those restaurants which are tied to a major public corporation. For example, an estimated 85 percent of McDonald's restaurants are owned and operated by franchisees or private joint ventures.

The food service industry is attractive because, on a per square foot basis, it uses much more energy than most other commercial buildings (Figure 2). Food service establishments use 2.2 times the energy per square foot of the typical commercial building (258 versus 116 kBtu/ft^2) and have the highest energy intensity in the commercial building sector.

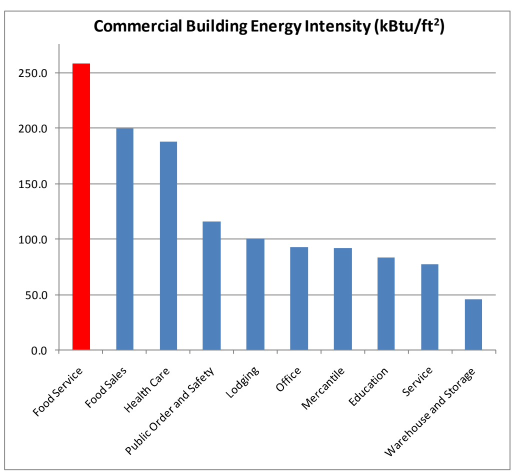


Figure 2: Commercial Sector Energy Intensity (DOE-EIA 2003 CBECS)

As evidenced by the relative energy intensity of foodservice establishments, energy is cited as one of several key factors of concern to food service operators. The following table shows results from the National Restaurant Association survey on key challenges perceived by full-service restaurant operators. Energy typically falls in the range of the top 5-6 areas of concern – and varies somewhat depending on the type of restaurant.

Table 4: Top Seven Challenges for Foodservice Operators in 2008

	Tableservice Segment		
	Family Dining	Casual Dining	Fine Dining
Recruiting and retaining employees	17%	23%	14%
Building and maintaining sales volume	12	11	22
The economy	13	13	17
Competition	17	6	13
Labor costs	11	10	10
Gas and energy costs	11	8	5
Food costs	7	10	3

Source: National Restaurant Association, 2007 Tableservice Operator Survey

The National Restaurant Association estimates that 49 percent of consumer spending on food is expended in the foodservice sector (the balance being food bought in grocery stores and consumed at home). This compares to only 25 percent of the consumer spending in 1955. Forty-four percent of consumers say that restaurants are an essential part of their lifestyle, with over 40 percent saying they are more productive eating at restaurants or using take-out or delivery foodservice.

This long-term demographic shift, where consumers are increasingly spending their food dollars in restaurants, presents an opportunity and a threat for the natural gas industry. With less food prepared at the home, there is a threat to natural gas sales to the residential sector and potential for displacement with electro-technologies in the home (e.g., microwaves and radiant or inductive heating). However, if a strong position for natural gas can be retained in restaurants, the net effect should be minimal.

The lifestyle elements of food and eating are evident. Sixty-five percent of consumers say their favorite restaurant foods provide flavor and taste sensations they cannot easily duplicate at home. One element to consider, however, is the growing popularity of at-home cooking shows on television featuring a plethora of celebrity chefs – and a dedicated cable station, The Food Network – along with growing enrollment in culinary schools (which includes those pursuing a career as well as for personal enjoyment and development).

Tying natural gas into the lifestyle elements of culinary arts is an important branding consideration for the natural gas industry. As will be highlighted, natural gas has certain positive branding factors, but can face strong competition from newer electro-technologies that may be perceived as

> "At the Culinary Institute of America in Hyde Park, N.Y., administrators increased their five-day, $2,095 "Basic Training" boot camp to 14 classes a year, up from 10 three years ago. The Whole Foods in the Soho neighborhood of New York City saw enrollment in the store's cooking classes increase 46% between 2009 and 2008, says a company spokeswoman."
> **Source: Wall Street Journal, Cutting Costs at Culinary School (Aug, 12, 2009)**

cleaner, more high tech, cleaner, greener, or safer. Tapping into culinary arts schools or collaborating with celebrity chefs to expose them to the latest natural gas commercial foodservice products could be an effective marketing approach.

Generally, natural gas has a strong position in the commercial foodservice segment. Table 5 and Figure 3 provide a snapshot view of natural gas and electric product sales. In several product categories – for example, ranges, convection ovens, and conveyor ovens – natural gas is the clear market leader. Leading electric product categories include: fryers, convection ovens, combi-ovens, and free-standing steamers. There are two categories where electric products have over 50 percent market share – counter-top steamers and combi-ovens. The rightmost column highlights product categories that are currently being addressed by UTD or SMP funded R&D efforts.

Table 5: Commercial Foodservice Product Sales (2006, Source: Fryett)

Equipment Category	Total Sales ($MM)	Gas Sales ($MM)	Gas Share (%)	Electric Sales ($MM)	UTD/SMP/ Projects
Underfired Broilers	$9.8	$9.8	100%	$-	
Pizza / Deck Ovens	$18.0	$18.0	100%	$-	☑
Wok Ranges	$30.0	$30.0	100%	$-	☑
Steamers - Pressure	$9.0	$8.0	89%	$1.0	
Charbroilers	$17.4	$15.0	86%	$2.4	
Ranges	$175.6	**$146.5**	83%	$29.1	☑
Conveyor Broilers	$35.0	$29.0	83%	$6.0	
Conventional Ovens	$15.0	$12.0	80%	$3.0	
Conveyer Ovens	$93.9	**$72.5**	77%	$21.4	☑
Rotisserie Ovens	$34.4	$26.5	77%	$7.9	
Griddles	$46.5	$35.0	75%	$11.5	
Pressure Fryers	$61.9	$46.5	75%	$15.4	
Fryers	$247.2	**$175.0**	71%	**$72.2**	☑
Over-fired Broilers	$36.8	$24.1	65%	$12.7	☑
Convection Ovens	$135.9	**$77.4**	57%	**$58.5**	☑
Steamers - Free-Standing	$68.0	$38.0	56%	**$30.0**	
Tilting Skillets	$46.3	$24.0	52%	$22.3	
Combi Ovens	$100.0	$46.0	46%	**$54.0**	
Steamers - Counter-Top	$39.5	$9.9	25%	$29.6	
Total	**$1,220.2**	**$843.2**		**$377.0**	
% of Total		**69.1%**		**30.9%**	

Fryers are a key market retention product for the natural gas industry due to the size of the market. While holding a 71 percent market share in 2006, this segment is threatened by electric products – especially with the recent shift to low oil volume fryers. This segment represents the highest dollar volume sales category for electric products. Also, for low oil volume fryers, electric units were developed and field tested one year before gas-fired models because of the extra development time required to design gas-fired burners. This situation places natural gas models of popular natural gas foodservice equipment at risk in terms of timing of commercial introduction or – in the most extreme cases – may be dropped from the product line-up if manufacturers do not see the benefit/cost of investing in a gas offering.

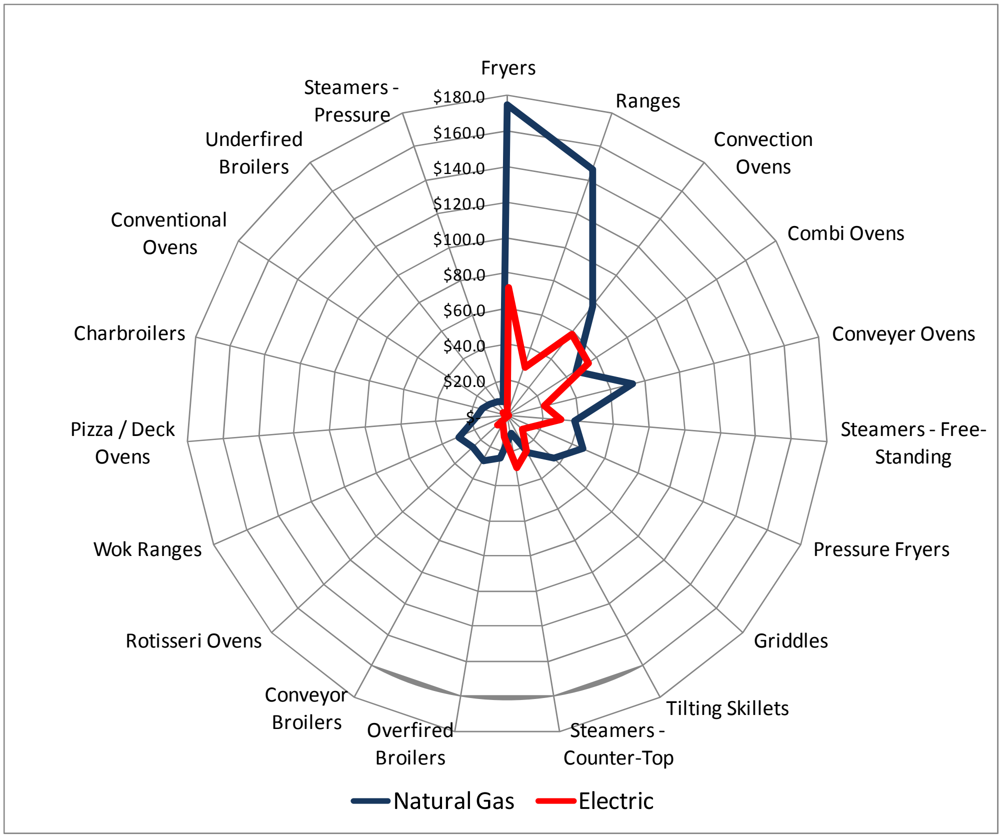


Figure 3: Commercial Food Service Equipment Sales by Category (2006, $millions)

Product Drivers

Historically, the demand for new or healthy food products has driven the foodservice industry to develop new and innovative technologies and equipment. An example is what could be called the "Boston Market" effect during the early 1990's. The popularity of roasted chicken grew tremendously with the initial Boston Market restaurants, leading several other restaurants – including existing chains – to add roasted chicken to their menus. This also led several manufacturers to develop rotisserie ovens for cooking chicken. Another example is the rapid increase in bagel preparation equipment that was spawned by the increasing popularity of bagels several years ago.

A current driver in the foodservice industry is the removing or banning of trans-fat oils by several restaurant chains or metropolitan areas. Trans-fats, present in many deep-frying oils, are linked to unhealthy levels of cholesterol levels -- a fact that has received considerable media exposure. For this reason, partially hydrogenated oils and trans-fat oils are the subject of growing scrutiny from public health officials and health-conscious consumers. By mid 2008, cities such as New York and others passed legislation to ban or tightly control the use of trans-fat oils in any public restaurant. Restaurant chains including McDonald's, Arbys and KFC have either discussed or are eliminating trans-fat oil from their menu items. The main issue with using trans-fat free oils is not availability; they are widely available, but cost more and have a different taste. In response to this, restaurants looked to the foodservice industry and manufacturers for solutions. One result was the development of low oil volume fryers by manufacturers including Frymaster, Pitco and Henny Penny. Low oil volume fryers address the increased cost of the non trans-fat oils by using less oil than standard fryers, 30 to 35 pounds of oil compared to over 50 pounds. The savings is realized by throwing away less oil during each oil change. Oil savings are also realized by improved filtering methods in some of the low oil volume fryers that increase the useful life of the oil.

Rethermalization is an area of potential market change. The concept behind rethermalizing is to use either vendor-prepared or commissary-made food products in place of "from scratch" cooking. In addition to helping restaurants address high demand periods, this can result in labor savings, energy savings, improved consistency, and potentially improved food safety.

In this process, large batch cooking is employed to make a product (e.g., soup) that is quickly chilled and placed into multiple vacuum-sealed bags of food. This is also referred to as the *sous vide* process. Vacuum sealing helps to keep out harmful pathogens while retaining flavor and aroma.

The rethermalization process at the restaurant involves reheating the product – typically with lower temperatures and considerably less time than would be required by cooking from scratch. As noted earlier, labor is a major cost and operations issue for restaurants. Using rethermlized food can reduce restaurant labor costs and – to some extent – the quality of labor needed (compared to cooking from scratch).

> "From the standpoint of equipment, in some cases we may be headed for the **fireless kitchen** without pots or pans. This also would reduce, or in some cases even eliminate, exhaust requirements of many professional kitchens."
> **Source: "Rethermalize it," Nation's Restaurant News, Oct. 8, 2007.**

Rethermalizing is an area that could represent a threat or opportunity for the natural gas industry. A shift towards a "fireless" kitchen – one that mainly uses electricity for reheating pre-cooked products – is clearly a potential threat.

Ventilation is both an area of opportunity and concern for the restaurant operator and the natural gas industry. Employee turnover is very high in the restaurant industry; in some segments, the turnover rate is 200 percent. This puts additional costs on the restaurant through training and absenteeism costs.

By making the kitchen a more comfortable workplace through advanced ventilation practices and safer cooler equipment surfaces, employee turnover rates may be reduced. Ventilation issues also impact energy use (heating, cooling, fan power, etc) and indoor air quality in the kitchen environment. There are also fire safety consideration with ventilation systems and cleaning of grease to prevent fires.

Kitchen ventilation is an opportunity for improved comfort and energy savings. In most kitchens, exhaust fans will run at a constant speed throughout the day. This can impact space conditioning loads along with fan energy requirements. Opportunities for improvement include using demand ventilation approaches that can modulate fan speed depending on work conditions.

New emission standards have driven the development of new appliances in the residential/commercial markets at different times in the past few decades. Lower emissions requirements in California on residential water heaters led to the development of new combustion systems for all water heaters currently sold in the state. Establishing NO_x emission levels on residential furnaces by the South Coast Air Quality Management District led to the development of new furnace designs and combustion systems. While new emissions legislation is usually more focused on residential appliances, new NO_x emission standards are being considered for commercial cooking equipment in California. Agencies in California are also proposing new limits on the particulate emissions from charbroilers. Particulate emissions and grease build-up in ventilation systems is a serious issue for restaurants. GTI is currently working with the gas industry and manufacturers to explore options to address these environmental and restaurant workplace issues.

Energy Use and Natural Gas v. Electric Positioning

Table 6 provides a breakdown of typical costs and pre-tax profits in the restaurant business. The dominant cost factors are food and beverage, followed by salaries and benefits. Labor-related issues – controlling labor costs, employee retention, increasing productivity – are key concerns for restaurant operators (as noted in Table 4). The other item of note is that most restaurants have relatively modest income before taxes – around 4 percent. Reducing costs even one percent can translate into a 20-30 percent relative increase in profits.

Table 6: Typical Restaurant Cost Stack

Food & Beverage	32%
Salaries & Benefits	34%
Occupancy	7%
General & Administrative	3%
Other	20%
Income Before Taxes	4%
Total:	**100%**

Source: NRA and Deloitte, Restaurant Industry Operations Report (2006/2007 Edition)

Generally, restaurants are a tight margin business with many competitors, as evidenced by the substantial number of outlets across the U.S. (525,000). Restaurants typically go through dynamic cycles of birth and death for a variety of reasons. Statistics indicate that one in four restaurants fail in the first year, with nearly 60 percent failing within three years.

The "other" category in Table 6 includes energy and other "utility" costs such as water. The importance of energy and other utility costs will vary depending on the restaurant type and sales volume. Table 7 illustrates the relative importance of utility costs depending on the restaurant type (using average check size as a differentiator). The relative impact of energy costs generally increases as the average check size goes down.

Table 7: Restaurant Energy & Utility Costs by Restaurant Type (% of revenue)

	Average Check <$15	Average Check $15-25	Average Check >$25
Lower Quartile	2.7%	2.5%	1.9%
Median	3.7%	3.4%	2.7%
Upper Quartile	4.9%	4.5%	3.8%

Source: NRA and Deloitte, Restaurant Industry Operations Report (2006/2007 Edition)

Table 8 provides an estimate of annual energy costs for an example restaurant as a function of annual sales and the percent of total sales allocated for energy and related utility costs. Using a typical restaurant sale volume of $1-1.5 million annually and energy costs of 3.4 percent of sales, annual energy costs for a nominal restaurant is in the range of $34-50,000. This value will likely be in the range of $50,000-$100,000 for higher sales volume stores.

Table 8: Energy Costs By Sales Volume and Energy Costs Percent of Sales

Energy Cost % Sales ➔ Annual Sales 🡇	2.5%	3.0%	3.5%	4.0%	4.5%
$500,000	$12,500	$15,000	$17,500	$20,000	$22,500
$1,000,000	$25,000	$30,000	$35,000	$40,000	$45,000
$1,500,000	$37,500	$45,000	$52,500	$60,000	$67,500
$2,500,000	$62,500	$75,000	$87,500	$100,000	$112,500

As noted, commercial food service establishments are attractive because they use considerably more energy (per square foot) than other commercial buildings and tend to contribute more to natural gas profits. The higher energy intensity is due to their process activities such as food storage (e.g., refrigeration), food preparation (e.g., cooking), and sanitation (e.g., cleaning dinnerware).

Figure 4 and Table 9 show DOE-EIA estimates of site electric and natural gas use in all foodservice buildings in the U.S. (based on the 2003 Commercial Buildings Energy Consumption Survey). Electricity and natural gas are the primary energy options used in the commercial food service sector, with electricity being about 70 percent of total energy costs. Equivalent electric use is about 217 trillion Btu (63 billion kWh) and 203 trillion Btu for natural gas.

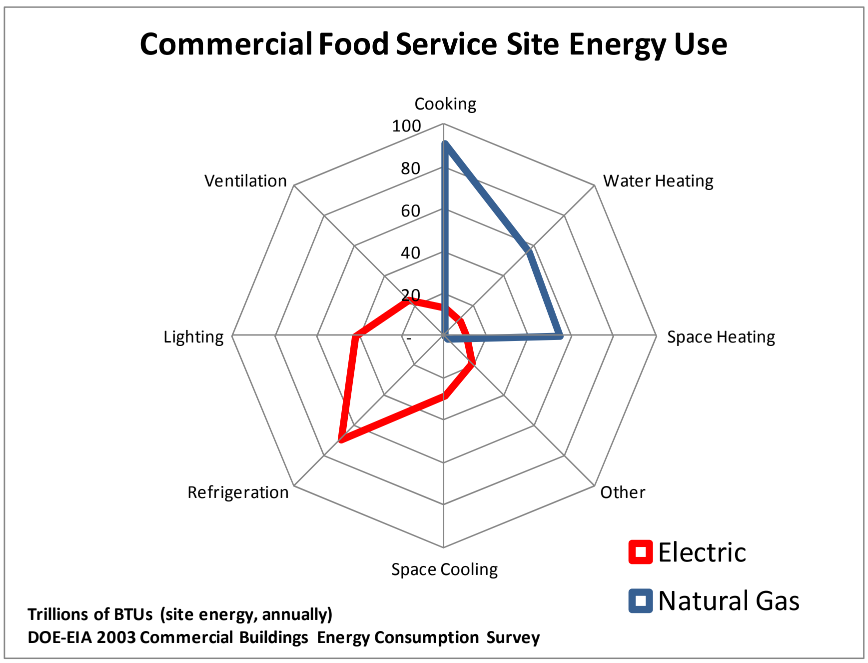


Figure 4: Commercial Food Service Site Energy Use – Electric and Natural Gas

The use of each of these two energy choices is highly differentiated, with most electricity used for refrigeration, space conditioning, lighting and ventilation. Natural gas is predominantly used for cooking, water heating, and space heating – holding over 80 percent share across the market. Retaining this market position against electric technologies should be a primary consideration for the natural gas industry.

Table 9: National Electric and Gas Site Energy Use for Commercial Food Service

	Electric	Natural Gas	% Gas
Cooking	13.6	91.0	87%
Water Heating	10.2	56.0	85%
Space Heating	10.2	54.0	84%
Other	18.1	2.0	N/A
Space Cooling	28.2	-	N/A
Refrigeration	69.5	-	N/A
Lighting	42.4	-	N/A
Ventilation	24.3	-	N/A

Source: DOE-EIA 2003 Commercial Buildings Energy Consumption Survey (Trillion Btu)

There is a substantial amount of energy consumed to produce and deliver electricity. The total source to site energy lost is often more than twice the amount of electric energy used onsite. DOE-EIA data indicate that total energy consumption for electricity in commercial foodservice is about 650 trillion on a complete source to use basis (compared to about 215 trillion Btu on a site-only basis). Figure 5 illustrates the substantial differences in total source energy use compared to a site-only basis. For example, refrigeration loads use slightly less energy on a site basis, but are more than two times more in energy consumption on a source basis.

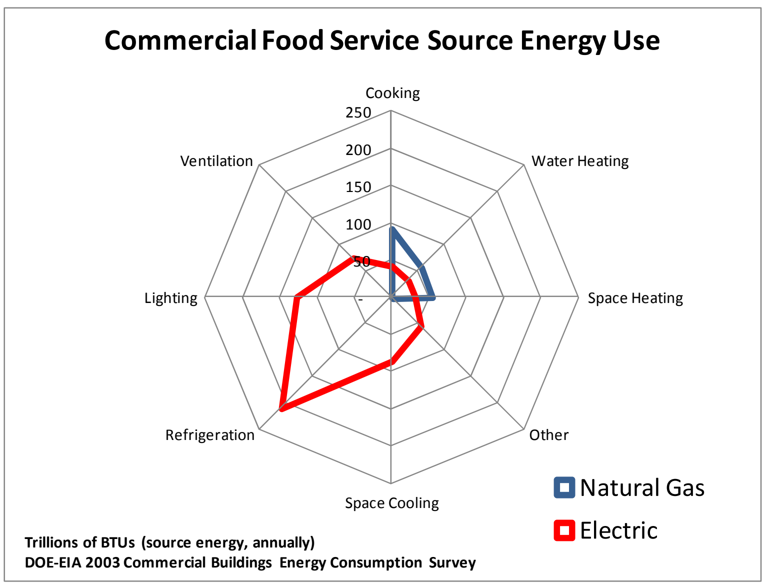


Figure 5: Commercial Food Service Source Energy Use – Electric and Natural Gas

The substantial differences in site versus source energy values can be an important factor when companies look at “green building” issues such as LEED compliance. Unfortunately, there has been a reluctance in some of these codes to recognize total source energy as a more complete and responsible measurement of national energy use.

Natural gas and electricity -- and the industries that represent them – have perceived strengths and weaknesses. The following table highlights some of these considerations.

Table 10: Natural Gas and Electric Strengths and Weaknesses

	Strengths	Weaknesses
Natural Gas	• Perceived as lowest life-cycle and operating cost options for end users • High energy rates with rapid response to changes in burner setting • High delivered energy density compared to electric. • Source energy and carbon emission advantages over electricity	• Less technologically advanced (e.g., manual controls, pilot lights) • Perception in some cases as being less safe than electric products • Manufacturers lack gas expertise or motivation to invest in state-of-the-art gas technology (e.g., indifferent on gas vs electric) • Perceived limited gas industry marketing focus in this segment • Lack of gas combustion engineers and burner design experts. Old designs tend to be reused
Electric	• Seen as cleaner, more technologically advanced • Perceived as safer than natural gas • Products are viewed as more reliable • Typically lower first cost equipment • Many 'green' building codes based upon site rather than total source energy	• Higher electric operating costs (energy and power demand) • Utility pressure to manage peak demand, control costs, ensure reliability • Typically higher source energy and emission factors (on a full-fuel-cycle basis) • Limited availability in some locations to add amperage or install higher voltage outlets needed for resistance heating

Operating costs are an important factor in the commercial food service sector. Survey data indicates that users perceive natural gas as a better value in terms of annual energy costs. The following table compares typical commercial natural gas and electricity prices in New York and Boston for commercial customers (Source: DOE-EIA, Oct. 2009 data).

Table 11: Comparison of Energy Costs in New York and Massachusetts

	Natural Gas	Electric	Electric/Gas Ratio
New York	\$10.46/mcf (\$10.25/MMBtu)	\$0.1568/kWh (\$45.93/MMBtu)	4.5:1
Massachusetts	\$11.38/mcf (\$11.16/MMBtu)	\$0.1912/kWh (\$56.00/MMBtu)	5.0:1

Using information from GTI's Building Energy Analyzer, the following table breaks down annual energy characteristics and energy costs for a typical 5,000 sq. ft. national chain casual full-service restaurant. This highlights the energy value provided by natural gas relative to electricity. Commercial food service establishments are paying monthly bills for electricity that are more than double their natural gas bills. This disparity likely helps underscore the consumer perceptions of natural gas being a better value – or, conversely, they are paying too much for electricity.

Table 12: Restaurant Energy Cost and Consumption Comparisons in New York City and Boston

	Natural Gas	Electric	Electric/Gas Energy Ratio	Electric/Gas $ Sales Ratio
New York, NY	Site Energy 3,087 MMBtu Source Energy 3,358 MMBtu Cost: $31,640	Site Energy 427,000 kWh; 89 kW Source Energy 4,239 MMBtu Cost: $66,950	0.47:1 (site) 1.26:1 (source)	2.1:1
Boston, MA	Site Energy 3,238 MMBtu Source Energy 3,552 MMBtu Cost: $36,140	Site Energy 420,000 kWh; 87 kW Source Energy 4,383 MMBtu Cost: $80,300	0.44:1 (site) 1.23:1 (source)	2.2:1

Note: Source emission factor of 2.91 for NY electricity, 3.06 for MA electricity, 1.088 for natural gas (Source: GTI)

The Northeast market may see further absolute and relative improvement in natural gas prices and electric/gas price ratios due to the substantial new natural gas supplies being developed in the Marcellus Shale region in Pennsylvania, New York. **The combined impact of expanding supplies coupled with market proximity (i.e., reduced transmission costs) is likely to further enhance the competitive position of natural gas in this market sector**.

As noted, there can be substantial differences between natural gas and electricity from an environmental perspective depending on whether you compare site or source (total) emissions. This is a relevant factor to highlight with respect to consumer awareness of energy, environmental, and sustainability concerns. Surveys indicate that consumers perceive electricity as being "more green" than natural gas (Figure 6) – even though natural gas emits lower greenhouse gases than electricity on a total energy basis.

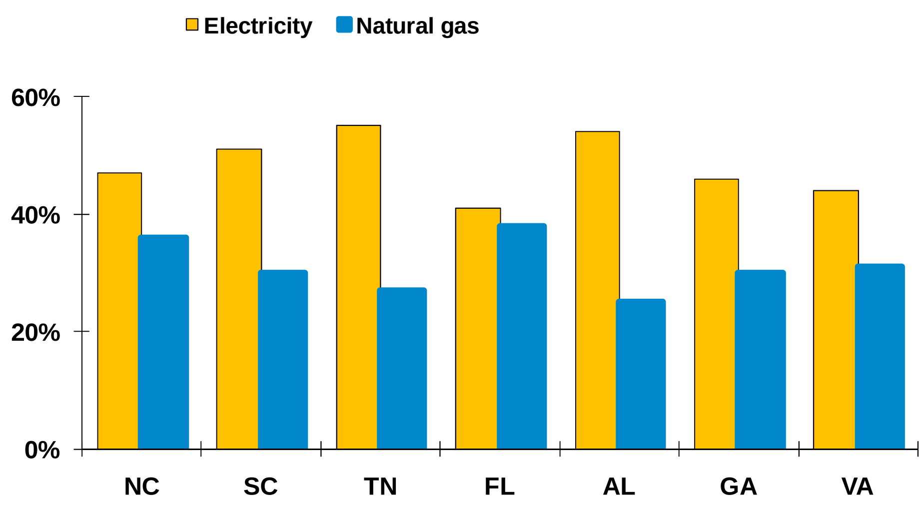


Figure 6: Consumer Perceptions of Environmental Friendliness

(Source: Council for Responsible Energy, 2007 data)

The natural gas industry is striving to elevate the source-to-site (or full fuel cycle) energy and environmental benefits of natural gas compared to electricity. Conveying this message to various stakeholders – individual consumers, businesses, and policymakers – is important. Decision makers in the commercial foodservice industry can also include architects, consulting engineers, and others – particularly those who are positioned in areas associated with "green buildings" (e.g., LEED-certified personnel).

There are market factors – opportunities and threats in the competitive marketplace -- that can influence the relative strengths and weaknesses of natural gas and electric now and in the future. The following is a summary of some of these factors that may impact natural gas and electric products and the customer's willingness to continue using or when purchasing new commercial food service products.

Table 13: Natural Gas and Electric Opportunities and Threats

	Opportunities	Threats
Natural Gas	• Developing state-of the-art natural gas products (e.g., pilotless ignition, new sensors and controls, • Smart technology that enhances control and communications • Features that increase productivity, product quality • Expanding the number of products recognized as Energy Star compliant • Utility marketing, outreach and incentive programs (e.g., test kitchens, live cooking demonstrations, incentives for high-efficiency products) • Marketing outdoor cooking and outdoor seating with gas heating to restaurants • Potential improved positioning of natural gas prices relative to electricity • Enhancing customer and policymaker awareness of source energy and environmental benefits	• Lower number of Energy Star appliances compared to electric • Reduced opportunity for customers to benefit from energy efficiency incentives (and potential switching to electric) • Larger and/or more aggressive electric utility marketing and incentive programs (7-10:1 greater energy efficiency funding) • Reduced level of skill and expertise among small to medium manufacturers – particularly with respect to natural gas technology • Tightening emission standards (e.g., NOx, particulates) • Higher cost and complexity of ventilation and interior piping systems • Bias in certain Green Building Codes towards site energy and "clean" electric
Electric	• Rethermalizing and similar trends that could reduce kitchen energy intensity and potentially favor all-electric kitchens • Advanced cooking techniques such as induction cooking • Smart technology that enhances controls and communications Leveraging green building codes that favor site energy	• Increasing electricity prices due to increasing cost of new power plants and added environmental costs to reduce carbon emissions • Concerns over peak electric demand and electricity supply reliability • Use of source energy in place of site energy for green building codes and energy efficiency metrics

Energy Efficiency Programs and Energy Star

Energy efficiency and sustainability are key concepts that resonate with restaurant and food service operators. Their tight operating margins provide an incentive to reduce fixed and variable energy costs. The following table from the NRA 2010 Restaurant Industry Forecast outlines steps taken in 2009 and plans for 2010 relative to energy savings and other resource conservation investments. These data indicate a higher inclination towards electricity savings steps (e.g., lights, air conditioning, refrigeration) followed by investments in energy-saving kitchen equipment. Water savings are generally lower priority resource conservation steps.

Table 14: NRA Sustainability Survey – Planned Actions

Sustainability steps

Proportion of restaurant operators, by type of operation, who took the following energy-saving actions in 2009 or who plan to in 2010

	Family dining		Casual dining		Fine dining		Quickservice	
	Did in 2009	Plan to in 2010	Did in 2009	Plan to in 2010	Did in 2009	Plan to in 2010	Did in 2009	Plan to in 2010
Purchased energy-saving light fixtures	69%	41%	66%	46%	52%	38%	43%	32%
Purchased energy-saving kitchen equipment	45%	34%	41%	34%	28%	32%	34%	31%
Purchased energy-saving refrigeration, air conditioning or heating systems	50%	32%	40%	28%	34%	27%	32%	30%
Installed water-saving equipment and/or fixtures	27%	26%	27%	23%	27%	24%	23%	23%

The somewhat greater leaning toward electric savings may reflect the reality that annual electricity costs are likely to be twice as high as natural gas costs – that is, electricity provides greater opportunity for savings.

Other factors to consider are:

- The availability of Energy Star and other high-efficiency equipment
- The availability of rebates, tax credits, and other incentives that may enhance the buying decision process for the consumer

For example, electric and natural gas energy efficiency programs have grown considerably in recent years. These programs can provide meaningful incentives for the purchase of new high-efficiency equipment. Historically, this funding has primarily been directed at electricity consumers, with a more recent trend of funding for natural gas.

According to the Consortium for Energy Efficiency, in 2009 approximately $4.4 billion million was invested in electric energy efficiency and $930 million in natural gas energy efficiency programs across the US. The following table breaks down state-level natural gas and electric energy efficiency program funds (including demand response) directed at the commercial and industrial sector in 2009 by CEE.

Table 15: Energy Efficiency Funding Comparison (Source: CEE, 2009 data)

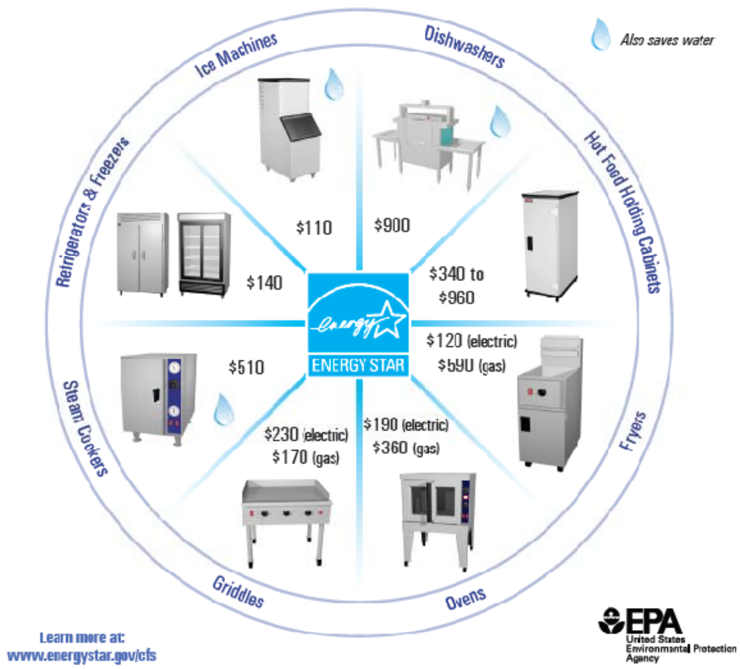
	Natural Gas	Electric	Electric/Gas Ratio
U.S. Total	$930.0 million	$4,400.0 million	4.7:1
New York	$42.9 million	$393.2 million	**9.2:1**
Massachusetts	$32.5 million	$176.1 million	**5.4:1**
New Hampshire	$3.0 million	$16.3 million	5.4:1
Rhode Island	$7.6 million	$30.7 million	4.0:1

Substantially greater funds are potentially available to commercial food service establishments for electric energy efficiency incentives and rebates compared to natural gas (by a factor of 4-9:1). Notably, the energy efficiency funding ratio is considerably higher than the national average in New York – that is, greater funds are available to incentivize the purchase of high-efficiency electric equipment. This underscores the potential threat to the natural gas industry of consumers switching to electric technologies based on the incentives provided by energy efficiency program funding.

A complementary issue is the availability of products that can qualify for energy efficiency funding. Energy Star is an international standard for energy efficient consumer products. It was first created as a United States government program by the Clinton Administration in 1992, but Australia, Canada, Japan, New Zealand, Taiwan and the European Union have also adopted the program. Devices carrying the Energy Star logo, such as computer products and peripherals, kitchen appliances, buildings and other products, generally use 20%–30% less energy than required by federal standards. There is considerable online information that can be found at www.energystar.gov – including product availability and other helpful information from consumers.

Initiated as a voluntary labeling program designed to identify and promote energy efficient products, Energy Star began with labels for computer products. In 1995 the program was significantly expanded, introducing labels for residential heating and cooling systems and new homes. As of 2006, more than 40,000 Energy Star products are available in a wide range of items including major appliances, office equipment, lighting, home electronics, and more. In addition, the label can also be found on new homes and commercial and industrial buildings. In 2006, about 12 percent of new housing in the United States was labeled Energy Star. The EPA estimates that it saved about $14 billion in energy costs in 2006 alone. The Energy Star program has helped spread the use of LED traffic lights, efficient fluorescent lighting, power management systems for office equipment, and low standby energy use.

There are eight types of commercial food service (CFS) appliances that can earn EPA's Energy Star. Qualified equipment models use less energy and less water than conventional CFS models. The following images from www.energystar.gov/cfs shows the potential annual savings of using Energy Star qualified compared to conventional appliances.



Energy Star appliances require sufficient information and usage data to determine the baseline energy consumption – a necessary pre-condition to establish an Energy Star performance level. There are limited categories for Energy Star products suitable to the commercial foodservice sector because the data either does not exist or has not been compiled into a useful set to establish Energy Star guidelines.

Current drivers within the foodservice industry are pushing the need to establish new categories of Energy Star appliances. Because of increasing energy and water utility costs and interest in being more sustainable, operators in the commercial foodservice industry are expressing increased interest in appliances and systems that are more energy efficient to replace older, less efficient units. Recent market surveys conducted by both GTI and the National Restaurant Association have shown a greater interest on the part of operators to invest in energy-efficient equipment. GTI surveys have shown that consumers within the past two years are more willing to spend extra on the first cost of new appliances if the units are significantly more efficient or Energy Star rated. Manufacturers also have expressed to GTI that concerns over energy efficiency and the environment have become major drivers in the foodservice industry compared to two years ago.

There is an ongoing challenge facing the natural gas industry to ensure there is a broad array of Energy Star-approved natural gas appliances available. Many utility energy efficiency programs use Energy Star as a product qualifying step for energy efficiency funds. Unfortunately, due to a variety of factors, there are numerous product categories in the commercial food service sector where there are no Energy Star-approved products available – either because the products do not exist or because there are no approved standards for that product category. Table 16 lists the current Consortium for Energy Efficiency “qualifying product” list. Only two categories tie with natural gas equipment – fryers and steamers; all product categories tie into electricity use. The lack of approved energy efficient product standards can stymie or inhibit:

- The development of new, high-efficiency equipment by manufacturers
- The ability of natural gas energy efficiency to incentivize the purchase of new high-efficiency natural gas equipment

Table 16: CEE Qualifying Commercial Foodservice Products (2010)

Dishwashers	**Fryers**	Ice machines
Hot food holding cabinets	**Steamers**	Refrigerators & freezers
Pre-rinse sprayers		

Table 17 outlines the major commercial food service products with GTI-developed rating criteria on Energy Star status. In nine equipment categories there is an impediment due to the lack of any current standard or standard development process underway. In three categories, a standard is in development. In total, twelve of the nineteen equipment categories (63 percent) of commercial foodservice products are lacking in a qualified Energy Star standard.

Table 17: Energy Star Availability Ratings for Commercial Food Service Equipment

Equipment Category	Energy Star Status*
Underfired Broilers/Charbroilers	1
Pizza / Deck Ovens	2
Wok Ranges	1
Steamers - Pressure	4
Ranges	1
Conveyor Broilers	1
Conventional Ovens	1
Conveyer Ovens	2
Rotisserie Ovens	1
Griddles	4
Pressure Fryers	1
Fryers	5
Over-fired Broilers	1
Convection Ovens	4.5
Steamers - Free-Standing	4
Tilting Skillets	1
Combi Ovens	2
Steamers - Counter-Top	3
Warewashers	3

* Energy Star Status Rating Key

5 = Standard Issued - Robust Qualified Gas Equipment

4 = Standard Issued - Some Qualified Gas Equipment

3 = Standard Issued - Electric Equipment Dominates

2 = Standard In Process

1 = No Standard

Taken together, these data on state-level energy efficiency programs, availability of industry recognized "qualified products" by CEE, and a substantial deficiency in Energy Star-approved standards and qualified equipment underscores the need for natural gas industry attention. Specifically:

- In selected Northeast states, such as New York and Massachusetts, there is a need to evaluate the relative availability of natural gas energy efficiency funds relative to those for electric in the commercial sector.
- A concerted natural gas industry effort is required to:
    - Substantially enhance the availability of Energy Star standards for various commercial food service equipment.
    - Expand efforts with CEE and other organizations to document and support an expanded list of energy efficiency commercial foodservice products.
    - Substantially expand the number of qualified Energy Star and CEE-recognized natural gas commercial food service products that are developed and available to consumers.

Gas Industry RD&D and Commercialization

Based on these results, GTI sees the following as fertile areas in the foodservice industry for National Grid's territory:

Area 1. **Development of higher efficiency and Energy Star-compliant natural gas appliances, coupled with support of new energy efficiency standards and protocols**
Benefits: Energy savings, lower emissions and gas appliance positioning with the "green" and sustainability movement. Increased availability of "qualified products" for natural gas energy efficiency program incentives. Avoiding market erosion to electric equipment.

Area 2. **Improved space conditioning and ventilation in the work area for a healthier work environment**
Benefits: Improved workplace comfort, lower employee turnover, and energy cost savings.

Area 3. **Development and marketing of equipment that is easier to operate and maintain**
Benefits: Improved productivity, improved product quality, and lower energy costs for restaurant and commercial foodservice operators. Avoiding market erosion to electric equipment.

Area 4. **Expanded marketing and outreach programs: Test Kitchens and Live Cooking Demonstrations, increased use of rebates and incentives for natural gas energy efficient products**
Benefits: Greater customer and trade ally recognition of the availability and benefits of new natural gas products.

When assessing the needs, opportunities, and threats within the commercial food service sector, it is important to explore the spectrum of the product development and commercialization stages.

Figure 7 outlines an example of the steps required in the product development and commercialization process.

Natural gas R&D

The natural gas industry has two primary collaborative R&D programs – the GTI Sustaining Membership Program (SMP) and Utilization Technology Development (UTD, an independent industry-driven non-profit RD&D organization). These organizations primarily span RD&D activities up to Stage 6, demonstration and deployment.

Leading towards commercialization, the roles of SMP and UTD are complemented by the Energy Solutions Center (ESC) as well as an expanding number of natural gas energy efficiency programs that support Stage 6, 7 and 8 efforts through marketing programs and outreach as well as incentives that help support new technology acceptance in the market. A part of the ESC includes the Gas Food Equipment Network, or GFEN. Utility energy efficiency programs also have a national organization called the Consortium for Energy Efficiency (CEE).

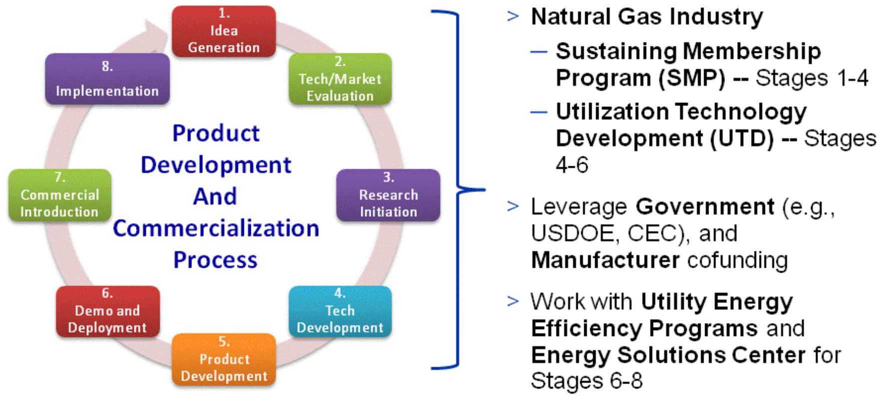


Figure 7: Product Development and Commercialization Process

For the reasons outlined in this report – notably, the energy intensity of commercial foodservice operations – GTI and UTD natural gas industry partners have maintained a focused concentration on product development for commercial foodservice customers. The research, development, and demonstration (RD&D) efforts of UTD has led to several successful commercial foodservice products (Table 18).

Table 18: Example UTD-Supported Commercial Foodservice Products

	**Low-Oil-Volume Fryers** A new commercial foodservice low-oil-volume fryer unit, marketed by Frymaster as Protector® fryers, increases energy efficiency while also extending cooking oil quality and life to provide significant customer savings.	**Contact: Linda Brugler** Frymaster 318-866-2488 lbrugler@frymaster.com www.frymaster.com
	**Stellar Countertop Steamer** This compact gas-fired countertop steamer for commercial food service offers enhanced cooking rates while providing users with added savings of energy and water consumption. The unit is the first gas-fired boilerless steamer with an ENERGY STAR rating.	**Contact: Market Forge Industries/Stellar Steam** 617-387-4100 866-698-3188 custserv@mfii.com www.mfii.com www.stellarsteam.com
	**Avantec Combi-Oven** The combination oven uses a patented technology for improving cooking performance, quality, and efficiency. Able to operate in various cooking modes, the oven provides enhanced uniformity when compared to similar-sized ovens.	**Contact: Dave Goble** Avantec Food Service Equipment 800-322-4374 dave@twomarket.com www.avantecequipment.com

The UTD Foodservice Working Group is composed of representatives from UTD member gas utilities with expertise in the foodservice arena. The group holds regular conference calls to discuss issues and potential solutions for the foodservice industry and how the utilities can participate in this process. The development and maintenance of quality foodservice equipment is important to both the gas industry and the foodservice manufacturers.

During the past few meetings, several issues have been brought to the group for discussion. The biggest topic has been the need for more efficient gas-fired appliances to be introduced to the market. Specifically, utilities are looking for an expanded list of Energy Star eligible appliances that would qualify for rebates from the utilities. This expansion includes both increasing the number of efficient appliances in existing Energy Star categories and expanding the number of Energy Star categories to include more appliance types. Specific appliances discussed for investigation of improved energy efficiency include: convection ovens, conveyor ovens, and ranges. Specific energy efficiency issues for each appliance are discussed below:

- **Convection Ovens**
  Typical gas-fired full-sized convection ovens have heavy load efficiencies in the mid 30 percent range. The best gas-fired models that have been tested at the Foodservice Technology Center attain near 45 percent heavy load efficiency. The currently proposed standard for Energy Star rating will be 44 percent, meaning only a few models of existing convections ovens will receive an Energy Star Rating. Design elements that may contribute to the lower efficiency include: door gasket material, method of firing the burner (direct vs. indirect heating), construction seals and door design (split vs. one piece). There are an estimated 15,000 gas-fired convection ovens operating in National Grid Service territory, with an associated gas load of 9 million therms annually. Improving the stock efficiency of gas-fried convection has the potential to reduce the commercial gas load by 3 million therms per year. The associated carbon savings is 39 million pounds of CO_2 produced per year.
- **Conveyor Ovens**
  Over the past 30+ years, conveyor ovens have taken over the majority of baking pizzas in restaurants. Because of several factors in the design of conveyor ovens, the efficiencies tend to be low compared to other foodservice appliances, about 40 percent for large conveyor ovens and 20 percent for small ovens. A large majority of the larger ovens are gas; however, for the smaller ovens, there are more electric than gas models. More progress has been made to improve the efficiency of the larger ovens than the smaller ovens by improving stand-by losses in the ovens. However, other design issues tend to keep the efficiency of the smaller ovens lower than the large ovens. These include the open ends of the conveyor, cooking tunnel design/dimensions and air flow distribution. There are an estimated 3,000 gas-fired conveyor ovens operating in National Grid Service territory, with an associated gas load of 6.5 million therms annually. Improving the stock efficiency of gas-fried convection has the potential to reduce the commercial gas load by 2 million therms per year. The associated carbon savings is 26 million pounds of CO_2 produced per year.
- **Ranges**
  Commercial ranges are one of the most common appliances in the foodservice industry and 90

percent of ranges are gas fired, resulting in a significant gas load. Gas fired commercial ranges currently have very low efficiencies due to three main issues:

- Pilot lights – While most residential gas-fired ranges feature pilotless ignition, a very high percentage of commercial ranges have pilots. Some manufacturers have offered pilotless ignition, but the market has not embraced this feature.
- The ASTM water-boil efficiency is in the low 30 percent range.
- Some operators leave burners operating when there is no load in place on the burner.

Another issue is that there are new hood interlock rules from both the international mechanical code and the international fuel gas code that require gas to be shut off to cooking equipment when the kitchen hoods are not in operation. This forces the restaurant to either run a separate gas line for pilot operation or re-light their pilots every morning. The new hood interlock rules are forcing the industry to consider using ranges without pilots so they will not have to worry about relighting the pilot each morning. There are an estimated 21,000 gas-fired commercial range tops operating in the National Grid Service territory. These are broken into heavy-duty ranges, restaurant ranges and stock pot ranges. The estimated gas-load for the three subcategories of ranges is 20 million therms per year. Estimating 200 new ranges produced per year with 50 percent energy savings provides 1 hundred thousand therms of energy savings in the first full year of deployment alone.

The members also expressed interest in participating in the process of establishing Energy Star ratings and providing information to the customers on rebates and the advantages of using Energy Star appliances.

Another issue growing within the foodservice industry is the concept of "green" appliances and environmental benefits in term of carbon footprint of gas vs. electric. The group expressed the need to understand and define terms that apply to the "greenness" of an appliance and how information can be conveyed to the utilities and its customers.

The current RD&D process for commercial foodservice is reasonably robust, but could benefit from further investment. The following are R&D funded by UTD or SMP::

- Gas-fired wok
- Gas-fired rethermalizer
- Gas-fired conveyor oven
- Gas-fired convection oven
- Gas-fired commercial range
- Gas-fired warewasher

Beyond these readily identifiable products suited to the kitchen environment, there are several cross-cutting technology development initiatives that can benefit the commercial food service sector, such as:

- Early-stage cross-cutting technologies:

    - Advanced flat-panel radiant burner and controls (could be applied to various foodservice cooking devices)
    - Low NO_x burners
- Hybrid tankless hot water technologies
- High-efficiency rooftop packaged gas heating units
- Desiccant-based dehumidification systems
- Commercial hybrid solar thermal/natural gas systems

One area of note is a UTD project that is addressing a growing trend in the foodservice industry: preparing certain food products in larger quantities at a centralized location and delivering those to restaurants for reconstituting or rethermalizing. The main driving factors for this are productivity and labor savings from centralized large-scale production, speedier in-restaurant preparation, and energy savings. Products like soups, gravies, vegetable side dishes and sauces have been shown to be prepared in this method and served in restaurants without any perceived sacrifice in flavor or texture. Data suggests that significant energy and labor savings can be realized by preparing these items in bulk.

Commercialization

The Energy Solutions Center is a technology commercialization and market development organization representing energy utilities, municipal energy authorities, and equipment manufacturers and vendors. The mission of the Center is to accelerate the acceptance of and deployment of new energy-efficient, gas-fueled technologies that enhance the operations and productivity of commercial and industrial energy users, and improves comfort and reliability for residential energy users.

The ESC and its members identify, evaluate, and prioritize new market opportunities and then implement market development initiatives designed to move products from R&D success to broad market acceptance.

The Gas Foodservice Equipment Network (GFEN) is an international alliance of utilities, foodservice equipment manufacturers, gas industry associations and foodservice trade allies organized to be a source of gas solutions for the commercial foodservice segment. The objective of GFEN is to maintain and build natural gas load by ensuring that our commercial food service customers have an array of clean, efficient, cost-effective and high performance natural gas products from which to choose and are made aware of these products and their benefits.

There are a select number of utilities that have adopted targeted marketing efforts for the commercial foodservice sector using Test Kitchen facilities. This approach allows restaurant operators, cooks, equipment manufacturers and other stakeholders to test new products, learn about new energy efficient practices, and make side-by-side comparisons of competitive brands – including comparing natural gas and electric products.

Several utilities have invested in foodservice centers and test kitchens, including Southern California Gas, PG&E, Southwest Gas, Piedmont Natural Gas, Alabama Gas, and Centerpoint Energy, . Figure 8 shows a profile on Piedmont's test kitchen from a recent GFEN publication.

PIEDMONT NATURAL GAS
TECHNOLOGY CENTERS

Piedmont's Gas Technology Center in Charlotte has 6,000 square feet of space, two 10-foot sections of kitchen ventilation hood and five gas and electric connections. Both natural gas and electric cooking equipment can be compared in a real-world environment. A data acquisition system provides the capability to measure and calculate equipment performance, energy use and efficiency, and food production. In addition, there are large prep and cleanup areas with both condensing and high-efficiency commercial gas water heaters and a dishwasher with a gas booster heater.

When not used for equipment testing or demonstrations, the Centers have extensive audio/video capabilities and seating for 70 people which make them ideal for sales meetings, customer workshops, and ServSafe training sessions.

Charlotte, NC · Spartanburg, SC
Sandra Minter · 704.731.4014

Figure 8: Piedmont Natural Gas Test Kitchen Profile (Source: GFEN, Spring 2009)

The Consortium for Energy Efficiency (CEE), a nonprofit public benefits corporation, develops initiatives for its North American utility members to promote the manufacture and purchase of energy-efficient products and services. Their goal is to induce lasting structural and behavioral changes in the marketplace, resulting in the increased adoption of energy-efficient technologies. CEE members include utilities, statewide and regional market transformation administrators, environmental groups, research organizations and state energy offices in the U.S. and Canada. Also contributing to the collaborative process are CEE partners – manufacturers, retailers and government agencies. The U.S. Department of Energy and Environmental Protection Agency both provide support through active participation as well as funding.

Commercial Foodservice Market Channels

Commercial Foodservice Trade Associations

National Restaurant Association

The National Restaurant Association represents more than 380,000 commercial food service businesses — from restaurants and suppliers to educators and non-profits. They produce annual reports and information products for their members as well as advocacy. They also network with a variety of state organizations, including:

New York State Restaurant Association
409 New Karner Rd
Albany, NY 12205-3883
Phone: (518) 452-4222
Web site: www.nysra.org

Massachusetts Restaurant Association
333 Turnpike Rd Ste 102
Southborough Technology Park
Southborough, MA 01772-1755
Phone: (508) 303-9905
Web site: www.marestaurantassoc.org

New Hampshire Lodging & Restaurant Association
PO Box 1175
Concord, NH 03302-1175
Phone: (603) 228-9585
Web site: www.nhlra.com

Rhode Island Hospitality Association
94 Sabra St
Cranston, RI 02910-1031
Phone: (401) 223-1120
Web site: www.rihospitality.org

The annual National Restaurant Association show is a venue to find the latest ideas, products and educational programs. Attendance can include over 75,000 industry professionals participating in over 60 free seminars.

The NRA also has period webinars to allow members to learn from industry experts and operators. This could be a possible communications channel for energy companies.

The North American Association of Food Equipment Manufacturers (NAFEM)

NAFEM is a trade association of more than 625 foodservice equipment and supplier manufacturers that provide products for food preparation, cooking, storage and table service. NAFEM's biennial trade show attracts approximately 20,000 foodservice professionals and features more than 600 North American manufacturers.

Foodservice Equipment Sales and Service Channels

Table 19 shows information from a USEPA document outlining supply channel actors for the commercial foodservice sector. This is a fairly typical multiple channel arrangement – with the added role of *design consultants* who would specialize in the commercial foodservice sector. This role is similar to that provided by architect and engineering firms, consulting engineers, etc.

Table 19: Supply Channel Actors

Dealers: Dealers primarily sell to individual restaurants, which is often the most difficult market to reach. Smaller dealers may join buying groups so they can compete more effectively with larger dealers. Many dealers display their products in showrooms and tend to stock lower-priced, popular models that are usually not energy-efficient. A dealer's main objective is usually to sell the products they have on hand, and they are generally more interested in attracting customers with low prices rather than emphasizing the overall value of higher-end products (e.g., lifetime cost savings). Given that many manufacturers offer sales incentives to move lower-end models, dealer incentives can be an effective strategy to promote stocking and sales of energy-efficient equipment.
Distributors: Distributors primarily supply bulk quantities of equipment to dealers and sell commodity equipment (e.g., ice machines, fryers) directly to end users. Since distributors usually supply dealers, developing a good working relationship with distributors helps funnel energy-efficient CFS products into dealer showrooms. In addition, some restaurant food distributors sell CFS equipment and should also receive program outreach.
Manufacturers and Reps: CFS equipment manufacturers generally sell through product reps, although manufacturers may also sell directly to large end users such as national restaurant chains. Though all supply channels gravitate toward inexpensive, fast-moving pieces of equipment, a key value proposition for engaging reps is the up-sell potential of high-value, high-efficiency equipment. Sales of high-quality products earn reps a higher commission and generate long-term value for the customer, often leading to repeat business.
Design Consultants: Design consultants assist in the planning and design of new or renovated commercial kitchens, typically working with large or chain-owned restaurants, hotels, universities, and hospitals. Conducting targeted outreach to design consultants helps to ensure that energy- and water-efficient CFS equipment is considered in these types of projects. Design consultants are typically focused on the overall design and aesthetics of the space and controlling project costs, and back-of-the-house equipment is often a low priority. In addition, they often have established relationships with buying groups and may receive incentives for selling lower-end equipment. Equipment quality and performance are key selling points for engaging design consultants.

Source: USEPA Energy Star publication. Energy Star for Commercial Kitchens: Helping Customers Manage Costs, (June 30, 2009).

Market Channel Participant Interviews

In order to gauge market conditions in National Grid's territory, GTI undertook targeted primary market research by talking to key market channel players in the Northeast commercial foodservice sector. An independent consultant was deployed to conduct phone interviews with foodservice consultants and dealers that operated in the National Grid Service territory.

Phone Survey

GTI worked with Mr. Richard Topping of RFTopping Consultants to organize and conduct the telephone interviews. This encompassed two major Foodservice Consultant firms (Colburn & Guyette and Clevenger Foster LaVallee) and four foodservice equipment dealers/design houses (Kittredge, Trimark, Perkins and May Foodservice). As a practical matter, there are similarities between these two types of organizations but the consultants tend to work on bigger jobs and may be less brand-biased. The results of the interviews appear quite consistent across all six firms.

The most positive outcome from the survey is that participants felt that natural gas is firmly entrenched in the Northeast and that situation seems to be holding steady. No one sees any serious movement to electric equipment at this time.

The overall status of gas foodservice equipment in National Grid's service territory is good. Generally, responses show that gas provided good value and was a "green fuel." The relatively high electric rates in this area may be a contributor in this area. Several items that stood out as potential areas for improvement are highlighted below:

1. There were strong indications that neither the gas nor the electric utilities were involved in a significant role in the decision process for these marketers selling equipment. It is clear that all of the survey participants would welcome more utility involvement.
2. Venting of gas equipment was identified as an issue for five of the six companies.
3. Several of the respondents stated that electric appliances are perceived by some to generally be safer and more technologically advanced than gas-fired appliances.
4. All six responded that gas-fired booster water heaters face issues with being installed including venting, reliability, cost and efficiency.
5. According to three of surveyed sources, gas-fired warewashers face a disadvantage compared to electric because they require venting[1] (note: electric warewashers also require venting for the steam and steam hoods can also be used to vent flue products).
6. Three respondents expressed the need for pilotless ignition, especially on ranges, to address new hood interlock rules that require gas to be shut off to appliances when the kitchen hoods are not turned on. This forces the restaurant to either run a separate gas line for the pilots or re-light their pilots after each time the hoods are turned off.

Fuel cost is a major issue and natural gas has the advantage relative to electricity. Also, natural gas has a solid history and reputation. Electric is only preferred when deemed absolutely necessary, usually due to the lack of suitable gas service or ventilation issues (kiosks).

Interviewees were spread across the New York and Massachusetts areas. The detailed responses from the participants are included in tabular form in an appendix to this report.

The overall conclusion from this market survey effort is that, generally speaking, natural gas holds a good position in National Grid territory. Dealers and consultants feel that gas is the preferred fuel except when venting issues arise.

Several areas are candidates for some improvement if resources allow:

1. This issue arose when the dealers tried to support a gas booster heater program. The gas booster was not integral to the warewasher and required a separate vent. Since replacement sales are a significant component of the market for these appliances, venting is a big issue. GTI has been working with Jackson MSC to develop a warewasher with integral booster heater that vents through the body of the dish machine and should overcome the venting issue.

- Foodservice appliance manufacturers are relatively small in size and lack resources in engineering. They often need support in their gas designs, both for new product development and for troubleshooting existing designs.
- The surveyed dealer/consultant group did not receive information and support from the utilities that might help them promote gas equipment sales. This is probably a result of the loss of gas utility commercial marketing that has come about in the last few years.
- Energy efficiency and “greenness” are of extreme importance now. Appliances which can bear the Energy Star label are good sellers. At this time there are only a few appliance categories for foodservice where there is energy star. The community is working to expand this list over the next few years.

Conclusions

The commercial and institutional food service sector represents an important – **and growing** -- market for the natural gas industry. According to the National Restaurant Association (NRA), there are approximately 525,000 commercial food service establishments nationwide with annual sales of $580 billion.

State-level characteristics on four key states – New York, Massachusetts, Rhode Island, and New Hampshire – indicate a market size of 56,900 commercial foodservice locations with annual sales in excess of $43 billion. Using a nominal value of 3.4 percent of sales, annual utility costs (electricity, natural gas, water, etc) exceeds $1.4 billion in these four states (and approaches $20 billion nationally).

According to Energy Information Agency (EIA) survey data, commercial foodservice customers have 2.2 times the energy intensity (Btu/ft^2) of the average commercial customer. Audits conducted by Southern California Gas and Piedmont Gas found that natural gas sales to commercial foodservice customers account for 12 percent of the volume of gas sold, but comprised a healthy 19 percent of their profits.

In terms of new equipment, the estimated annual sales of new commercial foodservice equipment totaled about $1.2 billion in 2006. Of this, about 69 percent was natural gas-based products – indicating a strong market position for natural gas relative to electricity. The report provides further analysis of sales by product category and, an important consideration, the availability of Energy Star-rated products.

While a significant and growing market, there are continual threats and opportunities to assess within the commercial food service market segment, including:

- Natural gas market share is currently strong and holding against electric market share. New electric products; perceptions of electric as clean, simple, and reliable; and growing electric energy efficiency programs represent potential threats. There is also a market perception that electric equipment is more advanced or higher end than gas equipment.
- Natural gas is perceived as more cost-effective by users, with current electric-to-natural gas price ratios of 4.5:1 or higher. A typical restaurant is paying over twice as much annually for electricity than natural gas – underscoring the perception of natural gas as being cost effective.
- Rising labor, food, and energy costs are motivating foodservice providers to seek new and innovative equipment designs that could save operating costs through productivity improvements and speedier delivery.
- **Labor issues are a dominanting factor in this sector** – the major issues are obtaining and retaining quality workers, labor costs, and productivity. Increased labor turnover motivates foodservice providers to seek methods or equipment to improve the working environment for employees in terms of comfort, ease of equipment usage, and cleaning.
- Key purchase factors for new equipment include price, efficiency (operating costs), after-sales support, and productivity improvement. Equipment obsolescence and deterioration is typically the main reason to buy new equipment. One of the problems with old gas equipment is that is lasts for many years and restaurants do not tend to replace equipment until is total breaks down

instead of updating to new equipment. Getting information to users about the cost and energy saving associated with new equipment is lacking.

- Trends toward healthier and/or more environmentally responsible eating habits can influence the market, but the economic benefits/effects are not fully understood by the industry.
- The industry is concerned about lower emissions standards (including NO_x and particulates) – especially where such requirements have been imposed on residential appliances.
- The green movement is a threat to natural gas. Consumer surveys show that electric is perceived as being more green, possibly due to the site-based efficiency claims. There is an opportunity to position the new gas equipment as green through consumer education - identifying the financial and environmental benefits.

References

Czachorski, M. and Leslie, N., "Source Energy and Emission Factors for Building Energy Consumption," Gas Technology Institute for American Gas Foundation, Nov. 2009.

Energy Information Agency, "2003 Commercial Buildings Energy Consumption Survey," www.eia.doe.gov.

Environmental Protection Agency, Energy Star www.energystar.gov.

Frable, F., "Rethermalize it," Nation's Restaurant News, Oct. 8, 2007.

Fryett, D.K., "So, What's Going On Out There In The Food Service Industry That We Need To Know About," Final Report, Gas Food Equipment Network (2008).

Gas Food Equipment Network, "Cooking Up Greener Solutions, Spring 2009 Newsletter.

Melink, S., "Kitchen Hoods Using Demand Ventilation," ASHRAE Journal, Dec. 2003.

National Restaurant Association, "2010 Restaurant Industry Forecast," (2010).

National Restaurant Association and Deloitte, "Restaurant Industry Operations Report (2006/2007 Edition).

Nevius, M., Eldridge, R., and Krouk, J., "The State of the Efficiency Program Industry Budgets, Expenditures, and Impacts 2009," Consortium for Energy Efficiency, March 5, 2010.

USEPA, "Energy Star for Commercial Kitchens: Helping Customers Manage Costs," Energy Star publication (June 30, 2009).

van Straten, G. and Brown, S., "Keeping Cooks in the Kitchen: Solving the Makeup Air Dilemma," ASHRAE Journal, June 2003.

Appendix A: Market Survey Results

Key Issues	Issue / Question	Colburn & Guyette response	Clevenger Foster LaVallee response	Trimark response	Kittredge response	Perkins response	May Food Service response
	What type of business is this?	Colleges, healthcare facilities, institutions. C&G do not design many restaurants; dealers have a foothold and do designs for free to sell equipment.	CFL does big commercial and institutional jobs; also does more chain and restaurant work than typical consultants.	Largest dealer in US; also Trimark conducts engineering for restaurants and hotels.	Full service dealer of commercial kitchen equipment including engineering and sales	Dealer and design firm for restaurants, health care, institutions, etc.	Equipment distributor and design firm for food & beverage operations, institutions, etc.
	What product lines do they have (we only care about cooking and warewashing equipment)?	C&G does the research and specs equipment for clients by brand and model. They use gas wherever possible (high market share). Gas is more efficient and quicker (higher food output)	N/A	Large selection of equipment and brands	Offer products of most major manufacturers	Perkins specs equipment for their clients.	Full line of commercial foodservice equipment
	Profile sales of gas vs. electric equipment						
	What are the actual sales of gas equipment / Actual numbers	N/A	N/A	N/A	N/A		
	Share of market/sales of gas vs. electric	Sees no change in share; still predominantly gas in their market.	Sees no significant change in market share between gas and electric	Predominantly gas in the Northeast	Gas is predominant.		
	Is this share ratio changing, and if so, why?	No	No	No. Electric energy cost is high which limits sales of electric equipment. Also, most chefs prefer gas because of better control and higher output.	No	No change seen; equipment is almost always gas.	No change seen in market share
	Why gas share is what it is						
	Who specs fuel type and what are the key criteria (availability, cost, ventilation, reliability, etc.)	C&G uses gas wherever possible. They use electric with recirculating ventilation systems by necessity in limited applications.	CFL specs equipment (make and model) in consultation with the owner. CFL gets information from trade shows, equipment reps, AutoQuotes, etc. Usually specifies gas whenever gas is available. In situations without venting, electric is used.	Trimark works with their clients to spec the optimum equipment; also sells equipment to projects where the design is done by A&E firms and Consultants.	Replacement equipment nearly always utilizes the same fuel; utility changeover is very expensive and a hassle for an operating facility. Gas is usually specified when available; viewed as cheaper.	Perkins specs gas almost exclusively. Small markets are developing for unique electric equipment such as induction cooktops. However, induction currently is offered only in one or two station countertop units, no induction ranges are currently sold in the US (some may be coming from Europe).	May does the site design and specs the equipment by fuel type, make, model, etc. Gas is used almost exclusively in the Northeast except for very limited applications of electric equipment.
	What are the respective roles of consultants, dealers, manufacturers, utilities, etc.?	Big jobs use consultants; usually brought in by the A&E firm responsible for the project. Some projects like nursing homes use dealers but this may be changing as well.	Consultants typically are brought in by architects and A&E firms on large jobs (80 – 90% of their business). Dealers tend to do restaurant work in return for the equipment business. However, CFL also markets to the chains and restaurants; they do more of this work than most consultants.	Trimark, because of its size, has test kitchens where customers can prepare their food products with different types of equipment to determine what is best for their needs.	Consultants are hired by A&E's and architects for big jobs. Project subcontractors may include Kittredge who bids on supplying suites of equipment. Restaurants use Kittredge and its showrooms to purchase equipment. Kittredge does engineering for restaurants and offers a rebate on purchased equipment.		Customers rely on May for recommendations on equipment.
!	What is the level of participation of utilities, gas and electric. Is one doing a better job?	Utilities (gas or electric) aren't really involved; would be helpful if they were. C&G gets its information from manufacturers and trade journals	Utilities (gas or electric) provide no assistance to CFL. They could use help, especially in the area of codes and standards. Codes are becoming more varied across the country and restrictive. CFL could use one consistent set of up-to-date data. One specific problem area mentioned was requirements for flex connectors.	Rebates for Energy Star (currently up to $1000 for a fryer) help with the sale of high efficiency equipment. Bob believes the West Coast utilities still support the sale of gas with test kitchens and information; the East Coast utilities never did much and now do less.	GasNetworks does a good job of offering and advertising rebates in New England. The electric utilities have been much slower to offer rebates. However, it is like "pulling teeth" to get any assistance from utilities.	Utilities currently are providing $1000 rebates for high efficiency fryers.	Utilities really are no help at all. May is very disappointed that utilities are not more active in providing assistance and information on programs such as rebates.
	Is the current energy situation affecting share?	No	No. The fuel choice decision is based on the availability of gas; not energy cost.	No, electric cost is still higher than gas.	People are forgetting about energy and worrying about the economy	No, fuel cost drives the business and gas remains cheaper than electricity.	No
	Is the current world economic crisis impacting sales?	Not yet, but it appears there is a slowdown coming on new construction.	Yes, the current recession is slowing building projects.	Absolutely, the chains are experiencing a significant downturn. Franchisees cannot secure financing.	Yes	Across the board.	Yes, definitely.
	What is perception of gas equipment (vs. electric) / Cost	Electric equipment is higher cost	Gas equipment is more expensive in some equipment categories; less expensive in others.	Gas equipment is perceived as less costly, although in reality it is not always so. Electronics have added cost.	Gas is viewed as less expensive.	Gas	Gas equipment costs less.

Key Issues	Issue / Question	Colburn & Guyette response	Clevenger Foster LaVallee response	Trimark response	Kittredge response	Perkins response	May Food Service response
	What is perception of gas equipment (vs. electric) / Reliability	On par with the newer products; electric used to be less reliable	Better in some categories (ranges) and worse in others (kettles, combi-ovens and braising pans). However, the gas equipment manufacturers have done a good job improving equipment reliability	Even	Gas viewed as more reliable	Gas	Gas equipment is more reliable.
	What is perception of gas equipment (vs. electric) / Cook Quality	Gas is better	Depends on the application; electric braising was better but gas has improved. Some chefs prefer electric in specialized applications (griddle range and induction) so there is some small penetration of dual fuel kitchens	Gas is better	Gas is viewed as better overall. Some segments, such as bakers, prefer electric deck and convection ovens for better baked product quality.	Gas	Gas is better.
	What is perception of gas equipment (vs. electric) / Efficiency	Gas is higher	No perceived difference.	Gasis viewed as higher but because of energy cost.	Dan believes electric products are more efficient at getting the energy to the food but admits most of his customers only are concerned with energy cost which is lower for gas.	Gas	Gas is more efficient.
	What is perception of gas equipment (vs. electric) / Output	Gas is better	Same or greater for gas.	Even	Gas is better	Gas	Gas is higher
!	What is perception of gas equipment (vs. electric) / Other issues including Venting	Electric is used if ventless systems are required	Venting is a major issue. For example, it prevents the use of gas booster heaters for warewashing in many applications. Without adequate venting, electric equipment is specified to prevent any potential problems.	Gas requires more ventilation and this is an issue. To expand, some facilities will add electric equipment to the current suite of gas products to eliminate the need to add more hood space.	Venting is a growing issue for all types and applications. Code officials and fire inspectors are requiring similar venting regardless of fuel type. Hoods are expensive. Even table top cooktops (bottled gas or induction) now need ventilation. Electric ignition is required in Massachusetts (though subject to fire inspector interpretation)	There is virtually no call for electric equipment other than small products (toasters) and induction cooktops which is desired by some sophisticated chefs.	Ventilation is not really an issue for the vast majority of applications since cooking requires venting regardless of fuel type.
!	For costumers that prefer electric, why?	Can avoid ventilation cost. Also, certain applications use specialized cooking equipment (induction). New microwave/convection ovens are ventless and cook well; they fill a niche.	Regulations, safety (important in schools), desire for induction. Electric speed ovens (TurboChef) are impinging on gas in settings such as Dunkin Donuts for sandwich preparation. 20 years ago, a gas grill and hood would have been used. Codes and regulations could accelerate this trend – a potential dark cloud for gas.	Electric technology has improved more than gas lately. Speed-cook ovens and induction ranges are impressive and have potential to grow electric market share.	See above; also some churches like electric because of safety.	Applications where gas is not available or ventilation may be an issue.	Kiosk applications may require electric equipment where venting is an issue.
	Is there a significant trend in fuel choice by segment?	No	No.	No	No	No	No
	Who do users rely on for information before buying equipment	In this segment, on the consultants who rely on manufacturers and trade journals	Consultants and dealers.	Dealers and manufacturers reps. Reps have taken up the slack from utilities and now are much more sophisticated with test kitchens, data, etc.	N/A		Dealers and designers. Some operators rely on this advice and really do not get involved. Others, like chains, are very much involved in the purchase decision.
	What can be done to grow gas share						
	What would cause the decision of gas vs. electric to change in the future	N/A	See above.	N/A	If users start to accept (believe) the efficiency benefit of electric and the fact that electric equipment can be cheaper to operate in some circumstances.		Large increase in gas cost.

Key Issues	Issue / Question	Colburn & Guyette response	Clevenger Foster LaVallee response	Trimark response	Kittredge response	Perkins response	May Food Service response
!	What can manufacturers/utilities do to influence that decision	N/A	Utilities or a national association (AGA, GTI, etc.) could help by providing a national data base on codes and regulations. Foster mentioned a particular problem in New York City where ConEd, the gas supplier, has decided to maintain low pressure service in high rise buildings. This requires a $50K compressor system for food service applications costing $100K, not a cost effective solution. Therefore, electric is being used. Also, the new electronic controls monitor gas pressure and shut the equipment down if the pressure drops below specs. Older equipment used to keep operating at lower output.	N/A	N/A		
!	Are there opportunities for gas in steamers and warewashing equipment?	C&G uses steamer and kettle combinations that utilize gas-fired boilers. Countertop steamers are electric and have the advantage or being more portable. C&G never specs gas for warewashing equipment; gas-fired boosters are hard to get approved. This is a growth opportunity for gas.	CFL sees an opportunity for large steam generators that can function under a hood and provide steam to several appliances (kettles, booster heater, etc.). Currently, plant steam is used but there is a trend to decentralize steam plants in buildings such as hospitals. Gas booster heaters aren't being widely used because they are hard to vent and restricted by codes.	There are problems with gas boilers in the Northeast because of high iron content in the water. Gas booster heaters for warewashing really are not popular because of the need for venting and the perception that electric is easier to locate, cheaper, and more reliable.	Ventilation and cost restricts the use of gas boosters for warewashing. Dan didn't see any promising additional opportunities for gas boosters or steam generators.	There is an opportunity for gas booster heaters if they can be made more reliable and venting can be more easily accomplished. Electric boosters require very heavy electric service (80 - 100 Amp, 3 Phase).	There are opportunities for booster heaters if gas equipment becomes more reliable, less expensive and more efficient.
	Is the Green movement good or bad for gas?	There is a perception that gas is greener.	Good for gas.	Not sure.	Good for gas; as a result, gas companies are aggressively marketing rebates	Not fuel specific; more the desire for higher efficiency.	Don't know.
!	What design improvements are needed for gas equipment (Efficiency, Cleanability, Performance, Price, etc.)	There is a need for electronic ignition in all gas equipment. The new ventilation systems turn off the gas supply when they are shut down. Electronic ignition is now required in some areas (Massachusetts)	The gas industry has done a good job overall with equipment. An additional needed design improvement is auto-shutdown for gas ranges. Currently ranges in many applications are turned on and left on. Also see above suggestion on steam generators	N/A	N/A	Pilotless ignition is being required by some codes. Electronic ignition systems have never been reliable in gas food service equipment; need improvement.	None come to mind.

Appendix B: National Restaurant Association Data Sheets

NATIONAL RESTAURANT ASSOCIATION®

2010
Restaurant Industry

Pocket Factbook

2010 Industry Sales Projection **$580 billion**

	2010 Sales (billion $)
Commercial	$ 530.4
Eating places	388.5
Bars and taverns	18.8
Managed services	40.9
Lodging place restaurants	26.9
Retail, vending, recreation, mobile	55.2
Other	$ 49.7

Restaurants
An Essential Part of Daily Life

- Restaurants will provide more than 70 billion meal and snack occasions in 2010.
- On a typical day in America in 2010, more than 130 million people will be foodservice patrons.
- 44% of adults say restaurants are an essential part of their lifestyles.
- 65% of adults say their favorite restaurant foods provide flavor and taste sensations that can't easily be duplicated in their home kitchens.

Restaurants
Small Businesses with a Large Impact on our Nation's Economy

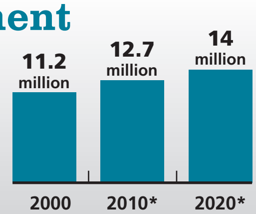
- Restaurant-industry sales are forecast to advance 2.5% in 2010 and equal 4% of the U.S. gross domestic product.
- The overall economic impact of the restaurant industry is expected to exceed $1.5 trillion in 2010.
- Every dollar spent by consumers in restaurants generates an additional $2.05 spent in the nation's economy.
- Each additional dollar spent in restaurants generates an additional $0.82 in household earnings throughout the economy.
- Every additional $1 million in restaurant sales generates 34 jobs for the economy.
- Eating-and-drinking places are mostly small businesses. Ninety-one percent have fewer than 50 employees.
- More than seven of 10 eating- and drinking-place establishments are single-unit operations.
- Average unit sales in 2007 were $866,000 at fullservice restaurants and $717,000 at quickservice restaurants.

Restaurants
Cornerstone of Career Opportunities

- The restaurant industry employs about 12.7 million people, or 9% of the U.S. workforce.
- The restaurant industry is expected to add 1.3 million jobs over the next decade, with employment reaching 14 million by 2020.
- Nearly half of all adults have worked in the restaurant industry at some point in their lives, and more than one in four adults got their first job experience in a restaurant.
- Eating-and-drinking places are extremely labor-intensive — sales per full-time-equivalent non-supervisory employee were $75,826 in 2008. That's much lower than most other industries.
- One-quarter of eating- and drinking-place firms are owned by women, 15% by Asians, 8% by Hispanics and 4% by African-Americans.
- Eating-and-drinking places employ more minority managers than any other industry.
- The number of foodservice managers is projected to increase 8% from 2010 to 2020.
- Fifty-eight percent of first-line supervisors/managers of food preparation and service workers in 2008 were women, 14% were of Hispanic origin and 14% were African-American.

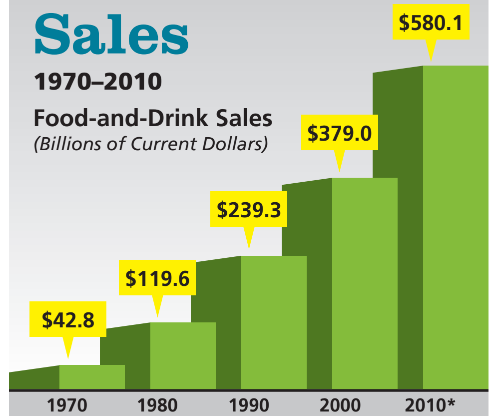
Restaurant Industry Share of the Food Dollar

Total Restaurant Industry Employment



Restaurant Sales
1970–2010

Food-and-Drink Sales
(Billions of Current Dollars)



Restaurants by the Numbers

- **$1.6 billion** Restaurant-industry sales on a typical day in 2010.
- **40** Percent of adults who agree that purchasing meals from restaurants and take-out and delivery places makes them more productive in their day-to-day life.
- **73** Percent of adults who say they try to eat healthier now at restaurants than they did two years ago.
- **57** Percent of adults who say they are likely to make a restaurant choice based on how much a restaurant supports charitable activities and the local community.
- **78** Percent of adults who say they would like to receive restaurant gift cards or certificates on gift occasions.
- **59** Percent of adults who say there are more restaurants they enjoy going to now than there were two years ago.
- **52** Percent of adults who say they would be more likely to patronize a restaurant if it offered a customer loyalty and reward program.
- **$2,698** Average household expenditure for food away from home in 2008.
- **29** Percent of adults who say purchasing take-out food is essential to the way they live.
- **54** Percent of adults who say they would be likely to use an option of delivery directly to their home or office if offered by a fullservice restaurant.
- **78** Percent of adults who agree that going out to a restaurant with family or friends gives them an opportunity to socialize and is a better way to make use of their leisure time than cooking and cleaning up.
- **63** Percent of adults who say the quality of restaurant meals is better than it was two years ago.
- **56** Percent of adults who say they are more likely to visit a restaurant that offers food grown or raised in an organic or environmentally friendly way.
- **70** Percent of adults who say they are more likely to visit a restaurant that offers locally produced food items.

1200 17th St. NW, Washington, DC 20036 | (202) 331-5900 | E-mail: askus@restaurant.org | www.restaurant.org

NATIONAL RESTAURANT ASSOCIATION® | www.restaurant.org/research

New York

Restaurant Industry at a Glance

New York's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in New York, and their sales generate tremendous tax revenues for the state.

The contribution of New York's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

New York Restaurants by the Numbers

LOCATIONS

In 2007, there were **37,354** eating-and-drinking places in New York.

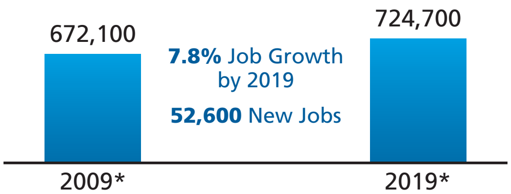
STATE ECONOMY

Every $1 spent in New York's restaurants generates an additional **$.98 in sales** for New York's economy.

Each additional $1 million spent in New York's eating-and-drinking places generates an additional **23.4 jobs** in New York.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **8 percent** of total employment in New York.

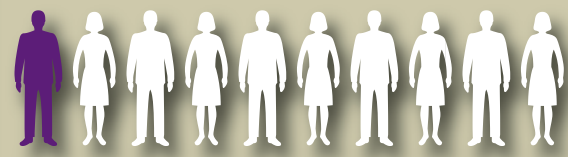
SALES

In 2009, New York's restaurants will register **$27.8 billion** in sales.*

* projected

America's Restaurants: By the Numbers

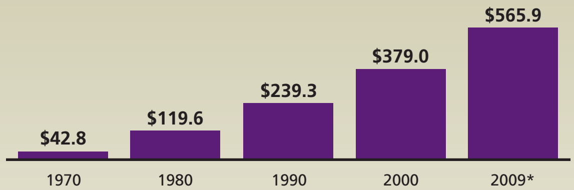
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION® | NEW YORK STATE RESTAURANT ASSOCIATION We serve you

www.restaurant.org | www.nysra.org

New York's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	Timothy H. Bishop (D)	1,350	17,431
2	Steve Israel (D)	1,225	15,812
3	Peter King (R)	1,357	17,513
4	Carolyn McCarthy (D)	1,436	18,534
5	Gary L. Ackerman (D)	973	12,560
6	Gregory W. Meeks (D)	476	6,151
7	Joseph Crowley (D)	919	11,866
8	Jerrold Nadler (D)	4,401	56,812
9	Anthony Weiner (D)	801	10,342
10	Edolphus Towns (D)	453	5,851
11	Yvette D. Clarke (D)	525	6,777
12	Nydia Velazquez (D)	975	12,587
13	Michael E. McMahon (D)	893	11,526
14	Carolyn Maloney (D)	2,559	33,039
15	Charles B. Rangel (D)	616	7,947
16	Jose Serrano (D)	446	5,756
17	Eliot Engel (D)	903	11,662
18	Nita M. Lowey (D)	1,465	18,915
19	John J. Hall (D)	1,129	14,574
20	*Vacant Seat*	1,352	17,459
21	Paul Tonko (D)	1,602	20,684
22	Maurice D. Hinchey (D)	1,722	22,235
23	John M. McHugh (R)	1,399	18,057
24	Michael A. Arcuri (D)	1,308	16,887
25	Daniel B. Maffei (D)	1,365	17,622
26	Christopher John Lee (R)	1,325	17,105
27	Brian Higgins (D)	1,651	21,310
28	Louise McIntosh Slaughter (D)	1,348	17,404
29	Eric J. J. Massa (D)	1,378	17,785
	TOTAL	**37,354**	**482,200**

***** Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®

www.restaurant.org

NEW YORK STATE RESTAURANT ASSOCIATION
We serve you

www.nysra.org

NATIONAL RESTAURANT ASSOCIATION | www.restaurant.org/research

Massachusetts

Restaurant Industry at a Glance

Massachusetts's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in Massachusetts, and their sales generate tremendous tax revenues for the state.

The contribution of Massachusetts's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

Massachusetts Restaurants by the Numbers

LOCATIONS

In 2007, there were **14,088** eating-and-drinking places in Massachusetts.

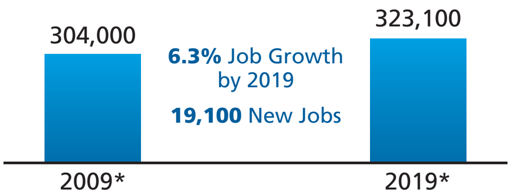
STATE ECONOMY

Every $1 spent in Massachusetts's restaurants generates an additional **$1.02 in sales** for Massachusetts's economy.

Each additional $1 million spent in Massachusetts's eating-and-drinking places generates an additional **24.1 jobs** in Massachusetts.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **9 percent** of total employment in Massachusetts.

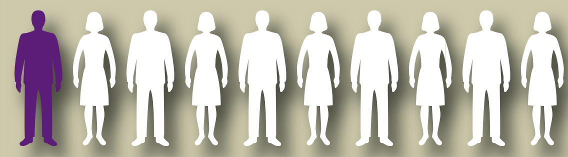
SALES

In 2009, Massachusetts's restaurants will register **$11.8 billion** in sales.*

* projected

America's Restaurants: By the Numbers

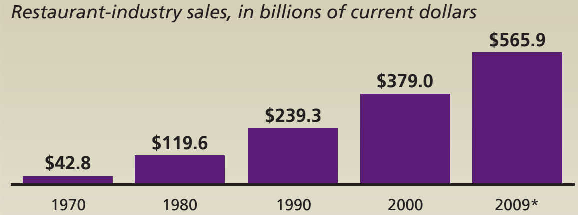
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION® www.restaurant.org

MRA Massachusetts Restaurant Association www.marestaurantassoc.org

Massachusetts's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	John W. Olver (D)	1,449	22,613
2	Richard E. Neal (D)	1,307	20,399
3	James P. McGovern (D)	1,483	23,132
4	Barney Frank (D)	943	14,706
5	Niki Tsongas (D)	1,211	18,893
6	John F. Tierney (D)	1,537	23,980
7	Edward J. Markey (D)	805	12,561
8	Michael Capuano (D)	1,926	30,053
9	Stephen F. Lynch (D)	1,521	23,738
10	William Delahunt (D)	1,905	29,724
	TOTAL	**14,088**	**219,800**

* Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®

MRA Massachusetts Restaurant Association

www.restaurant.org **www.marestaurantassoc.org**

NATIONAL RESTAURANT ASSOCIATION® | www.restaurant.org/research

Rhode Island

Restaurant Industry at a Glance

Rhode Island's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in Rhode Island, and their sales generate tremendous tax revenues for the state.

The contribution of Rhode Island's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

Rhode Island Restaurants by the Numbers

LOCATIONS

In 2007, there were **2,663** eating-and-drinking places in Rhode Island.

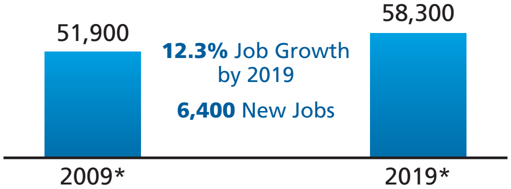
STATE ECONOMY

Every $1 spent in Rhode Island's restaurants generates an additional **$.85 in sales** for Rhode Island's economy.

Each additional $1 million spent in Rhode Island's eating-and-drinking places generates an additional **24.7 jobs** in Rhode Island.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **11 percent** of total employment in Rhode Island.

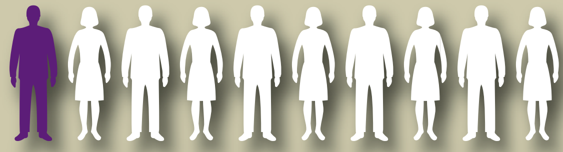
SALES

In 2009, Rhode Island's restaurants will register **$1.8 billion** in sales.*

* projected

America's Restaurants: By the Numbers

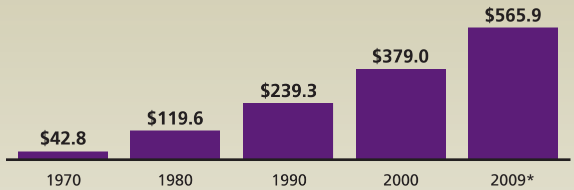
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION® — www.restaurant.org

RI HOSPITALITY ASSOCIATION / RI HOSPITALITY EDUCATION FOUNDATION — Voice of Rhode Island's Lodging, Restaurant and Tourism Industry — www.rihospitality.org

Rhode Island's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	Patrick J. Kennedy (D)	1,259	18,535
2	James R. Langevin (D)	1,404	20,665
	TOTAL	**2,663**	**39,200**

***** Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®
www.restaurant.org

RI HOSPITALITY ASSOCIATION
RI HOSPITALITY EDUCATION FOUNDATION
Voice of Rhode Island's Lodging, Restaurant and Tourism Industry
www.rihospitality.org

NATIONAL RESTAURANT ASSOCIATION® | www.restaurant.org/research

New Hampshire
Restaurant Industry at a Glance

New Hampshire's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in New Hampshire, and their sales generate tremendous tax revenues for the state.

The contribution of New Hampshire's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

New Hampshire Restaurants by the Numbers

LOCATIONS

In 2007, there were **2,824** eating-and-drinking places in New Hampshire.

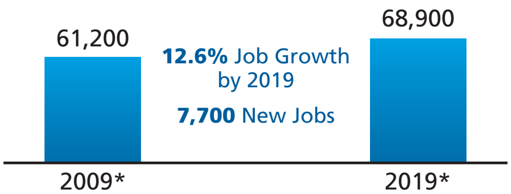
STATE ECONOMY

Every $1 spent in New Hampshire's restaurants generates an additional **$.84 in sales** for New Hampshire's economy.

Each additional $1 million spent in New Hampshire's eating-and-drinking places generates an additional **22.9 jobs** in New Hampshire.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **9 percent** of total employment in New Hampshire.

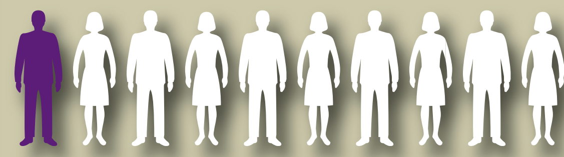
SALES

In 2009, New Hampshire's restaurants will register **$2.1 billion** in sales.*

* projected

America's Restaurants: By the Numbers

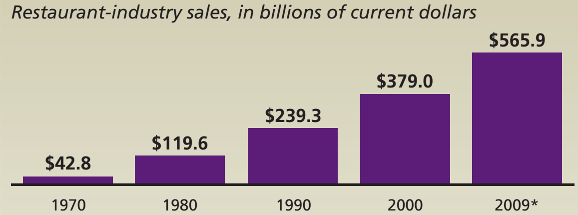
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION®
www.restaurant.org

NHLRA
NEW HAMPSHIRE LODGING & RESTAURANT ASSOCIATION
www.nhlra.com

New Hampshire's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	Carol Shea-Porter (D)	1,528	23,973
2	Paul W. Hodes (D)	1,296	20,327
	TOTAL	**2,824**	**44,300**

* Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®
www.restaurant.org

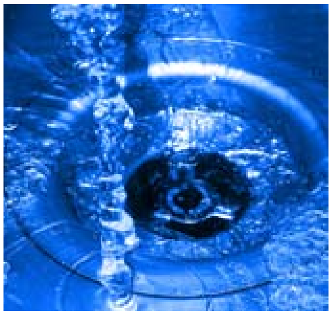
NHLRA
NEW HAMPSHIRE LODGING & RESTAURANT ASSOCIATION
www.nhlra.com

Appendix C: Commercial Foodservice Publications

ENERGY STAR

ENERGY STAR® Guide for Restaurants

Putting Energy into Profit



EPA
United States
Environmental Protection
Agency

LEARN MORE AT energystar.gov

ENERGY STAR®, a U.S. Environmental Protection Agency program, helps us all save money and protect our environment through energy efficient products and practices. For more information, visit www.energystar.gov.

Contents Page

IN PARTNERSHIP WITH

PG&E Food Service Technology Center is the industry leader in commercial kitchen energy efficiency and appliance-performance testing as well as a leading source of expertise in commercial kitchen ventilation and sustainable building design.

National Restaurant Association's Conserve initiative explores conservation efforts in restaurants around the nation and offers suggestions and resources to help operators reduce their costs and improve their environmental performance.

ACKNOWLEDGEMENTS

This best-practices guide was created with the assistance of California's four investor-owned utilities (Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison). These energy suppliers are working together to provide comprehensive energy efficiency resources for California's food service industry, including, but not limited to, the following resources: rebates for cooking and refrigeration equipment, food service specific seminars and workshops, Web tools, energy audits, appliance testing, and energy education centers. The California energy-efficiency research and educational programs are funded by California ratepayers under the auspices of the California Public Utilities Commission and are administered by the four investor-owned utilities.

Southern California Gas Company — A Sempra Energy utility® — *www.socalgas.com/business*

PG&E® — *www.pge.com/fstc*

SDGE — A Sempra Energy utility® — *www.sdge.com/foodservice*

Southern California Edison® — An Edison International® Company — *www.sce.com/CTAC*

Disclaimer: all energy, water, and monetary savings listed in this document are based upon average savings for end users and are provided for educational purposes only. Actual energy savings might vary based on use and other factors.

FIVE EASY STEPS TO SAVE ENERGY AND WATER

1 *Install compact fluorescent lamps* (CFLs) in your walk-in refrigerators and kitchen ventilation hoods (and throughout your restaurant where appropriate).

2 *Install a high-efficiency pre-rinse spray valve* in your dishroom and save hundreds of dollars a year!

3 *Fix water leaks immediately*—especially hot water leaks: wasted water, sewer, and water heating costs can add up to hundreds of dollars a year.

4 *Perform walk-in refrigerator maintenance:* check and replace door gaskets; clean evaporator and condenser coils; check refrigerant charge.

5 *Replace worn-out cooking and refrigeration equipment* with ENERGY STAR qualified models!

Get additional easy to implement tips at: http://conserve.restaurant.org

Energy efficiency is a sound business practice that improves profitability, reduces greenhouse gas emissions, and conserves resources. This guide is designed to help your restaurant save energy and water, protect our Earth, and boost your bottom line.

ENERGY EFFICIENCY AND YOUR RESTAURANT

Restaurants use about 2.5 times more energy per square foot than other commercial buildings.

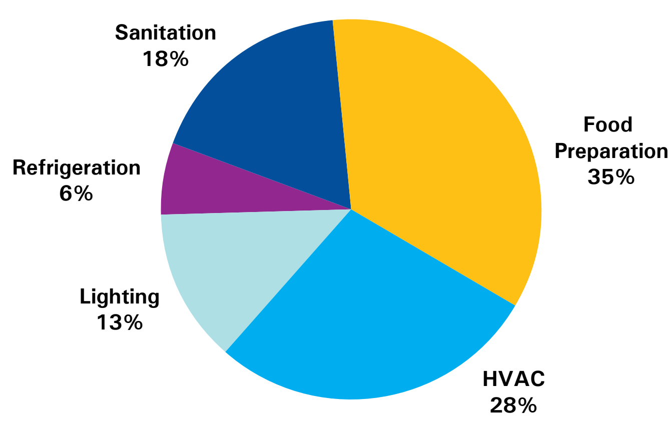
Energy costs have been increasing at a rate of 6 to 8 percent per year. Investing in energy efficiency is the best way to protect your business against rising energy prices.

Most commercial kitchen appliances are energy intensive. For instance, a typical electric deep fat fryer uses more than 11,000 kilowatt-hours (kWh) of energy per year which could cost you more than $1,100 in electricity.

You can reduce your restaurant's energy consumption by following the **Cost Saving Tips** outlined below and throughout this guide:

- Buy ENERGY STAR qualified appliances. If you're in the market for new equipment, think in terms of life-cycle costs, which include purchase price, annual energy costs, and other long-term costs associated with the equipment. High-efficiency appliances could cost more upfront, but significantly lower utility bills can make up for the price difference. Be sure to ask your dealer or kitchen designer to supply you with ENERGY STAR qualified equipment.
- Cut idle time. If you leave your equipment ON when it is not performing useful work, it costs you money. Implement a startup/shutdown plan to make sure you are using only the equipment that you need, when you need it.
- Maintain and repair. Leaky walk-in refrigerator gaskets, freezer doors that do not shut, cooking appliances that have lost their knobs—all these "energy leaks" add up to money wasted each month. Don't let everyday wear and tear drive up your energy bills.

Example of the Average Energy Consumption in a Full-service Restaurant
(British Thermal Units [Btu])



- Cook wisely. Ovens tend to be more efficient than rotisseries; griddles tend to be more efficient than broilers. Examine your cooking methods and menu; find ways to rely on your more energy-efficient appliances to cook for your customers.
- Recalibrate to stay efficient. The performance of your kitchen equipment changes over time. Thermostats and control systems can fail, fall out of calibration, or simply become readjusted. Take the time to do a regular thermostat check on your appliances, refrigeration, dish machines, and hot water heaters and reset them to the correct operating temperature.

COOKING APPLIANCES

When replacing old appliances or buying new ones, look beyond the sticker price. Buying and installing equipment that has earned the ENERGY STAR could trim hundreds of dollars from your annual utility bills. In order to realize the most savings from your ENERGY STAR qualified equipment you must train your staff to use energy wisely by following good operating practices such as those in the **Cost-Saving Tips** that follow.

Steamers

Steam cookers provide an effective way to batch-cook food but generating steam is an energy-intensive process. ENERGY STAR qualified steamers have a sealed cooking cavity that consumes a fraction of the energy and water required by traditional open systems. In many cases the dollar savings are so great that it makes sense to replace an existing steamer with an ENERGY STAR qualified one.

Cost-Saving Tips

- Look for the ENERGY STAR
- Close the door
- Use the timer
- Cut idle time
- Maintain & repair

Good practices can save:

$250 to $350 in annual energy costs for a traditional, electric, open-system steamer by eliminating an hour of idle time per day.

Buy an ENERGY STAR qualified connectionless steamer and save:

- $680 for water and sewer costs annually
- $510 for electricity annually (electric steamer), or
- $390 for gas annually (gas steamer)

Equating to an average $1,190 total savings for an electric steamer or $1,070 total savings for a gas steamer (some restaurants with high commercial sewer costs can save hundreds of dollars more annually)

Fryers

Energy-efficient fryers that have earned the ENERGY STAR offer shorter cook times, faster temperature recovery times, and ultimately higher pound-per-hour production rates through advanced burner and heat exchanger designs. Some models also offer an insulated fry pot, which reduces standby losses, giving the fryer a lower idle energy rate.

Cost-Saving Tips

- Look for the ENERGY STAR
- Cut idle time & turn off back-up fryers when possible
- Recalibrate

Good practices can save:

$250 annually for a gas fryer by cutting four hours of idle time per day.

Buy an ENERGY STAR qualified fryer and save:

- $120 for electricity annually (electric fryer), or
- $590 for gas annually (gas fryer)

Convection Ovens

Convection ovens are the industry standard due to faster cook-times produced by increased hot air movement inside the oven cavity. In addition, convection ovens are now eligible for ENERGY STAR qualification.

Cost-Saving Tips

- Look for the ENERGY STAR
- Cut idle time & turn off back-up ovens when possible
- Fully load the oven when cooking
- Replace seals & tighten hinges

Buy an ENERGY STAR qualified convection oven and save:

- $190 for electricity annually (electric oven), or
- $360 for gas annually (gas oven)

Griddles

Griddles are a versatile piece of equipment and a workhorse appliance found on most kitchen lines. Variations in efficiency, production capacity, and temperature uniformity make it important to choose wisely when shopping for a griddle. Many energy-efficient griddles can deliver both high production capacity and excellent temperature uniformity.

Cost-Saving Tips

- Look for the ENERGY STAR
- Cut idle time
- Recalibrate

Good practices can save:

$250 annually from a gas griddle by cutting three hours of idle time per day.

Buy an ENERGY STAR qualified griddle and save:

- $190 for electricity annually (electric griddle), or
- $175 for gas annually (gas griddle)

Holding Cabinets

ENERGY STAR hot food holding cabinets typically feature improved insulation, so heat stays in the cabinet and out of the kitchen. An insulated ENERGY STAR holding cabinet uses about half the energy consumed by an uninsulated cabinet. Other available features that could potentially save energy include magnetic door gaskets, auto-door closers, and dutch doors.

Cost-Saving Tips

- Look for the ENERGY STAR
- Shut off overnight
- Use the timer
- Replace missing or worn out control knobs

Good practices can save:

$500 annually by turning off an uninsulated holding cabinet when the kitchen is closed.

Buy an ENERGY STAR qualified holding cabinet and save:

- $340 to $960 annually for electricity

Combination Ovens

The combination oven is an extrememly versatile cooking platorm with the added bonus of a self-cleaning feature. Operating a combination oven in "steam" or "combination" mode typically uses more energy and water than operating in traditional convection mode. Use the oven's programming capabilities to properly control different cooking modes to maximize energy efficiency and cost savings. Do your homework when buying a combination oven: the most efficient models will use about half as much energy and water as the inefficient models.

Good practices can save:

$400 to $800 annually off an electric combination oven by cutting out two hours of idle time per day.

If ENERGY STAR qualified models don't exist for the type of equipment you're looking for don't worry: you still have options. Ask distributors and manufacturers for energy use information, and check online for equipment reviews. The California commercial food service incentive program is also a third party resource because, like ENERGY STAR, appliances that qualify must meet designated efficiency standards. The list of qualifying appliances can be found at: www.fishnick.com/saveenergy/rebates.

Broilers

Broilers are true kitchen workhorses but their dependability and simplicity come at a price: searing heat requires a great deal of energy and broilers have simple, non-thermostatic controls. This combination can make the broiler the most energy intensive appliance in the kitchen. For example, one gas broiler can use more energy than six gas fryers. A new generation of broilers incorporates better radiant designs, allowing the broiler to get the job done while consuming about 25 percent less energy.

Cost-Saving Tips

- Cut preheat time
- Turn off unneeded sections
- Reduce idle time
- Replace missing knobs

Good practices can save:

$600 annually by cutting out three hours of idle time per day.

Ranges

The range top is one of the most widely used pieces of equipment in restaurant kitchens. Ranges are manually controlled and can be energy guzzlers depending on how you operate them. A potential alternative to traditional range tops are induction ranges; they are more expensive but offer very high efficiency, rapid heat up, precise controls, and low maintenance.

Cost-Saving Tips

- Maintain and adjust burners
- Use a lid
- Cut idle time

REFRIGERATION SYSTEMS AND ICE MACHINES

Reach-In Refrigerators and Freezers

Compared to standard models, ENERGY STAR qualified commercial refrigerators and freezers can lead to energy savings of as much as 35 percent with a 1.3 year payback. Glass door refrigerators and freezers can now earn the ENERGY STAR too! Features that could potentially save energy include improved insulation and components such as high-efficiency compressors and motors.

Cost-Saving Tips

- Look for the ENERGY STAR
- Turn off door heaters when possible
- Clean coils
- Set defrost timers
- Replace worn gaskets

Buy ENERGY STAR qualified equipment and save:

- $200 for electricity annually (per solid door refrigerator)
- $140 for electricity annually (per solid door freezer)

Walk-In Refrigerators

Walk-in refrigerators are extremely important to any successful restaurant. Improve this equipment's energy performance with a few inexpensive upgrades and good practices, such as:

- Swapping out incandescent light bulbs for low-temperature ENERGY STAR qualified compact fluorescent lamps (CFLs) can reduce the lamps' heat output by 75 percent! (Look for the lowest possible "minimum start temperature" on the CFL box, e.g., zero degrees Fahrenheit.)
- Adding strip curtains and automatic door closers to your walk-in refrigerator: *they are inexpensive and easy-to-install.* Strip curtains can cut outside air infiltration by about 75 percent!
- Installing electronically commutated motors (ECM) on the evaporator and condenser fans reduces fan energy consumption by approximately two-thirds.

Cost-Saving Tips

- Allow air circulation
- Insulate suction lines
- Check refrigerant charge
- Repair and realign doors
- Clean coils

Ice Machines

Commercial ice machines that earn the ENERGY STAR are on average 15 percent more energy efficient and 10 percent more water efficient than standard models.

- Cut down on your daytime electricity demand by installing a timer and shifting ice production to nighttime off-peak hours.
- Bigger ice machines are typically more efficient than smaller ones, yet the price difference is usually not very large. Choose wisely and you could get twice the ice capacity at half the energy cost per pound of ice.
- Avoid water-cooled ice machines because of their high water cost, which make them significantly more expensive to operate. *Note: water-cooled ice machines do not currently qualify for ENERGY STAR.*

Cost-Saving Tips

- Look for the ENERGY STAR
- Clean the coils
- Keep the lid closed
- Adjust the purge water timer

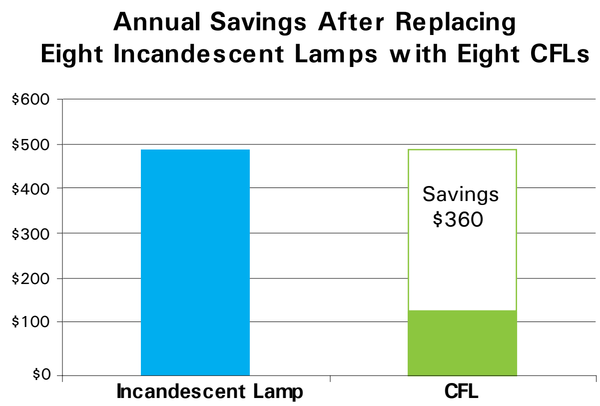
Buy an ENERGY STAR qualified ice machine and save:

- $120 for electricity annually

LAMPS AND LIGHTING FIXTURES

In a typical restaurant, lights are usually on for 16 to 20 hours a day. For many areas in your restaurant, high-efficiency ENERGY STAR CFLs and lighting fixtures are your ticket to savings.

- Install ENERGY STAR qualified fixtures and CFLs in your dining area and reduce energy consumption and heat output by 75 percent.
- Install occupancy sensors in closets, storage rooms, break rooms, restrooms, and even walk-in refrigerators. Look for sealed, low-temperature-specific sensors for refrigerated environments.
- If your restaurant features linear fluorescent lighting with T12 lamps and magnetic ballasts it is time to upgrade. Switch to more efficient T8 or T5 lamps with electronic ballasts. Electronic ballasts typically have faster on-times and do not hum or flicker. Look for utility incentives for lighting upgrades in your area.
- Swap your old Open/Closed and EXIT signs with LED technology for electricity savings up to 80 percent.
- Visit www.energystar.gov/lighting for more cost-saving information.



CFL vs. Incandescent Light Bulbs

If each of the 945,000 restaurants in the United States replaced only one incandescent light bulb with a CFL, more than 630 million pounds of CO_2 emissions could be avoided each year (the annual greenhouse gas emissions from more than 52,000 passenger vehicles*), and the restaurant industry could save about $42.5 million annually.

*Source: EPA Greenhouse Gas Equivalencies Calculator: www.epa.gov/cleanenergy/energy-resources/calculator.html

Mercury and CFLs

CFLs contain a very small amount of mercury sealed within the glass tubing (approximately 4 milligrams). By comparison, older thermometers contain about 500 milligrams of mercury an amount equal to the mercury in 125 CFLs. No mercury is released when the bulbs are intact (not broken) or in use. For more information about recycling and disposing of CFLs visit: www.energystar.gov/mercury.

HEATING, COOLING AND VENTILATION

Making smart decisions about your restaurant's heating, ventilating, and air conditioning (HVAC) system can have a big effect on your utility bills—and your customers' comfort.

Heating and Cooling Systems

Heating and cooling systems account for a large portion of your restaurant's annual energy use. For many restaurants, heating and cooling is second only to food preparation in terms of annual energy consumption.

Energy use falls by 4 to 5 percent for every degree that you raise your cooling thermostat setpoint. Easing back on central cooling by only 3°F could trim air conditioning costs by 12 to 15 percent. Improve customer comfort by using an efficient ENERGY STAR qualified ceiling fan to compensate for the difference in air temperature. Ensure that your heating and cooling equipment is included in the start-up and shut down schedule to save even more.

Cost-Saving Tips

- Look for the ENERGY STAR
- Clean heat-transfer coils
- Replace air filters
- Consider an Energy Management System
- Repair broken duct work
- Recommission economizers

Don't forget about the restroom! ENERGY STAR qualified ventilating fans use 70 percent less energy than standard models.

Buy ENERGY STAR qualified equipment and save:

- $1.70 per square foot over the life of the HVAC equipment ($4,250 for a 2,500 square foot restaurant; the same as $430 annually)
- $17 annually for electricity costs per ceiling fan
- $75 annually for electricity costs for ventilating fans that are run continuously

According to the Consortium for Energy Efficiency (CEE), at least 25 percent of all rooftop HVAC units are oversized, resulting in increased energy costs and equipment wear. Properly sized equipment dramatically cuts energy costs, increases the life of the equipment, and reduces greenhouse gas emissions.

Kitchen Ventilation

An unbalanced or poorly designed kitchen exhaust system can allow heat and smoke to spill into your kitchen, spelling trouble both for your restaurant's air quality and for your utility bills. Spillage leads to a hot, uncomfortable working environment and higher energy bills for air-conditioned kitchens.

- Cut down on spillage by adding inexpensive side panels to hoods.
- Push each cooking appliance as far back against the wall as possible to maximize hood overhang and close the air gap between the appliance and the wall.
- Install a demand-based exhaust control. It uses sensors to monitor your cooking and varies the exhaust fan speed to match your ventilation needs. Demand ventilation controls could reduce your exhaust system costs by anywhere from 30 to 50 percent and can be installed on either new equipment or retrofitted to existing hoods.

Learning More About Kitchen Ventilation

If you're getting ready to design a new kitchen or renovate an old one, check out "Improving Commercial Kitchen Ventilation System Performance," a two-part kitchen ventilation design guide written by the experts at PG&E FSTC and available at: www.fishnick.com/equipment/ckv/designguides.

Windows

Applying a clear, heat rejecting window film will help cut your cooling costs while making your dining room more comfortable. Use only high quality window film installed by a qualified professional.

Patio Heaters

The best approach to saving money with patio heaters is to cut back their use—both for hours of operation and for the number of patio heaters running at any given time. Patio heaters are radiant devices that heat up quickly so there is no reason to leave them running if a seating area is temporarily empty.

Good practices can save:

$530 per heater annually by cutting three hours of use per day

WATER AND WASTE MANAGEMENT

Water Use

Using water more efficiently preserves water supplies, saves money, and protects the environment. By conserving hot water you trim not one but two bills: one for the water and sewer and another for the electricity or natural gas used to heat the water used in bathroom faucets, kitchen sinks, and dishwashers.

Cost-Saving Tips

- Look for the ENERGY STAR and WaterSense label
- Add aerators
- Install WaterSense labeled toilets
- Repair leaks
- Reduce sink and tap usage

Similar to the ENERGY STAR, the WaterSense® label identifies water-efficient products and programs. WaterSense is a partnership program sponsored by EPA and additional information is available at: www.epa.gov/watersense.

look for WaterSense Meets EPA Criteria

Good practices can save:

$1,000 annually by turning down dipper wells and making sure they are OFF when the kitchen is closed

$1,000 annually by fixing leaks in sinks, mop-stations, and dishmachines

Look for WaterSense labeled equipment and use WaterSense irrigation partners to landscape your restaurant:

Bathroom faucets are 30 percent more water efficient

Landscaping with WaterSense irrigation partner could save you 15 percent compared to average watering bills

High-Efficiency Pre-Rinse Spray Valves

A high-efficiency, or low-flow, pre-rinse spray valve is one of the most cost-effective energy saving devices available to the foodservice operator. And it is easy to install! Just unscrew your old spray valve and screw in your new, water-efficient one.

In addition to minimizing hot water consumption, you can reduce both your water-heating and sewer expenditures per month. How? Typical spray valves can release hot water at a rate of three to four gallons of water per minute (gpm), while common high-efficiency units spray only 1.6 gpm or less without sacrificing cleaning power!

Buy a 1.6 gpm spray valve and save:

$300 to $350 annually for water, sewer, and natural gas costs annually (used one hour a day and compared to 3 gpm sprayer).

Additional information is available at: www.fishnick.com/equipment/sprayvalves.

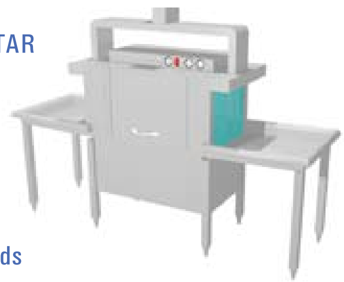
Dishwashers

From an operational standpoint, dishwashers are one of the most expensive pieces of equipment in your kitchen. Commercial dishwashers that have earned the ENERGY STAR are on average 25 percent more energy and water efficient than standard models.

- Run fully loaded dish racks through the dish machine. Cutting wash cycles could save you hundreds of dollars annually.
- Pay attention to your dishwasher's pressure gauge—if it's showing pressure above 25 psi, there is a good chance you are using much more water than is necessary. Most dishwashers require only around 20 psi.
- If you have a conveyor-style dishwasher, make sure you are using it in auto mode, which saves electricity by running the conveyor motor only when needed.

Cost-Saving Tips

- Look for the ENERGY STAR
- Turn off at night
- Replace torn wash curtains
- Repair leaks
- Replace worn spray heads



Buy an ENERGY STAR qualified dishwasher and save:

- $975 for electricity annually
- $200 for water annually

Waste Reduction Is Good Business

Waste reduction leads to increased operating efficiency and cost savings. Decreased solid waste generation reduces collection and disposal costs just as reducing electricity and water consumption reduces utility bills. Waste minimization also may reduce your purchasing costs for restaurant supplies.

Using recycling and composting bins, sustainable take-out containers, and "green" signage are all excellent ways to announce and to demonstrate to your customers your efforts to be more environmentally sustainable and aware.

For help identifying waste reduction opportunities please visit www.epa.gov/wastewise.

BEGIN THE PROCESS, LEARN MORE AND SAVE!

The best first step is to perform an energy audit on your facility. Energy service providers (utilities), state energy offices, and private sector product and service providers can assist you in identifying a trained professional to conduct your audit. However, comprehensive, affordable energy audits are not available everywhere in the country for commercial food service businesses.

To help address the lack of energy audits in many communities, ENERGY STAR provides free online tools and information to achieve energy savings. ENERGY STAR's basic guidance for self-assessments is part of the Guidelines for Energy Management, "Step 2: Assess Performance," at: www.energystar.gov/guidelines.

In addition, ENERGY STAR's Portfolio Manager software is designed to help businesses "benchmark" and track energy use, costs, and greenhouse gas emissions. Portfolio Manager also offers the option to track water use and renewable energy credits—all in a password protected online file. Portfolio Manager users can track multiple facilities independently or aggregate all the business locations into one file. Your restaurant can generate a Statement of Energy Performance which includes a "weather-normalized" kBtu/ft^2 energy use intensity calculation, associated greenhouse gas emissions and a national average for similar building types. Access to the software and free online training in use of Portfolio Manager is available at: www.energystar.gov/benchmark.

Once you have identified the areas of potential energy savings, decide which energy efficiency upgrades you want to install and what practices to initiate. If your finances and operating schedule make it impractical to perform all the upgrades at once, you can take a staged approached and install them as time and money allow.

Remember, having your **restaurant manager** 100 percent on board is absolutely key to saving your restaurant money and protecting the environment! Your best-laid energy-saving plans are only as good as the staff that is implementing them!

For more information, please consult the following online resources:

- ENERGY STAR Commercial Food Service: www.energystar.gov/cfs
- ENERGY STAR Restaurants: www.energystar.gov/restaurants
- ENERGY STAR Portfolio Manager: www.energystar.gov/benchmark
- PG&E Food Service Technology Center: www.fishnick.com
- National Restaurant Association Conserve: http://conserve.restaurant.org
- EPA WaterSense: www.epa.gov/watersense
- EPA WasteWise: www.epa.gov/wastewise

Find Monetary Incentives

ENERGY STAR CFS Incentive Finder: go to www.energystar.gov/cfs and click on “Special Offers” or go to www.energystar.gov/cfsrebate _ locator

December 2009

EPA 430-R-09-030

For more information visit www.energystar.gov.

Food Service Technology Center
Promoting Energy Efficiency in Food Service

conserve
solutions for sustainability

NATIONAL RESTAURANT ASSOCIATION®

LEARN MORE AT energystar.gov

ENERGY STAR

ENERGY STAR® FOR COMMERCIAL KITCHENS: HELPING CUSTOMERS MANAGE COSTS

Buildings with restaurants and other food service operations are very energy intensive, consuming roughly 2.5 times the energy per square foot as other commercial buildings, or close to 250,000 British thermal units (Btu) of energy per square foot.[1] Energy efficiency program administrators can help these customers rein in operating costs while also reducing energy use, peak demand, and water use by promoting ENERGY STAR qualified commercial food service (CFS) equipment and other best practices. Utility cost savings of 10 to 30 percent are achievable without sacrificing service, quality, style or comfort—all while making significant contributions to a cleaner environment.[2] The U.S. Environmental Protection Agency (EPA) is working with about 50 efficiency program administrators throughout the nation to integrate ENERGY STAR qualified CFS equipment into their program offerings. EPA is providing this fact sheet to introduce more program administrators to ENERGY STAR and the savings opportunities in commercial kitchens, as well as to share best practices for program design, implementation, and evaluation based on the experiences of recent CFS programs.

DELIVERING SOLUTIONS IN COMMERCIAL KITCHENS

Promoting the installation of energy-efficient equipment in commercial kitchens is an important part of a comprehensive CFS program. It saves significant amounts of energy and offers meaningful financial benefits to the establishment. Utility costs are a major operating expense for the CFS industry, on the level of about one-half to almost parity with their profit margins—which, for a full service restaurant, is around 5 percent of sales.[3] Due to rising energy costs, CFS customers may be increasingly receptive to program administrator assistance for improving energy efficiency and reducing related utility bills. And the savings opportunities are significant: as much as 80 percent of the food service sector's $10 billion annual energy bill is expended on energy that does no useful work and a substantial portion of this waste is related to equipment inefficiencies.[4]

ENERGY STAR provides a comprehensive and cost-effective platform for promoting greater equipment efficiency and related best practices to CFS customers. ENERGY STAR currently identifies efficient products in eight product categories: hot food holding cabinets, solid door refrigerators and freezers, fryers, steam cookers, ice machines, commercial ovens, griddles, and dishwashers.

These energy-efficient products offer energy savings of 10 to 65 percent over standard models, depending upon the product category. Three of the product categories, commercial dishwashers, ice machines, and steam cookers, also offer water savings of up to 90 percent over standard models. Three CFS utility programs have earned ENERGY STAR awards for promoting these energy-saving products and are showing promising early returns. They include:

- California's four investor-owned utilities (IOUs)—Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), and San Diego Gas & Electric Company (SDG&E)—offer a coordinated statewide incentive program with strong early results, achieving annual electric savings of around 20.6 million kilowatt-hours (kWh) and annual natural gas savings of around 526,000 therms.[5]
- The Energy Trust of Oregon's (ETO) CFS program is achieving annual savings of nearly 1.2 million kWh and over 190,000 therms by partnering with dealers that sell CFS equipment directly to restaurants.[6]
- Wisconsin's Focus on Energy offers CFS customers a bonus incentive to encourage the purchase of multiple ENERGY STAR qualified products and is achieving annual electric savings of nearly 350,000 kWh and annual natural gas savings of nearly 22,000 therms.[7]

Outfitting an entire commercial kitchen with a suite of ENERGY STAR qualified equipment could save around 300 million Btus of energy and about $3,600 per year.

PROGRAM DESIGN AND IMPLEMENTATION

A key factor in effective program design is understanding the market barriers to greater adoption of energy-efficient equipment and developing strategies to overcome these barriers. Common barriers in the CFS market include:

- ***Hard-to-reach market***—The CFS market is highly fragmented, both in terms of equipment supply channels and end use sectors.
- ***Lack of readily available supply***—CFS equipment suppliers typically compete on low prices and therefore stock only a limited supply of energy-efficient products. This barrier is compounded by customers who make short-term purchasing decisions due to the need to replace equipment quickly when it fails.
- ***Incremental costs***—ENERGY STAR qualified CFS equipment is generally more expensive than standard efficiency equipment and can cost significantly more than refurbished models sold in the used equipment market.
- ***Lack of knowledge***—Equipment suppliers and end users might not be aware of energy-efficient products, might have misperceptions about tradeoffs between energy efficiency and performance, or both.

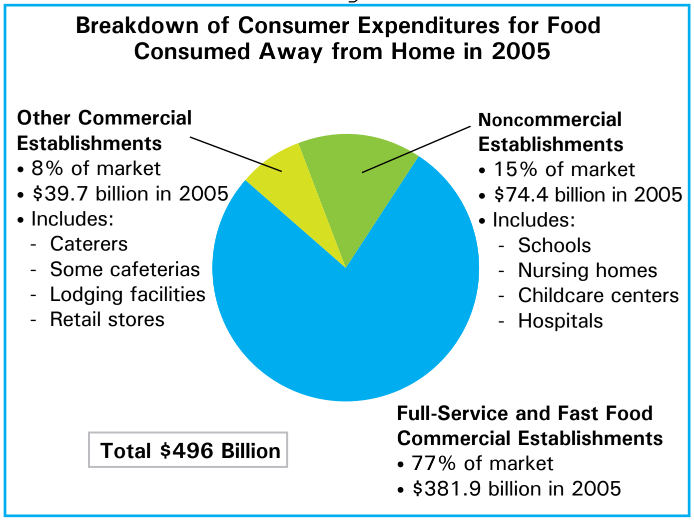
The following sections describe the CFS equipment market in further detail and discuss program strategies for addressing the key barriers listed above.

Understanding and Engaging the CFS Market

Foodservice establishments include commercial and noncommercial entities, diverse business sectors, and account for approximately \$500 billion in expenditures for food consumed away from the home (e.g., meals and snacks for on-premise or immediate consumption). Commercial establishments—including full service restaurants, fast food outlets, caterers, some cafeterias, lodging facilities, and retail stores—account for about 85 percent of this total with full-service restaurants and fast food restaurants representing the two largest industry segments, accounting for 77 percent of expenditures for food consumed away from the home. Noncommercial foodservice operators—those that prepare and serve food as an adjunct service in institutional settings (e.g., schools, nursing homes, childcare centers, and hospitals)—account for the remaining 15 percent.[8]

In addition to the diverse business sectors that comprise the foodservice industry, the CFS equipment market is complicated by multiple equipment distribution channels including:

- Dealers that primarily sell to individual restaurants.
- Distributors that primarily supply bulk quantities to equipment dealers and sell commodity equipment (e.g., ice machines, counter-top fryers) directly to end users.



Source: *Adapted from U.S. Department of Agriculture Economic Research Service, Briefing Room: Food Marketing System in the United States.*

- Manufacturers that sell through manufacturer representatives (reps) but may also sell directly to large end users such as national restaurant chains.
- Consultants that assist in either designing new or renovating existing commercial kitchens, typically working with restaurant chains, hotels, hospitals, and universities.

(Additional information on supply channel actors and strategies for influencing them can be found in the text box on page 3).

Due to the complexity of the CFS market and potential for widespread variability between service territories, program administrators should consider conducting a market assessment to: 1) understand the major sectors and primary distribution channels influencing the CFS equipment market in their territory, 2) develop estimates of likely program uptake for each sector

ITW Food Equipment Group

2008 and 2009 ENERGY STAR Partner of the Year, ITW Food Equipment Group (ITW FEG)—the parent organization of independent companies such as Hobart, Stero, Vulcan, Traulsen, and Wittco—understands the importance of supporting customers in their drive to cut costs, use less water and consume less electricity, and has responded by offering 381 ENERGY STAR qualified CFS products.

> "ENERGY STAR plays an important role in helping foodservice operators and food retailers design a sustainable kitchen that's good for the environment and good for business in terms of efficiency, productivity and quality...Our partnership with ENERGY STAR enables us to emphasize the value of selecting equipment engineered for high efficiency and low water consumption."
>
> —*John McDonough, President of ITW FEG*

taking into account the uniqueness of each sector (e.g., while restaurants are often the largest segment, they are often the hardest segment to influence), and 3) establish program baseline conditions (e.g., what is the current market share for an efficient product, and what is the best estimate of market share over time absent a program). See related discussion under Measurement and Verification, page 7.

Another key best practice is to engage equipment suppliers and other key stakeholders, such as large and small restaurant customers and their trade associations, during program design. Engaging stakeholders early in the planning process can help program administrators better understand stakeholder business models and gauge receptivity to potential education, marketing, and incentive strategies.

Continuing this dialogue during program launch, particularly with supply-side market actors, is essential to ensuring that manufacturer reps, distributors, dealers, and businesses are familiar with program incentives, policies and procedures, and are able to effectively communicate the key benefits and features of qualified energy-efficient equipment to their customers. During these meetings, it is important to communicate both the mechanics of how the CFS program works and the business benefits of program participation.

An ENERGY STAR qualified commercial refrigerator can save a restaurant around $200 on energy costs per year. This may not seem like much until one considers the slim profit margins in the restaurant industry. If a restaurant operates with a profit margin of around 5 percent (the industry average), it will need to make roughly $4,000 in sales to earn $200 in profit.

Improving Availability of ENERGY STAR® Qualified Equipment

In the retrofit market, purchasing often occurs when existing equipment fails, and the top priority is getting new equipment online quickly. Decisions on product selection and purchase are usually driven by product availability, price, and advice from the equipment supplier. Unfortunately, many suppliers do not stock or promote efficient equipment due to price premiums that range from 10 to 85 percent, depending on product category.

The following are important strategies for motivating suppliers to sell and stock ENERGY STAR qualified equipment:

Make the business case—It is important to educate suppliers on the value proposition for promoting ENERGY STAR qualified CFS equipment to their customers. While efficient equipment may have

Supply Channel Actors

Dealers—Dealers primarily sell to individual restaurants, which is often the most difficult market to reach. Smaller dealers may join buying groups so they can compete more effectively with larger dealers. Many dealers display their products in showrooms and tend to stock lower-priced, popular models that are usually not energy-efficient. A dealer's main objective is usually to sell the products they have on hand, and they are generally more interested in attracting customers with low prices rather than emphasizing the overall value of higher-end products (e.g., lifetime cost savings). Given that many manufacturers offer sales incentives to move lower-end models, dealer incentives can be an effective strategy to promote stocking and sales of energy-efficient equipment.

Distributors—Distributors primarily supply bulk quantities of equipment to dealers and sell commodity equipment (e.g., ice machines, fryers) directly to end users. Since distributors usually supply dealers, developing a good working relationship with distributors helps funnel energy-efficient CFS products into dealer showrooms. In addition, some restaurant food distributors sell CFS equipment and should also receive program outreach.

Manufacturers and Reps—CFS equipment manufacturers generally sell through product reps, although manufacturers may also sell directly to large end users such as national restaurant chains. Though all supply channels gravitate toward inexpensive, fast-moving pieces of equipment, a key value proposition for engaging reps is the up-sell potential of high-value, high-efficiency equipment. Sales of high-quality products earn reps a higher commission and generate long-term value for the customer, often leading to repeat business.

Design Consultants—Design consultants assist in the planning and design of new or renovated commercial kitchens, typically working with large or chain-owned restaurants, hotels, universities, and hospitals. Conducting targeted outreach to design consultants helps to ensure that energy- and water-efficient CFS equipment is considered in these types of projects. Design consultants are typically focused on the overall design and aesthetics of the space and controlling project costs, and back-of-the-house equipment is often a low priority. In addition, they often have established relationships with buying groups and may receive incentives for selling lower-end equipment. Equipment quality and performance are key selling points for engaging design consultants.

a higher first cost, it costs less to operate. With today's rising energy costs, efficient equipment will continue delivering dividends through lower utility bills for years to come. It is also important to highlight non-energy benefits of efficient products such as water savings, reduced noise, reduced waste heat, and other quality and performance features. Businesses that can effectively up-sell higher-end equipment can increase their bottom line.

Sales incentives—Upstream incentives, including salesperson incentives or "spiffs," can be effective at motivating equipment suppliers to promote the multiple benefits of energy-efficient products, rather than steering customers to low-cost products, which is the norm. Puget Sound Energy (PSE) offers a $30 "spiff" for each completed incentive application submitted by an equipment supplier; San Diego Gas & Electric Company (SDG&E) offers a $25 spiff.

Program Highlight

Puget Sound Energy's $30 spiff rewards equipment suppliers for submitting completed incentive applications to the utility for processing on behalf of the customer. The supplier discounts the purchase price by the amount of PSE's customer rebate, so the customer receives an incentive at the point-of-purchase. Suppliers are reimbursed for the amount of the customer rebate, and get the $30 reward for their time and effort. This approach has led to higher turn-in rates for incentive applications, and fewer paperwork errors.

Provide program information—Providing easy access to up-to-date information about program offerings and procedures is essential to engaging and maintaining effective trade ally relationships. Initial kick-off workshops provide an opportunity to discuss the benefits of ENERGY STAR qualified CFS equipment and to inform participants of program requirements and incentive offerings. Conducting regular visits to trade ally showrooms/offices to discuss the program and distribute educational literature, point-of-purchase marketing materials, and incentive applications are also highly effective strategies for keeping trade allies informed. Other best practices include establishing a dedicated Web site and distributing electronic newsletters to keep equipment suppliers updated on program activities.

Offering Customer Incentives to Overcome First-Cost Barriers

The incremental cost of some ENERGY STAR qualified equipment can be a significant barrier to purchasing products. In general, the incremental cost is highest for fryers and hot food holding cabinets; moderately high for commercial dishwashers, refrigerators and freezers, and ice machines; and lowest for steam cookers.

Equipment rebates—To overcome the significant barrier of incremental cost, the majority of CFS programs offer prescriptive rebates for the purchase of qualified equipment. Program administrators typically set incentive levels at 50 percent or less of the incremental cost of purchasing the ENERGY STAR qualified model versus a standard efficiency model. There is, however, no set formula for success when choosing equipment rebate levels, and CFS programs are achieving success with a range of levels. As of August 2008, the following incentive ranges were available from the online ENERGY STAR CFS equipment incentive finder tool.

Table 1: Range of Incentives Offered by Program Sponsors (as of 5/09)*

Product	Incentive Range
Fryers	$150–$1,000
Hot food holding cabinets	$200–$500
Refrigerators and freezers	$50–$500
Steam cookers	$200–$1,500
Ice machines	$50–$600
Commercial dishwashers	$200–$2,000

Some programs, like Wisconsin's Focus on Energy, promote comprehensive kitchen efficiency upgrades by offering bonus incentives for the purchase of two or more pieces of qualified equipment. The customer is eligible for the usual per-unit equipment incentive, plus an additional $100 if they purchase two or more pieces of qualifying equipment, or $300 if they purchase three or more pieces of eligible equipment at a time. This strategy can be particularly effective when targeting commercial kitchen renovation and new construction opportunities.

The following are common best practices related to incentives:

- Tie incentive levels to ENERGY STAR specifications whenever possible to help customers easily identify products that qualify for rebates and to take advantage of the growing consumer awareness, market momentum, and supporting infrastructure provided by the program.
- Keep incentive application processes simple and straightforward.
- Maintain relatively consistent incentive levels from year to year, trending downward as market penetration increases.
- Ensure suppliers and buyers have easy access to a list of qualified models and related incentive levels. ENERGY STAR qualified product lists are available on each of the specific

* Note: *data include some programs offering incentives for equipment achieving higher efficiency levels than ENERGY STAR.*

product pages at *www.energystar.gov/cfs*. The California IOUs, which offer incentives for CFS equipment beyond ENERGY STAR qualified products, provide an online list of qualified equipment through PG&E's Food Service Technology Center (FSTC).

- Promote program and incentives through the online ENERGY STAR CFS equipment incentive finder tool (*www.energystar.gov/CFSrebate _ locator*).
- Educate customer call centers about program offerings, procedures, and where to direct customers for additional information.

Audits—Offering free or reduced-cost audits for commercial kitchen facilities is another form of incentive that can be useful for helping customers, particularly regional and national franchise chains, identify and correct operational inefficiencies, and for encouraging customers to take advantage of program rebate offerings when equipment purchases are needed. Customers are more likely to make smart decisions about CFS appliances if they have time to research options and secure the necessary capital to purchase new equipment. Many utilities offer audits to national restaurant chains as part of the menu of services they receive as managed accounts, and offer a higher level of support in helping such customers specify efficient equipment options for their facilities.

Audits can be offered for a nominal fee or at no cost to the customer. Some programs make a free audit contingent upon implementation of a minimum number of energy- and water-saving recommendations. Immediate energy savings benefits can be achieved by conducting direct installation of low-cost measures (e.g., high-efficiency pre-rinse spray valves, gaskets on refrigeration equipment, or compact fluorescent light bulbs).

Program Highlight

To effectively serve the diverse set of CFS market participants, the programs sponsored by the **California IOUs** offer an array of services, including site audits, equipment testing, and new restaurant plan review, as well as regular energy efficiency seminars for food service professionals.

Audits help to develop the customer relationship, increasing the likelihood that the customer will take advantage of program offerings when it comes time to replace equipment or conduct comprehensive facility upgrades. To ensure that the program is viewed as a credible resource, it is critical that auditors be knowledgeable about the unique challenges and business realities of CFS operations, and deliver realistic recommendations. A recent evaluation of the PG&E's FSTC found that in order to deliver the most value to food service operators, audit reports should include detailed information on costs and savings associated with the recommended improvements.[9]

Educating the Marketplace

Lack of knowledge about efficiency opportunities among end users and equipment suppliers, as well as misperceptions about tradeoffs between efficiency and performance, continue to inhibit greater adoption of energy-efficient equipment in the CFS market, despite improvements in this area since EPA introduced ENERGY STAR specifications for a variety of CFS products—as of May 2009, there are more than 98 ENERGY STAR CFS manufacturing partners and 2,600 qualified CFS products on the market.

The following strategies have been effective for getting information to end users to overcome these barriers:

Target marketing—Program information needs to be timely and relevant in order to motivate consumers to take action. For this reason, program administrators often develop targeted marketing strategies and messaging for each major market segment they are trying to reach—restaurants, hotels, schools, hospitals, etc.—taking into account business cycles and major industry events in timing promotions and outreach.

Training and equipment demos—Equipment suppliers may have little experience selling energy-efficient equipment, and they and their customers may be confused by different efficiency claims in the market or think energy efficiency comes with a tradeoff in productivity or product features. Equipment demonstrations and hands-on training can be particularly effective for persuading consumers that ENERGY STAR qualified CFS equipment comes with no tradeoffs in features or performance. Some programs have dedicated demonstration facilities for this purpose, while others work to assist suppliers in developing their own equipment demonstrations.

- PG&E's FSTC evaluation found that training seminars were a good way to build relationships with food service operators, leading to energy savings impacts over time.[10]
- New York State Energy Research and Development Authority's (NYSERDA) Small Commercial Kitchen Pilot successfully used cooperative marketing dollars to assist suppliers in developing their own equipment demonstrations (see text box on page 6).
- ETO gives an annual 45 minute sales training to CFS dealers to ensure sales staff understand the energy, monetary, and ancillary benefits of ENERGY STAR qualified CFS equipment.

Cooperative marketing—CFS programs create opportunities for cooperative advertising, showroom promotions and other collaborative marketing efforts with equipment suppliers. Programs often provide collateral marketing materials such as point-of-purchase banners, tags or stickers to identify rebate-eligible equipment, and informational flyers and brochures. Providing cooperative advertising funds is also an effective approach as it allows businesses the flexibility to market and advertise their ENERGY STAR qualified products in a way that is best aligned with their business model. For example, equipment suppliers that join

Program Highlight

ETO developed a highly successful document modeled after CFS dealers' handbooks (folders with equipment specification and sell sheets) that dealers take with them on the road. The handbooks contain all the relevant information that a dealer would need to sell ENERGY STAR equipment, such as:

- What is energy efficiency
- What is ENERGY STAR
- List of incentives available in Oregon
- A territory map showing where incentives are available
- Qualified product lists
- Tables listing the energy, water, and monetary savings for energy-efficient equipment (e.g., fryers, ice machines, refrigerators)
- Ancillary benefits of ENERGY STAR equipment
- Incentive application forms

Alliant Energy's trade ally network can be reimbursed for up to 50 percent of the cost of cooperative advertising, subject to utility pre-approval and other minimum requirements. For CFS products that save energy and water—commercial dishwashers, ice machines, and steam cookers—a growing number of energy and water utilities are pursuing opportunities for cooperative marketing, joint program implementation, or both.

Trade association outreach—CFS programs can leverage existing trade association networks to raise awareness of program opportunities and boost participation by customers and suppliers. Program administrators should consider joining the local restaurant association and trade associations serving food service equipment suppliers, as well as state restaurant associations. Membership in these organizations will keep program managers abreast of developments in the industry and alert them to outreach opportunities available through trade shows, meetings, and monthly publications. Informational seminars, industry conferences, and well-crafted articles are excellent ways of reaching service decision-makers. At these events, program administrators can also conduct informational seminars and display information and materials to publicize CFS program offerings.

Communications and outreach—A robust communications plan utilizing multiple channels including newsletters, targeted mailings, personal contact, seminars, and electronic communications increases awareness of program opportunities. Personal contact (i.e., "face time") is extremely important for implementing a successful program. Energy efficiency is a new concept in the CFS market and supply channel actors often need additional support from utilities before stocking, promoting, and selling energy-efficient CFS equipment. Program administrators can contact ENERGY STAR for assistance in identifying trade allies and developing outreach materials.

Program Highlights

1) **CenterPoint Energy** (MN) uses its Commercial Food Service Learning Center in Minnesota to provide hands-on education to trade allies about the benefits of high-efficiency equipment. CenterPoint is also a member of several food service trade associations and regularly attends the **Upper Midwest Restaurant Show.**

2) Distributor **Saratoga Restaurant Equipment Sales** (SRES) leveraged cooperative marketing opportunities through **NYSERDA's Small Commercial Kitchen Pilot** and increased sales of qualified equipment by 50 to 900%, depending on the product. Promotional efforts included a showroom event and equipment demonstration, hang tags on qualified equipment, and direct mail. SRES also streamlined the application process by filling out rebate paperwork on the customer's behalf.

3) As part of their program outreach activities, the four **California IOUs** attend the annual **Western Food Service and Hospitality Expo** in Los Angeles. The show is a great way for California program sponsors to engage with trade allies and to reach their key audience: restaurants.

Motivating Behavior Change and Continuous Energy Performance Improvement

In addition to purchasing energy and water efficient equipment, there are a number of operational best practices that program administrators can share with food service operators. The ENERGY STAR Restaurant Guide provides both short- and long-term recommendations for saving energy in commercial kitchens, equipment use and maintenance tips, and general energy savings tips, in addition to outlining the benefits of energy-efficient equipment installation. Program administrators can use this guide as part of education efforts with commercial kitchen customers to promote additional savings. EPA's Portfolio Manager tool can also be used to obtain a weather-normalized energy performance benchmarks for buildings, assisting food service operators in tracking their building's energy use and reducing it over time.

EPA also works cooperatively with the Consortium for Energy Efficiency (CEE) Commercial Kitchens Initiative. CEE is a nonprofit corporation whose membership includes utility, state, and nonprofit administrators of energy efficiency programming. The goal of the initiative is to define a high performance commercial kitchen package that CEE members can deliver to customers in targeted CFS sectors. A bundled whole-kitchen approach may be particularly appropriate for new construction or major renovation projects. For more information, please visit: *www.cee1.org/com/com-kit/com-kit-main.php3*

Program Highlight

PG&E has developed a Food Service Edition of the Smart Business Rebate Booklet identifying over $6,000 in rebates for the food service industry. The booklet provides information on nearly two dozen ways that PG&E can help customers save energy in commercial kitchens. The booklet tells customers how to apply for rebates, how to access education and training through PG&E's Food Service Technology Center, and how to develop an energy management plan using PG&E's online tool, SmartEnergy AnalyzerTM.

MEASUREMENT AND VERIFICATION

Measurement and verification (M&V) are central to the success of energy efficiency programs, and are used to assess the market during program design, monitor program performance during program implementation, validate program impacts, and justify continued investment in a program.

During the program planning and design phase it is important to establish a baseline and capture important data before it is lost.

Baseline Assessment

During the program planning process, it is useful to develop a baseline market assessment of the energy savings potential from commercial kitchens. This baseline will allow program managers to set realistic savings goals and design programs that are well-suited for the target market. Understanding market potential and the market penetration of energy-efficient CFS equipment is well worth the effort, providing valuable insights into how the program should be delivered, and what incentive levels would be cost-effective and successful at moving the market.

Many program administrators quantify kWh savings potential by customer segment. Some market assessments employ a survey process to develop baseline assumptions. At a minimum, a market assessment will identify the number of independently owned and franchised restaurants, hospitality businesses, and large institutional users of CFS equipment (e.g., hospitals, schools, prisons) within the service territory, and provide general information on the baseline equipment installed in such facilities. Growth projections for key end-use sectors and annual run time for qualified equipment are also useful metrics to include.

Program Tracking

Developing and maintaining a program tracking system is important for measuring program progress and tracking energy savings. Program administrators have found the following indicators useful in tracking program performance over time: energy savings (kWh and kW) from approved incentive applications; level of rebate activity by product type; level of rebate activity by customer type (restaurant, hospitality, etc.); trade ally participation; and program costs.

Incentive applications are an important source of information for collecting basic information not only to justify rebate payment, but also to inform future program impact evaluation. The following are commonly required inputs:

- Customer contact information
- Type of facility (restaurant, hotel, etc.)
- Equipment type
- Manufacturer
- Model number
- Equipment cost
- Number of qualified units installed
- New installation or retrofit
- Proof of purchase (including serial number)
- Trade ally contact information (if trade ally incentives are offered)

It is important to keep in mind the significant lag time between implementing a program and achieving program results. According to PG&E, CFS incentive programs take approximately 12 months to demonstrate changes in equipment stocking, selling, and purchasing behavior.

Process and Impact Evaluation

CFS programs are typically subject to two types of evaluations: process evaluation and impact evaluation. Process evaluations review program design and implementation to assess what elements of the program are working well and identify opportunities for improvement. Impact evaluations estimate the energy and demand savings that directly result from a program. The Model Energy Efficiency Program Impact Evaluation Guide, a resource of the National Action Plan for Energy Efficiency, is a useful resource for learning more and is available at *www.epa.gov/cleanenergy/documents/evaluation _ guide.pdf*

PROGRAM COST EFFECTIVENESS

ENERGY STAR qualified CFS equipment provides substantial savings opportunities for program administrators. While CFS programs can be operational within a two to four month period, given the diffuse nature of the distribution and purchasing patterns associated with this equipment, seeing significant progress in terms of program participation may take as long as one year.

Measure-level cost-effectiveness analysis, conducted during program planning, requires data on incremental measure cost, per-unit savings (kW, kWh, therms), annual hours of operation, and measure life. Program administrators typically base hours of operation assumptions on the type of facility where the equipment is installed (e.g., full service restaurant, quick service restaurant, hospital, school). As refrigeration measures are weather-sensitive,

Figure 1: Example of Co-Branded Marketing Document

ENERGY STAR supports development of co-branded marketing materials, like this flyer from **Wisconsin's Focus on Energy** highlighting the benefits of ENERGY STAR qualified equipment.

savings assumptions may vary based on the climate zone where the equipment is installed.

Measure-level data are available from a number of public sources, including the following:

- The Database for Energy-efficient Resources (DEER), maintained by the California Energy Commission and California Public Utilities Commission: *www.energy.ca.gov/deer*
- Program work papers filed by the California IOUs, available through the Energy Efficiency Groupware Application: *http://eega2006.cpuc.ca.gov*
- PG&E's FSTC Web site: *www.fishnick.com*
- NYSERDA also has a Deemed Savings Database, available by request

Table 2 presents program administrator cost (PAC) effectiveness results for three existing programs that provide incentives for ENERGY STAR qualified CFS equipment. These calculations only include the equipment incentive and administrative costs, but are estimated for the useful life of the equipment and discounted to net present value using 7 and 9 percent discount rates.

Program administrator costs are different, and usually lower than, total resource cost (TRC), which include the end users' marginal cost for purchasing energy-efficient equipment. For example, PG&E's PAC cost per kWh is estimated at $0.04 for both 7 and 9 percent discount rates; TRC is estimated

Table 2: Estimated Program Cost Effectiveness for Three Utilities*

	Pacific Gas & Electric Company[11] (PG&E)	Southern Minnesota Municipal Power Agency[12] (SMMPA)	Energy Trust of Oregon[13] (ETO)
Implementation Period (years)	2.75	2.00	4.00
Implementation Dates	01/06 to 09/08	05/06 to 05/09	05/05 to 04/09
Total Rebated Units	3,026	60	4,757
Gas	858	7	2,601†
Electric	2,168	53	2,156
Total Therms Saved	490,625	1,402	458,970
Total KWh Saved	13.3 million	183,147	3.4 million
Levelized CCE - Natural Gas ($/Therm)°	$1.06 –1.18	$1.54 – 1.70◊	$0.44 – 0.47◊,†
Levelized CCE - Electricity ($/kWh)°	0.04	$0.01◊	$0.10 – 0.11◊

* Levelized Cost of Conserved of Conserved Energy (CCE) estimates using the Program Administrator Cost Test (also known as the Utility Cost Test).

° Levelized CCE is presented using a range for discount rates of 7% and 9%.

◊ Administrative costs: for ETO and SMMPA an administrative cost of 11% was used in calculating CCE based on a published cap on administrative costs from the Oregon Public Utility Commission (www.energytrust.org/who/090323_Facts_EnergyTrust.pdf). PG&E data includes administrative costs supplied by the utility in program files and imbedded in measure level estimates.

† Includes 2,202 low-flow pre-rinse spray valves (PRSVs) provided free of charge to restaurants by ETO.

between $0.12 and $0.13 per kWh for the same discount rates (9 and 11 present respectively).11 The difference between these two estimates is the end users' added costs for purchasing the equipment. Utilities should analyze both PAC and TRC when deciding what types of equipment to incentivize.

ENERGY STAR SUPPORT FOR CFS PROGRAMS

In order to take full advantage of the ENERGY STAR platform for CFS programs, program administrators sign an ENERGY STAR Partnership Agreement with the government. The ENERGY STAR Program has an established national network of program administrators, equipment manufacturers, and marketing support firms that can provide advice and technical assistance during program start-up and implementation. Examples of support and resources include:

- **Specifications**—ENERGY STAR specifications currently cover six CFS equipment types, with new product categories evaluated every year. Information on new specifications and revisions to existing specifications is available at *www.energystar.gov/productdevelopment*.

Figure 2: Example of Co-Branded Incentive Booklet

Be creative when publicizing your programs! Southern Minnesota Municipal Power Agency created the Food Service Equipment Rebate booklet to showcase the comprehensive incentive program they developed for their 18 Member utilities. The booklet includes information on the utility's CFS equipment rebates, emphasizes ENERGY STAR's role in CFS market transformation, and provides product- and market-specific information for end users.

The Food Service Equipment Rebate booklet is available at: *http://www.SaveEnergyInBloomingPrairie.com/Upload/FoodServiceBooklet.pdf*

- **Marketing tools and resources**—Downloadable logos, equipment-related information, and educational tools like the ENERGY STAR Guide for Restaurants allow program administrators to customize a variety of marketing and informational materials, while using high-quality ENERGY STAR graphics and language that effectively describes how ENERGY STAR works in commercial kitchens (see figure 1 and 2).
- **Training resources**—A variety of materials are available to support program training activities, including customizable train-the-trainer presentations and opportunities for online or in-person training conducted by PG&E's FSTC (minimum participation requirements apply).
- **Partner matchmaking**—ENERGY STAR facilitates contacts between energy efficiency program administrators and manufacturers, equipment suppliers, and restaurant associations to support program marketing and outreach.
- **Savings calculators**—Spreadsheet tools estimate lifecycle energy, water, and cost savings for each category of ENERGY STAR qualified CFS equipment and are available at *www.energystar.gov/cfs* by clicking on the relevant product page.
- **Manufacturer and product lists**—Regularly-updated lists of equipment models that have earned the ENERGY STAR support rebate verification activities and are available at *www.energystar.gov/cfs* by clicking on the relevant product page.
- **Best practices tools**—Spreadsheet tools for quick service restaurants and full service restaurants estimate lifecycle energy and cost savings from additional energy-efficient food service equipment categories not currently covered by ENERGY STAR, and are available at *www.energystar.gov/cfs*.
- **CFS Equipment Incentive Finder**—Online database of available rebates for qualified equipment is searchable by zip code or by product type and is available at *www.energystar.gov/CFSrebate _ locator*.
- **CFS Program Guide**—Regularly-updated publication informs food service equipment suppliers about cross-promotional opportunities available through efficiency programs.
- **CFS newsletter**—Bimonthly electronic publication is distributed to industry associations, equipment suppliers, and efficiency program administrators highlighting efforts to promote ENERGY STAR qualified CFS equipment.
- **Case studies**—Success stories highlight commercial kitchens saving energy and money by leveraging energy efficiency programs and purchasing ENERGY STAR qualified equipment.

RESOURCES FOR ADDITIONAL INFORMATION

The following links are useful resources for energy efficiency program administrators that would like to learn more.

- ENERGY STAR for Commercial Food Service: *www.energystar.gov/cfs*

- ENERGY STAR for Restaurants: *www.energystar.gov/restaurants*
- ENERGY STAR Purchasing and Procurement with Product Savings Calculators: *www.energystar.gov/purchasing*
- ENERGY STAR Small Business Network: *www.energystar.gov/smallbiz*
- CEE Commercial Kitchens Initiative: *www.cee1.org/com/com-kit/com-kit-main.php3*
- PG&E's FSTC: *www.fishnick.com*
- GasNetworks: *www.gasnetworks.com/efficiency/pdf/Fryer_Rebate_Form_07_08.pdf*
- Green Restaurant Association: *www.dinegreen.com*
- National Restaurant Association: *www.restaurant.org*
- National Restaurant Association Conserve Initiative: *www.conserve.restaurant.org*
- North American Association of Food Equipment Manufacturers (NAFEM): *www.nafem.org*

PROGRAMS PROMOTING ENERGY STAR QUALIFIED CFS EQUIPMENT

Selected efficiency programs offering rebates for ENERGY STAR qualified CFS equipment include:

- Avista Utilities: *www.avistautilities.com/business/rebates/washington_idaho/Pages/incentive_7.aspx*
- The Energy Trust of Oregon: *www.energytrust.org/buildingefficiency/restaurants.html*
- MidAmerican Energy: *www.midamericanenergy.com/kitchen*
- New York State (NYSERDA): *www.nyserda.org/Commercial_Industrial/CommercialKitchens/default.asp*
- Pacific Gas & Electric Company: *www.pge.com/mybusiness/energysavingsrebates/incentivesbyindustry/hospitality*
- Puget Sound Energy: *www.pse.com/solutions/forbusiness/pages/comRebates.aspx?tab=4&chapter=4*
- San Diego Gas & Electric Company: *www.sdge.com/foodservice*
- Southern California Edison: *www.sce.com/RebatesandSavings/SmallBusiness/ExpressEfficiency/FoodServiceEquipment*
- Southern Minnesota Municipal Power Agency (SMMPA): *www.smmpa.org/members.asp?utility=59&service=326*
- Wisconsin's Focus on Energy: *www.focusonenergy.com/foodserviceincentives*

SOURCES

[1] Consortium for Energy Efficiency. Commercial Kitchens Fact Sheet. Available at: *www.cee1.org/resrc/facts/comkit-fx.pdf*

[2] PG&E Food Service Technology Center.

[3] National Restaurant Association (2008). 2007/2008 Restaurant Industry Operations Report, as cited in National Restaurant Association, 2008 Restaurant Industry Forecast.

[4] PG&E Food Service Technology Center.

[5] California Public Utilities Commission (CPUC) (2008). Energy Efficiency Groupware Application, 4th Quarter 2007 E3 Calculators. Available at: *http://eega2006.cpuc.ca.gov*

[6] Personal communication, Energy Trust of Oregon, July 9, 2008.

[7] Personal communication, Wisconsin's Focus on Energy, July 16, 2008.

[8] U.S. Department of Agriculture Economic Research Service. Briefing Room: Food Marketing System in the United States. Available at: *www.ers.usda.gov/Briefing/FoodMarketingSystem/foodservice.htm*

[9] PA Consulting Group (2008). Pacific Gas & Electric: Process Evaluation and Strategic Assessment of the Food Service Technology Center. Available at: *www.calmac.org/publications/PGE_FSTC_Eval__Report_-_Final_Feb_14_2008.pdf*

[10] PA Consulting Group (2008). Pacific Gas & Electric: Process Evaluation and Strategic Assessment of the Food Service Technology Center. Available at: *www.calmac.org/publications/PGE_FSTC_Eval__Report_-_Final_Feb_14_2008.pdf*

[11] Pacific Gas and Electric Company. E-mail communication and data sharing, January 2009.

[12] Southern Minnesota Municipal Power Agency. E-mail communication and data sharing, April 2009.

[13] Energy Trust of Oregon. E-mail communication and data sharing, April 2009.

ENERGY STAR®, a program sponsored by the U.S. EPA and DOE, helps us all save money and protect our environment through energy-efficient products and practices. Learn more. Visit www.energystar.gov.

ENERGY STAR

Date of Request: April 11, 2016 DPS Request No. DPS-421 JL-4
Due Date: April 21, 2016 KEDNY/ KEDLI Req. No. BULI-438

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, Sean Mongan

SUBJECT: Research and Development Costs - KEDNY

Request:

Provide the following:

1. Using the table below, provide five (5) years of data (one table for each year, 2011-2015, showing the annual planned budget, program revenues (surcharges/base rates) collected from customers, actual program expenditures, and reconciled accrued program dollars for each of the three major R&D program areas (KEDNY Internal, NYSERDA, and Millennium). If the amount is $0 for any cell, please indicate the $0 amount and explain why the amount is zero.

2. For 2016, provide the same data as requested in question 1, showing the projected/estimated program expenditures, program revenues to be collected during 2016, actual program expenditures to-date, and accrued program dollars for each of the three major R&D program areas ((KEDNY Internal, NYSERDA, and Millennium).

KEDNY Research and Development 2010 Revenues and Expenditures				
	Program Budget	Revenues Collected	Actual Expenditures	Total Program Accruals
Internal Programs				
NYSERDA				
Millennium				
Total				

3. To the extent that the Companies currently engage in internal research and development, identify how these projects differ from those end-use technologies that will be developed by Utilization Technology Development (UTD).

4. On p. 16, of your testimony for KEDNY, you show planned cost associated with UTD of $250,000 annually and identify flexibility for KEDNY to determine which projects they wish to support. Explain where the program dollars will come from that KEDNY plans to direct to projects that have the greatest potential to benefit its customers. For example, will these expenditures come from the $250,000 planned annual expenditures for this program or another source? If these expenditures will come from the $250,000, how much of these dollars will be under the control of KEDNY? If they will come from another source, explain where they originate from.

Response:

1. Please see below:

KEDNY Research and Development 2011 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$128,170	$0	$128,170	$0
NYSERDA	$1,745,995	$1,807,190	$1,745,995	$0
Millennium	$1,282,501	$1,232,890	$1,282,501	$49,611
Total	$3,156,666	$3,040,080	$3,156,666	$49,611

KEDNY Research and Development 2012 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$81,561	$0	$81,561	$0
NYSERDA	$1,456,349	$1,845,141	$1,456,349	$0
Millennium	$1,184,936	$1,164,547	$1,184,936	$20,389
Total	$2,722,846	$3,009,688	$2,722,846	$20,389

KEDNY Research and Development 2013 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$105,592	$0	$105,592	$0
NYSERDA	$1,465,455	$1,797,772	$1,465,455	$0
Millennium	$687,730	$1,875,017	$687,730	($1,187,287)
Total	$2,258,777	$3,672,789	$2,258,777	($1,187,287)

KEDNY Research and Development 2014 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$187,805	$0	$187,805	$0
NYSERDA	$814,840	$1,835,525	$814,840	$0
Millennium		$2,559,962	$766,988	($1,792,974)
Total	$1,002,646	$4,395,487	$1,769,633	($1,792,974)

KEDNY Research and Development 2015 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$78,944	$0	$78,944	$0
NYSERDA	$1,995,469	$1,835,525	$1,995,469	$0
Millennium	$1,010,897	$799,032	$1,010,897	$211,865

Total	$3,085,311	$2,634,557	$3,085,311	$211,865

Total Program Accruals are $0 for Internal Programs and NYSERDA as these are not subject to true-up

2. Please see below:

KEDNY Research and Development 2016 Revenues and Expenditures				
	Program Budget	**Revenues Collected**	**Actual Expenditures**	**Total Program Accruals**
Internal Programs	$64,122	$0	$64,122	$0
NYSERDA	$1,995,469	$1,835,525	$534,309	$0
Millennium	$1,422,351	$0	$820,785	$820,785
Total	$1,422,351	$1,835,525	$820,785	$820,785

Total Program Accruals are $0 for Internal Programs and NYSERDA as these are not subject to true-up

3. Current internal R&D is focused on short term research (worked expected to be 24 months and less duration) and technology to improve gas distribution operations in the areas of safety, cost-effective operations, damage prevention, reliability and environmental performance. As such, this research almost exclusively supports the development of technologies for deployment on the Company's side of the meter (*e.g.*, threat risk model improvements, cured-in place liners technology transfer and trenchless service replacement prototype) not end-use utilization. National Grid's Three Year Research, Development, and Demonstration Report (Attachment 2) discusses these programs in more detail.

   The United Technology Development (UTD) program is focused on supporting the development of technologies for application on the customer side of the meter that utilize natural gas, including technologies to improve the energy performance of customers' buildings or processes with natural gas in terms of life-cycle costs, reliability and environmental performance. The technologies are of interest to National Grid because they support the expanded use of natural gas, including advanced residential applications, distributed generation, commercial HVAC applications such as thermal air conditioning, natural gas vehicles, commercial process such as foodservice, and renewable technologies. For example, there are more than 7,200 foodservice businesses in the KEDNY service area. Attachment 3 is a 2010 GTI assessment of the energy challenges and technology opportunities in the foodservice industry in areas served by National Grid.

4. The $250,000 to participate in the UTD program is proposed to be included in KEDNY's revenue requirement as an annual operating expense. This is the only funding for gas end-use R&D (other than the internal labor to manage National Grid's participation).

The UTD program is managed by the Gas Technology Institute (GTI). Each member company appoints a representative to the Board of Directors and a member of the technical program committee.

Individual project proposals are initially developed by the GTI staff based on their review of relevant technological opportunities and needs. In some cases, projects are conceived by the member companies. For each project identified, the members of the program committee allocate a portion of their company's dues to the projects of interest to their company. A member's funds can only be allocated by a member's vote. Projects that receive sufficient interest, by virtue of the total funding allocated, proceed and those that do not achieve the required minimum funding do not proceed and those funds are available for re-allocation. National Grid's representatives will be responsible for allocating funds to projects that have the greatest potential benefit to KEDNY's customers or for proposing projects if none are sufficiently relevant.

One of the benefits of the UTD program is the ability, on a project-by-project basis, to leverage the funds of other companies with similar customer benefits and also to leverage external funding from federal or state research programs, such as the US Department of Energy or NYSERDA. Co-funding is usually a requirement or a factor in scoring for DOE or NYSERDA funding and, by pooling funds, the UTD program makes it easier to achieve the minimum required co-funding.

Name of Respondent:	Date of Reply:
Chris Cavanagh/Mary Holzmann	April 21, 2016

nationalgrid

Tae Kim
Associate Counsel
Legal Department

April 5, 2016

VIA ELECTRONIC DELIVERY
Honorable Kathleen H. Burgess, Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223

Re: Case No. 98-G-1304 - National Grid's Three Year Research, Development, and Demonstration Report

Dear Secretary Burgess:

The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, and Niagara Mohawk Power Corporation d/b/a National Grid hereby submit for filing their Three Year Research, Development, and Demonstration Report.

Please direct any questions regarding the enclosed report to Mary Holzmann, Principal Engineer – Gas Research, Development & Deployment at (631) 770-3449 or mary.holzmann@nationalgrid.com.

Respectfully submitted,

/s/ Tae Kim
Tae Kim

Enc.

One Metrotech Center, Brooklyn, NY 11201
T: 929-324-4550 ■ F: 917-310-0132 ■ Tae.Kim@nationalgrid.com ■ www.nationalgrid.com

National Grid

Three Year RD&D Report

Prepared for

**New York State
Public Service Commission**

Albany, NY

Prepared by

**Mary Holzmann
Principal Engineer
Gas RD&D**

April 2016

Introduction

National Grid distributes natural gas to 2.5 million customers in Nassau and Suffolk Counties on Long Island and in Brooklyn, Staten Island and parts of Queens in New York City, and large portions of Upstate New York, including the cities of Albany and Syracuse. National Grid also distributes natural gas to 1.2 million customers in Massachusetts and Rhode Island.

In addition to its gas distribution business, National Grid owns and operates electric generation in Nassau and Suffolk Counties of New York State and also distributes electricity to customers in Upstate New York, Massachusetts and Rhode Island.

Goals of the RD&D Program

National Grid's Gas Research, Development & Demonstration (RD&D) program is designed to improve distribution operations. Targeted operations improvements involve enhanced public safety, cost reductions, improved worker safety, environmental and regulatory compliance. Within these broad areas, National Grid's ongoing research program focuses on the following technical categories:

- Damage Prevention. Technologies that allow the accurate detection of hard-to-find underground facilities such as plastic pipe with inoperable tracer wire, sewer laterals, or joints on cast iron systems. Technologies that warn of impending damage to underground gas facilities, or detect obstacles in the path of directional drilling machines
- Leak Location. Technologies that allow quicker, more accurate and less costly detection of leaks.
- Integrity Management. Various technologies to facilitate National Grid's compliance with the Pipeline Safety Improvement Act of 2002 and subsequent pipeline safety regulations which includes robotics, cased-pipe, material verification and integrity, improvements in asset tracking and traceability, TIMP and DIMP, crack detection, plastic pipe, and other risk and pipeline integrity management challenges.
- Live Maintenance and Repair. Live Repair technologies eliminate customer downtime by allowing repairs with gas mains in the live, operating condition.
- Trenchless Technology. Techniques that allow pipelines to be rehabilitated with minimal excavation.
- Gas Quality. The Company is engaged in various research projects to help prepare us for the expected changing picture in gas supply. The research is focused on the potential impacts that new supplies may have on our infrastructure and our customers.
- Environmental Technologies. New technologies that could be brought to bear on methane and advanced leak detection methods, residential methane sensors, manufactured gas plant (MGP) site remediation, monitoring, and other projects related to climate change.

- Infrastructure Support. Various projects targeted in improving infrastructure operations, corrosion control, construction and the tracking and traceability of underground assets.
- General Operations Improvement. Various projects targeted at improving operational safety, efficiency and/or worker ergonomics.
- Metallurgy, Welding, and Joining Process Improvements.

Projects active during the past three years within these categories, are described in the body of this report.

Execution of the Program

Most RD&D projects within these program areas are performed with a high degree of collaboration via the following research consortia:

NYSEARCH
NYSEARCH, whose members consist of 19 local distribution companies (LDCs) and one Pipeline Company in North America, is the research sub organization of the Northeast Gas Association (NGA). The NGA is a regional trade association focusing on education, training, research and development, operations planning and increased public awareness on natural gas in the Northeast US. NGA member companies collectively serve 9.5 million customers in eight states. NYSEARCH was originally created as a committee within the former New York Gas Group but has since become national in scope. In addition to the Northeast, NYSEARCH membership comes from the Middle Atlantic States, Mid-West and the West Coast and Canada. NYSEARCH focuses primarily on Operations projects. The NYSEARCH Staff of four project managers manage an active portfolio of projects within the program areas above. Member LDCs join projects at their discretion, commit funds according to their size, act as project advisors, and may host field demonstrations. For the NYSEARCH program, the Company's budget is set by first analyzing the projects that are approved. The project schedules are then established and a spending forecast is developed jointly with NYSEARCH. The company may contribute "in-kind" expenses towards a project in the form of field demonstrations and those costs are also considered. If a new project is still awaiting approval, a forecast is made of projected spending, again in conjunction with NYSEARCH.

Operations Technology Development (OTD)
OTD consists of 25 LDCs throughout North America and is an Illinois based not-for-profit (NFP) company administered by the Gas Technology Institute (GTI). GTI also performs project management services and researches about half the project portfolio. OTD focuses on operations projects. OTD Member LDCs join projects at their discretion, commit funds as they deem appropriate, act as project advisors, and may host field demonstrations. The OTD business model calls for an up-front pre-determined (based on company size) payment of annual dues each calendar year. For the OTD program the Company's annual dues are $750,000. As projects are approved they are funded by the annual dues. Unused funds can be used to offset the following year's dues. The company exercised this option for 2012.

A sub-program within OTD, the Sustaining Membership Program (SMP) is a longer term GTI program focusing on basic science, which usually results in a proof of concept that which is further developed in the OTD program. National Grid terminated its participation in the SMP program effective January 2013.

In some cases, National Grid may choose to enter into development contracts with research providers jointly with other LDCs or by ourselves.

NYSERDA

The Company is currently assessed an annual amount of approximately $4.9 Million for the NY State Energy Research and Development Authority (NYSERDA). The assessed rate is based upon NYS Intrastate Revenue – (Sales for Resale and Transmission for Others). The Company has no say in which projects are funded through the NYSERDA program. However, the company monitors the various NYSERDA Project Opportunity Notices (PONS) and may elect to submit a proposal to NYSERDA for cofunding a Company RD&D project.

Funding

Part of National Grid's ongoing RD&D program is funded via the "Millennium" Fund and surcharge, authorized by the New York Public Service Commission's February 14, 2000 Order in Case 99-G-1369 (the "Millennium Order") to replace the mandatory FERC pipeline research surcharge. A maximum allowable collection rate of $0.0174/dekatherm on firm transportation and sales is the source of funding for the program. National Grid currently collects $0.0067/dekatherm from its KEDNY operations and $0.0000/dekatherm from its Long Island and Upstate Operations. The winter of 2014-15 was unusually cold with extended periods below freezing. This caused the collection rates, which are tied to dekatherm usage, above the current spending levels for a period of time. Additionally, a great deal of R&D focus has been on residential methane detectors which is not being funded through Millennium but is being funded via company funds through the Long Island Settlement Agreement instead. So we have decreased the collection rates in KEDLI and NMPC in order to levelize balances with current R&D commitments. Since the last report, the changes in spending levels are in part due to National Grid Downstate has been funding the majority of the development of the Explorer 16/18 inch internal inspection robot for un-piggable pipelines in this range of larger diameter transmission piping. While this project benefits our Upstate territory, the larger share has been funded through the Downstate surcharge due to the larger inventory of 16 inch un-piggable pipe there. More recently, projects looking into the use of drones in gas operations will be of greater potential use in our Upstate NY area which will shift R&D investment dollars to Upstate as that work progresses.

Unlike the phased-out Federal Energy Regulatory Commission (FERC) surcharge, the Millennium fund is controlled by National Grid and spent on eligible projects via NYSEARCH, OTD, GTI or other research providers at National Grid's discretion. As specified in the Commission's Millennium Order, in order to qualify for Millennium funding a project must be medium to long term in nature (i.e., projects that are at least twenty-four months or more from becoming a commercially deployable product); 80% of Millennium funds must be spent on co-funded projects and cannot be directed to fund natural gas appliance research or supply/storage projects. The projected budget for the next three years averages $2.7 Million. The Company realizes a high degree of cofunding from other participating LDCs, and from the US Department of Transportation (DOT) Pipeline Safety Research Program. Because of this, the Company's leverage is about 7:1, meaning for every RD&D dollar we spend we realize seven dollars of overall RD&D funding.

National Grid maintains an internal budget to fund projects that do not meet the criteria set forth in the Millennium Order. The budget is $183,000 and typically funds short term "quick hit" RD&D efforts, association (NYSEARCH) dues, and patent protection fees.

Attachment 1 shows actual and projected spending for the Company's Gas RD&D program, Internal, External (NYSEARCH and OTD) and the NYSERDA Assessment.

Program Management

The management and administration of the operations program is by National Grid's Gas Materials and Standards, group within the Gas Engineering/Network Strategy organization. Subject matter experts throughout the company are used as needed when specific technical expertise is required on projects.

Selection of Projects

The Company uses four criteria to judge the merits of RD&D projects. The first is safety. Some projects are undertaken to enhance the safety of workers in the field, or the general public.

The second criterion is compliance with regulations. An excellent example of this is the transmission pipeline safety regulations. In the Pipeline Safety Improvement Act of 2002, Congress directed the US Department of Transportation to establish and promote a research partnership with industry to develop tools and techniques to improve pipeline safety. Ensuring the highest level of pipeline safety requires tools and techniques that have been developed over the last 10 years, such as the robotics program for internal inspection of unpiggable pipelines.

The third is increased knowledge about gas operations which can lead to increased efficiencies, material improvements and or better techniques for conducting daily operations.

The fourth criterion is financial benefit. The R&D budget is looked at based upon historical spending levels and is adjusted depending upon if there is an increase or decrease in current challenges being addressed and priorities that require research investment are funded. The Company may use a benefit/cost (B/C) ratio test to determine whether RD&D projects should be adopted into our operations. Benefits are the net savings in operational costs that are realized via implementation of new technology. Costs are the project costs to fund and implement the new technology. In some cases R&D studies can also lead to operational savings and the same B/C test applies. However, not all studies have a definitive cost benefit. Studies may lead to increased safety measures or process improvements.

Most projects have multiple benefits, for example, projects undertaken for worker safety can lower injuries and reduce sick time (thereby providing a financial benefit), and compliance with regulations can improve safety of the gas system and the public. A project with a marginal financial benefit may also be approved if it meets one or more of the other criteria.

Benefits

National Grid, in collaboration with other funders, has been involved with bringing the following products or increased knowledge to market over the past few years:

- Keyhole Tools and Methods
- Pipe Splitter
- PFT Chromatograph for Leak Detection
- No-Interrupt Service Transfer (NIST) Tee
- Cured in Place Liner Improvements
- Butt Fusion Repair Sleeve (BFRS)
- 4” and 6” Variable Length PE Repair Sleeve
- Remote Methane Leak Detector (RMLD)
- Studies on Plastic Pipe Performance
- A Full Suite of Live Internal Gas Main Video Inspection Devices
- NYSEARCH/Kiefner Interacting Threats Modeling Software
- Cased Pipe Integrity Assurance Model
- Explosion Proof Light Fixture
- Guidance Document on Biomethane
- Explorer Suite of Inspection Robots for the Inspection of Unpiggable Pipelines – Pipetel Technologies, Inc. EXP 6/8, EXP 10/14, EXP 16/18, EXP 20/26, EXP 30/36, Supporting Technologies and enhancements in detection capabilities
- Cased Pipe Annular Space Inspection Robot
- CISBOT
- Acoustic Pipe Locator
- Metallic Joint Locator

<u>Active Project Discussion</u>

<u>Internal Budget – Non-Millennium – NYSEARCH Projects</u>

Projects that do not meet the criteria set forth in the Millennium Order (i.e., medium to long term and no end use or appliance funding) are funded via National Grid's internal budget. Internal projects (also referred to as Non-Millennium or Traditional R&D) are research that is of short term duration (work that is expected to be completed in less than 2 years) or work that is appliance or storage related.

T759 - Ergonomic Study to Develop and Test a New Design Needle Bar. A needle bar is a manually operated tool used to make small diameter holes, called barholes, in paved or unpaved areas over gas mains to allow pinpointing of leaks. During a typical leak investigation as many as 15-25 such holes may be required. The repetitive up-down motion required when using the tool is often a source of soft tissue injury if the user fails to maintain an upright position when using the tool. An ergonomic needle bar with a ratcheting handle was developed. This tool allows the operator to remain in an upright position for the duration of time it takes to create a barhole. The drawback is that the tool is heavier. Field trials were conducted throughout the National Grid territory and the tool failed to gain universal user acceptance. However, these efforts have stimulated manufacturers to continue working independently working towards more ergonomic tool design. The benefit of this work is a reduction in soft tissue injuries.

T763 - PE Rock Impingement Study. A study was undertaken to determine whether the requirement for clean backfill around polyethylene (PE) pipe could be relaxed given the high resistance to slow crack growth demonstrated by modern PE materials. In many situations, a common practice is to truck in clean, screened backfill in lieu of using native materials, at an increased cost. Testing performed in Europe has demonstrated that modern PE materials have such superior resistance to point loadings that use of select backfill is no longer required. No such testing had been undertaken in the US so, through NYSEARCH, Jana Labs was commissioned to perform the tests. Medium density and high density PE pipe, which is representative of the PE pipe installed now at the Company, were subjected to extreme point loading to simulate contact with rocks which could be present in native backfill. (Test loadings were so severe that the indentation was visible at the interior pipe wall.) The sample pipes were then pressurized and hot tank tested (standard testing protocol – which compresses many years of testing into a relatively short time period). Tests have shown no harmful effects from extreme simulated rock impingement loading and the projected time-to-failure in normal operating conditions is well in excess of 100 years. This work is an excellent validation of the superior toughness of modern PE materials. Significant cost savings have already been experienced in the Company's New York City Operation.

T764 - Auto Gas Lamp Field Evaluation. Working through NYSEARCH, the Company undertook an evaluation of a gas lamp for street lighting that was equipped with an igniter and a photo sensor which would shut off during daylight hours and reignite in the evening. Independent testing confirmed that the lamp and igniter system performed well in lab testing and several lamps were deployed in funders' territory. The benefit of the project is a savings of natural gas during daylight hours, a corresponding reduction of CO2 emissions, and improved customer relations and satisfaction.

T765 - Gas Interchangeability Study for Installed Residential Appliances. The addition of new gas supplies (imported LNG, unconventional gas) is expected to accelerate, leading to wider ranges of natural gas compositions. While the industry is expanding supply sources, to date there has been no standardized approach for evaluating the impacts of varying gas compositions on in-service residential gas appliances. The benefits of such a study are to determine the extent to which potentially sensitive appliances exist and to identify which specific appliances are affected based on type, vintage, adjustment practices, and maintenance characteristics. With that information, better decisions can be made about whether adjustments are necessary to those appliances in order to successfully accommodate varying gas compositions. The project consists of two phases; in Phase I, over 2400 appliances were visited in the field and firing rate, percent excess air, CO and NOx formation were measured and flame quality was observed. In Phase II, lab testing was performed on selected appliances (about 20) subjecting them to a wide range of future expected gas compositions to determine their performance. This phase of the study yielded important information about how typical appliances will perform over a wide range of gas compositions and benefits the company by allowing it to more effectively negotiate future tariffs and plan for remedial actions for more sensitive appliance types. This work is nationally recognized. Project results have been shared with the American Gas Association (AGA) and key findings will be incorporated into the next revision of “Bulletin 36,” which addresses gas interchangeability concerns. Based on the results of this work an appliance assessment software tool is now available on the NYSEARCH website. NYSEARCH RANGE™ is one of the deliverables of the NYSEARCH Gas Interchangeability for Appliances project which studied and modeled how changing gas composition can impact the performance of in-service residential appliances. This risk assessment model is available to purchase for on-line use.

T766 - Technology Transfer Improvements. An ongoing study to investigate specific member lessons learned with successes and failures of technology transfer and to share procedures so that more companies can be successful with a process for cultivating company support and longevity in implementing new technology

T768 - NYSEARCH/Kiefner Interactive Threats Project. The project defined and prioritized interacting threats that impact pipeline integrity. A more robust treatment of interacting threats was incorporated in risk models. To ensure that the NYSEARCH/Kiefner Interacting Threats model stays current, PHMSA's annual incident and Kiefner's forensic failure databases are being checked and incorporated into annual software version upgrades.

T769 – Test Program for Picarro Leak Surveyor. In early 2012 the Company became aware of a new technology for leak survey manufactured and marketed by Picarro Corp. The technology is vehicle mounted laser based sensing of methane at sensitivity levels never achieved before by standard leak detection technology. Methane at 30 parts per billion (PPB) above background concentrations can be detected. Along with methane sensing, this vehicle based technology also records atmospheric conditions such as wind speed and direction, temperature, humidity and cloud cover. When methane is detected

the Picarro technology plots out an area that should be investigated and pinpointed. The area to be investigated is based on the methane concentration that was detected, and the atmospheric conditions, such as wind speed and direction. This gives operators a good idea from which direction the methane is coming.
Through the NYSEARCH consortium, the company and others wanted to do a side-by-side comparison of Picarro technology to existing distribution leak survey methods in use at the Company. A double blind test protocol was established and for two days the standard company leak survey procedure – which is a walking survey using Bascom Turner "Rover" leak detector – was run on the same days on the same streets as the Picarro mobile survey technology. Results of the comparative surveys for the Company and other project participants have been compiled. No report can be released due to legal agreements with Picarro. This project was completed in Nov. 2014.

T-770 - Technology Transfer, Demonstration & Post Mortem Testing of Cast Iron & Steel Pipe Lined with Cured-in-place Pipe Liners. See details under Live Inspection, Maintenance and Repair section.

T-773 - Trenchless Replacement of Small Diameter Steel Gas Service Lines. See details under Trenchless Technology section.

T-774 - Impact of Gasoline/Oil on PE Pipe. The objective of the project is to understand the impact of external contaminated soil conditions on the external surfaces of PE pipe and develop a practical engineering and operator's guideline that provides specific instructions for evaluating in-service PE pipe exposed to contaminated soils.

National Grid Study on Risks Associated With Natural Gas Appliances Immersed In Water. Flooding and flood damage are not unusual events in the United States (U.S.). According to the National Oceanic and Atmospheric Administration (NOAA) and the National Weather Service (NWS) data, annual flooded property losses exceed $7.8 billion on average during the past thirty years. Major episodic events such as Hurricanes Katrina and Sandy can substantially raise losses and place substantial strain on natural gas and electric utility operations due to the extensive damage done to delivery infrastructure and customer equipment. This study was undertaken to help qualitatively assess the failure modes and potential risks associated with natural gas appliances immersed in water for extended periods. Survey questions were used to facilitate interaction with several natural gas furnace, boiler, and water heater manufacturers.

In general, funding for "internal projects" is used to pilot new products and technology—e.g. keyhole, live main insertion, leak sealants, or to perform short term studies. Any appliance related work would also be internally funded.

<u>Millennium Program</u>

NYSEARCH and OTD Projects

Damage Prevention and Pipe Location

According to the US Department of Transportation (DOT), third party damage is the primary cause of pipeline incidents on LDC distribution systems, accounting for over one third of all reportable incidents. Repair costs due to Third Party Damage are estimated at $10 Million annually, and often result in loss of service to customers. National Grid is funding the following efforts:

M2001-005 – Handheld Pipe Locator using Ground Penetrating Radar (GPR). GPR is high frequency electromagnetic radiation that has proven capabilities to detect underground features but no hand held GPR device existed. The goal of the project is to develop a user friendly GPR device that can be deployed by field crews when standard locating technology cannot precisely locate suspected underground facilities. A portable, light-weight free scanning plastic pipe locator for use by LDCs and construction crews to identify the lateral position of hard-to-find plastic pipe (can also locate other metallic pipe). The target application for this technology is plastic pipe with inoperable tracer wire. Such pipe cannot be located by standard "clip-on" locating technology. The product has been designed, developed and tested. NYSEARCH worked with Pipehawk LLC, a UK company, to develop the technology but attempts to commercialize it in 2006 were unsuccessful. Difficulties arose when attempting to transfer this product to a commercializer for engineering improvements (such as ergonomics) and preproduction testing. Another potential commercial partner, Sensors and Software, a recognized leader in both development and manufacture of GPR locating equipment, had been engaged to explore potential commercialization. This contractor is now assessing the feasibility and potential market for this technology. A successful device would provide company crews with the ability to quickly locate plastic pipe without tracer wire. After multiple attempts with a selected contractor who had interest in commercializing, no additional work or funding was promoted.

M2002-011 PhIII - FFT Damage Prev Monitoring - Advances with Aura. Damage Prevention and particularly proactive monitoring for third party intrusion near transmission and distribution pipelines is a high priority for many gas companies. Due to interest expressed by members in revisiting the FFT's fiber optic intrusion detection system, and in particular its advanced system known as Aura™, NYSEARCH renewed this project (renewing the former FFT project that worked with the Secure Pipe product) to test this higher resolution distributed sensor product as it applies to two different test sites with different conditions; one at Woodbridge NJ in PSEG's territory and one in Ontario in Enbridge's territory. Tests and results are finalized. Final Reports for PSEG complete; final report for Enbridge work pending.

M2002-018 - Proactive Infrasonic Sensor This system consists of seismic sensors that can be installed near critical gas mains or other facilities and can sense activity near those facilities and send a warning to a control center or other company facility. The system is "trained" to distinguish benign threats (truck traffic, etc) from real threats. Comparable systems on the market now differ in one important distinction; they all require physical contact with the sensor, this system will detect activity as far away as 300 ft. Benefits of this project are reduced incidences of third party damage and associated repairs.

M2007-007 Advanced Video Surveillance (A-Gas) System. This project uses a video image approach to detect possible third party damage. Standard video cameras are trained on an area of concern and proprietary software is used to "learn" the scene so that normal activity can be discounted but abnormal activity alarmed. The A-Gas system is available for security applications. The research component of this project is to adapt the technology to the new concept of advanced warning to LDC operators of potential third party damage. In a second phase of the project we are working with the vendor to develop an environmentally hardened version of the camera/software system which can be mounted outdoors without any special environmental enclosures. The benefits of this project are reduced incidences of third party damage and associated repairs.

M2008-001 – Advanced Development of PipeGuard™ – Proactive Pipeline Damage Prevention. This system by Magal/Senstar is technically similar to the Proactive Infrasonic Sensor system but is a commercially available system that is used for security applications. The goal of this project is to adapt this security based technology for use in the natural gas industry to be utilized in an underground surveillance mode to detect occurrences at or near the surface to alert the operator of third party activity, presumably excavation, in the vicinity of the installed sensors. This project includes the evaluation of a geophone-based pipeline monitoring capability that will warn an LDC of impending damage to pipeline facilities. Following the initial technical feasibility assessment, through NYSEARCH, the Company is hosting a demonstration site on Long Island to test this technology adaptation. The target goal for detection alarms for backhoe, pneumatic piercing tools, and pavement breakers is 250 feet from the sensing units. This will provide total monitoring coverage of 1000 feet along the pipeline run when two sensing units are installed. It is expected that detection distances for shovels and manual post-hole digging tools will be significantly lessened. Benefits of this project are reduced incidences of third party damage and associated repairs through proactive monitoring in advance of actual work performed by a third party.

M2011-005 – Fiber Sen System Development and Testing In the last 10 years advanced damage prevention technologies using fiber optic cable have been marketed. Most of these technologies are suitable for extremely long lengths of transmission piping and one system even uses satellite transmission of data to a central monitoring site in Europe. Systems such as this do not meet the needs of the Company. Through NYSEARCH, the Company became aware of Fiber SenSys Inc., who is interested in developing a shorter version of existing technology which would be more applicable to the needs of distribution companies.

Fiber SenSys proposed to develop a fiber optic cable which can be installed parallel to an existing gas transmission main, or alternately the cable can be incorporated into a new main installation. The system functions by detecting vibrations in the soil around the pipeline. The vibrations alter the characteristics of the laser light in the cable and can be detected and alarmed. Requirements are that the system be able to detect presence of commonly used excavation equipment, while recognizing and filtering out other acoustic signals that would be generated by benign threats such as truck or rail traffic. The system must perform in all types of soil that can commonly be encountered in the Company's territory. A NYSEARCH member company has offered a test site where a prototype system can be installed and tested. The target cost of the system, depending on length monitored, would be as low as $3000 per mile. The benefit to the Company is enhanced damage prevention and potential avoidance of a major pipeline accident due to third party damage. This project expanded on lessons learned from a prior project related to proactive monitoring for third party damage using fiber optic sensors. The project developed a system for shorter runs of pipe based on the contractor's (Fiber Sensys's) system for longer runs of pipe. The 'short ranger' system was tested and evaluated for gas distribution applications and its technical and economic feasibility was studied.

M2011-008 – BioBall Test Program. A NYSEARCH member company has worked with a technology company to develop a simple technical approach to accurately locate sewer laterals. The technical approach is to simply wind a length of copper wire on to a biodegradable "spool" which can be flushed down a commode in a residence. The wire will unspool and standard locating equipment can be connected to it and the location of the sewer lateral can be determined. NYSEARCH member companies want to determine whether the idea is feasible and have funded a test program. The Company has conducted a week long field test program on this technology. Results were mixed; in many cases gaining access to the residence was problematic. In those cases access to the sewer lateral was through an outside cleanout. Where the bioball did deploy successfully, location of the lateral was determined within +/- 2 ft. Interest in this project is high because of a concern with "crossbores," in which pipe installed via directional drilling inadvertently punctures a sewer lateral. The situation may not be detected for years until the sewer line clogs and a plumber is called by the homeowner, with potentially disastrous results.
The benefit of this technology is accurate location of sewer laterals and subsequent avoidance of a crossbore.

OTD 1.8.a - GPS-Based Excavation Encroachment Notification This project focuses on linking Global Position System (GPS) technology with digging operations to provide a warning system to prevent excavation damages to underground facilities. The objective is to develop and demonstrate a system to ensure that excavation activities are occurring within a valid "One-Call Ticket" area (which authorizes excavation) and are not encroaching upon underground pipes and facilities. The Company and other project funders are partnering with Virginia Utility Protection Service (VUPS), a "one-call" center for utility locates, that has been conducting pilot programs to demonstrate the feasibility of using GPS-enabled cell phones (Phase 1) and GPS-enabled locators (Phase 2), and excavating equipment (Phase 3) to call in excavation projects, access information, and prevent unauthorized excavations. The benefits of this project are more accurate and smaller "white-line" (areas needing markout) areas, more accurate locating, and warnings to excavators if they are excavating in unmarked areas. All of this reduces the threat of third party damage. The company is participating in a follow on project to implement a similar pilot program in upstate NY.

OTD 1.h and 1.10.c – Hand Held Acoustic Pipe Locator. Plastic pipe without tracer wire remains a vexing problem for LDC locating crews because standard electromagnetic locating techniques will not detect plastic pipe. Ultrasonic waves are ideally suited for this application because they will travel well through solid mediums (soil) but are reflected off of voids, air pockets or lighter density materials. The acoustic locator has shown that it can reliably detect plastic pipe. A follow on to this project (described next) will target location of sewer laterals, an important issue lately as more LDCs are using directional drilling to install gas mains. Accurate location of our buried facilities is the main benefit of this project. Completed 2013.

OTD 1.10.e – Enhancing Damage Prevention in New York. The objective is to conduct a pilot project to demonstrate the procedures and technologies for implementing an electronic as-built process and radio frequency (RF) tag based asset locating system. The proposed technology will automate the as-built process by using new high-accuracy GPS technology and aerial photography to document the location of newly installed facilities. RF tags will be used to enhance the locating and mark-out process by providing field personnel with additional asset location information. Phase 3 will develop a prototype system that allows the collection of highly accurate spatial data in urban canyons where traditional GPS technology is ineffective.

OTD 1.11.e - Crossbore National Database and Risk Model. As crossbores, where a natural gas line installed via trenchless construction methods, has penetrated a sewer main/lateral. For example, homes with sloping front yards and no basements may have sewer laterals that are close to the surface and therefore more likely to be intersected by a horizontal directional drilling operation. The objective of this project is to gather as many parameters as possible associated with crossbores actually identified in the field. In addition to the Company, other LDCs are gathering data on crossbores. There has not been a unified effort nationally to collect this data. By combining this data into national database users can identify those situations and field conditions where crossbores are more likely to occur in its own territory, and can prioritize and focus remedial action on the highest risk areas. The purpose of the database is to collect information on crossbores root causes, environmental and situational factors, and compile incident reports to facilitate the sharing of lessons learned and increase public safety.

OTD 1.12.b – Crossbore Detection Using Mechanical Spring Attachment
In the concluding phase of OTD 1.11.a, “Evaluation of Chemical Detection Methods for Detecting Sewer Lateral Crossbores,” one of the project funders suggested a brainstorming session for innovative ideas to detect crossbores. The leading idea is to use a simple spring loaded sensor on a drillhead that would “snap open” upon encountering a void, such as would happen if the drillhead suddenly penetrated a sewer lateral.
GTI engineers will design and test a prototype tool that will detect a hit to sewer laterals during the HDD or mole installation of PE gas pipe. The tool utilizes a low-cost and easy to use mechanical system that is attached to the HDD/mole head during drilling or to the PE pipe during pullback. The mechanical system is activated inside the sewer pipe void; thus locating the lateral and providing a real-time alarm identifying a hit. At the conclusion of the project, commercialization activities will begin. A simple yet accurate

method for detecting a crossbore in this fashion is a tremendous benefit to the company because crews are present to immediately rectify the situation.

Leak Detection and Methane Emissions

Rapid and more accurate leak detection and location (pinpointing) has always been a research focus for the industry and for National Grid in particular. We are funding the following efforts:

M2010-002/T-776 – Methane MR Sensor/ new Residential Methane Detector Development Program. NYSEARCH/NGA has been developing a small, reliable, intrinsically safe, line and/or battery powered, miniature methane (natural gas) sensor based on micro-resonator technology that measures the viscosity of a gas mixture. The sensor would be used in detecting natural gas leaks and other applications. The instrument is being developed for two applications; an analytical sensor for measurement with data output, and as an improved safety sensor for use in residential applications. Due to the high reliability and resistance to false alarms, this program has shifted its focus entirely to the residential sensing application. Following extensive testing of advanced prototypes, precommercial prototypes are being tested by UL and a pilot test program is being implemented following completion of UL testing. This project has produced a novel type of methane sensor using the principle of micro-resonance. The theory behind the sensor is that micro-size tuning forks will vibrate at different frequencies when exposed to a methane/air environment than it would in free air. This concept was uncovered during a technology search undertaken as part of the “Oracle” project. After extensive testing it has been found that this methane sensing device does not exhibit false positives in the presence of many household chemicals which is makes it superior as safety device over currently commercialized devices. It has not demonstrated any false positives.

The sensor is capable of measuring the methane concentration from 0% to 100% in air at different pressures, relative humidity levels and in a wide temperature range. The measurement range of primary interest corresponds to 0-100% Lower Explosive Limit (LEL) with the ability to measure gas concentrations up to 100%. [LEL for methane corresponds to approximately 5% methane/natural-gas concentration in air.] The sensor has a detection limit and an accuracy of 0.25% natural gas concentration in air. The sensor is capable of operating at various gas gauge pressures ranging from 30 to 110 kPa and temperatures of -20°C to 50°C. The response time of the sensor is targeted at 1 second or less. To verify and validate the performance of the MR Methane detector (safety sensor/alarm monitor) a pilot testing program will be implemented. Detectors will be deployed in residential settings to test them under real life conditions under a variety of operational conditions and environments. The following issues will be addressed: (a) having a sufficient number of installations, (b) covering a wide range of housing types, (c) evaluating different detector locations within the homes, (d) selecting locations that expose units to possible interfering chemicals (e.g., masking, false positive) and potentially damaging conditions (e.g., humidity, temperature, chemicals, insects), (e) considering the impacts of ventilation rates and air flow patterns in homes, (f) monitoring performance in all seasons, (g) monitoring performance at various elevations, and (h) validating detector performance before, during, and after the field trial.

M2014-002 - Leak Pinpointing Inside Pipe. The overall program goal is clear to design, develop and test an innovative system that can precisely locate gas leaks from inside the pipe. The selected technology needs to apply to a range pipe sizes, 2” – 12” in diameter. During testing the experienced JD7 operator inserted the instrument into the flow loop through an ALH/WASK valve fitting after the simulated leak was created and covered. The first round of testing was designed to determine if the JD7 could detect leaks of various sizes and pressures. This initial round of testing was performed without air flow (fans were off). The JD7 proved capable of detecting leaks as low as 6” water column pressure leaking at the rate of 0.12 scf/hr. and at our top simulated pressure of 40 psig with a leak rate of 52.5 scf/hr. The JD7 was also capable of detecting leaks at various pressures and leak rates in between these upper and lower tested limits. A second round of testing was performed. The JD7 was manually inserted down the test pipe and located the leak without knowledge of the leak location. This testing was conducted without air flow and with air velocities of 2.5 mph (one fan) and 12 mph (both fans). The JD7 located leaks at no flow as small as; 1) 0.70 scf/hr. at 12” water column and 20 psig, 2) between 5.23 and 8.33 scf/hr. at 2.5 mph air velocities at both 5 psig and 40 psig, and 3) at 12 mph air velocity with a leak rate of 52.5 scf/hr. at 40 psig. Although initial flow loop testing of the JD7 at Heath was a success, improvements should be made to the JD7 Gas Investigator in a proposed Phase II of this project in order to improve its efficiency of operational performance. These improvements should subsequently be blind tested in a buried flow loop containing simulated leaks with the capability of varying pressures and flows.

M2014-004 - Technology Evaluation and Test Program for Quantifying Methane Emissions. The overall objective of the project is to identify, test and validate what technology or technologies are available that can be applied from a mobile platform in an urban environment to quantify methane emissions rates.

M2015-002 - SRI Standoff Gas Flow Imaging and Analysis System. The overall objective of the approved program is to quantify the flow rate from gas distribution leaks using the schlerien optical imaging technique as applied on a portable, field-usable system.

OTD 1.9.a – GPS Based Leak Survey. The objective of this project is to develop and utilize a software application that automates leak surveying with GPS. Using standard GPS receivers a leak surveyor’s route is automatically uploaded to company maps and a permanent record of the actual route surveyed is created and preserved. The application attaches GPS coordinates to survey routes and leaks while electronically documenting work to demonstrate compliance. The application also allows the user to create and populate an electronic leak form that can be directly transferred to a back-office leak management system or a Geographic Information System (GIS). New leak detection equipment that is on the market will be linked via software to company maps or images to automatically track routes of leak surveyors, thereby creating a traceable record of survey routes walked. The benefits of this project are reduced time for documentation and more accurate record keeping.

National Grid funded an additional phase of the project to conduct an actual field trial of the technology in a select area in New York City. Due to Hurricane Sandy, the pilot was delayed until April 2013 and was completed in August 2013.

OTD 1.11.c - Methane Sensor The goal of this project is a low cost reliable methane sensor for in-home use or use in company facilities (gate stations etc.) to detect and alarm on the presence of methane in air. Instruments are available to do this but typically can be set off by non-methane hydrocarbons which could be present in a house basement, paint thinner or hairspray for example. The testing protocol was designed to test the accuracy and stability of the six KWJ MEMS sensors by testing them at various methane concentrations, different temperatures, different relative humidities, and different interfering gases. In order to execute the testing protocol a testing chamber was designed to monitor and control all of the different conditions. After the completion of several basic testing conditions, the project team concluded that further testing should be terminated. Termination of the testing was recommended for several reasons. Because of our concerns on the path forward of this project, National Grid elected not to continue this effort.

OTD 1.14.d - Field Measurement of Leak Flow Rate. The goal of this project is to develop an inexpensive and repeatable device that can provide a measurement of the gas-leakage rates in the field from Class 2 and 3 non-hazardous pipe leaks. The current phase of the project involves improvements on an alpha prototype and upgrading the technology to provide increased accuracy, precision, lower cost, and ease of use. In 2015, an enhanced prototype was placed in a test chamber and subjected to varying levels of methane at constant temperature and humidity. The prototype is Wi-Fi enabled and presents an access point that the user can log into. A web page is presented that displays the parameters being measured by the prototype and allows control of the sampling fan. This allows access to the prototype through a device that supports Wi-Fi and a web-browser. Additional work was performed in the area of calibrating the Figaro methane sensor that is used in the prototype. The goal is to develop an accurate calibration curve that relates the raw sensor output voltage to % LEL with corrections for temperature variation. The current version of the prototype measures the flow through the device accurately but is somewhat limited in the range of flows achievable. The flow sensor represents a constriction in the measurement path of the prototype. At this time a high-powered fan is required to draw samples through the system. GTI is currently considering replacing the thermal flow sensor with a rotating vane type that would lower the requirement on the fan and consequently on the overall power consumption.
The alpha prototype was demonstrated to OTD at the fall 2015 meeting. — A basic demonstration of the Phase 2 beta prototype is planned for the fall 2016 OTD meeting.

OTD 1.14.g - Residential Methane Detectors Program. In this program, several discrete initiatives are being addressed as tasks, with the initial work being a consumer behavior study to better understand how customers react to potential leaks and the development of a “Fit-for-Purpose” standard for residential methane detectors. This program also includes a comprehensive pilot program to evaluate commercially available detectors that performed well during laboratory evaluations. — A pilot testing program is currently under way, with detectors being placed in residential homes throughout the U.S.

OTD 1.15.e - Triple+ Shutoff Valve Pilot Program. Triple Plus Ltd. has made available the Triple+ NGL™ version 4.0 of its gas leak management system, a product capable of detecting gas leaks and automatically shutting off the gas supply and stopping the leak. The objective for this project is to perform controlled testing of the valve portion of the product. Researchers are collaborating with Triple Plus to evaluate a technology that combines a methane detector with an automatic shutoff valve as a safety solution to prevent risks due to leaks and other events (e.g., hurricanes, earth-quakes, floods). This unit is assembled in-line with existing gas systems. If a gas ball valve is installed, there is no need to cut, replace, or remove existing pipelines or valves. — Plans are being made for a testing program with OTD sponsors.

OTD 5.14.j - Residual Gas Removal - Identify Technologies, Limitations & Best Practices. This effort reviews current and new venting equipment and strategies utilized by gas operators to effect safe and timely extraction of in-ground residual gas. The presence of residual in-ground gas poses hazards to the public and nearby infrastructure, complicates leak pinpointing efforts and obfuscates effectiveness of performed leak repairs. A lingering presence of odorized gas can also generate secondary leak reports by the public for extended periods after a leak repair has been completed. Numerous equipment and strategies for venting and dispersing residual in-ground gas exist. A number of field visits to residual gas mitigation job sites were made to evaluate current practices and provide best practice guidance to the industry. In light of findings from industry surveys and sponsor discussions, the frequency of residual gas mitigations requiring more than natural venting strategies such as that provided from barholing, trenching or the use of vented manhole covers, was significantly lower than anticipated. Other traditionally employed devices such as aerators and air movers, that utilize pneumatic power to generate suction via the Venturi principle, are highly effective in the bulk of residual gas extraction scenarios. Though ultimately dictated by local soil and site conditions, the need to utilize dedicated or higher flow capacity vacuum extraction approaches is minimal and reflected by slow market uptake of specialty equipment such as Vapor Extraction Unit (VEU). Safety aspects and some factors dictating how best to elevate extraction efforts in dealing with persistent in-ground gas indications at the site of repaired leaks are summarized in the project report. Due to the low frequency of this issue and demonstrated effectiveness of the most simple, low cost strategies in the majority of residual gas removal scenarios faced by operators, it was agreed that there is no need to propose follow-on quantitative evaluation of techniques as of Q1 2015.

OTD 5.14.w - Testing Program for Valve with Water Sensor for Storm Hardening. In this project, researchers are evaluating a valve integrated with a water sensor to assist with storm hardening. Phase 1 testing was completed in 2015. Additional phases will be addressed based on development status and needs of the project sponsors. Evaluations involve a battery of tests, including: visual tests, pressure tests, debris tests, water-intrusion tests, corrosion tests, humidity testing, drop tests, and others. — A Phase 1

Final Report was issued in August 2015. Additional work continues in the development and addition of methane sensor to couple with the valve actuator.

OTD 7.15.b - Remote Gas Sensing and Monitoring for First Responders. The safety of workers, first responders, and the general public will be greatly increased by being able to monitor the atmosphere of buildings and other structures remotely. In addition, continuous remote monitoring of various gas levels during known gas leak situations will allow for better and quicker analysis of the situation. The remote sensors can be placed and/or operated in multiple buildings, sewers, and other structures in the area of the known gas leak. The remote device can wirelessly provide real-time information back to first responders, gas company personnel and others in charge of monitoring and assessing the gas levels in the structures. The objective of this project is to create a device to remotely monitor the level of gases during emergency situations. The device will provide critical information to first responders and gas company personnel, allowing them to determine the concentration of methane, CO, and possibly other key indicators inside buildings, sewers, and other structures from a safe distance.

Integrity Management

The passage of the 2002 Pipeline Safety Improvement Act – which required detailed assessments of all pipelines operating at 20% or higher of specified minimum yield strength (SMYS) - is the driver for this research for National Grid. National Grid is funding innovative research in the areas of wall loss sensing for unpiggable pipelines and novel methods to assess the condition of cased pipe. These challenges have resulted in the Integrity Management area being the largest R&D spending area for National Grid. Within the overall category of Integrity Management there are three project areas:

Robotics: In line Inspection (ILI) using smart pigs is considered the most desirable method of pipeline inspection among the three methods (In line inspection, Direct Assessment, Hydrostatic Test) specified by the US DOT’s Pipeline and Hazardous Materials Safety Administration (PHMSA), yet many of National Grid’s older transmission lines are not piggable. To meet this challenge we participate in the NYSEARCH Robotics program which is developing robotic, self powered sensors for 6” through 36” transmission pipe. These inspection tools are battery powered and are launched “live” into the pipeline and communicate via wireless signal. Pipe wall thickness measurements are either remote field eddy current (RFEC) sensing or magnetic flux leakage (MFL) sensing. The robotics program has received significant support and cofunding from the USDOT and other industry outside NYSEARCH; to date about $8 million has been received from the USDOT alone. The benefits of this technology investment is pipeline safety, ILI, as mentioned, is the most desirable of the three mandated inspection methods, and savings can be considerable, though highly site specific. In this reporting period the Company has funded the following projects:

M2001-014 - Explorer 2026 Robotic Inspection System for Unpiggable Pipelines using Magnetic Flux Leakage (MFL) Sensing. Explorer 2026 is a live entry, battery powered untethered robot designed to enter and inspect transmission pipelines 20 in. through 26 in. diameter at pressures up to 750 psi. Wall loss measurements are by industry standard MFL sensing. The design of the robot and sensor specifically overcomes the restrictions that cause a pipeline to be designated “unpiggable.” These restrictions include short radius or back to back elbows, mitered bends, presence of plug valves (these are valves that do not have a full diameter opening and won’t allow a typical pig to pass through) or no/low flow conditions. The robot is launched “live” into a pipeline and travels under its own power along the pipeline taking wall thickness measurements along the way. Explorer 2026 is fully developed and has completed two of three field demonstrations at host LDC sites. It will be in full commercial operation later in 2013.

M2003-009 - Explorer 6/8 (Explorer II) Robotic Inspection System for Unpiggable Pipelines using Remote Field Eddy Current Sensing (RFEC). Explorer 6/8 is a live entry, battery powered, untethered robot designed to enter and inspect 6 in and 8 in diameter pipelines operating at pressures up to 750 psi. Wall loss sensing is through a novel sensor called “Remote Field Eddy Current” (RFEC) sensing. Development of this sensor was itself a separate R&D effort and the sensor represents advancement over state-of-the-art magnetic flux leakage (MFL) sensing. The reason this new sensing technique was developed is that traditional MFL sensing creates high strength magnetic fields and given the small diameter of these pipelines not enough robot power could be developed to overcome these forces and move the robot down the pipeline. The robot is specifically designed to overcome obstacles that traditionally cause a pipeline to be classified unpiggable, such as mitered bends, back to back elbows, and low or no flow conditions. The robot consists of drive modules, steering modules, cameras on front and back, and the RFEC sensing module in the middle. The robot is placed in a specially designed launch tube which is mounted on standard hot tapping equipment affixed to the pipeline. The robot is then launched into the pipeline under live gas conditions and travels down the pipeline under its battery power at about 15-20 feet per minute, collecting wall thickness measurements. After the conclusion of the “pig run,” data is analyzed and a report on anomalies found, if any, is made.

An important part of any R&D project is a serious and robust field demonstration phase. For this project, the Company served as a field demo site at its 6 in dia 473 psi gas transmission pipeline in Oneida, NY. During this 3 day demo, the Explorer 6/8 robot scanned over 4900 ft. of this pipeline and found no anomalies. This scan provided the company with added insurance that there is in fact no corrosion defects present in this high pressure gas main. This robot and its supporting technology has been licensed to Pipetel Inc, a robotic inspection services company in Buffalo NY, and is now in full commercial operation.

M2011-006 – Robotics Supporting Technologies. Modifications are being designed that will allow in-line battery recharging (to extend the range), new sensors to detect cracks, and a “rescue tool” that will allow a disabled robot to be retrieved.
In testing conducted to date, battery life is the factor most limiting the range of the robots. It was realized by the company and others that a more efficient way was needed to recharge the batteries than removal of the entire robot from the pipeline. The technology developer, Invodane Engineering Inc. conceived of an innovative method of recharging

the robot via an "in-line" charging system. A charging cable will be inserted through a small tap on the main and the robot can remain in the pipe while being recharged overnight. Based on recent industry pipeline accidents there is increased focus on sensors that can detect cracks. Although less of a threat than corrosion wall loss, crack sensing is the focus of new development efforts. The benefit of this technology is increased assurance of the integrity of the company's transmission system.

A rescue tool" will be developed that will assist in the retrieval of a failed robot. This will give the company greater assurance that the robots can reliably be placed inside its piping network. On some critical pipelines this may be a requirement before the robot is placed in the pipeline. The project is designing, developing and testing additional sensors to add to NYSEARCH's inspection platform for unpiggable mains. Supporting technologies that are being addressed under this project include mechanical damage sensor/ovality sensor, crack sensor, MFL sensor for 6/8, bend sensor, methods for cleaning the pipe at the launch point and ahead of the tool and methods for in-line active charging as well as a rescue tool for the commercial system. We are also developing and testing a hardness test module to add to the Explorer series of robotic platforms for internal testing of material hardness and yield strength.

M2011-009 – Explorer 30/36 Robotic Inspection System for Unpiggable Pipelines using Magnetic Flux Leakage (MFL) Sensing. The Company and two other LDCs are funding Explorer 3036 which addresses larger size transmission piping inspections in 30" through 36" pipelines. This project is still in the development phase and will incorporate all the features of the existing suite of robotic inspection tools such as live launching, plug valve and short radius bend negotiation, all in pipelines up to 750 psi operating pressure.

M2013-001- Explorer 16/18 - Inspection of Unpiggable Pipelines. This Special Project was an Accelerated Development effort cofunded by Invodane to design, manufacture, integrate sensors and supporting technologies and test prior to commercialization.

M2013-002 - RMD Crack Sensor using Eddy Current Technology. RMD has developed a new eddy current sensor that in early studies has shown promise for detecting crack defects. The new sensor is different from existing eddy current sensors in two regards: (a) it uses solid state technology instead of the traditional coils (which have inherent limitations in providing high accuracy and detectability), and (b) it is easily and inexpensively fabricated in inflexible and flexible substrates using mass production techniques. The combination of these two factors results in an inexpensive sensor with resolution and sensitivity superior to traditional eddy current sensors. This project first proved the feasibility of using their EC technology for the detection of cracks in natural gas pipelines and is now advancing to development and testing as well as integration onto the EXP series of robotic platforms.

Cased Piping: Research into cased pipe assessments is an important part of the transmission pipe integrity management program. Transmission piping placed concentrically within a larger "casing" is a common practice when pipelines pass under major highways, railroads or bodies of water. Assessing the condition of these "carrier" pipes within casings can be difficult if the pipeline is not piggable. The company is involved in several research efforts to address this important issue. The efforts consist of software tools to evaluate casings, and inspection hardware to perform inspections. A very promising technology is "Guided Wave," in which an ultrasonic signal is propagated along a pipeline from a remote location revealing flaws in inaccessible areas of the pipeline.

M2001-003 - Cased Pipe Risk Assessment Model. This project involved the construction of a software tool program that prioritizes casings in terms of relative risk. The program considers inputs including, but not limited to corrosion rate, degree of cathodic protection, presence of moisture and wall thickness of the pipe and categorizes casings in terms of probability of failure. Casings with higher risk scores can be scheduled for further follow up inspections while those with lower scores can be monitored. Consequence of failure can also be added to the model, thereby producing a total risk score, which is the product of probability of failure and consequence of failure. Depending on the degree and accuracy of the data that is input into the model, the model can also calculate time to failure in years. A follow on to this project involved lab and field analysis of corrosion rates in various environments. With this information, a corrosion rate can be entered into the model which would be most representative of actual corrosion expected in the field, and not theoretical (overly conservative) rates. This project benefits the company by allowing it to prioritize inspections of riskier casings first and perform remedial actions, if required, on those riskier casings.

M2007-001 - Mini-camera for cased pipe inspections. This is a crawler camera magnetically attached to the casing. It can navigate down the length of the carrier pipe returning video image of the pipe. The camera has been deployed successfully at several sites and a follow on phase to the project will incorporate ultrasonic sensors for wall thickness readings and humidity gauges to assess the presence of moisture (a key ingredient that can accelerate corrosion). The mini-camera does not, by itself, provide a complete assessment of the carrier pipe condition but is rather another "tool in the toolbox" when used with other assessment methods such as Guided Wave technology.

M2007-003 - Multi Technology Validation Testing for Cased Pipe Applications. This is a testing program for various technologies, which may have promise for inspecting wall loss and other defects on carrier pipes within casings. Technologies tested were guided wave, magnetostrictive sensors (an in-situ type of guided wave), the casing camera, and Time Domain Reflectometry (TDR). Some of the technologies tested are commercially available and some are still in the development phase. The results of this test program gave the company valuable information on to the effectiveness of these various inspection techniques. The two most promising are guided wave and the casing inspection camera. The magnetostrictive sensors were not as sensitive as traditional guided wave, and TDR, although promising, will not be seriously pursued at this time. A new phase of this project has recently been authorized which will focus on more detailed testing of guided wave. All tests are conducted at the NYSEARCH test bed, which is a network of above ground and buried pipe containing machined defects. This is an effective way to compare technologies as all tests are on the same piping components, and defect locations are known only to NYSEARCH staff. However, the company took an additional step and developed a test program for guided wave on its own in-service piping. This project is more fully discussed later in this report.

M2011-007 – Cased Pipe Inspection via Vents. National Grid has had success in its downstate territory with the mini-camera for cased crossings, described above, but the drawback to this technology is the requirement for costly excavations to gain access to the casing annular space at the end seal. An alternate approach is to gain access to the annular space from above ground, through small diameter vent piping which is present on casings. Technology to provide this visual inspection does not exist. The technical approach on this project is to use commercially available camera technology and adapt it to travelling down through the vent piping until it reaches the casing annular space. Through a technology search for new technology providers, NYSEARCH has qualified a small robotics company, Honeybee Robotics, to perform robotics work, and they will perform on this project in a two- phased approach with a go – no/go decision point after Phase 1. Phase 1 will demonstrate the feasibility of adapting existing technology to the task of negotiating the vent piping to gain access to the casing annular space. Such access will be constrained by the small diameter and sharp ninety degree bends that are normally present in casing vent piping. Cleanliness of these vent pipes may also be an issue. If the testing reveals that access to most typical casings can be gained, then the project will proceed to development of a prototype system that can enter the annular space and obtain meaningful information. The benefit is compliance with pipeline integrity management regulations at a significantly lesser cost than traditional means of gaining access to a casing. This project is focused on developing and testing concepts of a compact tethered robotic camera. The successful robotic camera is intended to provide the operator with insight about a cased pipe by gaining access to the annular space through a typical casing vent without requiring excavation.

Other Integrity Management Research

Included here are various projects that contribute to our understanding of, or help us meet, transmission or distribution integrity management requirements.

M2005-003 - Design, Construction & Operation of Regional Test Bed. An above ground and below ground pipe network that has been built specifically for testing new inspection technologies by member gas engineers. This 1200 foot network features different coatings, known anomalies of different sizes, varying soil types, varying welds with good and bad weld practices, different joints and other features for future use on other gas operations purposes. The test bed site is a NYSEARCH/NGA site that is leased from New York State Electric & Gas in upstate New York (Johnson City near Binghamton).

M2007-005 - TransKor Remote Inspection Testing (Magnetic Tomography). The magnetic tomography method (MTM) is a commercial, non-intrusive, above ground method of pipeline inspection developed in Russia by TransKor. Through NYSEARCH, the Company became interested in this technology as an additional "tool in the toolbox" for transmission pipeline assessment. Although other above ground assessment techniques are in use today, they rely primarily on detection of coating failures. MTM measures the inherent magnetic field surrounding a metallic pipeline and detects stress risers in the pipeline by analysis of the pipeline's magnetic field. Stress risers are indicative of wall loss, welds, manufacturing defects, or mechanical damage such as dents or gouges. A test program is underway by the Company and other LDCs who are members of NYSEARCH to thoroughly test the capabilities and accuracy of the MTM. The ultimate goal of the test program is to evaluate the performance of MTM and have it recognized by PHMSA as an "other technology" suitable for transmission pipeline assessment. MTM could provide a significant benefit to the company's Integrity Management plan by providing a much less expensive and more thorough assessment method which requires only a simple walk-over of the transmission pipeline being assessed.

M2009-001 - Holistic Review of Distribution Integrity Management Plan (DIMP) Risk Practices and Models. In 2010 the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued regulations requiring operators of natural gas distribution systems to implement a formal distribution integrity management program. The regulations are not prescriptive and don't require specific types of inspections and assessments as do the transmission integrity regulations, but they require operators to risk rank their distribution system. The Company undertook this project to more fully understand exactly what type of risk modeling may be best suited to analysis of a gas distribution system. Some of the projects' findings suggest that age of the distribution piping alone is not a complete indicator of risk, but other factors such as material type, location, and potential for operator error all factor into a relative risk ranking. Availability of data on the distribution system is also key to developing a reasonable and useful risk model. (For example, although age, material type and location of pipeline segments are certainly known, various component types or specific installation practices are not always known with the same certainty.) Conversely, overloading a risk model with too much specific data does not result in a useful risk tool either.
The final report on the project provides suggestions on a risk management approach and guidelines on making decisions on purchase or development of a specific risk model. The benefit is information and guidance to the company regarding the best method to risk rank its distribution network.

M2012-003 – Enterprise Level Assessment of Data Management Systems. This project addresses a relatively new requirement for gas distribution operations, namely to establish traceability – from initial manufacture to installation – of gas system piping components, and a means to track the location and installation parameters of these components, and integrate this information into existing company data management systems. The best methods of doing this, both from a hardware and software perspective, are being explored in this project. The company is funding this project to gain important information about this new industry initiative, but because we are conducting active field demonstrations via a similar OTD project (OTD 5.11.m) we will only be observers for this project.

OTD 2.11.d - RSD X-Ray. This non-destructive examination (NDE) method has advantages over traditional X-Ray. For example, radiation levels are reported to be lower, and resolution can potentially be higher. Additionally, images can be displayed in real time. As opposed to traditional X-Ray, which requires through-the-wall penetration from the radiation source to a film on the back side of the weld, RSD X-Ray works on the principle of backscatter, or reflection of the X-Ray signal. The detector can be outside the pipe, co-located with the source. Before such a new technique is adopted it needs to be tested to demonstrate that it is capable of identifying flaws in welds with the same sensitivity and accuracy as traditional X-Ray. GTI will work with the vendor of this equipment to perform blind tests to demonstrate this. The results of the blind tests will indicate whether the project should proceed and whether equipment and techniques should be developed for practical applications in the gas industry. If successful, this method of non-destructive examination (NDE) could also be applied to pipeline integrity assessments of existing transmission pipeline segments via incorporation on to a pipeline pig, or a robotic internal inspection device.

Using Nucsafe’s Scatter X-ray Imaging (SXI) technology, the first iteration of this investigation utilized standardized PE disks with precisely measured defects placed in the fusion interface. The objective was to develop a repeatable methodology of introducing specific defects into the fusion interface and to scan a sufficient number of replicates that would allow probability of detection statistics to be calculated. A set of calibration specimens was prepared at GTI and sent to Nucsafe for scanning. The scan results showed that while the disks were detectable the interfaces between the disks and the pipe dominated the signal and masked the included defects in many instances. The initial approach was abandoned in favor of that utilized in OTD Project Number 2.6.e which was more successful.

OTD 4.7.g - Yield Strength Determination. Operators with incomplete records need a better way to determine the yield strength of their pipeline segments if it is unknown. Current regulations require that operators either take a full size cutout of the pipeline and subject it to laboratory testing, or assume a low value of 20,000 psi. Obtaining full size cutouts is disruptive to pipeline operations as it would require a full shutdown of the pipeline. Assuming 20,000 psi could result in the pipeline being in an (assumed) over pressure condition when in fact it may not be. GTI developed a method to determine the yield strength of a pipeline through lab testing of “sub-size” samples. The samples can be obtained easily by using standard hot tapping equipment without shutting down the pipeline. A follow on phase to the project will utilize sophisticated statistical techniques to possibly lower the number of sub-size coupons required for given lengths of pipeline. The benefit to the company is a less expensive and less disruptive method for positive determination of yield strength, should any of the company’s records be incomplete.

OTD 4.8.a - Guided Wave Equivalent to Hydrotest. The objective of this project was to perform a validation effort to allow the use of GWUT as an acceptable inspection technique by demonstrating the ability of GWUT to perform equal to, or better than, a hydrotest. The specific objectives of this project were to perform the following: Compile data from GWUT inspections that have been validated by design, ILI, or direct measurement, Demonstrate that GWUT finds defects that would pass a hydrotest (therefore substantiating that GWUT will find all larger defects), and Provide a validated methodology for a new standard. Data collection involved gathering all available and acceptable data from prior GWUT inspections and the associated dig records (defect geometry, pipe diameter, wall thickness and grade). Data was only accepted and reported in this study if the GWUT could be verified through direct inspection. The collected data was used to calculate the failure pressure for rupture using the most conservative federally approved methodology, i.e., ASME B31G for all validated data points. The validation calculations were undertaken to confirm or substantiate the following hypothesis: GWUT misses no defects that would fail a hydrotest, and GWUT misses no defects that were found in the direct examination (i.e., determine the False Call Rate). The percentage wall loss vs. anomaly length diagrams plotted to B31G confirmed that GWUT is equivalent to hydrotesting. The GWUT methodology found all those anomalies that would have been found by the hydrostatic testing and GWUT also found anomalies that were too small to have been detected and would survive in a hydrostatic test to a pressure equivalent to the pipe's Specified Minimum Yield Strength (SMYS).

OTD 4.8.i - Extended Reassessment via Wax Fill of Casings. A proper wax fill of a casing eliminates the threat of external corrosion on the carrier pipe by removing any electrolytes in the annular space between the casing and the carrier pipe and replacing it with a dielectric medium (the wax fill). Although techniques for filling casings with wax are well known, there has been no known technique for validating the effectiveness of the wax fill operation so that assessment intervals could be extended. For this project, corrosion monitoring techniques and techniques to determine the completeness of the initial wax fill operation have been developed. Casings were filled with wax and monitored to determine the extent, if any, of corrosion. To simulate actual field conditions, water was left in some of the test sections prior to filling the annular space with wax as well as through ports made through the casing wall and water forced into created voids. Such testing conditions were extreme. Upon post examination, after 1 year of service, extremely low corrosion growth rates were found, at a much lower rate than would be expected. Longer term testing could provide additional data to verify if the corrosion rate drops, stabilizes or does neither over time. More work would be required to quantify actual corrosion rates over a longer time period

OTD 4.9.a - Leak vs. Rupture Boundary. The current Pipeline Integrity rule requires that all pipelines operating at 20% or higher of the specified minimum yield strength (SMYS) are subject to the more stringent transmission integrity assessments. (20% is thought to be the lower limit of pipeline stress at which pipelines fail by rupture). However, there remained questions as to whether 20% is a realistic lower limit. With the support of the USDOT, investigations of past failures coupled with detailed mathematical modeling can confirm that the 20% limit is overly conservative and a more realistic lower limit may be 30%. The Company may then elect to designate certain pipeline segments as covered under the new Distribution Integrity Management rules. GTI investigated over 20,000 pipeline failures worldwide and was able to draw conclusions as to the parameters that cause pipes to fail via leakage vs. rupture. Not only yield strength but also diameter, pressure, and toughness are factors that determine whether pipes fail by rupture or leakage. The project results showed that for most modern pipeline materials the leak-rupture boundary is more like 30%. Using the results of the project, operators can – with proper regulatory approval – place their pipeline segments in the appropriate integrity management program. The benefit would be that company resources can be directed to assessing the more vulnerable pipeline segments.

OTD 4.11.f and T 768 (non-Millennium Project) - Understanding Threat Interactions. Part of an operator's Transmission Integrity Management program is a relative risk assessment of the various threats that could impact a pipeline. There are various risk models in use that can quantify the relative risk of pipeline failure via the threats that are present. What is not so well developed is a ranking methodology that accounts for threats that can interact, or occur simultaneously on a pipeline segment. For example, what is the additional risk to a segment if external corrosion occurs on a manufacturing defect, or if earth movement occurs in an area with a defective weld? This project will examine a realistic combination of multiple threats that can reasonably be expected and will calculate the additional risk of failure to a pipe segment due to the presence of these interacting threats. This is timely work since the Company and others have been questioned during safety audits by regulators on their methodology for addressing interactive threats. This benefits the company by allowing the most accurate risk ranking and subsequent assessment of the integrity of those segments. Because this is an important issue the Company funded two parallel projects. The first is a short term effort through NYSEARCH that focuses on (but is not limited to) evaluating interacting threats through the existing Kiefner Model, which many LDCs use today. This effort took far longer than expected but an algorithm is now available (Nov. 2015) for use in determination of the risk associated with interactive pipeline threats. Yearly updates will be made to this model as incident data is reported and updated through the DOT under a 5-year contract with the developer. The second is a longer term more theoretical approach by GTI which could provide more overall flexibility.

OTD 4.12.b – Correlating Pipeline Operation to Potential Crack Initiation and Growth. Based on recent industry events coupled with new or proposed regulations, the gas industry is expected to increase the amount of pressure, or "hydrostatic" testing on existing pipelines. In addition to a standard pressure test (in which the pipeline is pressure tested to 1.5 times its operating pressure) there is the possibility that operators would be required to perform a "spike test" in which the pipeline is raised to 90% of yield strength (which could be significantly higher than a normal hydrostatic pressure test).
Such pressure testing, while having advantages over other integrity assessments, can cause cracks to initiate and/or grow. This has been observed in other industries (boiler tubes) but is not well understood in the gas industry. The Company is aware of the advantages of pressure testing but wants to understand the risks that could present themselves due to pressure and spike testing. GTI will leverage previous work done in

the boiler tube industry to develop a model to predict crack growth due to pressure testing. Validity of the model will be tested by subjecting actual pipe specimens to laboratory pressure cycling which can simulate years of pressure testing and/or pressure excursions in a matter of hours. The deliverable of the project will be a model that will relate historical and planned pipeline operations to potential crack initiation, growth and arrest. This benefits the company by insuring that pressure testing does not degrade the pipe segment being tested, with the associated possibility that the pipe could fail while in service.

OTD 4.13.a - DIMP Consequence Model. The objective of this project was to develop a model that quantifies the consequence of failure for distribution systems and DIMP based factors such as population density, proximity of critical infrastructure and business districts, failure mode based on material properties, gas migration patterns, soil and surface conditions, pressure and potential energy. The deliverable of this project is a DIMP consequence model that operators and software vendors can incorporate into existing risk modeling tools.

OTD 4.13.b - Demonstration of 3D Scanners for Anomaly Assessment. A validated tool that eliminates manual data collection of in-the-ditch anomaly measurements using a pit gauge will improve data quality and increase operational efficiency. Automating the process of measuring anomalies found through ECDA and ILI runs could be achieved through various 3D scanning devices. This project's goals are to validate and demonstrate the performance of 3D scanners for automated in-the-ditch anomaly measurement and assessment of corrosion, dents and gouges. The two 3D scanners that were tested demonstrated the ability to provide more accurate and reliable anomaly assessments compared to manual pit-gauge measurements. Recommendations for further assessment include: 1) Evaluate the cost of the products in relation to the value that they provide in terms of improved data accuracy and reliability and time savings during data collection and management. 2) Ensure that 3D scanners are compliant with federal and state regulations.

OTD - 4.13.c EMAT Sensor for Small Diameter and Unpiggable Pipe. This project goal is to develop a bi-directional electromagnetic acoustic transducer (EMAT) sensor that can be used to assess small diameter and unpiggable pipelines containing reduced diameter fittings and other restricting features. Phase 2 focuses on constructing and testing a field-ready prototype based on the success of the bench-scale prototype sensor developed in Phase 1. This research will enable natural gas pipeline operators to identify defects that are traditionally difficult to find and assess and therefore improve system integrity and public safety. The EMAT sensor will be designed to find and characterize cracks in welds and pipe walls. PHMSA is co-funding phase 2 effort with industry funders of this project.

OTD - 4.13.d.3 - Hydrotest Alternative Ph 3. The third phase of this program is to identify and validate inspection and assessment technologies that are equivalent to a 1.25x Maximum Allowable Operating Pressure (MAOP) hydro-test for Integrity Verification Process (IVP) compliance. Phase 2 created the Finite Element Analysis

(FEA) critical flaw data and collected Probability of Detection (POD) data for Electromagnetic Acoustic Transducer (EMAT) and Acoustic Resonance Technology (ART) sensors. Phase 3 will create the critical flaw curves that will allow a comparison to In-Line Inspection (ILI) tool detection capabilities. The deliverable of Phase 3 will be a tool that operators can potentially use to demonstrate equivalence to a hydrotest for a specific pipe segment. The ability to use internal and/or external inspection tools to perform an integrity assessment as a regulatory acceptable alternative to hydro-testing would ensure the operator of the safety of the pipeline and provide significant cost savings in complying with new regulations. It would also provide operators an integrity assessment solution for those critical pipelines that cannot be taken out of service. Furthermore, hydro-testing may increase risk by introducing water that cannot be removed and may accelerate crack growth for certain susceptible pipeline materials. Acceptable alternative methods to hydrotesting are a critical need.

OTD - 4.14.a Fitting and Component Catalogue for IVP. The goal of this project is to develop a catalogue of legacy fittings and components to assist operators in identifying and characterizing assets to comply with PHMSA's Integrity Verification Process (IVP). The envisioned catalogue will contain pictures, descriptions, strength class ranges, and material and mechanical properties. A catalogue of legacy fittings and their characteristics will assist operators in complying with pending federal regulations, specifically the new IVP requirements. An industry catalogue will reduce the cost of gathering and compiling this information and provide support for strength requirements and assumptions when a fitting can be positively identified. This project has encountered issues with obtaining suitable documentation of data for inclusion in the catalog. Initially critical documentation had been located via the internet (only 2 copies existed) and one copy was ordered but the shipment never arrived. The other copy is not for sale and is owned by Chinese interests. Securing composite catalogs of vendor products and parts from the desired pre-1970 era are actively being worked and GTI is in the process of obtaining a paper copy of a large document from Gulf Publishing via loan that may include useful information. Digitizing and collating the potentially thousands of relevant vendor catalog pages from Gulf documents could ultimately lead to generation of a searchable online tool for LDC use. This effort would likely require significant resources outside the scope and budget of this project.

OTD 4.14.c - Surface Indentation for Material Characterization Correlation of Surface Properties Based on Vintage. There is a need to develop correlation factors to relate surface properties to actual material properties to allow surface indentation techniques to be used for material property validation for pipelines. These correlation factors will be based on pipe vintage by decade. Past research has proven the ability of surface indentation techniques such as stress-strain microprobes and hardness testing to accurately determine material properties of pipes within a localized area, but variations in material properties through the wall are problematic for local interrogation techniques. GTI will develop probabilistic confidence intervals that will allow operators to use surface indentation techniques by applying correlation factors to pipe materials that may have through-wall variability. The ability to characterize material properties, particularly yield strength, of in-service pipelines without taking the line out of service or removing samples will significantly reduce the cost of complying with existing and pending federal regulations. Backfilling records with material property information such as yield strength and toughness also improves integrity management through system knowledge that allows enhanced modeling and analysis. It is anticipated that the results of this research will facilitate the regulatory approval of stress-strain microprobes and hardness testing to characterize material properties of in-service pipe. It will also empower internal inspection tools (such as PRCI's signature pig under development or TDW's MFL tool that may be able to detect signatures) to use surface readings from the inside of the pipe to be applied to the entire pipe wall.

OTD 5.8.e - Tracking and Traceability. One of the requirements of a Distribution Integrity Management program is to "know your system." But there is no industry standard for manufacturers to mark gas piping and appurtenances with critical manufacturing information nor is there a standard for LDCs to record data when installing permanent additions to their gas systems. On the manufacturing side, date of manufacture and lot number need to be recorded in a standard fashion across industry, and installers need a standard way to record location of the installation and identify the crew doing the work. For this project, GTI and a subcontractor formed a steering committee to identify which commonly used materials should be identified, and what pertinent information should be recorded. The steering committee consisted of manufacturers and LDCs. An ASTM F2897 standard was developed to which capture the results of the Steering Committee's decisions and a bar coding protocol was agreed upon. A future phase of the project will develop methods to record, store, and retrieve, if necessary, data on installed components.

OTD 5.9.j - Gas Distribution Model. With Distribution Integrity Management Program (DIMP) regulations now in place, operators will be developing data collection strategies to ensure compliance. One tool that could help operators in this process is a non-proprietary, industry standard data model for distribution assets and operations. A standard data model, the Pipeline Open Data Standard (PODS) model was developed to assist transmission operators in managing their data and ensuring regulatory compliance. The PODS model is an open, industry-standard data model that has successfully been used for over ten years to reduce the cost of implementing software and improve interoperability for the pipeline industry.

Now with DIMP there is a similar need for an industry-standard data model for distribution assets and operations. Gas Technology Institute (GTI) initiated a program to develop the Gas Distribution Model (GDM) to meet this need with three specific purposes. First, the model will be used as a data exchange function between operator data models and vendor's software products to reduce the need for customization. Second, the model can store both transmission and distribution data and will facilitate vertical data integration. Third, GDM could be used as the primary data model for operators to avoid the need for internally developing a model. The Company engineers and IS personnel felt that such a data model would benefit the business and also would facilitate transition to the new SAP system. The GDM initiative brought together a diverse group of operators, vendors, and industry experts to collaboratively develop a GIS-neutral model that holds promise to reduce the cost of software implementation and improve interoperability. GDM is a flexible model that will grow and expand with continued use and development.

OTD 5.11.m – Intelligent Utility Installation Process (Asset Tracking and Traceability). This project will develop methodology and suggest field processes for capturing data during new installations. It is a logical follow on to the requirements of recently enacted DIMP regulations which require operators to "know their systems." It also will provide the means to implement the results of the "Tracking and Traceability" project which created an industry standard for manufacturers to mark their products with manufacturing data. A key component of the Intelligent Utility Installation project is to achieve standardization across industry. When this project is implemented the company will benefit by knowing precise attributes of its distribution system and will be able to quickly react to reports of possible defective pipe material or fittings.

OTD 5.15.b - Roadmap for an Enterprise Decision Support System (EDSS). By striking the proper balance between competing influences, operators will maximize business health. There is a growing realization among operators and regulators that ad hoc decision making, based on the latest crisis, is not the optimal method for enterprise management and ultimately system reliability, safety, and efficiency. The objective of this project to develop an Enterprise Decision Support System (EDSS) technology roadmap. The EDSS will allow LDC operators to integrate all data and business knowledge sources into a decision support system that will optimize policies related to: risk mitigation, safety, code compliance, customer satisfaction, environmental stewardship, efficient operations and future growth. It is increasingly necessary to optimize various operational decisions based on predefined rationale coupled with comprehensive knowledge of data/system inputs and a methodical risk analysis. Enterprise decisions and risk analysis that will be supported through this process include repair vs. replace vs. rehabilitate, predictive threat interactions and consequence of failure, risk based prioritization of O&M activities, scenario analysis for various risk mitigation strategies, economic analysis, amongst others. Additionally, new asset-based data streams are continually being developed as directed by distribution and pipeline integrity programs as well as the relative ease in which large volumes of system data can be collected. The EDSS will integrate these disparate data streams into a logical system capable of rationalizing the inputs to enable sound decision making. The deliverable of this project will be a well formulated roadmap that provides guidance on how to realize an EDSS. This roadmap will be used to execute a series of stage-gate linked projects that progressively move us towards the goal of a fully functional EDSS.

Plastic Pipe Research

The bulk of piping added to LDCs' networks each year is medium or high density polyethylene (PE), or plastic pipe. Last year alone, the Company added over 500 miles of such pipe to our system. Working with NYSEARCH and GTI, the Company is involved in several research projects designed to improve our understanding of PE performance and develop new products.

M2000-001 - PE Repair Sleeves for Damaged PE Pipe. As an alternative to squeeze off and cutout of minor defects on PE pipe, the Company and others are developing, through NYSEARCH, repair sleeves to reinforce PE pipe in the area of the butt fusion joint, or along the length of the pipe. During routine operations such as new service additions or main extension, minor damage – not causing leakage - can be noticed on the existing PE pipe that is uncovered. The substandard conditions noticed can be either a scratch or gouge on the pipe itself, or a questionable appearing butt fusion joint. The solution, up to now, is removal of the defective pipe segment. Removal is usually accomplished by first "squeezing off" ahead of and behind the pipe segment in question, then cutting it out and replacing it. As an alternative, the PE repair sleeve can be fitted over the defective area in question and fused on to it. The fitting is designed to withstand line pressures up to 124 psi but will not be installed if an active leak is present. The benefit of this technology is lowered repair costs and improved reliability of PE piping systems by reducing the amount of "squeeze-offs" made. These repairs can also be made without causing an outage, whereas a squeeze-off may require a short outage if the pipe is a one way feed.

M2006-002 – Butt Fusion Integrity. This project examines current butt fusion parameters such as pressure and temperature at the joint interface with an aim towards optimizing them. Through a novel test method, the "whole pipe creep rupture test" several test fusions are made and subject to this laboratory destructive test. This test more accurately simulates stresses that actual in-service pipe experiences, and results of these tests can serve to further refine butt fusion parameters and associated procedures.

M2008-010 – UV Degradation of PE Pipe. The Company wants to understand, through testing, what the real time limit for PE pipe to withstand UV exposure without a harmful effect would be. Current USDOT regulations specify two years but the current version of ASTM D2513 (the industry standard for manufacture and use of PE pipe) specifies an outdoor storage limit of 3 years for medium density PE pipe and 10 years for high density PE pipe. But this current standard has not been accepted by the USDOT, who recognize the previous version which limits outdoor storage to 2 years. This project was undertaken to demonstrate, through testing, that pipe stored outdoors longer than 2 years is still suitable for use. Both non-destructive and destructive tests have demonstrated that pipe stored outdoors for three years is suitable for use. The work now is to present the information to the USDOT and request a rule change. The benefit to the Company will be immediate; National Grid recently discarded over $300,000 worth of PE pipe that exceeded the 2 year requirement.

M2009-008 – Ultrasonic Inspection Device for PE Butt Fusions. The aim of this project is to develop a field instrument to rapidly and easily examine butt fusions in the field, providing on-the-spot assurance of the integrity of a newly made butt fusion joint. A low cost user friendly butt fusion inspection device has been a goal of gas industry research for quite some time. Such a device gives greater assurance of butt fusion quality by allowing "on-the-spot" inspections by field crews or supervisors actually doing the work. The Welding Institute (TWI), located in the UK, is a leader in plastic pipe research and was selected to carry out this work in a phased approach. In the first phase, an instrument was configured to examine and return information on the presence or absence of flaws in the butt fusion. The next phase of the project is to determine which flaws can be accepted and which will cause the pipe to fail. This is done via destructive testing; fusions with varying degrees of flaws are subjected to testing and a "library" of flaws is developed and flaws are categorized as either "causes failure" or "does not cause failure." Based on similar European technology for metric sizes, the objective is to develop and test a nondestructive tool for examination of butt fusion joints (particularly for use with advanced PE materials). This project has taken advantage of significant research already performed by The Welding Institute (TWI) for the European gas and PE piping industries. Extended long term testing is being performed because the test protocols/data from Europe showed that U.S. failures do not occur as rapidly and to test to failure, different conditions needed to be imparted. The significance of this extensive testing is that NYSEARCH and TWI are developing acceptance criteria for use in a tool that does not require a trained technician. Other phased array NDE tools are either not state-of-the-art OR they require a trained technician. In its final form, the instrument will examine field fusions and compare them to fusions in the "library" and be able to give a simple "good fusion" or "bad fusion" reading. The benefit of this work is greater assurance of the quality of a butt fusion and increased safety and reliability of the gas distribution network.

OTD 5.13.c - PE Pipe Splitting—Technology Evaluations, Enhancements, and Standardization of Tool Kits A research team is evaluating and refining existing PE pipe-splitting equipment and developing guidelines. In October 2015, manufacturers performed various pipe-splitting activities with plastic-pipe-replacement construction techniques. — Researchers are seeking additional field sites for this project.

.

Live Inspection, Maintenance and Repair

The Company is always looking to minimize customer downtime or gas main shutdown during routine maintenance activities. The following projects help us meet this goal.

M2001-006 - Development/Testing/Commercialization of Real Time Gas Distribution Sensor Network - Phase I-V. This distribution sensing system is intended to provide network sensor data acquisition, robust wireless communication and encrypted data accessible for pipeline monitoring and assessment. Data from these real-time sensors will include pressure, temperature, humidity, flow volume, and direction. The objective of the program is to complete development and testing to the point where Enetics/Telog can commercialize the technology.

M2008-003 - Evaluation of Rapid Crack Propagation. A study to model and test the existing ISO correlation formulas used to determine rapid crack propagation in PE pipe. Through this project, it has been determined that existing formulas are overly conservative and need to be changed.

M2014-001 - sUAS Technology - Regulatory & Technology Assessment. The objective of the project is to evaluate regulatory issues and technology of small unmanned aerial systems (sUAS) devices as applied to gas industry inspections and surveys. Further, NYSEARCH has been investigating development of methane leak detection module and control system capable of using at tree-top level for leak survey and methane emissions measurement on a sUAS.

M2014-005 - Critical Valve Operability. The objective of the project is to develop a method of confirming valve position and provide validation of a critical valve operability test.

M2016-001 (Millennium); T-770 and T-776 (non-Millennium) - Cured In-Place Composite Liners projects and Technology Transfer, Demonstration & Post Mortem Testing of Cast Iron & Steel Pipe Lined with Cured-in-place Pipe Liners. The objectives of the project were to: 1) gain understanding and support from regulators using Cured-in-Place Pipe (CIPP) Liners as a rehabilitation technique for cast iron and steel pipe, 2) provide an engineering assessment to advance the understanding of liner/host pipe interaction and demonstrate structural equivalence towards repair/remediation of lined pipe/appurtenances, and 3) validate the effectiveness of CIPP-lined cast iron and steel pipe through examination of past studies & further demonstration and lab testing.

M2016-001 (Millennium) - Chemical Longevity & Post Mortem Slow Thermal Cooling Testing of Field Aged Cured-In-Place Lined (CIPL) Cast Iron and Mechanically Joined Steel Pipe. The primary objective of this proposed Phase II project is to further address regulatory concerns by testing field aged extracted cured-in-place segments as they interact with host steel or cast iron pipe to demonstrate the actual impact of slow thermal cooling and perform chemical aging longevity evaluation tests to (100) years. Six test segments of CIPL pipe, three steel (12”-16” diameter) with a mechanical coupling, and three for cast iron (12”-16” diameter) are proposed to be extracted after years of gas service and will be further tested using a solid foundation of protocols by scientists at Cornell University. The cast iron pipe will be flexed to create a circumferential crack prior to testing. Project goals include: 1) performing thermal testing to simulate actual slow cooling in the field, and, 2) conducting independent tests to examine the chemical longevity of a new CIPL pipe to a (100) year life cycle equivalent, 3) completing a workshop with funding member SME’s and Cornell professional staff on “best practices” for evaluating corrosion and structural limitations of host steel and cast iron pipe segments, and, 4) providing a platform that encourages industry and regulatory dialogue regarding the use of CIPL pipe as an option for the renewal of our aging pipeline infrastructure. This will involve preparing information so that the gas industry sponsors develop a unified approach to addressing levels of host pipe corrosion acceptable for CIPL use in field aged CI or steel pipelines.

OTD 2.11.a - Above Ground Leak Repair Systems Testing. The Company and other LDCs desire to qualify various repair products that are sold for repair of above ground leaks on natural gas piping as a permanent repair system. The application is for above ground meter piping on distribution systems. No use of these products on below ground piping is contemplated. Two available products are being tested. Initial tests will be short term testing to establish the proof, or “burst” pressure of the repair system. These tests

are complete with burst pressures found to be well above (by an order of magnitude) normal operating pressures. Plans for long term testing are now underway.
A successful outcome of this project would be that these repair systems would qualify as a permanent repair thus repairs can be made more inexpensively than a shutdown and rebuild of meter piping, with the associated inconvenience to the customer.

OTD 2.12.e - Selection of Liners Composites for the Rehabilitation of Distribution and Transmission Lines. This project is an evaluation of the use of composite pipes and cured-in-place (CIP) liners in the rehabilitation of gas distribution and high-pressure lines. The replacement and rehabilitation of these pipeline systems in congested, urban areas with very limited right of way space is particularly problematic. This project investigates the trenchless rehabilitation options of these pipes.

OTD 2.13.b - Guidelines for Special Permits for Structural Composite Rehabilitations. The objective of this project is to develop guidelines for submitting special permits to state and federal regulators to request approval to use composite materials for structural pipe rehabilitation. The need for new techniques to repair and replace pipe will continue to increase as infrastructure continues to age. While open trench replacement will be the most cost effective technique for many applications, some situations will require the use of trenchless or alternative techniques that use the host pipe as a conduit for installing a new pipe. Composite materials hold much promise for rehabilitating aging infrastructure, including high pressure pipes. Composite materials can have properties that are superior to steel and can be installed in flexible configurations. Guidelines for submitting special permit requests will reduce the cost and time associated with filing the application. Guidelines will also improve the likelihood of obtaining approval through a special permit by ensuring that permit applications are complete and address the issues that are of interest to state and federal regulators. Other means are being explored for regulatory acceptance, as such; this project is temporarily on hold.

OTD 2.13.c - Long-Term Evaluation of Liners and Composite Pipe Materials.
An engineering assessment was conducted to improve testing methods for predicting the long-term performance of liners and composites used in the rehabilitation of aging gas distribution and transmission lines. The focus was on high-pressure (up to 350 psig) composites and liners installed using trenchless technology. — A Final Report containing guidelines is being prepared.

OTD 2.14.a - Composite Repair Wrap for Polyethylene Systems
Researchers are evaluating a new composite pipe-wrap system for the repair of damaged PE gas pipe. Efforts are under way to establish the correct combination of adhesive and wrapping material. — Repaired specimens are being monitored under long-term hydrostatic pressure testing.

OTD 2.14.b - Steel-Pipe-System Repair Technique
A novel repair method for live leaking steel-infrastructure applications was developed and tested. The method uses a mold, resin, and composite wrap to provide safe,

permanent repairs. The goal is to have the technique applicable to steel couplings, threaded joints, cast-iron bell joints, and service tees. Testing is complete and a patent for the technology was filed. — A Final Report is being prepared. Discussions with potential manufacturers are under way.

Trenchless Technology

The Company's primary research effort in this program area is to find ways to complete maintenance with minimal excavation. These technologies will lower cost and result in less disruption to the customer.

M2010-001 – Service Tee Renewal The purpose of this project is to develop a means to renew a service tee under live conditions without an excavation. Gas mains can be rehabilitated via cured in place lining with minimal excavations. Steel service lines are routinely renewed by inserting plastic tubing, with no need to shut the main down. An alternate process, called "Renu" seals the interior of a steel service line with access gained at the meter. The weak link in this process is the service tee, usually made of carbon steel, which is not routinely replaced during the above mentioned gas main and service rehabilitation projects. The Trenchless Technology Center, retained by NYSEARCH to conduct this research, focused first on an appropriate sealant that would effectively seal the interior of the service tee. Spray coatings, liners, and mechanical seals were investigated. A hybrid mechanical seal concept was judged the best of the three alternatives but significant design challenges existed, mostly related to delivery of the sealing system down the length of the service line to the tee (up to 100 ft in some cases). Because of the uncertainties associated with these approaches the Company and the other funders will request proposals for alternate solutions.

T 773 (non-Millennium) - Trenchless Replacement of Small Diameter Steel Gas Service Lines. The objective of the project is to design, develop and test a new system for extracting small steel services, bare or wrapped in the size range of ¾" – 1 ¼" diameter to replace them with same size or larger size PE pipe. If successful for the smaller steel services, the contractor and cofounder also envisions a Phase II to address steel services with diameters of 1 ½" and larger.

OTD 2.8.e - Structural Liners – Technology Search. Large diameter cast iron mains can be effectively rehabilitated by lining them and Ngrid has been using this technology successfully since 2003. The current approved liner for use on gas systems relies on the structural integrity of the host pipe. For this reason, lining is generally limited to cast iron or protected steel pipelines. If a liner could be developed that had structural properties (meaning it would resist external loads such as traffic loading) more pipelines could be candidates for lining.
Four liner manufacturers who make structural liners for other industries (water) were contacted and their products' capabilities were discussed. One manufacturer seems to have a product that may meet the requirements for gas service and further evaluations will be required. This project would benefit the Company by expanding the available pipelines that could be rehabilitated by lining as opposed to replacement, resulting in lower cost and less disruption to the community and customers.

OTD 5.10.f – Cold Assisted Pipe Splitting One of the methods to renew deteriorated steel pipe is to split it by pulling a tool with cutters through it. A new length of PE pipe is attached to the rear of the cutter. When the cutter emerges from the pipe, the new length of PE pipe remains as the new gas carrier. This can be a cost effective rehabilitation method but many times the splitting operation is difficult because of the ductility of steel pipe. This project investigated whether liquid nitrogen or some other cryogenic liquid could lower the temperature of a steel pipeline to a level at which the pipe would transition into the “brittle” zone and be easier to split.
GTI Engineers determined that the quantities of cryogenic liquid required would be excessive, and further found that during testing; the cooling effect was not uniform through the length of the pipe. Since the project had reached a go / no-go milestone the Company decided not to continue further funding.

Gas Quality

The gas supply picture for the Company’s service territory – and indeed for much of the nation – is evolving, and unconventional supplies such as LNG, shale gas, biogas, and gas from other geographic regions will soon be a part of our supply picture. While research into supply itself is outside the scope of the Millennium funding mechanism, the effect that these diverse supplies may have on our existing infrastructure is a new and growing R&D area for us.

M2005-005 – Gas Interchangeability for Installed Components A multi-phase study investigating LDC coupling components and associated materials and whether varying gas compositions in a range of temperatures and pressures can create leakage in the couplings. This project studies the effect that a wide range of future expected gas supplies from non-traditional sources may have on installed infrastructure components such as gaskets, O-rings, seals, and diaphragms. Anecdotal evidence exists that suggests that gas supplies outside of normal expected limits may have been the cause of component failure in two east coast LDC distribution systems, but no definite conclusions can be reached, and no similar studies have ever been undertaken. This test program is designed to determine, through controlled laboratory testing at GTI test facilities, whether gas composition changes affect the performance of elastomer components mentioned above. Baseline and test gasses were agreed upon and procured, and infrastructure components were removed from the field and sent to the GTI lab for testing. Components are cycled through a “baseline” gas (the gas normally expected) and then cycled through several “test” gases (representing future expected supplies). During this cycling, pressure and temperature are also varied. The results of this test program will allow the Company to take action by removing and replacing components determined to be “at risk” or set new supply tariff limits with a scientific basis for setting them.

M2011-002 - Storage Effects on Gas Quality - A portion of the gas entering the Company’s system comes from underground storage in geological formations. There is anecdotal evidence that gas leaving storage can have different properties than gas entering storage, for several reasons. These reasons can include presence of water or other substances in the storage formation, temperature variations in the formation (which could affect dew point), blending (or lack of blending) and others. None of this is well understood or modeled. The Company would like to understand this better from the perspective of the ultimate effect on our distribution system. This would help us better negotiate tariffs for gas delivered that would not have harmful effects on pipe materials as well as gaskets, seals and diaphragms. NYSEARCH commissioned a subcontractor for a two phase effort; the first phase is a literature search which will identify the key parameters that affect gas quality in storage. Assuming a successful outcome of the first phase, a second phase would develop a predictive model so that ultimate gas qualities can be more accurately projected. This benefits the company by enabling it to better predict quality, set tariff limits that recognize the potential for change in the quality of the gas in storage, and ultimately insure the integrity of our infrastructure.

M2011-003 – Odor Masking. Odor Masking is a phenomenon recently observed in gas distribution systems in which the odorant, although present in the required concentrations, is not perceptible to the human sense of smell. It is manifested by no odor or a markedly different odor than is usually associated with natural gas. This is different from Odor Fade, in which the concentration of odorant is lowered due to its being absorbed by the pipe (common in new piping systems) or by trace constituents in the gas stream. The Company is concerned about this issue because absence of the characteristic gas odor will prevent recognition of gas leaks or other hazardous situations.
Odor Masking is not well understood but the Company and other NYSEARCH members are working with Cardiff University in the UK and a professor there who has done some research in this area.

It is known that pairs of compounds, called "antagonistic pairs" can act together to change the perception or intensity of an odor and that this reaction actually occurs in the human nose or brain. In Phase I of this project, researchers at Cardiff University have demonstrated that certain chemicals that can be present in a natural gas stream can mask the odor of some sulfur compounds that are commonly used in odorant. This was shown by actual tests involving volunteers at the university who ranked the intensity and pleasantness of these chemicals before and after mixing. The Phase 1 work will attempt to identify as many of these antagonistic pairs as possible. In Phase II, just beginning now, researchers will attempt to identify where this human response is taking place. This is important because it will lead to certain mitigative strategies depending on where the response takes place.

The ultimate goal and benefit of the project is a practical pipeline operator guideline on how best to mitigate this phenomenon. For example, the guideline could call for tariff limits on certain trace constituents be set at a lower level, or it could recommend the use of certain odorant types that are more resistant to masking. A successful project outcome would eliminate the situation where a gas leak goes undetected with potentially catastrophic results, such as the Texas school explosion in 1937. The project identified the causes and mechanisms associated with a phenomena that is not fully understood, odor masking. The overall goal was to develop guidelines to mitigate odor masking and anticipate issues that arise from variations in gas quality. While the mechanisms were identified and confirmed, the program did not move to distinct measures for mitigation due to results that unveiled more issues to resolve in terms of human variability in terms of concentration sensitivity. Status is "Complete" until parallel work determines need

M2013-003 - WKU Advanced Chemical Sensor. Through the TecFusion/Oracle program, NYSEARCH identified the smart nose technology of Western Kentucky University (WKU). This technology uses nanosensors to develop a smart nose that is rather sensitive and can be used to also detect a certain gas signature. The Western Kentucky University (WKU) project first completed a feasibility study for using an "artificial nose" system to detect a series of analytes of interest to the natural gas industry. The nanosensor technology leads itself very well to small, low power instruments, ideal for field deployment. This project is now advanced to development and testing of advanced prototypes.

OTD 7.8.a – Pipeline Quality Biomethane: Guidance Document for Landfill and Water Treatment Conversion. This is a national study and sampling program to determine acceptable gas quality for introduction of landfill and wastewater-derived biomethane into Ngrid's distribution system. No such standard exists in the US today. Information was assembled on landfill and wastewater biogas production, treatment, gas quality standards, and test protocols surrounding biogas production and use. A lab test program was executed testing raw and processed biogas samples for over 400 chemical species. A guidance document was prepared for safe interchangeable use of landfill and wastewater treatment biomethane in LDC networks. The results of this project show that these biomethane sources can be safely introduced into LDC networks.

OTD 7.9.c – Assessing Acceptable Siloxane Concentrations in Biomethane
Siloxanes are a class of compounds that are silica-based and found in many personal hygiene and health care products. As such, they enter waste streams and can be found in biomethane produced from landfill or wastewater biogas cleanup systems. There is evidence that siloxanes, when combusted, can result in excessive deposits of silicon dioxide on boiler tubes or gas turbine blades. The Company is also concerned because the effect of siloxane on standard infrastructure components is unknown. GTI is assessing industry data and attempting to determine what levels of siloxanes in biomethane would lead to issues with end use equipment or pose indoor air quality issues. In addition to the acceptable concentration of siloxane, other unknowns must be understood, such as where, and at what ratio, the biomethane enters the LDCs' distribution systems, and what flows and velocities can occur at the end use equipment. This project fills an important knowledge gap and allows the company to prepare for the introduction of another non-traditional supply into our existing infrastructure.

OTD 7.10.a – Trace Constituents in Natural Gas. Significant research to identify the complete range of trace constituents in natural gas has not taken place in 20 years. In that time span, non-conventional supplies are entering LDC systems and these supplies are expected to have trace constituents in them. The objective of this project is to build a database of trace constituents specific to current supplies of gas flowing into LDC systems. The Company will use this database to assess new gas supplies from unconventional sources such as shale gas to see whether these new supplies are compatible with existing supplies. Routine analysis of natural gas supplies is an established practice. Heating value, specific gravity, hydrocarbon content, and some inerts such as nitrogen are measured periodically, but trace constituent analysis is not routinely done. A partial list of trace constituents of concern would include halocarbons, volatile organic compounds (VOCs), siloxanes, ammonia, trace metals, and bacteria. Comprehensive knowledge of the presence and amount of these constituents would allow intelligence to be placed on setting limits for these constituents in future supplies.

OTD 7.10.b - Odor Fade. Odorants used in the gas industry in North America all contain sulfur, carbon, and hydrogen and belong to a category of chemicals known as organosulfurs. The most common odorants used are alkyl mercaptans such as t-butyl mercaptan, alkyl sulfides such as dimethyl sulfide (added to lower the freezing point of the mixture), and tetrahydrothiophene (a cyclic odorant). This project was designed to investigate causes of odor fade in natural gas distribution systems. A preliminary literature survey reviewed the availability of current and historical data. It concluded that the primary causes of odorant fading include: 1) surface interactions of odorants with different pipe materials, 2) scrubbing or dissolution by condensates or cleaning fluids, 3) chemical reaction/oxidation of odorant with other components in the gas stream, and 4) other system state variables. Thermodynamic prescreening was one tool used to look at the possible reactions involving more common blend stock odorants. In addition to forming (mainly) disulfides and iron sulfides, mercaptans might also decompose or react with trace gas processing constituents (e.g., methanol). Analysis of data collected by funders over the study period indicated that: most odor fade events were reported to have been prompted by weak sniff test results and most respondents reported performing follow-up quantitative analyses. No instances of solvent odors were reported. Two odor fade events were reported with plastic (PE) pipe, the others with steel pipe. Ambient temperature ranged from 20-90°F. All events involved a single source of natural gas. No pipe cleaning was mentioned as having been employed by any of the respondents. Odorants involved were t-butyl mercaptan mixtures with either dimethyl sulfide, i-propyl mercaptan, or tetrahydrothiophene; no odorizer operational issues were noted. Supplementary odorant injection was employed to increase odorant levels by all but one of the respondents. Findings include: analysis of TBM loss in plastic pipe with respect to temperatures. THT loss with respect to temperature, TBM reactivity with steel pipe vs. plastic pipe material, and steel pipe and odorant levels of TBM and THT in relation to presence of rust. When water was introduced into the steel reactor, the rate of loss increased further. Water by itself had no effect (as seen in the inerted reactor tests), but had a significant effect when iron was present. Initial modeling of the 1-step versus multi-step reaction mechanism showed the multistep mechanism to be more robust. The information gained in this project was used to prepare a suggested revision to Chapter 7 of the current edition of the AGA Odorization Manual, last revised in 2000. This study was completed end of 2014

OTD 7.11.a – Gas Quality Resource Center. The Gas Quality Resource Center is intended to provide technical support necessary to identify and fill knowledge gaps regarding potential industry issues associated with changes in gas composition profiles in North America. The Resource Center will provide a centralized "clearing house" for information related to gas quality, analysis of current flowing gas supplies in North America, identification of constituent trends across identified regions, analysis of current technical regulatory trends associated with pipeline tariff negotiations and identification of research needed to help fill information gaps ultimately aimed at maximizing supplies while balancing the needs of pipeline integrity and end use concerns. The resource center would maintain information on gas compositions and pipeline tariffs, and would serve to identify and launch research as appropriate related to gas quality issues. Issues such as odor masking or siloxane levels are examples of the types of research that could result from the Company's participation in the Gas Quality Resource Center.

OTD 7.11.b – Trace Constituents Sensors This project will identify candidate sensors or sensor technologies for measuring, perhaps in real-time, trace constituents in new gas supplies, such as landfill gas, biomethane derived from a variety of biomass sources, and unconventional supplies such as shales, tight sands and coal bed methane. The Company is aware that its future fuel mix will include renewable and unconventional gas. The need to understand the composition of a new gas supply and to monitor its components is increasing as the number and variety of sources grows along with their frequency of introduction into the natural gas pipeline network. The project will proceed on a phased approach, future supplies must be identified, and constituents of concern present in these supplies also need to be identified. For some new supplies such as landfill gas, research into gas trace constituents had already taken place, for others for example shale gas, less information exists. Once the constituents have been identified, instruments that can sense these constituents will be identified and assessed. The benefit of this work is the ability to monitor the composition of new gas supplies and the associated capability of protecting our distribution assets.

OTD 7.15.a - Real-Time Gas Quality Sensor. The introduction of shale gas and upgraded biogas into the gas transmission network is increasing the importance of accurate and regular monitoring of the natural gas heating value and composition. Currently used gas chromatographs (GC) are expensive and slow. The project objective is to demonstrate development of a practical, reliable, and real-time gas quality sensor (GQS) that can detect changes in gas quality (heating value, and concentrations of methane, ethane, propane, butane and carbon dioxide concentrations) in real time and can provide this data to the operators of an LNG plant or other facility.

Environment

Projects in this area are focused on new technologies to more easily and cost effectively remediate MGP sites. A more recent focus in the Environment area is related to Climate Change Concerns.

M2001-002 – Management of Impacted Sediments. The company formed and led this project, which was funded by other NYSEARCH members as well as a national consortium of industry and the US Navy. This project studied the correlation between polycyclic aromatic hydrocarbon (PAH) concentrations in manufactured gas plant (MGP) sites and the actual bioavailability of these compounds to living organisms, with the goal being more realistic guidelines for site remediation. Not all PAHs at MGP sites are actually bioavailable, and therefore harmful, to organisms and the environment. This project developed a new analytical method to determine actual bioavailability. Benefits include the potential of a greatly reduced remediation area. A final report has been submitted and accepted by the project funders as well as the USEPA, the NY State DEC and the NY State Department of Health. In February 2012 the NY State DEC issued a remedy decision based on the new analytical method for the city of Hudson NY (Water Street) company site. Savings realized for this one remediation are approximately $26M.

M2008-006 – Expanding the function of No Blow Tools. Tools to make "live" taps into gas mains are commercially available but during certain operations small amounts of blowing, or escaping gas are present. A set of innovative tooling was developed to enable plug insertion or removal, or insertion of stoppers. This benefits the environment by reducing the amount of methane (a greenhouse gas 21 times more potent than carbon dioxide) released into the atmosphere, and also contributes to worker safety. A second phase of the project developed an innovative method to reinject gas into an adjacent main segment rather than blow it off to atmosphere during a special test called a "flow test." This method reduced greenhouse gas emissions and lessens customer concerns and complaints.

M2009-003 – Adaptation to Climate Change. The company and others recognize that there are two aspects to climate change, how we, through our methane and CO2 emissions, affect climate change, and how we, as LDCs, adapt to climate change effects and impacts that are certain to occur in the future. To meet this latter goal the Company and others commissioned a study that investigated a range of future climate models, predicted maximum and average expected temperatures and sea level rise, and developed a framework for estimating risk and remedial action to address those climate changes. Phase II examined more detailed flood risks at the local level for sponsoring companies. The benefits of this project will be the development of a gas-industry specific risk-based framework for addressing the impacts of climate change on a broad geographic level to give LDCs quantitative information on which climate effects and impacts to focus on and which portions of our natural gas infrastructure are most susceptible to those climate impacts. A final report has been issued and sea level rise has been identified as the main threat to a natural gas distribution system.

M2010-002/ T 776 – Methane MR Sensor/Residential Methane Sensor Pilot Testing Program. See details under Leak Detection and Methane Emission section of this report.
M2010-004 – Soil Vapor Intrusion The work in this project involves characterizing manufactured gas plant (MGP) coal tar vapors so that volatile organic compounds (VOCs) can be conclusively identified as either coming from an MGP or from some other source. For example, benzene, a constituent in coal tar, could also be present in a dwelling from common household sources. If compounds such as benzene are identified near a dwelling, current regulations require extensive sub-slab (below the basement or slab of a dwelling) sampling at a cost of $10,000 per dwelling. However, if MGP coal tar can be ruled out as the source of the contamination, less expensive investigations would be warranted.

M2011-004 – Carbon Calculator. The Company has been voluntarily reporting fugitive methane emissions since the mid-nineties and is committed to reducing its carbon footprint. One component of that carbon footprint is carbon dioxide emissions resulting from normal construction activities. The intent of this project is to quantify the emission reduction that would result from choosing a less energy intensive method of construction. For example, there are two alternatives to installing a new gas main. The first is traditional open trench, where a trench 18 in wide by 3 ft deep is excavated along the proposed length of the installation. In an alternate method, the pipe may be installed via directional drilling. This latter method is quicker, uses less equipment for a shorter time, and eliminates the bulk of new paving that must be applied. But up until now there has been no way to quantify the reduction in emissions. This project involves quantifying the emissions that result from each step of the construction process.

NYSEARCH, together with the North American Society for Trenchless Technology (NASTT) is working with ETA/Environ, to develop the spreadsheet tool. In the first phase of the project, subject matter experts from the participating companies are quantifying types and time on the jobsite of various pieces of construction equipment used on various construction activities. Then, ETA/Environ will use the latest EPA “non-road” emission factors to compile emission rates for the various pieces of equipment. In the final step, ETA/Environ will create a robust, user friendly spreadsheet tool to enable gas company managers to compare the carbon impact of alternative constriction practices.

There are several benefits from this project; determining the construction methods with the least environmental impact, validating the additional (environmental) benefit to public authorities who may be skeptical about the use of a newer or non-traditional construction technique; and it could allow the Company to be proactive in tracking and reporting (if required) these emissions.

OTD 6.8.a - Carbon Management Information Center.
The Carbon Management Information Center (CMIC) was established in 2007 to serve as an on-line clearinghouse for relevant carbon management information. The CMIC serves the gas industry, its customers, and other stakeholders by developing resources and analytical tools to provide clear, concise, and technically-sound information on issues related to reducing the nation's energy consumption, source energy codes and standards, and carbon emissions.

OTD 7.9.d and 7.10.c – Improving Methane Emission Estimates for Natural Gas Distribution Companies. The Company and other LDCs have been voluntarily reporting fugitive methane emissions from their distribution systems under the US Environmental Protection Agency (EPA) “Star” Program since the 1990s. With the recent passage of EPA “Subpart W” LDCs are now required to report these emissions.
To report emissions from its piping network, which account for over 80% of the Company’s fugitive emissions from its gas distribution system, the EPA allows the use of emissions factors, expressed in terms of cubic feet of methane per mile of pipe per year.

Different pipe materials have different emissions factors. The factor is simply applied to the mileage of pipe in the system and total emissions are reported.

These emissions factors were developed in the early nineties via a testing and measurement program sponsored by the USEPA and conducted by the Gas Research Institute and subcontractors. The factors have never been updated and the Company and industry in general, are aware that the factor for plastic (PE) pipe is unrealistically high. For example, a similar study in the UK conducted in the early 2000s resulted in a leakage factor for PE pipe that is one half the value used in the US. PE piping systems are fabricated with improved materials and installed under better quality control than in the nineties, and the emissions testing program for PE pipe done then only contained six data points – for the entire nation!

Working through GTI and subcontractors, and with the knowledge of the USEPA, the Company and others are replicating the test methods from the previous study and attempting to develop a more realistic emission factor. Project funders (there are 18 LDCs participating) are identifying leaks in the field and the GTI team measures them. In parallel with conducting the leakage measurement (which involves exposing the leaking pipe segment) an alternate measurement technique is being applied which involves only surface measurement of leakage. If the two separate techniques agree, more field measurements can be taken with the less expensive surface measurement technique. Several field tests have taken place so far with others scheduled. After the PE leakage factor is revised, a second phase of this project will revise the factors for cast iron and bare steel pipe materials. The benefit of this project is more accurate reporting and a better representation of the company's contribution to greenhouse gas emissions.

Infrastructure Support

The following projects benefit overall company operations in areas such as safety, sensing and measurement, advanced material research, community and customer concerns, and general operations improvements.

M2009-002 - Mercaptan Sensor Development. To insure proper odorant levels in natural gas, LDCs are required to perform a periodic "sniff test." The human nose can detect odorant levels in the ppb range and if the gas is properly odorized this provides adequate warning to the public that gas is present at levels well below the "lower explosive limit" (LEL). However, sniffing by humans is subjective and technicians performing these tests can sometimes be desensitized to the odor of mercaptan. Also, the recently identified phenomenon called "odor masking" can cause the characteristic odor of mercaptan to change or disappear. This project aims to develop a portable sensor that can detect mercaptan in the ppb range. It would not replace the sniff test – which is required by code – but would supplement those tests, and would also be installed in areas where odor fade or masking is suspected, to verify that proper odorant levels are present. The technical approach is a unique combination of standard gas chromatography and a relatively new technology called differential mass spectroscopy. This technology was discovered via the NYSEARCH "Oracle" project mentioned above. Feasibility testing has been successfully completed and a prototype instrument is being built. Due to an instability issue, re-design work was attempted by the first contractor in place of additional field tests. With that work not solving the problem, NYSEARCH sought additional expertise and is now working with UC Davis to resolve the engineering issue associated with instability before going to advanced prototyping and testing. The benefit is advanced warning of possible odorant deficiencies.

M2010-002/T-776 – Methane MR Sensor. See details under Leak Detection and Methane Emission section of this report.

M2010-003 – PCB Absorption in PE Piping. Every year the Company discards quantities of polyethylene (PE) pipe that have been removed from service because they have been damaged by third parties, or for other miscellaneous reasons. The Company ships such pipe to a special landfill that accepts PCB-contaminated pipe because there is no EPA-approved method for decontaminating PE pipe potentially exposed to PCBs. The Company determined that the same approved procedures used to clean and decontaminate steel pipe may be applicable to PE pipe, if it can be proven that PCBs are not absorbed into the wall of PE pipe. Such testing has never been conducted for PE pipe. This is a Material Science Study to evaluate whether there are particular PE pipe characteristics that interact with PCBs. Address decontamination issues so that abandoned PE pipe can potentially be left in place. The Company, through NYSEARCH, engaged Jana Labs – a respected plastic pipe research and testing laboratory – to conduct this testing. The tests are underway with Jana. Pending a successful outcome of the test program, the Company will work with the USEPA to create a standard for cleaning and decontaminating PE pipe so it may be discarded in a normal fashion.

M2011-001 – Self Healing Pipe. Through the NYSEARCH “Oracle” Program, the Company has become aware of advances in material science through nanotechnology. Several concepts related to advanced materials were addressed and the two most promising were self locating pipe (pipe containing materials that would respond to conventional above ground locators, thereby solving the problem of broken or malfunctioning tracer wire) and self healing pipe. (Self locating pipe was discussed among NYSEARCH members and the group, after careful consideration, decided not to pursue that technology at this time.) The Company and other NYSEARCH members want to explore further the concept of self healing pipe so this project was authorized. Our investigations indicated that the addition of different types of nanoparticles into polyethylene (PE) material can enhance its mechanical or electrical properties. One type of adder can actually induce self-healing capabilities in the base PE material. A crack in the material will release a bonding agent and lab experiments conducted by others show recovery of up to 75% of tensile strength of the base material. The Company wants to pursue this further and feasibility discussions with manufacturers will commence. This is a long term project with ultimate benefits realized perhaps 25 years into the future. The project will be carefully monitored and will proceed in phases. Reduction in distribution pipeline incidents due to damage is the benefit of this research. The objective of the program is to develop a new generation of PE based pipes with self-healing properties for use in the natural gas industry. Following completion of the feasibility study, additional work was completed to prove that the PE pipe when altered for the self-healing nanomaterial would retain its required strength properties and at those conditions, still provide self-healing capability. It has been proved that the strength properties are maintained. Additional research is necessary as to evaluation of all conditions and development of various PE piping appurtenances. NYSEARCH is reframing the program to move from feasibility testing to more advanced development.

OTD 1.12.b - Cross-Bores Detection Using Mechanical Spring Attachment. Research is under way to develop a tool that will detect a hit to a sewer pipe during the installation of a gas pipe. A prototype for field testing was built that uses a mechanical spring system that is activated inside the sewer pipe void to provide a real-time alarm identifying a hit. Laboratory and field tests were conducted in 2013-2014 and a patent application for the technology was filed. In testing, the tool was able to successfully indicate the voids in pipes which were hit (i.e., providing positive indications). Several modifications of the proto-type may be performed with future commercializers. — A report on the results of field-test activities is being prepared.

OTD 1.13.a - Real-Time, Multiple Utility Detection During Pipe Installation Using HDD Systems. Research and testing is being conducted on an acoustic-based technology to detect obstacles during horizontal directional drilling (HDD) operations. The ultimate goal is to develop a system that can automatically and rapidly detect buried pipes/obstacles in front of and adjacent to the drill-head of HDD machines. The system was tested with seismic/noise sources and under differing attack angles to pipes. Post-processing data showed that the acoustic system was able to achieve the average pipe detection accuracy of ± 2.1' during the trials. — New and improved noise sources are being developed for further evaluation.

OTD 1.14.e - Plastic Pipe Locating—Alternatives to Traditional Tracer Wire. OTD along with GTI and 3M submitted a White Paper to DOE/PHMSA for a project that would have a very similar work scope as this current OTD project. The proposal resulted in an award from PHMSA with work expected to begin in the fourth quarter. The revised scope of the project is to develop an electronic marking system that will provide locatability on various-diameter HDPE and MDPE pipes. The project will also assess the technology capabilities versus pipe diameter, burial depth, and pipe-burial methods (horizontal directional drilling, open trench, etc.) —The contract for the new PHMSA-supported project is being finalized.

OTD 1.15.a - Cross Bores—Sewer System Cleanout Safeguard Device. This project focuses on the development of a safety device that provides the ability to seal the sewer-system cleanout opening in the event a natural gas line (inadvertently installed in a sewer) is struck by a power auger or other mechanical tool. The project team finalized a prototype cap design. Based on evaluations, 35 split caps were manufactured and shipped to sponsors for evaluation. — The project team has been in discussions with a manufacturer regarding commercialization of the split-cap safety device.

OTD 1.15.d - Improved Camera Imaging to Identify Cross Bores. The objective of this project is to provide an evaluation of imaging systems with the potential to work in conjunction with various types of trenchless pipe-installation technologies (including the use of horizontal directional drilling equipment with drilling mud) and still be able to positively identify a cross bore. An initial patent/literature search produced no new information on sewer camera technology. This, along with discussions with experts in the industry, indicated that there is little that can be done to improve this technology without additional technology platforms. Subsequently, several potential alternative platforms were identified. — Communications are being arranged with project sponsors to discuss the technologies identified and deter-mine future plans.

OTD 2.7.d - Cold Adhesive Repair and Joining of Polyethylene Pipes with Minimal Surface Preparation. In this project, researchers tested a cold-adhesive repair technique in an effort to develop an economical, reliable, and safe technology to quickly and effectively repair damaged plastic gas pipes. Long-term test results of PE pipes patched with the repair method found that the patching system can be effective. Testing also resulted in additional information about the effective application of the adhesive. — A Final Report on the project is being prepared.

OTD 2.10.b - In-Service Field Evaluation of Polyurea Coating Systems.
As a follow-up to a previous project, research into field-applied polyurea coatings for gas industry use is being conducted on promising coatings. Long-term field trials will be performed to evaluate these coatings and determine a cost-effective coating-application method and process for structural liners. — Installation and evaluation of the coating was successfully completed at a sponsor site in November 2015.

OTD 2.11.a - Development of a System for Repair of Aboveground Leaks.
Researchers are conducting a thorough evaluation of repair methods for leaks on aboveground piping in an effort to establish a basis for choosing the right repair method for a specific leak, establishing levels of adequate preparation, and providing the proper installation for increased reliability. Prototype test samples were constructed to simulate aboveground leaks from varying levels of corrosion (pin holes) and from threaded joints. Test samples were fabricated, fitted with the corresponding repair systems, and hydrostatically tested to failure. — Testing is ongoing.

OTD 2.12.a - Integrated Expert Monitoring and Training System for Butt Fusion.
A set of critical fusion variables is being developed to provide an integrated technology package for use in pipe-fusion training and field operations. The goal is to produce a system capable of flagging marginal fusions in all operating conditions. In the third quarter of 2015, all butt-fusions and low-temperature high-speed tensile tests were completed and creep testing initiated. A significant amount of test data post-processing was completed and correlation of the test data to butt-fusion conditions initiated. — A Final Report is being prepared.

OTD 2.14.c - Assessment of Squeeze-Off Location for Small-Diameter Polyethylene (PE) Pipe and Tubing. Researchers developed a model for predicting the effects of squeeze-off on small-diameter PE pipes. Mechanical testing was tailored specifically for the squeeze-off mod-el to capture the application's conditions. Technicians prepared a total of 230 specimens for testing. The results from the squeeze-off FEA model indicate that a squeeze-off can be performed at a distance three pipe diameters from a fitting with any size pipe. The project team initiated efforts to revise ASTM F1041; however, feedback received from ASTM indicates the project needs to address squeeze-off near mechanical fittings as well. This additional scope of work is to be submitted to the project sponsors for consideration.

OTD 2.14.e - Guidelines/Best Practices for Scraping PE Pipe and Fittings
Research is focused on the development of a functional set of improved, up-to-date guidelines for PE pipe and fittings that take into account current tooling and practices (e.g., scraping) while addressing the variables associated with fusion execution. Information from survey results was combined with data from previous projects and a test matrix for the pertinent tools was developed.

OTD 3.8.a - Addressing Jackhammer Noise Abatement. In urban areas of the Company's territory there is increasing pressure from city officials to lower the noise of commonly used construction equipment. Evening and weekend work, such as is required for emergency response work, only amplifies this need. Pneumatic jackhammers are among the noisiest of commonly used construction equipment. National Grid, in New York City, experimented with insulated fabric jackets that are placed around the jackhammer and while these helped to reduce noise levels, a more permanent solution is desired. The Company and others are working through GTI to try to engage jackhammer manufacturers to examine the design of a typical jackhammer to see if there is any opportunity to reduce the noise produced. It is recognized that noise from a jackhammer is produced from three distinct sources, the internal piston operating inside the cylinder, the air exhaust, and the bit striking the pavement.

The objective of the project is to engage manufacturers and determine whether they are open to a basic redesign effort of their tools to make them less noisy. GTI identified several manufacturers but only one was willing to attend a meeting to discuss the intent of the project. As a result, the project will most likely not proceed to Phase 2, which would have involved detailed noise analysis and would have served as the basis for a redesigned jackhammer.

OTD 3.14.a - MBW Soil Compaction Survey Enhancements. The SCS fills a need to verify soil compaction levels during field operations (excavation back-filling). The memory media that was used in the previous version of the SCS is cumbersome to use and has become obsolete. The industry practices in field data collection have also evolved considerably since the SCS was first introduced. The objective of this project is to upgrade the capabilities of the Soil Compaction Supervisor (SCS) to make it compatible with modern Geographic Information System (GIS) data capture practices as well as more user friendly through better data logging and reporting capabilities. Initial efforts will also be investigated to determine the SCS's ability to be correlated to a standard proctor value or range. The ability to attach metadata such as GPS coordinates and photos to compaction data is now wanted for entry into a GIS. Transferring compaction data from a mobile device to a GIS with the additional capabilities available on mobile devices (GPS, camera, etc.) will be incorporated into the data acquisition for the compaction record. By redesigning the SCS, a useful tool will continue to be available and the data generated can be directly imported into utility GIS or other data systems. Capturing and archiving the soil compaction data will help ensure that compaction is being performed properly (quality control) and will enable a utility to validate proper compaction to jurisdictional and/or regulatory authorities. The testing portion of the project seeks to better understand the correlation of the SCS data with that from a nuclear densitometer to provide a lower cost alternative.

OTD 3.14.b - Update ASTM Standard of DCP Compaction Control. Through this project, interactions were made with ASTM to update its current standard on the five-pound Dynamic Cone Penetrometer (DCP) compaction control device. The ASTM standard D7380-08 (Test Method for Soil Compaction Determination at Shallow Depths Using 5- lb. DCP), which was developed in an earlier OTD project, completed the balloting process of its standards in September 2015. The OTD-developed standard passed both the sub-committee ballots with no negatives. —The project team is following up with the ASTM Publications Committee to complete the process of adding the new version to the ASTM 2016 standards publication.

OTD 5.6.e – Portable Propane Air Temporary Residential Supply, Phase II
Many routine gas operations require temporary disruption of service to customers. Replacement of aging gas mains requires a brief interruption while the service is transferred from the old main to the new main. Meter change activities also require a brief shutdown. Rehabilitation techniques such as cured-in-place lining can require an outage lasting 12 hours or more. In such cases compressed natural gas (CNG) bottles can be used but they are heavy and cumbersome. The propane air mixer has been under development since 2006. It mixes propane from a standard gas barbecue tank with air and delivers the mix at the proper heating value. A prototype was built by GTI engineers and subjected to extensive operational and end use testing, including local field testing in Chicago. Tests were successful with the exception of results with one particular brand of water heater, which shut down on high flame temperature. Phase II of this project will redesign the unit to produce a cooler flame and the testing will be repeated on a mix of appliances. Firing rate, flame temperature and emissions will be recorded. If the testing is successful (meaning all appliances performed within spec on all tests) then a new phase of the project will investigate commercialization of the unit. The benefit is better customer service using a more efficient and ergonomic method.

OTD 5.7.p - GPS/GNSS Consortium. The project objective is to facilitate the sharing of information related to the use of GPS, Global Position System [US reference] and GNSS, Global Navigation Satellite Systems (International reference) technology for utility operations. The GPS/GNSS Consortium is a cost effective way for utilities to better understand this rapidly growing technology field and how GPS technology can best be applied to daily operations to create operational efficiencies, enhance regulatory compliance, and improve the quality of field collected data. The program activities include technology development and integration, workshops, pilot projects, demonstrations, best practices/standards development and general information sharing. Over the last two years, the GPS Consortium has focused on technology development that will reduce the cost and complexity of deploying GPS for routine construction and O&M activities. A Real Time Kinematic (RTK) base station has been installed, on GTI's main campus. This base station was built using GNSS Consortium funds in 2014 and continues to be an important asset for GNSS and GIS research at GTI. The following emerging technologies were selected for evaluation; Garmin GLO, Swift Navigation Piksi RTK Kit, uBlox Neo-7P & EVK-7P. Additionally, the following well known legacy units were tested to provide base-line comparisons; Trimble GeoExplorer XH, Navcom SF-3040, Geneq SxBlue III. GTI has completed testing and results are currently being compiled.

OTD 5.8.a - Automated Welding. This project will identify and select an automation manufacturing partner, develop a beta prototype automated welding unit, and create procedures to perform the welds on various types of tees and nipples. Throughout the project, the project team will work with the selected manufacturer(s) to assist with the implementation of the unit as a commercially viable product for the industry. A final report will document these efforts.

OTD 5.8.d - Tool for the External Classification of Pipe Contents
Research is being conducted to develop a practical tool that can detect "live" three-phase electrical cable in pipe without breaching the pipe wall. The ultimate objective is to develop an affordable tool that could be carried in each crew truck. The current project phase involves the construction and demonstration of a pre-production proto-type tool. Recently, the main focus was to debug the software required to perform the Fast Fourier Transform (FFT) on the vibrations detected on a pipe. The hardware platform was demonstrated to run the FFT library functions correctly; however, the signal level captured was somewhat low. This will need to be corrected in the hard-ware by adding amplification between the vibration sensor and the processor. The project is behind schedule and potentially will require additional time. — Software and hardware modifications are under way.

OTD 5.08.e.2ab - Enhanced Material Tracking and Traceability-Development of Standardized Protocols/Identifiers for Meters, Regulators, and Transmission Pipelines, Phase 2 (TEJ). The objective of the program is to utilize the previously established base-62 di encoding system methodology and develop a series of unique identifiers and format to characterize pertinent information for meters and regulators conforming to ANSI B109 requirements. TEJ continued its work related to proposed changes to ASTM F2897 to incorporate key data related to transmission pipeline components (pipe / appurtenances). The initial ballot for the F17.60 subcommittee ballot was submitted in December 2013 (one negative and five comments were received). The negative has been resolved and proposed ballot has been revised accordingly. The revised amendments were submitted for concurrent main and subcommittee voting. Provided that the ballot is approved, all the necessary identifiers required to produce a 16-character code schema to mark transmission pipeline components should be in place. It is important to emphasize, even with the proposed changes in place, this simply provides all the elements needed to develop a similar 16-character code for transmission components and satisfy the objective of this phase of the program. Additional work will need to be incorporate these requirements within applicable API 5L standards and resolve underlying procurement practices and supply chain considerations within utility companies.

OTD 5.9.h - North American Outreach Manufacturer Outreach Program
Research was conducted to identify promising technologies that are under consideration but not currently under development by qualified North American manufacturers. The focus was on prospective products or technologies and that have sufficient commercial value to natural gas utilities to justify submission of a funding proposal to OTD. — A Final Report detailing project results is being prepared.

OTD 5.10.d - Remote QA QC. Development of a remote monitoring program with map based application for smartphones and tablets for field data capture and documentation will advance utility operations and quality inspections. The goal of this project will develop a mobile application with a supporting step-by-step field procedure for its use including guidelines. The focus is to develop technologies and protocols to allow operators to remotely monitor and record the quality of various operations. The quality of field work can then be monitored in real-time using a step-by-step procedure, GPS-enabled cameras, and a web-repository to capture, store, and share photos and create permanent records. Using smartphones to capture time-stamped photographic documentation during field operations improves quality and enhances quality control, particularly for new installations. Field crews, both in-house and contractors are encouraged to follow specifications and procedures because pictures are used to document important steps. Using remote QA/QC methods allows 100% of new installations to be monitored by a quality inspector or office manager and support staff, no matter where they are, they will be able to view pictures of all new installations in real-time and share information. Further, pictures are captured in a GIS environment and can be stored for long-term usage such as validating regulatory compliance, future locating, and engineering operations.

OTD 5.11.a – Dewatering System for Mains. Excessive amounts of water in gas mains can cause service outages. This “water intrusion” is particularly prevalent in low pressure areas where groundwater can enter into a gas main through leaky joints in high water table areas. The normal solution is to locate the area of water intrusion and pump the water out. This project is investigating novel methods to remove residual moisture that can be present even after water is pumped out. Two methods that have been investigated are desiccant and molecular sieve technologies that can more permanently dry out the interior of a gas main, and chemical additives such as methanol foam which can allow moisture to flow out of low points and not collect there. Once the feasibility of such methods is evaluated, the next step in the project will be to decide whether the successful technology can be adapted to installation on a gas distribution system. This project will decrease the amount of customer outages in areas prone to water intrusion. Completed June 2015.

OTD 5.12.b – Development of a Portable Flash Fire Suppression System. During live gas operations the potential for rapid ignition of natural gas (a flash fire) is present. Although workers follow strict safety procedures and are protected with fire retardant clothing and breathing air apparatus, bodily harm can occur within milliseconds if an ignition were to occur. A true industry need exists for a system that can rapidly detect and extinguish flash fires. The project was initiated in GTI's Sustaining Membership Program (SMP). Two separate and distinct challenges were investigated, the ability of a sensor to detect a flash fire in less than ½ second, and the ability of a fire suppression system to limit injury as low as is reasonably achievable. In testing at GTI facilities both concepts were proven; a UV detector reliably detected fires within 30 milliseconds, and two separate suppression systems, high velocity air, and nitrogen extinguished the fire but each had some drawbacks needing further investigation. The Company is extremely interested in this project and Safety Dept. personnel will act as advisors to the GTI project team. A successful outcome of the project will be a portable flash fire suppression system that will effectively detect and extinguish flash fires should they occur and be simple to deploy. Enhanced worker safety and avoidance of serious or even fatal injuries is the obvious benefit of this research.

OTD 5.12.g – Evaluation and Adaptation of Kleiss Inflatable Stoppers for the US Natural Gas Industry. Current line stopping equipment in the natural gas industry has been used since inception (~ 50 years) in the same trim without substantial re-design. This equipment certainly works but is heavy, costly to maintain, and is somewhat time consuming and labor intensive when the installation of the necessary components required are taken into account. New line stopping equipment that may reduce these problematic issues, while providing the same assurance of safety and performance, could contribute to substantial time and money savings when incorporated into day-to-day operations. Through a technology search such equipment was sourced. This apparatus is produced by a European Vendor, Kleiss and Co., and has shown promising performance. The objective of this effort is to evaluate these existing medium and high pressure inflatable stoppers as an alternative to currently employed stopping equipment for use on US natural gas distribution systems. GTI will test and evaluate this inflatable stopper suite of tools (capable of stopping off line pressures of 60 psig at pipe diameters up to 24-inches). Deliverables include the development of testing criteria and a program to evaluate the current offering. In addition, it will identify the necessary modifications to the bagging system(s) and identify deployment fittings required to meet the US natural gas industry standards so that the system may be introduced and deployed for use in the US.

OTD 5.12.o and 1.14.h – Guidelines for Cast Iron Winter Operations and Cast Iron Winter Patrols study. The Company and others want to know the best methods for determining when to initiate winter frost patrols on their cast iron (CI) piping systems. Simply starting the patrols when the ground temperature or air temperature reaches a certain limit may not be optimum. There are other factors, in addition to temperature, which may influence the propensity of CI piping to break in frost conditions. Some of these factors are diameter and pressure of the main, age, soil type, and presence of other adjacent underground facilities. The ultimate deliverable of the project is a practical guideline for operators as to when to initiate frost patrols. GTI was selected to perform the study and is investigating – through examination of LDCs' records - the frequency of breaks in the presence or absence of the potential breakage factors. The study is not complete but has already determined that diameter is a key variable and that most breaks take place on smaller diameter piping and, at least for one LDC, there is no record of breakage for pipelines larger than 18" diameter. As more data is accumulated and analyzed patterns like this should emerge. The end result should be a fact-based guideline, based on the above parameters that affect breakage, stating exactly when, and for which segments, winter frost patrols should begin.

Under OTD 1.14.h, the company did an evaluation with GTI using Picarro's CRDS and some of Picarro's latest algorithms to evaluate if this advanced leak detection system and methodology could improve our winter patrols and identify CI breaks more rapidly. The frost conditions were extreme during the course of the investigation which was ideal for the study. However, it was found that numerous passes are required and the processing of the data took a great deal of time. GTI is evaluating the data to determine if there was significant improvement in detection, however to date, this has not translated into cost savings with this approach for CI winter patrols.

OTD 5.13.d - Transmission Cut In Valve. The development of proposed cut-in valve system will give operators options for the placement of valves without the need to shut off the flow of gas along with the benefit of greatly reducing the cost of installation. This valve concept can lead to: faster installation times especially in urban environments, no need for flow control and/or bypass of gas, single excavations with no need to stop off the flow in the pipe and no need to install a bypass, enhanced safety, and lower cost of installation. This system will be a unique design that meets all material and performance expectations while delivering a compact and fast alternative to traditional valve installation methods. It will be developed to provide important performance and installation benefits to pipeline operators working under difficult conditions and with critical needs. Initially, a concept transmission EZ Valve will be developed for sizes up to 12-inches with working pressures up to 300 psig. After initial proof of concept, a 6 inch prototype valve will be constructed.

OTD 5.13.f - Low-Cost Collision-Avoidance System
Efforts are under way to develop a low-cost, low-speed, collision-avoidance system that would provide gas industry utility vehicles the ability to provide driver alerts and, when necessary, automatic braking. A complete set of laboratory-based testing scenarios was conducted using an experimental test apparatus to generate datasets that represent typical driving maneuvers. Field tests of a wireless tablet PC user interface were completed. For testing, a video system was successfully integrated with the test hardware. — A video is being prepared to demonstrate the capabilities of the system.

OTD 5.13.g - Post Disaster Risk Assessment with LiDAR and GIS. The project objective is to develop pipeline risk assessment tool to identify high risk pipe segments after post-disaster events to prioritize repair and restoration activities. This work is performed along with a DOT-funded project with Rutgers, the State University of New Jersey, to develop a mobile mapping platform that harnesses commercially available technologies to provide remote sensing data collection capabilities and to implement a GIS-based platform for data management and pipeline risk assessment. Progress thus far: the risk assessment approach and model is completed, the Bayesian Network has been integrated into a web-based computer model, and a case study is being entered into this model to estimate damage potential of pipe segments at Ortley Beach, NJ after hurricane Sandy.
The results are pending at this time.

OTD 5.14.a - RFID Testing Program. A testing program is being conducted to compare the performance and features of multiple radio frequency identification (RFID) and related technology solutions for locating and tracking gas utility assets. RFID tag installations were completed for the 3M Marker Ball, the Berntsen Infra Marker, and the Eliot Marker System. Programming of tags, along with user experience and impressions, were recorded. Assets targeted for RFID tagging included a mix of steel and PE systems from existing pipe test beds in addition to available utility hook-ups (gas, electric, and water). — The project team is in the process of locating, reading, and testing all installed above- and below-ground tags.

OTD 5.14.b - Smart Leak Repair Form. A smart leak repair form will improve the quality of data collected during the leak repair process and will lead to improved threat identification and risk assessment for DIMP. The objective is to develop a system to capture more detailed information to allow for more granular analysis to be performed, such as the identification of leak trends. Development of a Fault Tree Analysis and Decision Tree logic will be employed in this framework to resolve issues concerning proper identification of root causes and categorization of failures. The objective of the sponsors is to define an appropriate logic for electronic data collection forms.

OTD 5.14.d 2a – Tracking &Traceability for Transmission Phase 2a: Standards for MTR and Coating Reports and Phase 2b: Data Collection Technology. The goal of this project is to develop standards, guidelines, and technology for tracking and traceability of transmission pipe and components. The ability to automate the process of capturing and storing tracking and traceability information for transmission pipe will improve data quality and reduce risk. Data quality will be improved by using electronic records and barcode scanning to capture data essential for MAOP calculations and integrity management. Eliminating manual, paper-based data collection will reduce the occurrence of human errors when capturing and transferring data into the asset management system. In addition to data quality, operators will have access to pipe and coating data that can be used for threat identification and risk modeling as part of integrity management. The results of this project will provide the industry with a standardized approach for capturing pipe, appurtenance, welding and coating data. Phase 1 identified data collection requirements, developed barcode labeling specifications, and created a design document for field data collection software. Phase 2a will create standardized forms for Mill Test Reports (MTR) and factory applied coating information. Phase 2b will create technology to capture manufacturer information using standardized barcodes and develop and test the technology in a proof-of-concept project. Phase 3 (future) will create standardized forms and technology to capture field welding and field applied coating data. GTI will propose a Phase 3 to develop standards and technology for data collection of field applied coatings and field welding operations.

OTD 5.14.f - Battery and Electric Powered Tool Evaluation, phase 1. The use of battery-powered power tools in Class 1 Division 2 environments is limited by most LDC's best practice policies; however, this project aims to investigate this topic to propose alternative ways to improve safety of these highly useful devices.

OTD 5.14.n - Construction Compliance Monitoring System. The goal of this project is to develop a risk-based Construction Compliance Monitoring (CCM) system to assist operators in ensuring and quantifying the compliance of new construction. The CCM system will be composed of a model and software. The system will assess new construction work from a system-risk perspective and will deploy audit resources based on the probability and consequence of failure for specific job sites. It will identify high risk construction activities, generate prioritized audit schedules, provide electronic audit forms on tablet computers, collect audit results, and quantify the level of compliance using industry-standard statistical methods. This project will create the CCM model and a proof-of-concept system that will be tested with one operator. Full commercialization will be pursued in a second phase, if desired by OTD. The deliverable of this project will be a model and software sufficient to prove the concept and demonstrate the value of a compliance monitoring system. Provide documentation of compliance that can be used in communicating with regulators, insurance providers, or in the event of potential litigation. The benefits of the project: Maximize the efficiency of resources devoted to ensuring compliance. Implementations of this methodology may reduce the number of field inspectors required to achieve the desired level of confidence by targeting and optimizing the deployment of audit resources, improve construction performance and efficiency, and continuously improve risk management efforts by better understanding the sources and frequency of installation error.

OTD 5.14.p - Developing Devices to Use with the Jameson Directional Insertion Tool The objective for this project was to evaluate and modify devices or attachments for use with the Jameson insertion tool to increase the use and capabilities of live in-pipe inspection. A survey was conducted to obtain information on the current tooling and practices for live camera insertion, water removal, and digital mapping. Tests were performed to evaluate the ability of a camera to be inserted into a two-inch PE pipe through various access fittings. Tasks related to water removal and mapping-device insertion have not moved forward as survey results did not identify any devices that sponsors are currently using. — A Final Report is being prepared.

OTD 5.14.t - Methods to Detect Inserted Plastic in Steel Mains. This is an investigation into the feasibility of techniques for detecting inserted PE pipe. Three methods were considered as the most promising from an ease of field application perspective: 1) flow noise, 2) rate of cooling, and 3) modal analysis. Measurement of flow noise and/or cooling rate should work for large volume flows and the results are a function of flow rate, becoming ambiguous when volume flow decreases to zero. Using a combination of the two requires developing a method relating flow noise to cooling rate that is different for pipes with an insert and no insert. Because gas flow in a main varies greatly (including zero flow), a method independent of gas flow would be preferable for this application. An impulse modal analysis, being independent of gas flow, was seen as the most promising for identifying inserts across the largest range of flow conditions. Practical, reproducible, and easy to apply methods for generating and detecting the acoustic waveforms were identified. This technique can be used on the crown of the pipe. Measurements were performed indoors on bare, 2-inch diameter steel pipe found a large number of acoustic vibration modes. The amplitudes of the frequencies are different and depend on the insert diameter and the separation distance between the impact point and transducer location. Although the spectra are complex and additional work is required, the indoor results suggest it should be possible to distinguish among no insert and various insert diameters. Similar measurements were made in the GTI's pipe farm. The 2 and 4-inch diameter steel pipes were longer, coated with fusion bonded epoxy, and buried at both ends beneath raised earthen berms. The frequency range was greatly reduced and any differences between inserted and non-inserted pipe were small at best. It is unclear whether the reduced spectral content of the signals is due to earth and/or pipe coating attenuation, or variations in the method of attachment for the accelerometer to the external pipe surface. Additional work would be required to determine if any of the three techniques are feasible. The work performed to date has been on the impact modal analysis technique. As noted above, promising results from the indoor work did not translate to the outdoor setup with soil and coating interactions. This work was completed in 2015.

OTD 5.14.u - Evaluation of Geospatial Technologies. The purpose of this project is to evaluate two new geospatial technologies that could have engineering and operations applications for operators. The technologies to be evaluated could include wearable augmented reality devices (such as Google Glass) and handheld 3D mapping tools (such as Google's Project Tango). This project will test select technologies at GTI and local utility sites and develop recommendations for applications such as leak survey guidance, facility location and attributes, equipment repair, mapping of new and existing facilities, and emergency response. There are many advancements being made in the consumer hardware space and that the hardware and devices being developed can hold a lot of potential for the gas industry. Through efforts such as this project, research on new technologies can identify applications for the gas industry. Not every technology is going to provide the benefits that are intended, but through testing and identification of these technologies, ongoing research can bring new technologies to the gas industry. Microsoft HoloLens and other successful technologies such as Google Project Tango were identified in this project as technologies showing potential for further gas applications from which the company and the entire gas industry may benefit.

OTD 6.6.a - Keyhole Consortium. This GTI program develops continuous improvements and innovations to small hole (keyhole) technology. Keyhole excavations involve 18” diameter road openings to perform many routine operations that would traditionally require a 4 ft. x 4 ft. opening. Soil is vacuumed out and work takes place from street level using special long handled tools. This reduces paving costs and in many cases the 18” core is reused – set back in the excavation so there are no paving costs associated with the work. The Keyhole Consortium meets twice yearly; Company representatives attend with other LDCs and manufacturers. At the meeting common issues and needs are discussed and new research ideas are generated.

OTD 7.14.a - Next Generation Water Clean-up Technology. The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) has proposed IVP regulations that will require operators to verify the integrity of transmission pipes without pressure test records. These regulations could potentially require the industry to hydrotest up to 90,000 miles of in-service pipe. Cleaning and disposing of the hydrotest water is a significant component of the overall cost of hydrotesting. The objective of Phase I of this project is to conduct a technology review and business case to quantify the cost of disposing of water using current methods and the potential savings that could be achieved with new technologies. It is anticipated that development and implementation costs will be significant, thereby warranting a formal business case prior to pursuing technology development or technology transfer. Results of the industry survey taken in this project indicates that conventional management of pipeline discharge waters most often includes either hauling of the water to a publicly owned treatment works (POTW) for disposal or field-based filtering of the water through a ring of hay bales. The POTW alternative requires significant expense in transportation and in discharge fees; all costs connected with this option often exceed $0.50/gallon (2014 dollars). The hay bale alternative (whereby water is forced through a ring of hay bales) is sometimes used in the field, but the method only seems to work for the control of oils and greases and suspended solids but is not effective in removing many soluble organic compounds of concern such as benzene. Clearly, a second generation treatment system is needed that allows low cost field based treatment that is reliably compliant with water quality criteria specified in permits for water reuse and discharge to surface waters. Primary treatment systems used by industry in the past such as sedimentation and dissolved air flotation have been effective in control of suspended solids and free oil and grease. Granular activated carbon (GAC) is effective in removal of soluble organics, but becomes expensive when treating waters that are greater than 1-5 mg/l of total organic carbon (TOC). Biological treatment can be used to remove soluble organics, but the process requires too much of a footprint to be practical. Chemical oxidation, however, can be used for oxidizing most of the soluble organics while taking up a very small footprint. What is needed, however, is a chemical oxidant that is easy to handle and use in the field as a part of the integrated mobile treatment system. A review of commercial chemicals indicates that many of them are not suitable for implementation in a highly mobile, treatment system applied to 1-2 day processing of hydrostatic test waters. A list of information gaps is described in the report; these gaps can be resolved with research and development concentrated on the oxidation step of the advanced treatment flowsheet.

On the basis of this technical evaluation, it is recommended that the industry consider development and optimization of the manganese dioxide oxidative process for the conditioning of pipeline discharge wastewaters. This development work should be pursued in the context of an integrated prototype that includes all of the treatment steps that preceded and follow the oxidation process.

Cathodic Protection, Coatings and Corrosion Related

M2012-001 - Development of a Corrosion Sensor Array. This project will attempt to develop a novel method of monitoring for external corrosion on a gas pipeline by installing an "array" of sensors on a pipeline. If successful, pipeline operators will have another "tool in the toolbox" for monitoring critical pipelines for external corrosion. This project utilizes an existing microsensor-based system to provide corrosion monitoring of full sections of gas pipelines. The project will initially modify the system and then assess its suitability for the natural gas industry through lab testing. The core technology employed is the micro-linear polarization resistance sensor developed originally for aerospace applications.

OTD 2.9.c - Field Applied Pipeline Coatings. Modern pipe materials are factory coated and these coatings stand up very well as long as they are not damaged by external forces. However, in locations where field welds or other field installed fittings are present, the necessary pipeline coating needs to be field applied. Field applied coatings vary in quality and are not always installed under ideal environmental conditions such as would be present in a pipe coating factory. This project tested the performance of several different types of coatings on buried pipe at Gas Technology Facilities in Chicago.
Throughout the world, a variety of generic coating systems are commonly applied to field girth welds, including the following: (1) fusion bonded epoxy (FBE), (2) heat shrink sleeves (HSS), (3) liquid applied coatings, (4) composite systems, and (5) tapes/wraps. Eighteen (18) manufacturers supplied seventy-five (75) different coating systems for the test program. The coatings were installed by the manufacturers on a network of 8" and 24" steel piping buried in rocky, sandy, and clay-like soils. Coating systems were unearthed and examined at 2, 5, and 7 year intervals. Some coatings exhibited no rust on any of the pipes in any soil, and other coatings exhibited rust on pipe in all soil. A key conclusion of the test program is that strict adherence to the manufacturers' recommended installation procedures is absolutely necessary. A final report on project results has been prepared. The benefit is improved pipeline safety and assurance that superior products, from a long term performance point of view, are installed on company facilities.

OTD 5.9.c - Mitigating Electrical Interference on Cathodic Protection Systems.
Electrical interference can impair or negate the effect of cathodic protection systems. The objective of this project is to understand the types of interference that can be present near pipeline systems and make recommendations to mitigate the effect of these interferences. Interferences can be steady state, such as would be present from adjacent high voltage power lines or transient, caused by a lightning strike or power line surge.
To implement the project, GTI selected three host sites and installed data logging instrumentation on cathodic protection systems there. Transient events and steady state

interference data is being gathered. The results of the data gathering exercise will be recommendations for enhanced equipment or better surveillance of cathodic protection systems to better protect them. Enhanced integrity of piping systems protected by cathodic protection is the benefit of this research.

OTD 5.9.f – Cathodic Protection Monitor. The objective is to develop and deploy a Cathodic Protection Monitor prototype that stores monthly CP readings. GTI has partnered with 3M to develop a completely encapsulated, direct burial monitoring device. A 3M handheld locator/reader is used to retrieve the readings electronically from above ground without requiring a direct connection. The data, consisting of 12 sets of monthly readings, can be downloaded from the handheld devices as tabular data. The first version of the CP Monitor has been successfully tested; as a result of testing additional product requirements were identified. The objective of Phase 2 is to develop and test a modified CP Monitor prototype with some or all of the following features: ability to record AC potential readings to detect stray currents, increased data storage, improved range with the ability to capture readings from a moving vehicle, programmable data recording intervals, and ability to transfer data to other handheld devices via Bluetooth for direct GIS integration. The benefit is improved monitoring of CP performance on protected piping, with the potential cost savings of making mobile readings

OTD 5.11.n – Quality Control Procedure for High Potential Anodes. The Company recently has been experiencing quality problems with magnesium anodes as delivered from manufacturers. Anodes that appear – upon visual inspection – to be sound have been experiencing premature failures in the field. Quick and simple voltage tests may initially reveal that the anode is generating the required voltage potential but this may be indicative of good quality of the surface layer of the anode only. If the entire anode is not of the same quality and purity the anode will deteriorate prematurely. The standard industry test for measuring anode purity, ASTM G97, is expensive and time consuming and it is not practical to conduct this test for all new anodes received. Therefore, there is an industry need for a quicker test that can validate the requisite quality and purity of anodes. GTI has received anodes from project participants and is currently evaluating alternate methods of testing them that can give results similar to the G97 test. As an indication of the need for this project, GTI reports that the project has experienced delays due to the time consuming nature of the G97 test, which is being performed in parallel as a control. The benefit is better assurance of the quality of materials received and installed in the company's gas system.

OTD 5.12.n – Advanced Tools for Improved AC Corrosion Prevention and Mitigation. Alternating Current (AC) corrosion is not common but can occur if gas mains are in proximity to railroads or overhead electric transmission lines. When it does occur, the corrosion rates can be rapid, thus the need for the Company to quickly identify and mitigate the occurrence of AC corrosion. The company is working with GTI on this project and they have proposed a two part solution, a model to predict rates of AC corrosion, and a calculator to determine the most effective mitigation measure. The project will draw heavily on existing work done by the National Association of Corrosion Engineers (NACE) and the Company's and other funders' experience. The final deliverable of the project will be the model and calculator, which can be used to prioritize inspections and gauge the impact of various mitigating measures on both new and existing gas pipelines.

OTD 5.14.x - Risk-Based Atmospheric Corrosion/Leak Survey Considerations
A study reviews historical and current data on atmospheric corrosion of indoor service piping. A detailed review of the published, peer-reviewed literature related to field data on indoor corrosion was made. A comparison of the fundamental principles of indoor and outdoor atmospheric corrosion was made. The research conducted compares and contrasts indoor atmospheric corrosion to outdoor corrosion for iron and steel piping materials. In addition, thousands of recent inspections in NY and New England States were completed on outdoor and indoor services by operators the data was collected and statistically analyzed to determine the trends and drivers behind the observed corrosion rates. A similar analysis was completed on exclusively indoor leak survey data from LDC operators. Finally, all the findings were summarized and related to risk-based considerations for setting appropriate inspection intervals for indoor service piping. This art of the study was completed in late 2014.

General and Other Areas Not Covered Elsewhere

M2001-013 - Millennium Website Development. A project for maintenance and upgrading of NYSEARCH's website and for use by the NY LDCs who utilize NYSEARCH as a clearinghouse for reporting to the NY PSC on the use of the Millennium R & D funds

M2002-008 - Oracle Technology Concept Investigation. Through the NYSEARCH research consortium, the Company and others fund a concept known as “Oracle.” The purpose of this program is to look outside the gas industry for novel technology solutions to gas industry needs. In the past, technologies from the military, biomedical, and telecommunications industries have been tracked. More recently, our focus has been sensor technologies using fiber optics or nanotechnology, and material science advances. Applications from these industries, when identified, will be funded as separate projects. An example of that is a current effort to take nanocomposite particles used in plastic in other industries and create self-healing PE pipe. Another example that came from this is the methane sensor using tuning fork technology.

OTD 5.14.c - Improving Cybersecurity for LDCs - Needs Identification & OTD 5.15.a Cybersecurity Collaborative. Initiated in February 2014 an initiative to review and to provide information on the status of cybersecurity R&D activities for LDCs and identify the short and long-range needs for cybersecurity capability improvement for LDCs. A workshop was conducted on April 16-17, 2014 at GTI facilities in Des Plaines, IL. Day 1 included presentations by representatives from GTI, AGA, DHS and SRI to orient the attendees to cyber related activities focused on the energy sector and natural gas specifically. Day 2 was dedicated to sharing lessons learned and identifying technology needs and gaps, and prioritizing project ideas. A summary report was prepared which identifies the industry need and business value of addressing cybersecurity issues, and summarizes the cybersecurity lessons learned for the participating utilities, A follow on effort under OTD 5.15.a continues as a multi-year collaborative program between natural gas distribution companies and the Department of Homeland Security (DHS) to address the high priority cybersecurity issues of participating members through a focused outreach and education process and a technology evaluation and transfer initiative.

OTD 6.14.a - Quality Audit Program for Natural Gas Utility Suppliers. Distribution Integrity Management regulations encourage utility companies to place a new focus on supplier and supply chain quality. Identifying threats and mitigating risks starts with the manufacturing process. Reducing supply chain risk requires a comprehensive and well-coordinated supplier audit program to ensure that the integrity of the supply chain is controlled and that the supplier is following policies and procedures required by customers and regulators. The purpose of this effort is to develop an audit program and provide natural gas utility operators with a mechanism to collaboratively audit supplier's quality management systems. The program will conduct an independent and unbiased assessment on behalf of participating operators to provide a reliable and standardized approach for monitoring suppliers. Participating operators will benefit from a collaborative program by creating efficiencies and promoting information sharing. Supplier audits identify non-conformances in manufacturing, shipping, engineering change, invoicing, and quality processes. After the audit, the supplier and auditors jointly identify corrective actions which must be implemented by the supplier within an agreed-upon timeframe. A future audit ensures that these corrective actions have been successfully implemented. While the need for enhanced quality audits and monitoring programs is increasing, the availability of resources to conduct these programs is decreasing due to operator's focus on operations and efficiencies. Therefore, there is a need for a coordinated collaborative audit program to allow gas utilities to efficiently monitor supplier processes. Participation in the collaborative program will provide value in the following ways: create efficiencies and cost savings by consolidating audits into one program, increase the number of audits performed, create leverage and increase influence with suppliers, utilize RAB/IRCA certified auditors with extensive experience, provide a high quality audit due to consistency and standardization of audit methodology and allow internal resources to focus on the core business rather than auditing. National Grid has participated in the development and pilot which has helped us review and improve our own auditing process but we are currently evaluating if we will continue in this GTI program.

Joint Industry Projects

The following three projects have been are jointly funded and managed between DET NORSKE VERITAS, DNV, and various industry co-funders:

Development of Industry Best Practices for Hot Tap Branch Connections Joint Industry Project (JIP) – a welding procedure is being developed and draft sent out to the group for comments, particularly for preheat. Concerns for maintaining preheat on a flowing pipeline are to be addressed.

Development of Industry Best Practices for Girth Weld Repair The objective of this JIP is to develop industry best practice for repair of pipeline girth welds during new construction activities, which will include the development and qualification of a suite of repair welding procedures in accordance with Section 10 of the Twenty-first Edition of API 1104. A guideline for selecting an appropriate procedure for a given application will also be developed. The scope will also include the development of guidance pertaining to other technical aspects of girth weld repair and repair welder qualification (e.g., preheating requirements, inspection requirements, time delay prior to inspection, minimum-required and maximum-allowable repair length, practical limits on wall thickness, etc.) that will be used to develop a generic company specification for repair of pipeline girth welds during new construction.

Validation of the ASME Procedure for Estimating Lower Bound Yield Strength of Pipe from Hardness Data. Forty-nine pipe samples representing a wide range of age, size, grade, composition, and manufacturing method were tested to demonstrate the validity of using hardness test data to estimate lower bound yield strength (YS) of steel pipe. Three different types of field portable hardness testers were used on each pipe sample. The hardness testing was performed in accordance with ASME CRTD-Vol. 91. The hardness test results were converted to estimated lower bound YS values using the correlations described in ASME CRTD-Vol. 57. The estimated lower bound YS was compared to the results of standard API 5L tensile tests. In addition, the metallurgical attributes of each pipe were characterized to determine if certain subsets of pipes produced better (or worse) correlations of estimated lower bound YS to YS determined from tensile tests. The results showed that hardness data can be used to estimate conservative values of lower bound YS using a range of different confidence levels.

National Grid Managed Projects

National Grid funds projects outside the NYSEARCH and OTD consortia and manages them ourselves or jointly with other LDCs. The following two projects are jointly funded and managed between National Grid Downstate and Consolidated Edison Co (Con Ed)

M2001-009 - Construction Interference Cost Reduction (CONCORD) Program. National Grid and Con Edison, along with the Urban Utility Center of Polytechnic Institute of New York, are working with New York City to introduce trenchless technologies to the city’s construction program. Trenchless technology – as compared to traditional “open cut” construction – can save National Grid and Con Edison significant dollars by eliminating the need to relocate our gas facilities if they interfere with the city’s new construction. We have introduced new trenchless technologies to the city’s engineers, conducted training programs, performed lab testing, and these efforts have culminated in New York City’s decision to rehabilitate two miles of a major water main in Manhattan via a trenchless method. This method involves insertion of a plastic liner into the existing cast iron water main and few adjacent gas facilities will need to be relocated. Con Ed estimates significant savings. If this program is successful and NY

City adopts trenchless technology for future construction, the savings to National Grid and Con Ed could be significant for years to come.

M2002-015 Cast Iron Sealing Robot (CISBOT): National Grid and Con Edison jointly fund and manage this project to design, construct and test a live, tethered robot that will internally seal cast iron joints. National Grid has the highest inventory of cast iron pipe in the nation, over 6000 miles, with over 2600 miles in the State of New York alone (Source, US DOT report). Cast iron is a very durable material but over time the joints – mechanical connections packed with jute and lead – can dry out and are the source of leakage. National Grid's predecessor company, KeySpan, partnered with Con Edison of New York to jointly fund the development of CISBOT. The robot was built by ESI Corp of Toronto, Canada. Upon completion of the robot Con Ed and National Grid entered into an agreement with ULC Robotics, a small high tech firm located on Long Island, to 'commercialize' the device and ultimately become the service provider for the CISBOT services. This is a typical business plan for high tech deployment in the gas distribution sector; ULC Robotics performs this type of work as their main line of business. To date, National Grid has spent over $2.2 Million on the project, with a similar amount funded by Con Edison. CISBOT is designed to seal joints in 16" through 36" diameter cast iron gas mains operating at pressures up to 25 psi. An excavation will be dug at a convenient point along the gas main and a special fitting is installed on the main which allows a 12" opening to be cut into the main in "live" conditions with no shutdown required and no blowing gas. (This is a fairly common procedure in the gas industry.) The CISBOT robot is then inserted into a launch tube and the launch tube is attached to the fitting on the main. The launch tube is purged of air with nitrogen and then a valve is opened and natural gas fills the launch tube. The robot is then lowered into the gas main. A tether connects the robot with external power and communication, and a small tube in the tether contains the anaerobic sealant which is used to seal the joints. An operator drives the robot using onboard cameras as a guide and stops at the first joint. A small hole is then drilled into the joint at a predetermined spot. Once the hole is drilled, a nozzle is inserted up into the drilled hole and anaerobic sealant is pumped into the hole, saturating the joint. Cameras on the robot are positioned to view the wicking action of the anaerobic fluid and pumping is stopped when the operator judges that a particular section of the joint is filled with sealant. The robot is then repositioned to a different "clock position" around the circumference of the joint and the drilling and sealing operation is repeated. Once the operator judges that the joint is sealed the robot will travel down to the next joint and the process is repeated.

CISBOT is undergoing an extensive program of field demonstrations over the past three years in New York City and Boston. Costs for the demonstrations outside NY State are borne by the area conducting the demonstration. In parallel with the demonstrations, the Company and Con Edison are negotiating a Commercial License with ULC Robotics. The cost of the service will be determined by ULC Robotics prior to their offering the service as a commercial business. National Grid NY and Con Ed will receive a discount from the stated list pricing. Because the final cost of the service has not yet been determined, it is difficult to accurately predict savings but assumptions can be made.

The basis for our assumed savings of $2.5M annually is to assume that CISBOT is deployed to a main segment where 50% of the joints are or will soon be leaking. Per job that's about 15 joints at an estimated cost of $3000 per joint to repair, total cost $45,000. This figure can vary depending on the final pricing structure set by ULC Robotics. Standard repair including a tight sheeted pit is estimated at $20,000 per repair for total repair cost of $300,000. Actual costs for tight sheeted pits in congested urban areas have been reported as much higher but this is a conservative estimate. Based on these assumptions the net savings is about $255,000 per job. Assuming full successful deployment of CISBOT, 10 such jobs per year could be performed, resulting in annual savings of $2,550,000.

National Grid expects to deploy this technology in its large diameter cast iron mains in New York State and Massachusetts. Any royalties received will be returned to NY ratepayers through the Millennium Fund.

Attachment 2 shows spending for these projects described above.

National Grid Gas R&D Spending

Includes Ngrid Downstate (KeySpan) and Ngrid Upstate (NMPC)

Calendar Year Expenditures ($)

	Actual		Projected		
Year	**2014**	**2015**	**2016**	**2017**	**2018**
National Grid Internal Program					
Utilization	$ 104,800	$ 211,426	$ 758,574	$ 170,000	$ 170,000
Operations	$ 57,708	$ 28,476	$ 200,000	$ 263,000	$ 263,000
Ngrid Labor and Expenses	$ 229,692	$ 184,741	$ 201,640	$ 207,689	$ 228,094
TOTAL INTERNAL	**$ 392,200**	**$ 424,643**	**$ 1,160,214**	**$ 640,689**	**$ 661,094**
National Grid Millennium Program					
NYSEARCH Projects	$ 2,265,234	$ 1,311,235	$ 1,571,000	$ 1,687,000	$ 1,150,000
OTD Projects	$ 750,000	$ 870,279	$ 750,000	$ 750,000	$ 750,000
National Grid Projects	$ 40,000	$ 103,502	$ 352,000	$ 400,000	$ 450,000
TOTAL MILLENNIUM	**$ 3,055,234**	**$ 2,285,016**	**$ 2,673,000**	**$ 2,837,000**	**$ 2,350,000**
TOTAL MILLENNIUM AND INTERNAL	**$ 3,447,434**	**$ 2,709,659**	**$ 3,833,214**	**$ 3,477,689**	**$ 3,011,094**
NYSERDA Assessment	$ 3,565,124	$ 4,906,042	$ 5,000,000	$ 5,250,000	$ 5,550,000
TOTAL R&D PROGRAM	**$ 7,012,558**	**$ 7,615,701**	**$ 8,833,214**	**$ 8,727,689**	**$ 8,561,094**

Note: Total spend, from books of Company

PROJECT NUMBER	PROJECT	START DATE	END DATE	TOTAL NGRID COMMITMENT	TOTAL SPEND 2013	TOTAL SPEND 2014	TOTAL SPEND 2015	TOTAL NGRID SPEND Joe YEARS
M-2000-001	Variable length sleeve - NYSEARCH	2000	2013	$ 147,356		$ 29,586.33		$ 111,970.00
M-2000-004	Explorer Commercialization, Phase I	2000	2006	$ 341,239		$ 14,906.96		
M-2001-002	Mgmt of Impacted Sediments - NYSEARCH	2001	2011	$ 430,061				$ 430,061.00
M-2001-003	Cased Pipe Risk Assessment Model	2001	2011	$ 274,472		$ 4,007.04		$ 184,501.00
M-2001-005	PipeHawk Hand-Held Pipe Locator - NYSEARCH	2001	2013	$ 435,090		$ 23,892.72		$ 392,895.00
M-2001-006G	Development / Testing / Commercialization of GASNET(tm) - Phase V	2001	open	$ 392,485			$ 31,593.94	
M-2001-009	Interference Avoidance/UUC Technology Demo Lab	2001	2010	$ 475,000				$ 446,000.00
M-2001-013	Millennium Web Development	2001	ongoing	$ 37,998		$ 5,751.81	$ 1,612.19	
M-2001-014	InspectionTool for Unpiggable Facilities - Automatika (TIGRE)	2001	2011	$ 967,261	$ (9,098.34)			$ 959,781.00
M-2002-008	Technical Expert (Oracle) to ID Quantum Leap Technologies	2002	ongoing	$ 53,931		$ 13,585.11	$ 179.87	$ 29,396.00
M-2002-011	FFT AUra Damage Prevention Systems - Testing Program - Phase III	2002	open	$ 202,380		$ 109,480.05	$ 43,194.73	
M-2002-015	CISBOT-Live IP CI Joint Sealing (KSE/ConED/ESI/ULC)	2002	2013	$ 2,356,825				$ 2,219,476.00
M2002-018	Infrasonic Sensor for Remote Pipeline Monotoring - NYSEARCH	2002	2010	$ 129,711				$ 104,858.00
M2003-009	Explorer II	2003	2012	$ 483,030		$ 24,727.35		$ 451,452.00
M2005-003	Test Bed Maintenance and Improvements	2005	ongoing	$ 110,108		$ 518.11	$ 1,225.31	
M2005-005	Gas Interchangeability for LDC Infrastructure	2005	2014	$ 753,336		$ 96,150.43	$ 25,514.42	$ 644,948.00
M2006-002	Butt Fusion Joint Integrity	2006	2011	$ 70,198		$ 9,776.81		$ 53,213.00
M2007-001	Mini-camera for Cased Crossings	2007	2012	$ 150,952		$ 10,491.88		$ 228,563.00
M2007-003	Multi Technology Validation Testing for Cased Pipe Applications	2007	2013	$ 73,315		$ 897.85	$ 2,952.00	$ 49,676.00
M2007-005	Testing Program for Remote Inspection-Transkor	2007	2012	$ 133,080		$ 15,387.64	$ 1,803.50	$ 75,901.00
M2007-007	Technology Advancement in Damage Prevention Tools and Communications	2007	2011	$ 91,973		$ 7,268.87		$ 64,243.00
M2008-001	Third Party Detection - Magal	2008	2013	$ 58,297		$ 5,522.13	$ 4,202.49	$ 29,419.00
M-2008-005	Developing Platelet Technology for use in Gas Transmission and Distribution Centers	2008	open	$ 23,280		$ 23,279.52		
M2008-006	Expand Function of No Blow Tools to Reduce GHG	2008	2012	$ 122,329		$ 6,055.00		$ 82,078.00
M2008-010	UV Degradation of PE Pipe	2010	2013	$ 14,125				$ 8,070.00
M2009-001	Holistic Review of DIMP Practices and Models	2009	2012	$ 48,750		$ 3,995.78		$ 44,409.00
M2009-002	Mercaptan Sensor Development	2009	open	$ 330,462		$ 60,282.16		$ 266,030.00
M2009-003	Adaptation Study	2009	2012	$ 23,500				$ 23,500.00
M2009-007	Particulate Dispersion Study	2009	2011	$ 75,000				$ 60,516.00
M2009-008	Ultrasonic Evaluation System for PE Butt Fusion	2009	open	$ 133,700		$ 20,632.90		$ 2,079.00
M2010-001	Service Tee Renewal	2010	open	$ 73,170		$ 27,692.85		$ 20,118.00
M2010-002	Methane MR Sensor Development	2010	open	$ 126,730		$ 12,318.70	$ 41,955.00	$ 23,265.00
M2010-003	PCB Absorption in PE Piping	2010	2013	$ 194,000		$ 60,613.68		$ 121,228.00
M2010-004	Soil Vapor Intrusion	2010	2012	$ 83,100		$ 39,199.82		$ 43,877.00
M2010-005	Guided Wave Test Program	2010	2012	$ 175,000				$ 95,082.00
M2011-001	Self Healing Pipe	2011	open	$ 232,442		$ 123,440.62	$ 45,986.48	$ 7,397.00
M2011-002	Storage Effects on Gas Quality	2011	2013	$ 26,555		$ 9,470.17		$ 12,628.00
M2011-003	Odor Masking	2011	open	$ 126,695		$ 89,198.22		$ 23,158.00
M2011-004	Carbon Calculator	2011	open	$ 24,450		$ 1,156.83		$ 12,234.00
M2011-005	Fiber Sen System Development and Testing	2011	open	$ 71,248		$ 32,464.79	$ 28,342.19	$ 6,316.00
M2011-006	Robotics Supporting Technologies	2011	open	$ 1,020,009		$ 411,841.51	$ 169,306.28	$ 152,941.00
M2011-007	Cased Pipe Inspection via Vents	2011	open	$ 386,760		$ 168,393.96	$ 94,646.85	$ 41,630.00
M2011-008	BioBall Test Program	2011	2013	$ 37,630		$ 37,630		$ -
M2011-009	Explorer 30 - 36"	2011	2013	$ 500,000	$ 64,500			$ 435,000
M2012-001	Development of Corrosion Sensor Array	2012	open	$ 72,310		$ 20,811	$ 49,013	$ -
M2012-003	Enterprise Level Assessment of Data Management Systems	2012	2014	$ 33,900		$ 33,900		$ -
M-2013-001	Explorer 16/18 - Inspection of Unpiggable Pipelines	2013	2015	$ 1,230,915	$ 307,730	$ 615,460	$ 307,725	$ 1,230,915
M-2013-002	Non-Destructive Inspection of Gas Pipes Using AMR Sensors for Eddy Current Testing (ECT)	2013	open	$ 342,668		$ 2,883	$ 45,940	
M-2013-003	Integrated Nanosensors for Analysis of Chemical Compounds in Natural Gas Applications (WKU Advanced Chemical Sensor)	2013	open	$ 189,885		$ 4,563	$ 152,422	
M-2014-001	Aeryon sUAS Technology - Regulatory & Technology Assessment	2014	open	$ 131,880			$ 10,396	
M-2014-002	Leak pinpointing inside pipe	2014	open	$ 27,380			$ 8,717	
M-2014-003	Picarro Methane Emissions Analyzer System	2014	open	$ 129,748			$ 129,748	
M-2014-004	Technology Evaluation & Test Program for Quantifying Methane Emissions Related to Non-Hazardous Leaks	2014	open	$ 54,210			$ 14,825	
M-2014-005	Critical Valve Operability	2014	open	$ 18,155			$ 7,033	
				$ 14,248,084	$ 363,132	$ 2,177,234	$ 1,218,335	$ 9,188,824
Keyspan dues					$ 55,000	$ 55,000	$ 60,000	
NMPC dues					$ 33,000	$ 33,000	$ 33,000	
					$ 451,132	**$ 2,265,234**	**$ 1,311,335**	
OTD 1.08.a	GPS-Based Excavation Encroachment Notification	2008	open	$ 134,269	$ 19,176			$ 134,269
OTD 1.08.a.CA	GPS Based Excavation Encroachment Notification for ROW Monitoring- CA (GTI)	2008	open	$ 33,142	$ 33,142			
OTD 1.08.c	GPS-Enabled Leak Surveying and Pinpointing (see 1.9.a)	2008	open	$ 50,000				
OTD 1.8.f	Electromagnetic and Acoustic Obstacle Detection Refund	2004	2011	$ 24,599	$ (12)			$ 24,599
OTD 1.8g	Acoustic Sewer Lateral Locator	2008	2012	$ 80,289	$ 7,300			$ 72,989
OTD 1.09.a	GPS Leaks - Phase 2 (from 1.8.c)	2009	2013	$ 129,080	$ (437)			$ 121,780
OTD 1.h and 1.10.c	Hand Held Acoustic Pipe Detector and tech transfer	2003	2013	$ 287,260				$ 287,260
OTD 1.10.e	Enhancing Damage Prevention in New York	2010	2015	$ 16,500				
OTD 1.11.a	Chemical Methods to detect crossbores	2011	2011	$ 2,870				$ 2,870
OTD 1.11.c	Low-Cost MEMS Methane Sensor Platform Phase 1	2011	2015	$ 30,000				$ 30,000
OTD 1.11.e	Cross Bores - National Database and Risk Model	2011	open	$ 35,000	$ 3,000			$ 35,000
OTD 1.12.b	Cross-Bores Detection Using Mechanical Spring Attachment	2012	2014	$ 10,000	$ 5,314			$ 10,000

PROJECT NUMBER	PROJECT	START DATE	END DATE	TOTAL NGRID COMMITMENT	TOTAL SPEND 2013	TOTAL SPEND 2014	TOTAL SPEND 2015	TOTAL NGRID SPEND Joe YEARS
OTD 1.14.d	Field Measurement of Leak Flow Rate	2014	open	$ 9,994		$ 5,000	$ 4,994	
OTD 1.14.g	Evaluation of Residential Methane Detectors	2014	open	$ 85,000		$ 85,000		
OTD 1.14.g.2	Evaluation of Residential Methane Detectors-Phase 2	2014	open	$ 32,097		$ 15,446	$ 10,000	
OTD 1.14.g.2a	Evaluation of Residential Methane Detectors-Phase 2 Pilot	2014	open	$ 175,000				
OTD 1.14.h	Picarro Surveyor Winter Patrol Implementation	2013	2015	$ 572,500		$ 25,000	$ 547,500	
OTD 2.07.a	2.7.a Refund				$ (9,014)			
OTD 2.8.e	Structural Liners and Sleeves - Technology Search	2008	2013	$ 12,132				$ 12,132
OTD 2.9c	Field Applied Coatings	2009	2012	$ 67,000				$ 67,000
OTD 2.11.a	Development of a System for Repair of Above Ground Leaks	2011	open	$ 44,611	$ 4,375			$ 40,236
OTD 2.11.d	RSD X-Ray for Metallic Pipe Assessment - Testing and Validation	2011	2012	$ 20,000				$ 20,000
OTD 2.11.d Refund	2.11.d Refund						$ (2,737)	
OTD 2.12.e	Selection of Liners Composites for the Rehabilitation of Distribution and Transmission Lines	2012	2015	$ 15,000	$ 15,000			
OTD 2.13.b	Guidelines for Special Permits for Structural Composite Rehabilitations	2013	open	$ 38,000	$ 38,000			
OTD 2.13.c	PHMSA Accelerated Dynamic Testing for Long Term Evaluation of Liners and Composite Pipe Materials add (PHMSA-21501)	2013	open	$ 39,063	$ 25,000	$ 14,063		
OTD 2.14.a	Composite Repair Wrap for Polyethylene (PE) Systems	2014	open	$ 5,000		$ 5,000		
OTD 2.14.b	Pipe System Repair Technique	2014	open	$ 40,000		$ 20,000	$ 20,000	
OTD 2.14.c	Assessment of Squeeze off Location for Small Diameter Polyethylene (PE) Pipe and Tubing	2014	open	$ 8,190		$ 5,000	$ 3,190	
OTD 2.14.d Refund	2.14.d Refund	2014		$ (17,964)		$ (17,964)		
OTD 2.14.d	Universal PE Entry Fitting	2014	cancelled	$ 20,000		$ 20,000		
OTD 2.14.e	Guidelines/Best Practices for Scraping PE Pipe and Fittings	2014	open	$ 1,251		$ 1,000	$ 251	
OTD 2.b	Service Applied Main Stopper			$ 152,078				
OTD 3.8a	Jackhammer Noise Abatement Issues	2008	2010	$ 20,000				$ 36,463
OTD 3.9a	Backfill Evaluation & Ecoroads	2009	2012	$ 24,295				$ 30,869
OTD 3.14.a	Soil Compaction Supervisor Enhancements	2014	open	$ 36,355		$ 25,000	$ 8,934	
OTD 3.14.b	Update ASTM Standard of DCP Compaction Control	2014	open	$ 1,000		$ 1,000		
OTD 4.7.g	Yield Strength	2007	2012	$ 27,672	$ 2,500			$ 25,172
OTD 4.08.a	Guided Wave Validation as Hydro Equivalent	2008	2015	$ 52,843				
OTD 4.8.i	Extended Reassessment Interval Validation Through Dielectric Wax Casing Fill	2008	2012	$ 58,929				$ 58,929
OTD 4.9a	Leak vs. Rupture Boundary	2009	2012	$ 68,048				$ 68,048
OTD 4.9.a Refund	4.9.a Refund			$ (99)			$ (99)	
OTD 4.11.f	Understanding Threat Interactions for Risk Analysis (GTI)	2011	2013	$ 30,000				$ 30,000
OTD 4.12.b	Correlating Pipeline Operations to Potential Crack Initiation Growth Arrest (GTI)	2012	open	$ 74,678	$ 30,000	$ 14,678		$ 30,000
OTD 4.13.a	DIMP Consequence Model	2013	2015	$ 55,200	$ 30,000	$ 25,200		
OTD 4.13.b	Validation of 3D Scanners for Anomaly Assessment	2013	2013	$ 25,000	$ 25,000			
OTD 4.13.c.2	PHMSA EMAT Sensor for Small Diameter and Unpiggable Pipe Phase 2 Construct and test field ready prototype	2013	open	$ 10,000			$ 5,000	
OTD 4.13.d.3	Hydro-testing Alternative Program - Phase 3	2013	open	$ 8,658		$ 5,000	$ 3,658	
OTD 4.14.a	Fitting and Component Catalogue for IVP	2014	open	$ 5,000		$ 5,000		
OTD 4.14.c	Surface Indentation for Material Characterization Correlation of Surface Properties Based on Vintage	2014	open	$ 58,301		$ 30,000	$ 28,301	
OTD 4.e	Inspection Platforms for Unpiggable Pipelines (NYSEARCH)			$ 303,963				
OTD 5.06.e	Portable Propane Air Residential Temporary Gas Supply	2006	open	$ 90,062	$ 14,851			
OTD 5.07.f	Automated Meter Shut-Off Device (AMS)	2007		$ 47,596				
OTD 5.07.p	5.07.p (GTI) GPS Consortium	2007	open	$ 15,000				
OTD 5.08.a.2	5.08.a.2 Development of Automated Welding Unit for Installing Laterals – Phase 2 (GTI)	2008	open	$ 42,500	$ 20,000	$ 22,500		
OTD 5.08.d.3	5.08.d.3 Tool for External Classification of Pipe Contents, Phase 3	2008	open	$ 1,000		$ 1,000		
OTD 5.8e	Gas Material Traceability	2008	2012	$ 77,008	$ 4,020			$ 72,988
OTD 5.08.e.b (b)	5.08.e.2ab Enhanced Material Tracking and Traceability-Development of Standardized Protocols/Identifiers for Meters, Regulators, and Transmission Pipelines, Phase 2 (TEJ)	2008	open	$ 6,749		$ 5,000	$ 1,749	
OTD 5.08.e.a (a)	5.08.e.a (a)Enhanced Material Tracking and Traceability Development of Standardized Protocols Identifiers For Meters and Regulators	2008	open	$ 5,000				
OTD 5.08.e.b (b)	5.08.e.b (b) Enhanced Material Tracking and Traceability Development of Standardized Protocols Identifiers For Transmission Pipeline	2008	open	$ 30,916	$ 7,916			$ 30,916
OTD 5.08.k Refund	5.08.k Refund				$ (287)			
OTD 5.08.l Refund	5.08.l Refund				$ (271)			
OTD 5.9c	Mitigating Elec. Interference on Cathodic Protection Systems	2009	2012	$ 80,522				$ 80,522
OTD 5.09.f	CP Monitor Prototype Modification and Field Trials Phase 2	2009	2015	$ 46,739	$ 15,326	$ 6,413		$ 25,000
OTD 5.09.f Refund	5.09.f Refund						$ (546)	
OTD 5.09.h	5.09.h North American Manufacturer Outreach			$ 1,893				$ 1,893
OTD 5.9j	Gas Distribution Model	2009	2012	$ 103,600				$ 103,600
OTD 5.9k	Low Impact Marking Study	2009	2012	$ 50,261				$ 50,261
OTD 5.10.d.2	5.10.d.2 Remote Field QA/QC Phase 2	2010	open	$ 73,450		$ 40,000	$ 33,450	
OTD 5.10.f Refund	5.10.f Refund			$ (21,616)	$ (21,616)			
OTD 5.10.f	Cold Assisted Pipe Splitting (CAPS), Phase 1	2010	2012	$ 46,615				$ 46,615
OTD 5.10.g	Indoor Air Quality and Safety Issues	2010	open	$ 25,000				$ 25,000
OTD 5.11.a	Dewatering Systems for Mains	2011	2013	$ 66,927			$ 2,000	$ 66,927
5.11.a Refund	5.11.a Refund						$ (229)	
OTD 5.11.m	Intelligent Utility Installation Process	2011	2014	$ 278,297	$ 191,000	$ 18,344		$ 68,953
OTD 5.11.n	Quality Control Procedure for High Protential Anodes	2011	2013	$ 44,929	$ 4,045			$ 40,884
OTD 5.11.n.2	5.11.n.2 Quality Control Procedure for High Potential Anodes – Phase 2	2011	2015	$ 20,000	$ 20,000			
OTD 5.12.b	Development of a Portable Flash Fire Suppression System (PFFSS)	2012	2014	$ 34,430	$ 14,430			$ 20,000
OTD 5.12.b.2	5.12.b.2 Development of a Portable Flash Fire Suppression System (PFFSS) Phase 2	2012	open	$ 10,000		$ 10,000		
OTD 5.12.g	Large Diameter Medium Pressure Inflatable Stoppers Evaluation of Kleiss System for the U.S. Natural Gas Industry	2012	2014	$ 20,000	$ 8,007			$ 20,000

PROJECT NUMBER	PROJECT	START DATE	END DATE	TOTAL NGRID COMMITMENT	TOTAL SPEND 2013	TOTAL SPEND 2014	TOTAL SPEND 2015	TOTAL NGRID SPEND Joe YEARS
OTD 5.12.n	Advanced Tools for Improved AC Corrosion Prevention and Mitigation	2012	2013	$ 70,000	$ 35,000			$ 35,000
OTD 5.12.o	Guidelines for Cast-Iron (CI) Winter Operations	2012	2013	$ 108,000	$ 48,000			$ 60,000
OTD 5.12.o.2	Assessment of Frost Impact on Cast Iron Pipes Phase 2	2012	2015	$ 37,410		$ 37,410		
OTD 5.12.p	NG Appliance Immersion Study	2012	2015	$ 104,606	$ 104,606			
5.12.p refund	5.12.p Refund	2012					$ (5,722)	
OTD 5.13.c	PE Pipe Splitting Technical Evaluations, Enhancements, and Standardization of Tool Kits	2013	open	$ 30,000	$ 30,000			
OTD 5.13.d.2	Transmission Cut In Valve Phase 2	2013	open	$ 50,000		$ 25,000		
OTD 5.13.f	Low Cost Collision Avoidance System	2013	open	$ 18,338	$ 10,000	$ 8,338		
OTD 5.13.g	Post Disaster Risk Assessment with LiDAR and GIS	2013	open	$ 50,000	$ 25,000	$ 25,000		
OTD 5.14.a	RFID Testing Program	2014	open	$ 25,277		$ 15,000	$ 10,277	
OTD 5.14.b refund	5.14.b Refund	2014		$ (829)			$ (829)	
OTD 5.14.b	Smart Leak Repair Form	2014	open	$ 18,500		$ 18,500		
OTD 5.14.c	Improving Cybersecurity for LDCs-Needs Identification Workshop	2014	open	$ 5,000		$ 5,000		
OTD 5.14.d	Tracking and Traceability for Transmission Pipe Materials	2014	open	$ 15,000		$ 15,000		
OTD 5.14.d.2a	Tracking and Treaceability for Transmission-Phase 2a Standards for MTR and Coating Reports, Rev	2014	open	$ 19,141		$ 10,000	$ 9,141	
OTD 5.14.d.2b	Tracking and Treaceability for Transmission-Phase 2b Data Collection Technology, Rev	2014	open	$ 23,725		$ 10,000	$ 9,091	
OTD 5.14.f	Battery and Electric Powered Tool Evaluation Phase 1	2014	2015	$ 20,000		$ 20,000		
OTD 5.14.j	Residual Gas Removal Identify Technologies Limitations Best Practices	2014	open	$ 15,000		$ 15,000		
OTD 5.14.n	Construction Compliance Monitoring System	2014	open	$ 29,234		$ 15,000	$ 14,234	
OTD 5.14.p	Pipe Insertion Technologies - Develop Devices to Use with Jameson Directional Insertion Tool	2014	open	$ 1,663		$ 1,000	$ 663	
OTD 5.14.t	Methods to Detect Inserted Plastic in Steel Mains	2014	2015	$ 11,909		$ 11,298	$ 611	
OTD 5.14.t Refund	5.14.t Refund	2014		$ (27)			$ (27)	
OTD 5.14.u	Evaluation of New Geospatial Technologies	2014	2015	$ 5,125		$ 5,000	$ 125	
OTD 5.14.u Refund	5.14.u Refund	2014		$ (1,221)			$ (1,221)	
OTD 5.14.w	Testing Program for Valve with Water Sensor for Storm Hardening	2014	open	$ 21,625		$ 21,625		
OTD 5.14.x	Atmospheric Corrosion / Leak Survey Considerations	2014	2014	$ 35,000		$ 35,000		
OTD 5.15.b	Roadmap for Enterprise Decision Support System	2015	open	$ 2,778			$ 2,500	
OTD 5.16.b	Alternative Caps for PE Service Tees Fusible Caps	2016	open	$ 5,620				
OTD 5.16.c	Piercing Tool Redevelopment Enhancement to Remove "Mole" from Small Excavations (12mo)	2016	open	$ 22,150				
OTD 5.16.d	Stopping Off LP Mains with No Excavation	2016	open	$ 19,982				
OTD 5.16.f	Improved Safe Excavation Productivity for Locating Buried Utilities	2016	open	$ 5,274				
OTD 5.16.g	Enhancement of the Dynamic Cone Penetrometer (DCP) Compaction Device	2016	open	$ 53,033				
OTD 6.a	Sustaining Membership Program - GTI (discontinued)	2003	2012	$ 152,000				$ 152,000
OTD 6.6.a	Keyhole Consortium - GTI	2006	2012	$ 100,000	$ 20,000		$ 20,000	$ 60,000
OTD 6.08.a	(GTI) Carbon Management Information Center	2008	ongoing	$ 65,000		$ 25,000	$ 25,000	
OTD 6.11.a	PRCI Membership	2011	2015	$ 10,000		$ 10,000		
OTD 6.13.a	Quantitative Risk Assessment Methodology Protocol for LNG Facilities Siting (AGA)	2013	open	$ -	$ (10,000)	$ 10,000		
OTD 6.14.a	Quality Audit Program	2014	open	$ 40,000		$ 20,000	$ 20,000	
OTD 7.8.a	Pipeline Quality Biomethane: Guidance Document for Landfill and Water Treatment Conversion	2008	2012	$ 65,990				$ 65,990
OTD 7.9.c	Assessing Acceptable Siloxane Concentrations in Boimethane	2009	2012	$ 52,972				$ 52,972
OTD 7.9.d and 7.10.c	Improving Methane Emission Estimates for NG Distribution Companies, Phase 1 and 2	2009	2014	$ 67,674				$ 67,674
OTD 7.10a	Trace Constituents in Natural Gas	2010	2013	$ 78,205				$ 78,205
OTD 7.10.b	Odor Fade (GTI)	2010	2014	$ 36,940				$ 36,940
OTD 7.10.b Refund	7.10.b Refund	2010		$ (1,570)			$ (1,570)	
OTD 7.10.b.2	Odor Fade Phase 2 (GTI)	2010	2014	$ -		$ (10,000)	$ 10,000	
OTD 7.10.c Refund	7.10.c Refund	2010					$ (43)	
OTD 7.10.c.2	Improving Methane Emission Estimates for NG Distribution Companies, Phase 2	2010	2014	$ 67,674				$ 67,674
OTD 7.10.c.3	Improving Methane Emission Estimates Phase III - Cast Iron and Unprotected Steel Pipes	2010	2014	$ 99,839	$ 50,000	$ 49,839		
OTD 7.10.c.4	Improving Methane Emission Estimates for Natural Gas Distribution Companies Phase IV	2010	2014	$ 6,880		$ 5,000	$ 1,880	
OTD 7.11.a	Gas Quality Resource Center	2011	2013	$ 65,000	$ 20,000	$ 20,000		$ 25,000
OTD 7.11.a.2	Gas Quality Resource Center	2011	2013	$ 20,000			$ 20,000	
OTD 7.11.b	Trace Constituents Sensors	2011	2014	$ 27,610				$ 27,610
OTD 7.14.a	Next Generation Water Clean-up Technology Phase 1	2014	open	$ 25,000		$ 25,000		
OTD 7.15.a	Real Time Gas Quality Sensor	2015	open	$ 4,981			$ 2,500	
OTD 7.15.b.2	Remote Gas Sensing and Monitoring Phase 2	2015	open	3000				
OTD 7.16.a	Leak Repair Prioritization	2016	open	20110				
OTD 7.16.b	Evaluate Gas Imaging Technologies for LDC Applications	2016	open	30000				
OTD 7.16.c	Secure Communication for Networked Gas Sensors	2016	open	21302				
OTD 8.16.a	Intelligent Field Data Collection Platforms	2016	open	19956				
OTD 8.16.b	Remote QA/QC: Fusion Inspection and Reporting	2016	open	39441				
OTD 9.16.a	Determining Data Quality Implication	2016	open	56224				
OTD 9.16.b	Establishing Risk Tolerance	2016	open	25358				
				$ 6,229,580	$ 838,371	$ 834,690	$ 802,024	$ 2,520,240

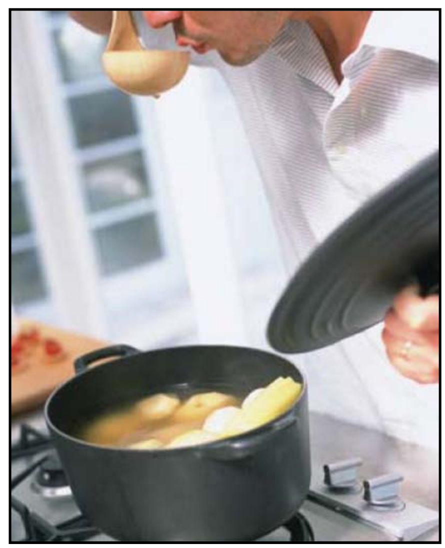
T759	Ergonomic Study to Develop New Needle Bar	2005	2012	$ 29,889		$ 557		$ 25,366
T763	Rock Impingement	2007	2011	$ 19,250				$ 21,100
T764	Auto Gas Lamp Evaluation	2009	2012	$ 27,500		$ 10,443		$ 10,314

the Energy to Lead

TOPICAL REPORT

GTI PROJECT NUMBER 20733

National Grid Foodservice Market Assessment



Report Issued:
March, 2010

Prepared For:
National Grid

GTI Technical Contact:
Dr. Frank Johnson
Senior Engineer
End Use Solutions
847-768-0670
Fax: 847-768-0501
frank.johnson@gastechnology.org

Gas Technology Institute

1700 S. Mount Prospect Rd.
Des Plaines, Illinois 60018
www.gastechnology.org

Disclaimer

This information was prepared by Gas Technology Institute ("GTI") for National Grid.

Neither GTI, the members of GTI, National Grid, nor any person acting on behalf of any of them:

a. Makes any warranty or representation, express or implied with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately-owned rights. Inasmuch as this project is experimental in nature, the technical information, results, or conclusions cannot be predicted. Conclusions and analysis of results by GTI represent GTI's opinion based on inferences from measurements and empirical relationships, which inferences and assumptions are not infallible, and with respect to which competent specialists may differ.

b. Assumes any liability with respect to the use of, or for any and all damages resulting from the use of, any information, apparatus, method, or process disclosed in this report; any other use of, or reliance on, this report by any third party is at the third party's sole risk.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

National Grid Foodservice Market Assessment

Executive Summary

The commercial and institutional food service sector represents an important – **and growing** – market for the natural gas industry. According to the National Restaurant Association (NRA), there are approximately 525,000 commercial food service establishments nationwide with annual sales of $580 billion. Remarkably, nearly one in ten workers in the U.S. is a restaurant employee. The NRA indicates total U.S. commercial foodservice employment is 11.2 million – a substantial figure that is projected to grow to 14 million by 2020 (25 percent growth).

There are approximately 37,400 restaurants in New York with gross sales of $27.8 billion and over 672,000 employees. In Massachusetts, there are over 14,000 restaurants with annual sales of $11.8 billion and 304,000 employees. Rhode Island has nearly 2,700 restaurants with $1.8 billion in sales while New Hampshire has over 2,800 restaurants with annual sales of $2.1 billion. Together, this totals nearly 57,000 establishments with annual sales in excess of $43 billion. Using a nominal value of 3.4 percent of sales, commercial food service annual utility cost (electricity, natural gas, water, etc) exceed $1.4 billion in these four states and approach $20 billion nationally.

According to Energy Information Agency (EIA) survey data, commercial foodservice customers have 2.2 times the energy intensity (Btu/ft^2) of the average commercial customer. Audits conducted by Southern California Gas and Piedmont Gas found that natural gas sales to commercial foodservice customers account for 12 percent of the volume of gas sold, but comprise a healthy 19 percent of their profits.

In terms of new equipment, the estimated annual sales of new commercial foodservice equipment totaled about $1.2 billion in 2006. Of this, about 69 percent was natural gas-based products – indicating a strong market position for natural gas relative to electricity. The report provides further analysis of sales by product category and, an important consideration, the limited availability of Energy Star-rated natural gas products.

While a significant and growing market, there are continual threats and opportunities to assess within the commercial food service market segment. This project was undertaken to generate insights on the current gas foodservice market in National Grid's Northeastern United States market territory, with findings intended to guide a course of action for future RD&D and marketing initiatives within the foodservice arena. In addition to market and technology insights from GTI's experience and literature review, interviews were conducted with six foodservice consulting firms and equipment dealers within National Grid territories.

From this, the following observations, trends, opportunities, and threats are identified for the natural gas industry in the commercial foodservice marketplace:

- Natural gas market share is currently strong and holding against electric market share. New electric products; perceptions of electric as clean, simple, and reliable; and growing electric energy efficiency programs represent potential threats. There is also a market perception that electric equipment is more advanced or higher end than gas equipment, posing a significant threat.

- Natural gas is perceived as more cost-effective by users, with current electric-to-natural gas price ratios of 4.5:1 or higher. A typical restaurant is paying over twice as much annually for electricity than natural gas – underscoring the perception of natural gas as being cost effective.
- Rising labor, food, and energy costs are motivating foodservice providers to seek new and innovative equipment designs that could save operating costs through productivity improvements and speedier delivery.
- **Labor issues are a dominant factor in this sector** – major issues are obtaining and retaining quality workers, labor costs, and productivity. Increased labor turnover motivates foodservice providers to seek methods or equipment to improve the working environment for employees in terms of comfort, ease of equipment usage, and cleaning.
- Key purchase factors for new equipment include price, efficiency (operating costs), after-sales support, and productivity improvement. Equipment obsolescence and deterioration is typically the main reason to buy new equipment. With older gas equipment lasting for many years, added effort is required to convince users to purchase new equipment. Getting information to users about the cost and energy saving associated with new equipment is needed along with meaningful incentives from energy efficiency programs.
- There is a paucity of Energy Star recognized standards and, subsequently, natural gas products in the commercial foodservice sector. This can impact the ability to use utility energy efficiency program funds to incentivize the shift to higher-efficiency equipment.
- More investment is needed to develop advanced, energy efficient natural gas appliances that would satisfy current or future Energy Star labeling requirements.
- Trends toward healthier and/or more environmentally responsible eating habits can influence the market, but the economic benefits/effects are not fully understood by the industry.
- The industry is concerned about lower emissions standards (including NO_x and particulates) – especially where such requirements have been imposed on residential appliances.
- Ventilation advancements represent an opportunity to increase energy efficiency and kitchen comfort and indoor air quality for workers. Improvements include demand ventilation systems.
- The green movement is a threat to natural gas. Consumer surveys show that electric is perceived as being more green, possibly due to the site-based efficiency claims. There is an opportunity to position new gas equipment as green through consumer education - identifying the financial, source energy, and environmental benefits.

Food Service Industry Market Characterization

The food service industry is a growing and diverse segment of the commercial market. Figure 1 shows the major segments of this estimated $580 billion industry, including "eating places" (i.e., various types of restaurants), vending & recreation, non-commercial (i.e., institutional), managed services, lodging, as well as bars & taverns.

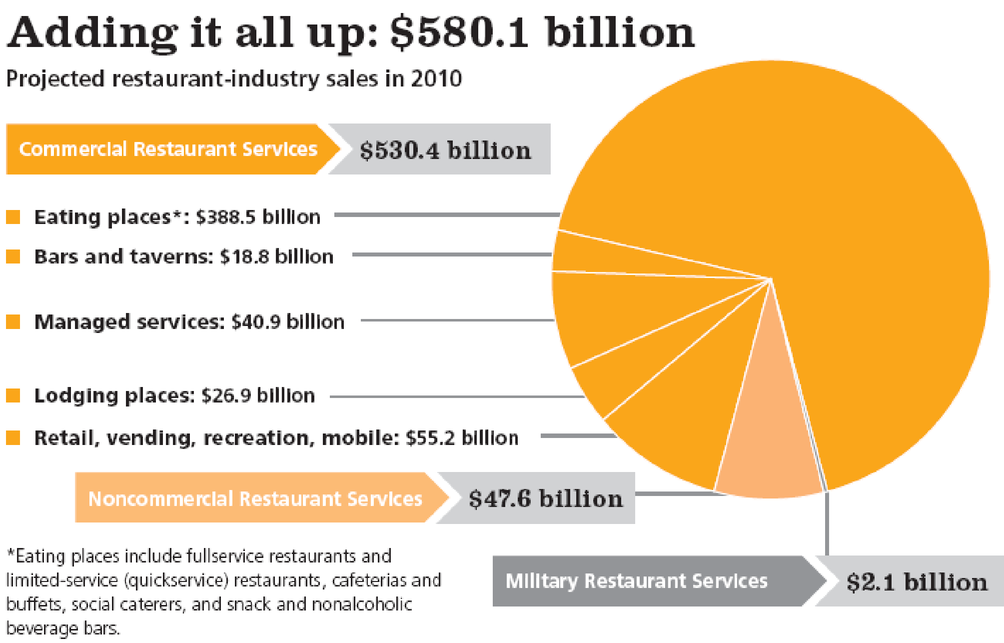


Figure 1: Foodservice Market Segmentation

(Source: NRA 2010 Restaurant Industry Forecast)

There are approximately 525,000 foodservice establishments across the country. State-level characteristics on four key states – New York, Massachusetts, Rhode Island, and New Hampshire – are shown in Table 1, with additional state profile data from the National Restaurant Association included in the appendix to this report. These four states include 56,900 commercial foodservice locations with annual sales in excess of $43 billion.

Table 1: Selected State Foodservice Data (2009)

Sales Volume	Foodservice Establishments	Annual Sales ($Million)	Employment
New York	37,400	$27,800	672,000
Massachusetts	14,000	$11,800	304,000
New Hampshire	2,800	$2,100	61,200
Rhode Island	2,700	$1,800	51,900

Source: National Restaurant Association

The foodservice market can be further broken down into major and niche segments (Table 2). Eating places are dominated by full-service restaurants – around $184 billion -- and limited-service (or quick-service) restaurants at over $165 billion. Together, these two groupings comprise 60 percent of the foodservice market. Beyond this are a number of smaller market niches, including institutions such as hospitals, schools, and universities.

Table 2: 2010 Restaurant Sales and Segmentation ($Billions)

GROUP I COMMERCIAL RESTAURANT SERVICES	2010 Sales	Growth?
EATING PLACES		
Full-service restaurants	$184.176	
Limited-service (quick-service) restaurants	$164.837	☑
Cafeterias, grill-buffets and buffets	$7.671	
Social caterers	$7.090	☑
Snack and nonalcoholic beverage bars	$24.736	
TOTAL EATING PLACES	**$388.510**	
Bars and taverns	$18.844	
TOTAL EATING-AND-DRINKING PLACES	**$407.354**	
MANAGED SERVICES		
Manufacturing and commercial offices	$9.218	
Hospitals and nursing homes	$5.053	☑
Colleges and universities	$13.649	☑
Primary and secondary schools	$5.863	☑
In-transit restaurant services (airlines)	$2.061	
Recreation and sports centers	$5.025	☑
TOTAL MANAGED SERVICES	**$40.869**	
Lodging Places	$26.943	☑
Retail-host restaurants	$30.936	☑
Recreation and sports	$12.518	
Mobile caterers	$0.635	
Vending and Non-store retailers	$11.097	
TOTAL — GROUP I	**$530.352**	
GROUP II NONCOMMERCIAL RESTAURANT SERVICES		
Employee restaurant services	$0.426	
Public and parochial elementary, secondary schools	$6.144	
Colleges and universities	$6.083	
Transportation	$1.830	☑
Hospitals	$15.225	☑
Nursing homes, homes for orphans, disabled	$7.145	☑
Clubs, sporting, recreational camps, community centers	$10.694	
TOTAL — GROUP II	**$47.547**	
GROUP III MILITARY RESTAURANT SERVICES	$2.161	☑
GRAND TOTAL	**$580.060**	

Source: NRA 2010 Restaurant Industry Forecast

Schools, universities, hospitals are addressed using either in-house foodservice (non-commercial) and by "managed services" such as foodservice contractors. For example, the total university segment includes a non-commercial component of over $6.1 billion and a managed services component of about $13.6 billion (which is growing faster than the non-commercial segment). Managed service providers could be an attractive point for targeted marketing by National Grid.

Restaurants have a wide level of variability in their size and operations. Table 3 shows a breakdown of annual sales volumes based on average check cost. More than half of restaurants do more than $1 million annually in sales, with nearly one quarter being greater than $2 million. Not surprisingly, sales volume tends upward with higher average check businesses.

Table 3: Restaurant Annual Sales Data (% of restaurants)

Sales Volume	Average Check <$15	Average Check $15-25	Average Check >$25
<$500K	19.3%	9.6%	12.3%
$500K-$1000K	25.5%	30.7%	15.8%
$1000-$2000K	31.7%	33.3%	31.0%
>$2000K	23.5%	26.4%	40.9%

Source: NRA and Deloitte, Restaurant Industry Operations Report (2006/2007 Edition)

Most restaurants are either owned by a private corporation (around 60-65 percent), sole proprietorship, or partnership (the latter two each being about 15-20 percent of the market). This ownership structure is true of those restaurants which are tied to a major public corporation. For example, an estimated 85 percent of McDonald's restaurants are owned and operated by franchisees or private joint ventures.

The food service industry is attractive because, on a per square foot basis, it uses much more energy than most other commercial buildings (Figure 2). Food service establishments use 2.2 times the energy per square foot of the typical commercial building (258 versus 116 kBtu/ft^2) and have the highest energy intensity in the commercial building sector.

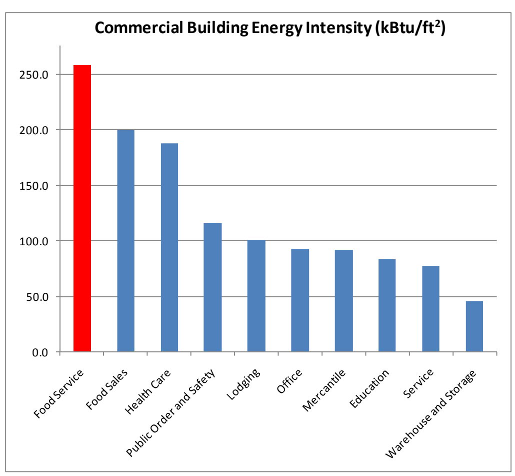


Figure 2: Commercial Sector Energy Intensity (DOE-EIA 2003 CBECS)

As evidenced by the relative energy intensity of foodservice establishments, energy is cited as one of several key factors of concern to food service operators. The following table shows results from the National Restaurant Association survey on key challenges perceived by full-service restaurant operators. Energy typically falls in the range of the top 5-6 areas of concern – and varies somewhat depending on the type of restaurant.

Table 4: Top Seven Challenges for Foodservice Operators in 2008

	Tableservice Segment		
	Family Dining	Casual Dining	Fine Dining
Recruiting and retaining employees	17%	23%	14%
Building and maintaining sales volume	12	11	22
The economy	13	13	17
Competition	17	6	13
Labor costs	11	10	10
Gas and energy costs	11	8	5
Food costs	7	10	3

Source: National Restaurant Association, 2007 Tableservice Operator Survey

The National Restaurant Association estimates that 49 percent of consumer spending on food is expended in the foodservice sector (the balance being food bought in grocery stores and consumed at home). This compares to only 25 percent of the consumer spending in 1955. Forty-four percent of consumers say that restaurants are an essential part of their lifestyle, with over 40 percent saying they are more productive eating at restaurants or using take-out or delivery foodservice.

This long-term demographic shift, where consumers are increasingly spending their food dollars in restaurants, presents an opportunity and a threat for the natural gas industry. With less food prepared at the home, there is a threat to natural gas sales to the residential sector and potential for displacement with electro-technologies in the home (e.g., microwaves and radiant or inductive heating). However, if a strong position for natural gas can be retained in restaurants, the net effect should be minimal.

The lifestyle elements of food and eating are evident. Sixty-five percent of consumers say their favorite restaurant foods provide flavor and taste sensations they cannot easily duplicate at home. One element to consider, however, is the growing popularity of at-home cooking shows on television featuring a plethora of celebrity chefs – and a dedicated cable station, The Food Network – along with growing enrollment in culinary schools (which includes those pursuing a career as well as for personal enjoyment and development).

Tying natural gas into the lifestyle elements of culinary arts is an important branding consideration for the natural gas industry. As will be highlighted, natural gas has certain positive branding factors, but can face strong competition from newer electro-technologies that may be perceived as

> "At the Culinary Institute of America in Hyde Park, N.Y., administrators increased their five-day, $2,095 "Basic Training" boot camp to 14 classes a year, up from 10 three years ago. The Whole Foods in the Soho neighborhood of New York City saw enrollment in the store's cooking classes increase 46% between 2009 and 2008, says a company spokeswoman."
> **Source: Wall Street Journal, Cutting Costs at Culinary School (Aug, 12, 2009)**

cleaner, more high tech, cleaner, greener, or safer. Tapping into culinary arts schools or collaborating with celebrity chefs to expose them to the latest natural gas commercial foodservice products could be an effective marketing approach.

Generally, natural gas has a strong position in the commercial foodservice segment. Table 5 and Figure 3 provide a snapshot view of natural gas and electric product sales. In several product categories – for example, ranges, convection ovens, and conveyor ovens – natural gas is the clear market leader. Leading electric product categories include: fryers, convection ovens, combi-ovens, and free-standing steamers. There are two categories where electric products have over 50 percent market share – counter-top steamers and combi-ovens. The rightmost column highlights product categories that are currently being addressed by UTD or SMP funded R&D efforts.

Table 5: Commercial Foodservice Product Sales (2006, Source: Fryett)

Equipment Category	Total Sales ($MM)	Gas Sales ($MM)	Gas Share (%)	Electric Sales ($MM)	UTD/SMP/ Projects
Underfired Broilers	$9.8	$9.8	100%	$-	
Pizza / Deck Ovens	$18.0	$18.0	100%	$-	☑
Wok Ranges	$30.0	$30.0	100%	$-	☑
Steamers - Pressure	$9.0	$8.0	89%	$1.0	
Charbroilers	$17.4	$15.0	86%	$2.4	
Ranges	$175.6	**$146.5**	83%	$29.1	☑
Conveyor Broilers	$35.0	$29.0	83%	$6.0	
Conventional Ovens	$15.0	$12.0	80%	$3.0	
Conveyer Ovens	$93.9	**$72.5**	77%	$21.4	☑
Rotisserie Ovens	$34.4	$26.5	77%	$7.9	
Griddles	$46.5	$35.0	75%	$11.5	
Pressure Fryers	$61.9	$46.5	75%	$15.4	
Fryers	$247.2	**$175.0**	71%	**$72.2**	☑
Over-fired Broilers	$36.8	$24.1	65%	$12.7	☑
Convection Ovens	$135.9	**$77.4**	57%	**$58.5**	☑
Steamers - Free-Standing	$68.0	$38.0	56%	**$30.0**	
Tilting Skillets	$46.3	$24.0	52%	$22.3	
Combi Ovens	$100.0	$46.0	46%	**$54.0**	
Steamers - Counter-Top	$39.5	$9.9	25%	$29.6	
Total	**$1,220.2**	**$843.2**		**$377.0**	
% of Total		**69.1%**		**30.9%**	

Fryers are a key market retention product for the natural gas industry due to the size of the market. While holding a 71 percent market share in 2006, this segment is threatened by electric products – especially with the recent shift to low oil volume fryers. This segment represents the highest dollar volume sales category for electric products. Also, for low oil volume fryers, electric units were developed and field tested one year before gas-fired models because of the extra development time required to design gas-fired burners. This situation places natural gas models of popular natural gas foodservice equipment at risk in terms of timing of commercial introduction or – in the most extreme cases – may be dropped from the product line-up if manufacturers do not see the benefit/cost of investing in a gas offering.

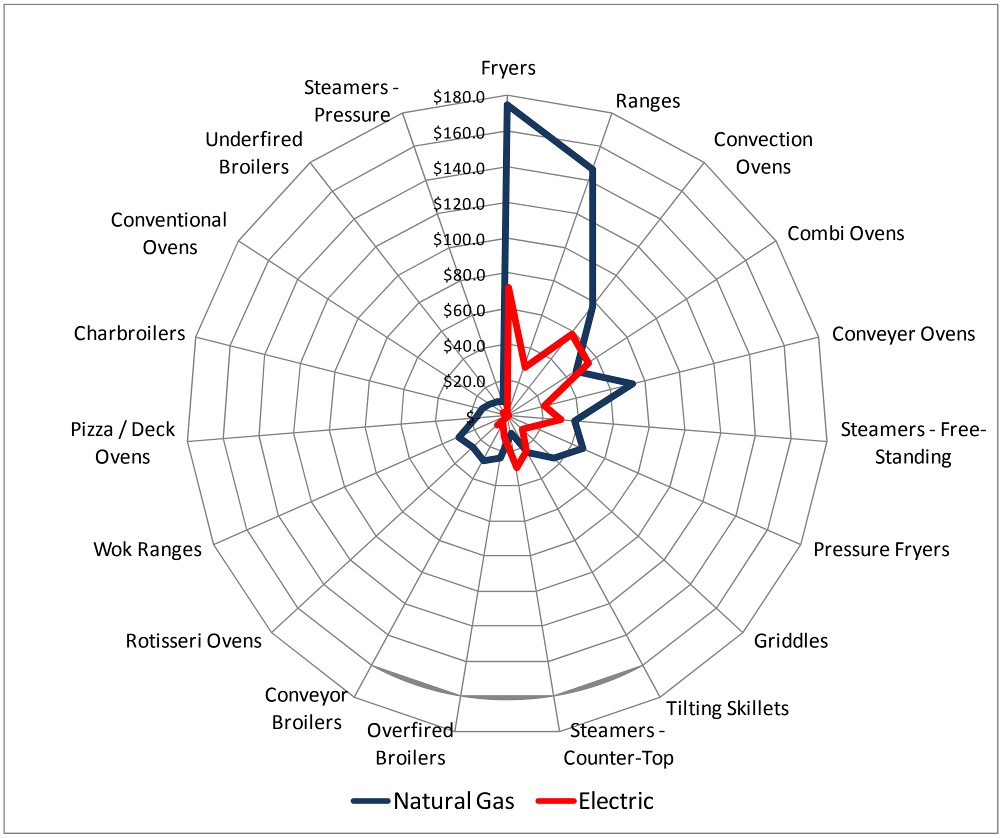


Figure 3: Commercial Food Service Equipment Sales by Category (2006, $millions)

Product Drivers

Historically, the demand for new or healthy food products has driven the foodservice industry to develop new and innovative technologies and equipment. An example is what could be called the "Boston Market" effect during the early 1990's. The popularity of roasted chicken grew tremendously with the initial Boston Market restaurants, leading several other restaurants – including existing chains – to add roasted chicken to their menus. This also led several manufacturers to develop rotisserie ovens for cooking chicken. Another example is the rapid increase in bagel preparation equipment that was spawned by the increasing popularity of bagels several years ago.

A current driver in the foodservice industry is the removing or banning of trans-fat oils by several restaurant chains or metropolitan areas. Trans-fats, present in many deep-frying oils, are linked to unhealthy levels of cholesterol levels -- a fact that has received considerable media exposure. For this reason, partially hydrogenated oils and trans-fat oils are the subject of growing scrutiny from public health officials and health-conscious consumers. By mid 2008, cities such as New York and others passed legislation to ban or tightly control the use of trans-fat oils in any public restaurant. Restaurant chains including McDonald's, Arbys and KFC have either discussed or are eliminating trans-fat oil from their menu items. The main issue with using trans-fat free oils is not availability; they are widely available, but cost more and have a different taste. In response to this, restaurants looked to the foodservice industry and manufacturers for solutions. One result was the development of low oil volume fryers by manufacturers including Frymaster, Pitco and Henny Penny. Low oil volume fryers address the increased cost of the non trans-fat oils by using less oil than standard fryers, 30 to 35 pounds of oil compared to over 50 pounds. The savings is realized by throwing away less oil during each oil change. Oil savings are also realized by improved filtering methods in some of the low oil volume fryers that increase the useful life of the oil.

Rethermalization is an area of potential market change. The concept behind rethermalizing is to use either vendor-prepared or commissary-made food products in place of "from scratch" cooking. In addition to helping restaurants address high demand periods, this can result in labor savings, energy savings, improved consistency, and potentially improved food safety.

In this process, large batch cooking is employed to make a product (e.g., soup) that is quickly chilled and placed into multiple vacuum-sealed bags of food. This is also referred to as the *sous vide* process. Vacuum sealing helps to keep out harmful pathogens while retaining flavor and aroma.

The rethermalization process at the restaurant involves reheating the product – typically with lower temperatures and considerably less time than would be required by cooking from scratch. As noted earlier, labor is a major cost and operations issue for restaurants. Using rethermlized food can reduce restaurant labor costs and – to some extent – the quality of labor needed (compared to cooking from scratch).

> "From the standpoint of equipment, in some cases we may be headed for the **fireless kitchen** without pots or pans. This also would reduce, or in some cases even eliminate, exhaust requirements of many professional kitchens."
> **Source: "Rethermalize it," Nation's Restaurant News, Oct. 8, 2007.**

Rethermalizing is an area that could represent a threat or opportunity for the natural gas industry. A shift towards a "fireless" kitchen – one that mainly uses electricity for reheating pre-cooked products – is clearly a potential threat.

Ventilation is both an area of opportunity and concern for the restaurant operator and the natural gas industry. Employee turnover is very high in the restaurant industry; in some segments, the turnover rate is 200 percent. This puts additional costs on the restaurant through training and absenteeism costs.

By making the kitchen a more comfortable workplace through advanced ventilation practices and safer cooler equipment surfaces, employee turnover rates may be reduced. Ventilation issues also impact energy use (heating, cooling, fan power, etc) and indoor air quality in the kitchen environment. There are also fire safety consideration with ventilation systems and cleaning of grease to prevent fires.

Kitchen ventilation is an opportunity for improved comfort and energy savings. In most kitchens, exhaust fans will run at a constant speed throughout the day. This can impact space conditioning loads along with fan energy requirements. Opportunities for improvement include using demand ventilation approaches that can modulate fan speed depending on work conditions.

New emission standards have driven the development of new appliances in the residential/commercial markets at different times in the past few decades. Lower emissions requirements in California on residential water heaters led to the development of new combustion systems for all water heaters currently sold in the state. Establishing NO_x emission levels on residential furnaces by the South Coast Air Quality Management District led to the development of new furnace designs and combustion systems. While new emissions legislation is usually more focused on residential appliances, new NO_x emission standards are being considered for commercial cooking equipment in California. Agencies in California are also proposing new limits on the particulate emissions from charbroilers. Particulate emissions and grease build-up in ventilation systems is a serious issue for restaurants. GTI is currently working with the gas industry and manufacturers to explore options to address these environmental and restaurant workplace issues.

Energy Use and Natural Gas v. Electric Positioning

Table 6 provides a breakdown of typical costs and pre-tax profits in the restaurant business. The dominant cost factors are food and beverage, followed by salaries and benefits. Labor-related issues – controlling labor costs, employee retention, increasing productivity – are key concerns for restaurant operators (as noted in Table 4). The other item of note is that most restaurants have relatively modest income before taxes – around 4 percent. Reducing costs even one percent can translate into a 20-30 percent relative increase in profits.

Table 6: Typical Restaurant Cost Stack

Food & Beverage	32%
Salaries & Benefits	34%
Occupancy	7%
General & Administrative	3%
Other	20%
Income Before Taxes	4%
Total:	**100%**

Source: NRA and Deloitte, Restaurant Industry Operations Report (2006/2007 Edition)

Generally, restaurants are a tight margin business with many competitors, as evidenced by the substantial number of outlets across the U.S. (525,000). Restaurants typically go through dynamic cycles of birth and death for a variety of reasons. Statistics indicate that one in four restaurants fail in the first year, with nearly 60 percent failing within three years.

The "other" category in Table 6 includes energy and other "utility" costs such as water. The importance of energy and other utility costs will vary depending on the restaurant type and sales volume. Table 7 illustrates the relative importance of utility costs depending on the restaurant type (using average check size as a differentiator). The relative impact of energy costs generally increases as the average check size goes down.

Table 7: Restaurant Energy & Utility Costs by Restaurant Type (% of revenue)

	Average Check <$15	Average Check $15-25	Average Check >$25
Lower Quartile	2.7%	2.5%	1.9%
Median	3.7%	3.4%	2.7%
Upper Quartile	4.9%	4.5%	3.8%

Source: NRA and Deloitte, Restaurant Industry Operations Report (2006/2007 Edition)

Table 8 provides an estimate of annual energy costs for an example restaurant as a function of annual sales and the percent of total sales allocated for energy and related utility costs. Using a typical restaurant sale volume of $1-1.5 million annually and energy costs of 3.4 percent of sales, annual energy costs for a nominal restaurant is in the range of $34-50,000. This value will likely be in the range of $50,000-$100,000 for higher sales volume stores.

Table 8: Energy Costs By Sales Volume and Energy Costs Percent of Sales

Energy Cost % Sales ➔ Annual Sales 🡻	2.5%	3.0%	3.5%	4.0%	4.5%
$500,000	$12,500	$15,000	$17,500	$20,000	$22,500
$1,000,000	$25,000	$30,000	$35,000	$40,000	$45,000
$1,500,000	$37,500	$45,000	$52,500	$60,000	$67,500
$2,500,000	$62,500	$75,000	$87,500	$100,000	$112,500

As noted, commercial food service establishments are attractive because they use considerably more energy (per square foot) than other commercial buildings and tend to contribute more to natural gas profits. The higher energy intensity is due to their process activities such as food storage (e.g., refrigeration), food preparation (e.g., cooking), and sanitation (e.g., cleaning dinnerware).

Figure 4 and Table 9 show DOE-EIA estimates of site electric and natural gas use in all foodservice buildings in the U.S. (based on the 2003 Commercial Buildings Energy Consumption Survey). Electricity and natural gas are the primary energy options used in the commercial food service sector, with electricity being about 70 percent of total energy costs. Equivalent electric use is about 217 trillion Btu (63 billion kWh) and 203 trillion Btu for natural gas.

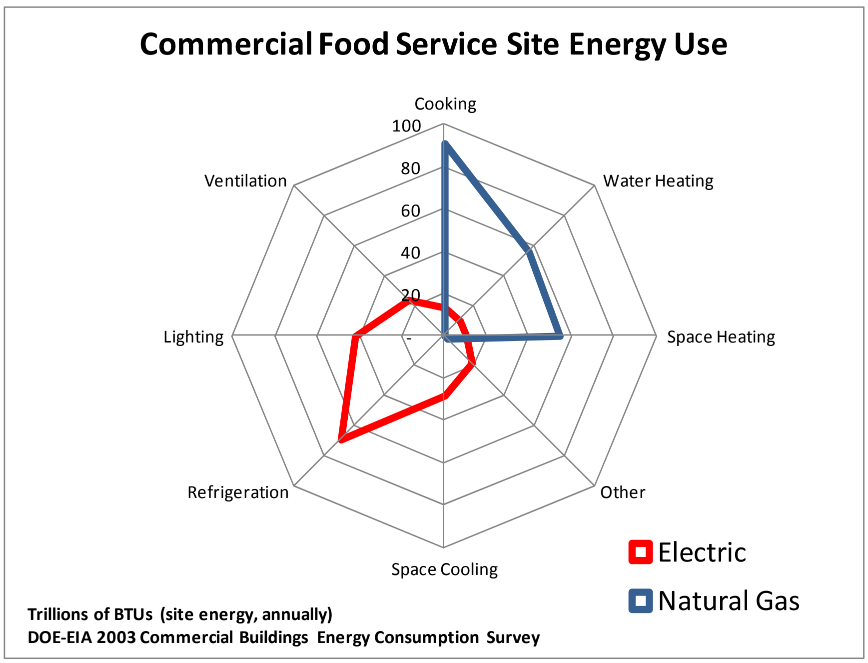


Figure 4: Commercial Food Service Site Energy Use – Electric and Natural Gas

The use of each of these two energy choices is highly differentiated, with most electricity used for refrigeration, space conditioning, lighting and ventilation. Natural gas is predominantly used for cooking, water heating, and space heating – holding over 80 percent share across the market. Retaining this market position against electric technologies should be a primary consideration for the natural gas industry.

Table 9: National Electric and Gas Site Energy Use for Commercial Food Service

	Electric	Natural Gas	% Gas
Cooking	13.6	91.0	87%
Water Heating	10.2	56.0	85%
Space Heating	10.2	54.0	84%
Other	18.1	2.0	N/A
Space Cooling	28.2	-	N/A
Refrigeration	69.5	-	N/A
Lighting	42.4	-	N/A
Ventilation	24.3	-	N/A

Source: DOE-EIA 2003 Commercial Buildings Energy Consumption Survey (Trillion Btu)

There is a substantial amount of energy consumed to produce and deliver electricity. The total source to site energy lost is often more than twice the amount of electric energy used onsite. DOE-EIA data indicate that total energy consumption for electricity in commercial foodservice is about 650 trillion on a complete source to use basis (compared to about 215 trillion Btu on a site-only basis). Figure 5 illustrates the substantial differences in total source energy use compared to a site-only basis. For example, refrigeration loads use slightly less energy on a site basis, but are more than two times more in energy consumption on a source basis.

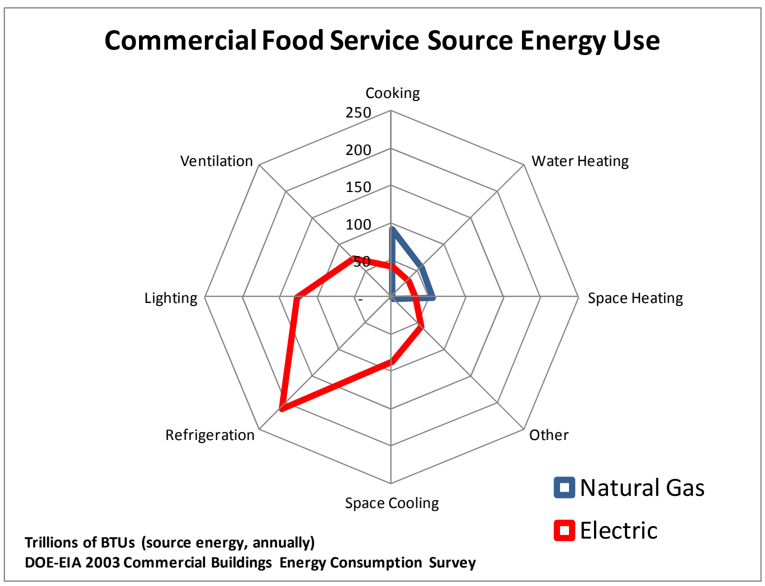


Figure 5: Commercial Food Service Source Energy Use – Electric and Natural Gas

The substantial differences in site versus source energy values can be an important factor when companies look at "green building" issues such as LEED compliance. Unfortunately, there has been a reluctance in some of these codes to recognize total source energy as a more complete and responsible measurement of national energy use.

Natural gas and electricity -- and the industries that represent them – have perceived strengths and weaknesses. The following table highlights some of these considerations.

Table 10: Natural Gas and Electric Strengths and Weaknesses

	Strengths	Weaknesses
Natural Gas	• Perceived as lowest life-cycle and operating cost options for end users • High energy rates with rapid response to changes in burner setting • High delivered energy density compared to electric. • Source energy and carbon emission advantages over electricity	• Less technologically advanced (e.g., manual controls, pilot lights) • Perception in some cases as being less safe than electric products • Manufacturers lack gas expertise or motivation to invest in state-of-the-art gas technology (e.g., indifferent on gas vs electric) • Perceived limited gas industry marketing focus in this segment • Lack of gas combustion engineers and burner design experts. Old designs tend to be reused
Electric	• Seen as cleaner, more technologically advanced • Perceived as safer than natural gas • Products are viewed as more reliable • Typically lower first cost equipment • Many 'green' building codes based upon site rather than total source energy	• Higher electric operating costs (energy and power demand) • Utility pressure to manage peak demand, control costs, ensure reliability • Typically higher source energy and emission factors (on a full-fuel-cycle basis) • Limited availability in some locations to add amperage or install higher voltage outlets needed for resistance heating

Operating costs are an important factor in the commercial food service sector. Survey data indicates that users perceive natural gas as a better value in terms of annual energy costs. The following table compares typical commercial natural gas and electricity prices in New York and Boston for commercial customers (Source: DOE-EIA, Oct. 2009 data).

Table 11: Comparison of Energy Costs in New York and Massachusetts

	Natural Gas	Electric	Electric/Gas Ratio
New York	\$10.46/mcf (\$10.25/MMBtu)	\$0.1568/kWh (\$45.93/MMBtu)	4.5:1
Massachusetts	\$11.38/mcf (\$11.16/MMBtu)	\$0.1912/kWh (\$56.00/MMBtu)	5.0:1

Using information from GTI's Building Energy Analyzer, the following table breaks down annual energy characteristics and energy costs for a typical 5,000 sq. ft. national chain casual full-service restaurant. This highlights the energy value provided by natural gas relative to electricity. Commercial food service establishments are paying monthly bills for electricity that are more than double their natural gas bills. This disparity likely helps underscore the consumer perceptions of natural gas being a better value – or, conversely, they are paying too much for electricity.

Table 12: Restaurant Energy Cost and Consumption Comparisons in New York City and Boston

	Natural Gas	Electric	Electric/Gas Energy Ratio	Electric/Gas $ Sales Ratio
New York, NY	Site Energy 3,087 MMBtu Source Energy 3,358 MMBtu Cost: $31,640	Site Energy 427,000 kWh; 89 kW Source Energy 4,239 MMBtu Cost: $66,950	0.47:1 (site) 1.26:1 (source)	2.1:1
Boston, MA	Site Energy 3,238 MMBtu Source Energy 3,552 MMBtu Cost: $36,140	Site Energy 420,000 kWh; 87 kW Source Energy 4,383 MMBtu Cost: $80,300	0.44:1 (site) 1.23:1 (source)	2.2:1

Note: Source emission factor of 2.91 for NY electricity, 3.06 for MA electricity, 1.088 for natural gas (Source: GTI)

The Northeast market may see further absolute and relative improvement in natural gas prices and electric/gas price ratios due to the substantial new natural gas supplies being developed in the Marcellus Shale region in Pennsylvania, New York. **The combined impact of expanding supplies coupled with market proximity (i.e., reduced transmission costs) is likely to further enhance the competitive position of natural gas in this market sector**.

As noted, there can be substantial differences between natural gas and electricity from an environmental perspective depending on whether you compare site or source (total) emissions. This is a relevant factor to highlight with respect to consumer awareness of energy, environmental, and sustainability concerns. Surveys indicate that consumers perceive electricity as being “more green” than natural gas (Figure 6) – even though natural gas emits lower greenhouse gases than electricity on a total energy basis.

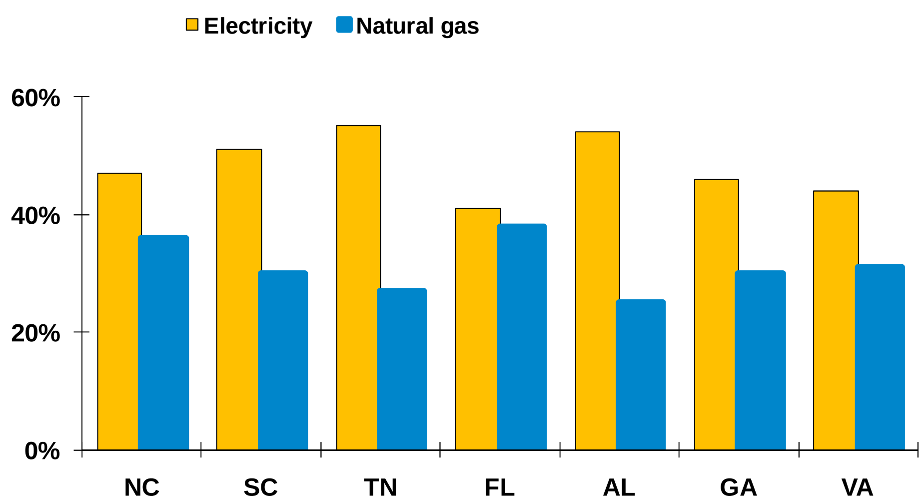


Figure 6: Consumer Perceptions of Environmental Friendliness

(Source: Council for Responsible Energy, 2007 data)

The natural gas industry is striving to elevate the source-to-site (or full fuel cycle) energy and environmental benefits of natural gas compared to electricity. Conveying this message to various stakeholders – individual consumers, businesses, and policymakers – is important. Decision makers in the commercial foodservice industry can also include architects, consulting engineers, and others – particularly those who are positioned in areas associated with "green buildings" (e.g., LEED-certified personnel).

There are market factors – opportunities and threats in the competitive marketplace -- that can influence the relative strengths and weaknesses of natural gas and electric now and in the future. The following is a summary of some of these factors that may impact natural gas and electric products and the customer's willingness to continue using or when purchasing new commercial food service products.

Table 13: Natural Gas and Electric Opportunities and Threats

	Opportunities	Threats
Natural Gas	• Developing state-of-the-art natural gas products (e.g., pilotless ignition, new sensors and controls, • Smart technology that enhances control and communications • Features that increase productivity, product quality • Expanding the number of products recognized as Energy Star compliant • Utility marketing, outreach and incentive programs (e.g., test kitchens, live cooking demonstrations, incentives for high-efficiency products) • Marketing outdoor cooking and outdoor seating with gas heating to restaurants • Potential improved positioning of natural gas prices relative to electricity • Enhancing customer and policymaker awareness of source energy and environmental benefits	• Lower number of Energy Star appliances compared to electric • Reduced opportunity for customers to benefit from energy efficiency incentives (and potential switching to electric) • Larger and/or more aggressive electric utility marketing and incentive programs (7-10:1 greater energy efficiency funding) • Reduced level of skill and expertise among small to medium manufacturers – particularly with respect to natural gas technology • Tightening emission standards (e.g., NOx, particulates) • Higher cost and complexity of ventilation and interior piping systems • Bias in certain Green Building Codes towards site energy and "clean" electric
Electric	• Rethermalizing and similar trends that could reduce kitchen energy intensity and potentially favor all-electric kitchens • Advanced cooking techniques such as induction cooking • Smart technology that enhances controls and communications Leveraging green building codes that favor site energy	• Increasing electricity prices due to increasing cost of new power plants and added environmental costs to reduce carbon emissions • Concerns over peak electric demand and electricity supply reliability • Use of source energy in place of site energy for green building codes and energy efficiency metrics

Energy Efficiency Programs and Energy Star

Energy efficiency and sustainability are key concepts that resonate with restaurant and food service operators. Their tight operating margins provide an incentive to reduce fixed and variable energy costs. The following table from the NRA 2010 Restaurant Industry Forecast outlines steps taken in 2009 and plans for 2010 relative to energy savings and other resource conservation investments. These data indicate a higher inclination towards electricity savings steps (e.g., lights, air conditioning, refrigeration) followed by investments in energy-saving kitchen equipment. Water savings are generally lower priority resource conservation steps.

Table 14: NRA Sustainability Survey – Planned Actions

Sustainability steps

Proportion of restaurant operators, by type of operation, who took the following energy-saving actions in 2009 or who plan to in 2010

	Family dining		Casual dining		Fine dining		Quickservice	
	Did in 2009	Plan to in 2010	Did in 2009	Plan to in 2010	Did in 2009	Plan to in 2010	Did in 2009	Plan to in 2010
Purchased energy-saving light fixtures	69%	41%	66%	46%	52%	38%	43%	32%
Purchased energy-saving kitchen equipment	45%	34%	41%	34%	28%	32%	34%	31%
Purchased energy-saving refrigeration, air conditioning or heating systems	50%	32%	40%	28%	34%	27%	32%	30%
Installed water-saving equipment and/or fixtures	27%	26%	27%	23%	27%	24%	23%	23%

The somewhat greater leaning toward electric savings may reflect the reality that annual electricity costs are likely to be twice as high as natural gas costs – that is, electricity provides greater opportunity for savings.

Other factors to consider are:

- The availability of Energy Star and other high-efficiency equipment
- The availability of rebates, tax credits, and other incentives that may enhance the buying decision process for the consumer

For example, electric and natural gas energy efficiency programs have grown considerably in recent years. These programs can provide meaningful incentives for the purchase of new high-efficiency equipment. Historically, this funding has primarily been directed at electricity consumers, with a more recent trend of funding for natural gas.

According to the Consortium for Energy Efficiency, in 2009 approximately $4.4 billion million was invested in electric energy efficiency and $930 million in natural gas energy efficiency programs across the US. The following table breaks down state-level natural gas and electric energy efficiency program funds (including demand response) directed at the commercial and industrial sector in 2009 by CEE.

Table 15: Energy Efficiency Funding Comparison (Source: CEE, 2009 data)

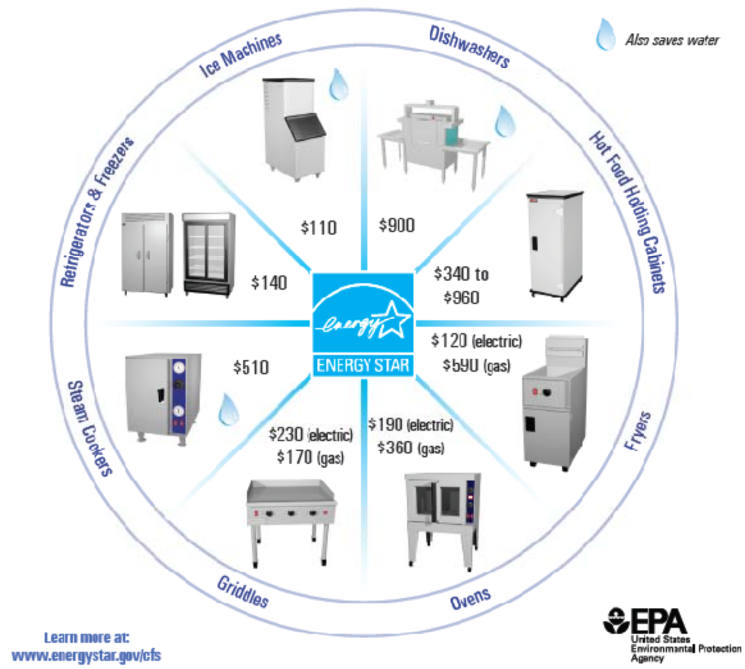
	Natural Gas	Electric	Electric/Gas Ratio
U.S. Total	$930.0 million	$4,400.0 million	4.7:1
New York	$42.9 million	$393.2 million	**9.2:1**
Massachusetts	$32.5 million	$176.1 million	**5.4:1**
New Hampshire	$3.0 million	$16.3 million	5.4:1
Rhode Island	$7.6 million	$30.7 million	4.0:1

Substantially greater funds are potentially available to commercial food service establishments for electric energy efficiency incentives and rebates compared to natural gas (by a factor of 4-9:1). Notably, the energy efficiency funding ratio is considerably higher than the national average in New York – that is, greater funds are available to incentivize the purchase of high-efficiency electric equipment. This underscores the potential threat to the natural gas industry of consumers switching to electric technologies based on the incentives provided by energy efficiency program funding.

A complementary issue is the availability of products that can qualify for energy efficiency funding. Energy Star is an international standard for energy efficient consumer products. It was first created as a United States government program by the Clinton Administration in 1992, but Australia, Canada, Japan, New Zealand, Taiwan and the European Union have also adopted the program. Devices carrying the Energy Star logo, such as computer products and peripherals, kitchen appliances, buildings and other products, generally use 20%–30% less energy than required by federal standards. There is considerable online information that can be found at www.energystar.gov – including product availability and other helpful information from consumers.

Initiated as a voluntary labeling program designed to identify and promote energy efficient products, Energy Star began with labels for computer products. In 1995 the program was significantly expanded, introducing labels for residential heating and cooling systems and new homes. As of 2006, more than 40,000 Energy Star products are available in a wide range of items including major appliances, office equipment, lighting, home electronics, and more. In addition, the label can also be found on new homes and commercial and industrial buildings. In 2006, about 12 percent of new housing in the United States was labeled Energy Star. The EPA estimates that it saved about $14 billion in energy costs in 2006 alone. The Energy Star program has helped spread the use of LED traffic lights, efficient fluorescent lighting, power management systems for office equipment, and low standby energy use.

There are eight types of commercial food service (CFS) appliances that can earn EPA's Energy Star. Qualified equipment models use less energy and less water than conventional CFS models. The following images from www.energystar.gov/cfs shows the potential annual savings of using Energy Star qualified compared to conventional appliances.



Energy Star appliances require sufficient information and usage data to determine the baseline energy consumption – a necessary pre-condition to establish an Energy Star performance level. There are limited categories for Energy Star products suitable to the commercial foodservice sector because the data either does not exist or has not been compiled into a useful set to establish Energy Star guidelines.

Current drivers within the foodservice industry are pushing the need to establish new categories of Energy Star appliances. Because of increasing energy and water utility costs and interest in being more sustainable, operators in the commercial foodservice industry are expressing increased interest in appliances and systems that are more energy efficient to replace older, less efficient units. Recent market surveys conducted by both GTI and the National Restaurant Association have shown a greater interest on the part of operators to invest in energy-efficient equipment. GTI surveys have shown that consumers within the past two years are more willing to spend extra on the first cost of new appliances if the units are significantly more efficient or Energy Star rated. Manufacturers also have expressed to GTI that concerns over energy efficiency and the environment have become major drivers in the foodservice industry compared to two years ago.

There is an ongoing challenge facing the natural gas industry to ensure there is a broad array of Energy Star-approved natural gas appliances available. Many utility energy efficiency programs use Energy Star as a product qualifying step for energy efficiency funds. Unfortunately, due to a variety of factors, there are numerous product categories in the commercial food service sector where there are no Energy Star-approved products available – either because the products do not exist or because there are no approved standards for that product category. Table 16 lists the current Consortium for Energy Efficiency "qualifying product" list. Only two categories tie with natural gas equipment – fryers and steamers; all product categories tie into electricity use. The lack of approved energy efficient product standards can stymie or inhibit:

- The development of new, high-efficiency equipment by manufacturers
- The ability of natural gas energy efficiency to incentivize the purchase of new high-efficiency natural gas equipment

Table 16: CEE Qualifying Commercial Foodservice Products (2010)

Dishwashers	**Fryers**	Ice machines
Hot food holding cabinets	**Steamers**	Refrigerators & freezers
Pre-rinse sprayers		

Table 17 outlines the major commercial food service products with GTI-developed rating criteria on Energy Star status. In nine equipment categories there is an impediment due to the lack of any current standard or standard development process underway. In three categories, a standard is in development. In total, twelve of the nineteen equipment categories (63 percent) of commercial foodservice products are lacking in a qualified Energy Star standard.

Table 17: Energy Star Availability Ratings for Commercial Food Service Equipment

Equipment Category	Energy Star Status*
Underfired Broilers/Charbroilers	1
Pizza / Deck Ovens	2
Wok Ranges	1
Steamers - Pressure	4
Ranges	1
Conveyor Broilers	1
Conventional Ovens	1
Conveyer Ovens	2
Rotisserie Ovens	1
Griddles	4
Pressure Fryers	1
Fryers	5
Over-fired Broilers	1
Convection Ovens	4.5
Steamers - Free-Standing	4
Tilting Skillets	1
Combi Ovens	2
Steamers - Counter-Top	3
Warewashers	3

* Energy Star Status Rating Key

5 = Standard Issued - Robust Qualified Gas Equipment
4 = Standard Issued - Some Qualified Gas Equipment
3 = Standard Issued - Electric Equipment Dominates
2 = Standard In Process
1 = No Standard

Taken together, these data on state-level energy efficiency programs, availability of industry recognized "qualified products" by CEE, and a substantial deficiency in Energy Star-approved standards and qualified equipment underscores the need for natural gas industry attention. Specifically:

- In selected Northeast states, such as New York and Massachusetts, there is a need to evaluate the relative availability of natural gas energy efficiency funds relative to those for electric in the commercial sector.
- A concerted natural gas industry effort is required to:
    - Substantially enhance the availability of Energy Star standards for various commercial food service equipment.
    - Expand efforts with CEE and other organizations to document and support an expanded list of energy efficiency commercial foodservice products.
    - Substantially expand the number of qualified Energy Star and CEE-recognized natural gas commercial food service products that are developed and available to consumers.

Gas Industry RD&D and Commercialization

Based on these results, GTI sees the following as fertile areas in the foodservice industry for National Grid's territory:

Area 1. **Development of higher efficiency and Energy Star-compliant natural gas appliances, coupled with support of new energy efficiency standards and protocols**
Benefits: Energy savings, lower emissions and gas appliance positioning with the "green" and sustainability movement. Increased availability of "qualified products" for natural gas energy efficiency program incentives. Avoiding market erosion to electric equipment.

Area 2. **Improved space conditioning and ventilation in the work area for a healthier work environment**
Benefits: Improved workplace comfort, lower employee turnover, and energy cost savings.

Area 3. **Development and marketing of equipment that is easier to operate and maintain**
Benefits: Improved productivity, improved product quality, and lower energy costs for restaurant and commercial foodservice operators. Avoiding market erosion to electric equipment.

Area 4. **Expanded marketing and outreach programs: Test Kitchens and Live Cooking Demonstrations, increased use of rebates and incentives for natural gas energy efficient products**
Benefits: Greater customer and trade ally recognition of the availability and benefits of new natural gas products.

When assessing the needs, opportunities, and threats within the commercial food service sector, it is important to explore the spectrum of the product development and commercialization stages.

Figure 7 outlines an example of the steps required in the product development and commercialization process.

Natural gas R&D

The natural gas industry has two primary collaborative R&D programs – the GTI Sustaining Membership Program (SMP) and Utilization Technology Development (UTD, an independent industry-driven non-profit RD&D organization). These organizations primarily span RD&D activities up to Stage 6, demonstration and deployment.

Leading towards commercialization, the roles of SMP and UTD are complemented by the Energy Solutions Center (ESC) as well as an expanding number of natural gas energy efficiency programs that support Stage 6, 7 and 8 efforts through marketing programs and outreach as well as incentives that help support new technology acceptance in the market. A part of the ESC includes the Gas Food Equipment Network, or GFEN. Utility energy efficiency programs also have a national organization called the Consortium for Energy Efficiency (CEE).

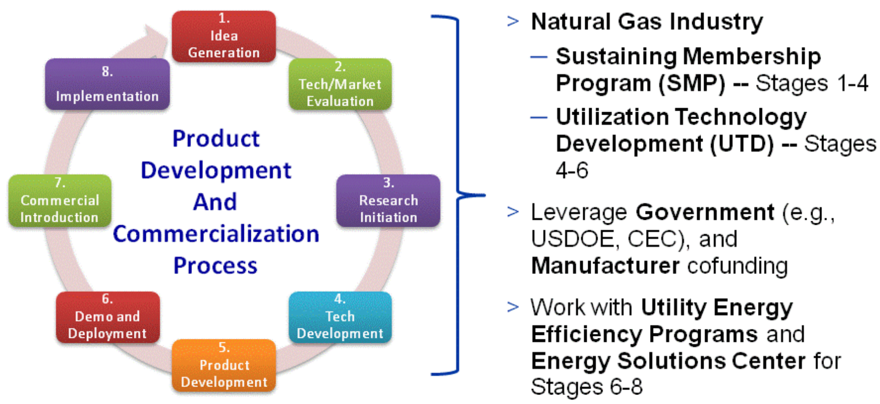


Figure 7: Product Development and Commercialization Process

For the reasons outlined in this report – notably, the energy intensity of commercial foodservice operations – GTI and UTD natural gas industry partners have maintained a focused concentration on product development for commercial foodservice customers. The research, development, and demonstration (RD&D) efforts of UTD has led to several successful commercial foodservice products (Table 18).

Table 18: Example UTD-Supported Commercial Foodservice Products

	**Low-Oil-Volume Fryers** A new commercial foodservice low-oil-volume fryer unit, marketed by Frymaster as Protector® fryers, increases energy efficiency while also extending cooking oil quality and life to provide significant customer savings.	**Contact: Linda Brugler** Frymaster 318-866-2488 lbrugler@frymaster.com www.frymaster.com
	**Stellar Countertop Steamer** This compact gas-fired countertop steamer for commercial food service offers enhanced cooking rates while providing users with added savings of energy and water consumption. The unit is the first gas-fired boilerless steamer with an ENERGY STAR rating.	**Contact: Market Forge Industries/Stellar Steam** 617-387-4100 866-698-3188 custserv@mfii.com www.mfii.com www.stellarsteam.com
	**Avantec Combi-Oven** The combination oven uses a patented technology for improving cooking performance, quality, and efficiency. Able to operate in various cooking modes, the oven provides enhanced uniformity when compared to similar-sized ovens.	**Contact: Dave Goble** Avantec Food Service Equipment 800-322-4374 dave@twomarket.com www.avantecequipment.com

The UTD Foodservice Working Group is composed of representatives from UTD member gas utilities with expertise in the foodservice arena. The group holds regular conference calls to discuss issues and potential solutions for the foodservice industry and how the utilities can participate in this process. The development and maintenance of quality foodservice equipment is important to both the gas industry and the foodservice manufacturers.

During the past few meetings, several issues have been brought to the group for discussion. The biggest topic has been the need for more efficient gas-fired appliances to be introduced to the market. Specifically, utilities are looking for an expanded list of Energy Star eligible appliances that would qualify for rebates from the utilities. This expansion includes both increasing the number of efficient appliances in existing Energy Star categories and expanding the number of Energy Star categories to include more appliance types. Specific appliances discussed for investigation of improved energy efficiency include: convection ovens, conveyor ovens, and ranges. Specific energy efficiency issues for each appliance are discussed below:

- **Convection Ovens**
  Typical gas-fired full-sized convection ovens have heavy load efficiencies in the mid 30 percent range. The best gas-fired models that have been tested at the Foodservice Technology Center attain near 45 percent heavy load efficiency. The currently proposed standard for Energy Star rating will be 44 percent, meaning only a few models of existing convections ovens will receive an Energy Star Rating. Design elements that may contribute to the lower efficiency include: door gasket material, method of firing the burner (direct vs. indirect heating), construction seals and door design (split vs. one piece). There are an estimated 15,000 gas-fired convection ovens operating in National Grid Service territory, with an associated gas load of 9 million therms annually. Improving the stock efficiency of gas-fried convection has the potential to reduce the commercial gas load by 3 million therms per year. The associated carbon savings is 39 million pounds of CO_2 produced per year.
- **Conveyor Ovens**
  Over the past 30+ years, conveyor ovens have taken over the majority of baking pizzas in restaurants. Because of several factors in the design of conveyor ovens, the efficiencies tend to be low compared to other foodservice appliances, about 40 percent for large conveyor ovens and 20 percent for small ovens. A large majority of the larger ovens are gas; however, for the smaller ovens, there are more electric than gas models. More progress has been made to improve the efficiency of the larger ovens than the smaller ovens by improving stand-by losses in the ovens. However, other design issues tend to keep the efficiency of the smaller ovens lower than the large ovens. These include the open ends of the conveyor, cooking tunnel design/dimensions and air flow distribution. There are an estimated 3,000 gas-fired conveyor ovens operating in National Grid Service territory, with an associated gas load of 6.5 million therms annually. Improving the stock efficiency of gas-fried convection has the potential to reduce the commercial gas load by 2 million therms per year. The associated carbon savings is 26 million pounds of CO_2 produced per year.
- **Ranges**
  Commercial ranges are one of the most common appliances in the foodservice industry and 90

percent of ranges are gas fired, resulting in a significant gas load. Gas fired commercial ranges currently have very low efficiencies due to three main issues:

- Pilot lights – While most residential gas-fired ranges feature pilotless ignition, a very high percentage of commercial ranges have pilots. Some manufacturers have offered pilotless ignition, but the market has not embraced this feature.
- The ASTM water-boil efficiency is in the low 30 percent range.
- Some operators leave burners operating when there is no load in place on the burner.

Another issue is that there are new hood interlock rules from both the international mechanical code and the international fuel gas code that require gas to be shut off to cooking equipment when the kitchen hoods are not in operation. This forces the restaurant to either run a separate gas line for pilot operation or re-light their pilots every morning. The new hood interlock rules are forcing the industry to consider using ranges without pilots so they will not have to worry about relighting the pilot each morning. There are an estimated 21,000 gas-fired commercial range tops operating in the National Grid Service territory. These are broken into heavy-duty ranges, restaurant ranges and stock pot ranges. The estimated gas-load for the three subcategories of ranges is 20 million therms per year. Estimating 200 new ranges produced per year with 50 percent energy savings provides 1 hundred thousand therms of energy savings in the first full year of deployment alone.

The members also expressed interest in participating in the process of establishing Energy Star ratings and providing information to the customers on rebates and the advantages of using Energy Star appliances.

Another issue growing within the foodservice industry is the concept of “green” appliances and environmental benefits in term of carbon footprint of gas vs. electric. The group expressed the need to understand and define terms that apply to the “greenness” of an appliance and how information can be conveyed to the utilities and its customers.

The current RD&D process for commercial foodservice is reasonably robust, but could benefit from further investment. The following are R&D funded by UTD or SMP::

- Gas-fired wok
- Gas-fired rethermalizer
- Gas-fired conveyor oven
- Gas-fired convection oven
- Gas-fired commercial range
- Gas-fired warewasher

Beyond these readily identifiable products suited to the kitchen environment, there are several cross-cutting technology development initiatives that can benefit the commercial food service sector, such as:

- Early-stage cross-cutting technologies:

   - Advanced flat-panel radiant burner and controls (could be applied to various foodservice cooking devices)
   - Low NO_x burners
- Hybrid tankless hot water technologies
- High-efficiency rooftop packaged gas heating units
- Desiccant-based dehumidification systems
- Commercial hybrid solar thermal/natural gas systems

One area of note is a UTD project that is addressing a growing trend in the foodservice industry: preparing certain food products in larger quantities at a centralized location and delivering those to restaurants for reconstituting or rethermalizing. The main driving factors for this are productivity and labor savings from centralized large-scale production, speedier in-restaurant preparation, and energy savings. Products like soups, gravies, vegetable side dishes and sauces have been shown to be prepared in this method and served in restaurants without any perceived sacrifice in flavor or texture. Data suggests that significant energy and labor savings can be realized by preparing these items in bulk.

Commercialization

The Energy Solutions Center is a technology commercialization and market development organization representing energy utilities, municipal energy authorities, and equipment manufacturers and vendors. The mission of the Center is to accelerate the acceptance of and deployment of new energy-efficient, gas-fueled technologies that enhance the operations and productivity of commercial and industrial energy users, and improves comfort and reliability for residential energy users.

The ESC and its members identify, evaluate, and prioritize new market opportunities and then implement market development initiatives designed to move products from R&D success to broad market acceptance.

The Gas Foodservice Equipment Network (GFEN) is an international alliance of utilities, foodservice equipment manufacturers, gas industry associations and foodservice trade allies organized to be a source of gas solutions for the commercial foodservice segment. The objective of GFEN is to maintain and build natural gas load by ensuring that our commercial food service customers have an array of clean, efficient, cost-effective and high performance natural gas products from which to choose and are made aware of these products and their benefits.

There are a select number of utilities that have adopted targeted marketing efforts for the commercial foodservice sector using Test Kitchen facilities. This approach allows restaurant operators, cooks, equipment manufacturers and other stakeholders to test new products, learn about new energy efficient practices, and make side-by-side comparisons of competitive brands – including comparing natural gas and electric products.

Several utilities have invested in foodservice centers and test kitchens, including Southern California Gas, PG&E, Southwest Gas, Piedmont Natural Gas, Alabama Gas, and Centerpoint Energy, . Figure 8 shows a profile on Piedmont's test kitchen from a recent GFEN publication.

PIEDMONT NATURAL GAS
TECHNOLOGY CENTERS

Piedmont's Gas Technology Center in Charlotte has 6,000 square feet of space, two 10-foot sections of kitchen ventilation hood and five gas and electric connections. Both natural gas and electric cooking equipment can be compared in a real-world environment. A data acquisition system provides the capability to measure and calculate equipment performance, energy use and efficiency, and food production. In addition, there are large prep and cleanup areas with both condensing and high-efficiency commercial gas water heaters and a dishwasher with a gas booster heater.

When not used for equipment testing or demonstrations, the Centers have extensive audio/video capabilities and seating for 70 people which make them ideal for sales meetings, customer workshops, and ServSafe training sessions.

Charlotte, NC · Spartanburg, SC
Sandra Minter · 704.731.4014

Figure 8: Piedmont Natural Gas Test Kitchen Profile (Source: GFEN, Spring 2009)

The Consortium for Energy Efficiency (CEE), a nonprofit public benefits corporation, develops initiatives for its North American utility members to promote the manufacture and purchase of energy-efficient products and services. Their goal is to induce lasting structural and behavioral changes in the marketplace, resulting in the increased adoption of energy-efficient technologies. CEE members include utilities, statewide and regional market transformation administrators, environmental groups, research organizations and state energy offices in the U.S. and Canada. Also contributing to the collaborative process are CEE partners – manufacturers, retailers and government agencies. The U.S. Department of Energy and Environmental Protection Agency both provide support through active participation as well as funding.

Commercial Foodservice Market Channels

Commercial Foodservice Trade Associations

National Restaurant Association

The National Restaurant Association represents more than 380,000 commercial food service businesses — from restaurants and suppliers to educators and non-profits. They produce annual reports and information products for their members as well as advocacy. They also network with a variety of state organizations, including:

New York State Restaurant Association
409 New Karner Rd
Albany, NY 12205-3883
Phone: (518) 452-4222
Web site: www.nysra.org

Massachusetts Restaurant Association
333 Turnpike Rd Ste 102
Southborough Technology Park
Southborough, MA 01772-1755
Phone: (508) 303-9905
Web site: www.marestaurantassoc.org

New Hampshire Lodging & Restaurant Association
PO Box 1175
Concord, NH 03302-1175
Phone: (603) 228-9585
Web site: www.nhlra.com

Rhode Island Hospitality Association
94 Sabra St
Cranston, RI 02910-1031
Phone: (401) 223-1120
Web site: www.rihospitality.org

The annual National Restaurant Association show is a venue to find the latest ideas, products and educational programs. Attendance can include over 75,000 industry professionals participating in over 60 free seminars.

The NRA also has period webinars to allow members to learn from industry experts and operators. This could be a possible communications channel for energy companies.

The North American Association of Food Equipment Manufacturers (NAFEM)

NAFEM is a trade association of more than 625 foodservice equipment and supplier manufacturers that provide products for food preparation, cooking, storage and table service. NAFEM's biennial trade show attracts approximately 20,000 foodservice professionals and features more than 600 North American manufacturers.

Foodservice Equipment Sales and Service Channels

Table 19 shows information from a USEPA document outlining supply channel actors for the commercial foodservice sector. This is a fairly typical multiple channel arrangement – with the added role of *design consultants* who would specialize in the commercial foodservice sector. This role is similar to that provided by architect and engineering firms, consulting engineers, etc.

Table 19: Supply Channel Actors

Dealers: Dealers primarily sell to individual restaurants, which is often the most difficult market to reach. Smaller dealers may join buying groups so they can compete more effectively with larger dealers. Many dealers display their products in showrooms and tend to stock lower-priced, popular models that are usually not energy-efficient. A dealer's main objective is usually to sell the products they have on hand, and they are generally more interested in attracting customers with low prices rather than emphasizing the overall value of higher-end products (e.g., lifetime cost savings). Given that many manufacturers offer sales incentives to move lower-end models, dealer incentives can be an effective strategy to promote stocking and sales of energy-efficient equipment.
Distributors: Distributors primarily supply bulk quantities of equipment to dealers and sell commodity equipment (e.g., ice machines, fryers) directly to end users. Since distributors usually supply dealers, developing a good working relationship with distributors helps funnel energy-efficient CFS products into dealer showrooms. In addition, some restaurant food distributors sell CFS equipment and should also receive program outreach.
Manufacturers and Reps: CFS equipment manufacturers generally sell through product reps, although manufacturers may also sell directly to large end users such as national restaurant chains. Though all supply channels gravitate toward inexpensive, fast-moving pieces of equipment, a key value proposition for engaging reps is the up-sell potential of high-value, high-efficiency equipment. Sales of high-quality products earn reps a higher commission and generate long-term value for the customer, often leading to repeat business.
Design Consultants: Design consultants assist in the planning and design of new or renovated commercial kitchens, typically working with large or chain-owned restaurants, hotels, universities, and hospitals. Conducting targeted outreach to design consultants helps to ensure that energy- and water-efficient CFS equipment is considered in these types of projects. Design consultants are typically focused on the overall design and aesthetics of the space and controlling project costs, and back-of-the-house equipment is often a low priority. In addition, they often have established relationships with buying groups and may receive incentives for selling lower-end equipment. Equipment quality and performance are key selling points for engaging design consultants.

Source: USEPA Energy Star publication. Energy Star for Commercial Kitchens: Helping Customers Manage Costs, (June 30, 2009).

Market Channel Participant Interviews

In order to gauge market conditions in National Grid's territory, GTI undertook targeted primary market research by talking to key market channel players in the Northeast commercial foodservice sector. An independent consultant was deployed to conduct phone interviews with foodservice consultants and dealers that operated in the National Grid Service territory.

Phone Survey

GTI worked with Mr. Richard Topping of RFTopping Consultants to organize and conduct the telephone interviews. This encompassed two major Foodservice Consultant firms (Colburn & Guyette and Clevenger Foster LaVallee) and four foodservice equipment dealers/design houses (Kittredge, Trimark, Perkins and May Foodservice). As a practical matter, there are similarities between these two types of organizations but the consultants tend to work on bigger jobs and may be less brand-biased. The results of the interviews appear quite consistent across all six firms.

The most positive outcome from the survey is that participants felt that natural gas is firmly entrenched in the Northeast and that situation seems to be holding steady. No one sees any serious movement to electric equipment at this time.

The overall status of gas foodservice equipment in National Grid's service territory is good. Generally, responses show that gas provided good value and was a "green fuel." The relatively high electric rates in this area may be a contributor in this area. Several items that stood out as potential areas for improvement are highlighted below:

1. There were strong indications that neither the gas nor the electric utilities were involved in a significant role in the decision process for these marketers selling equipment. It is clear that all of the survey participants would welcome more utility involvement.
2. Venting of gas equipment was identified as an issue for five of the six companies.
3. Several of the respondents stated that electric appliances are perceived by some to generally be safer and more technologically advanced than gas-fired appliances.
4. All six responded that gas-fired booster water heaters face issues with being installed including venting, reliability, cost and efficiency.
5. According to three of surveyed sources, gas-fired warewashers face a disadvantage compared to electric because they require venting[1] (note: electric warewashers also require venting for the steam and steam hoods can also be used to vent flue products).
6. Three respondents expressed the need for pilotless ignition, especially on ranges, to address new hood interlock rules that require gas to be shut off to appliances when the kitchen hoods are not turned on. This forces the restaurant to either run a separate gas line for the pilots or re-light their pilots after each time the hoods are turned off.

Fuel cost is a major issue and natural gas has the advantage relative to electricity. Also, natural gas has a solid history and reputation. Electric is only preferred when deemed absolutely necessary, usually due to the lack of suitable gas service or ventilation issues (kiosks).

Interviewees were spread across the New York and Massachusetts areas. The detailed responses from the participants are included in tabular form in an appendix to this report.

The overall conclusion from this market survey effort is that, generally speaking, natural gas holds a good position in National Grid territory. Dealers and consultants feel that gas is the preferred fuel except when venting issues arise.

Several areas are candidates for some improvement if resources allow:

1. This issue arose when the dealers tried to support a gas booster heater program. The gas booster was not integral to the warewasher and required a separate vent. Since replacement sales are a significant component of the market for these appliances, venting is a big issue. GTI has been working with Jackson MSC to develop a warewasher with integral booster heater that vents through the body of the dish machine and should overcome the venting issue.

- Foodservice appliance manufacturers are relatively small in size and lack resources in engineering. They often need support in their gas designs, both for new product development and for troubleshooting existing designs.
- The surveyed dealer/consultant group did not receive information and support from the utilities that might help them promote gas equipment sales. This is probably a result of the loss of gas utility commercial marketing that has come about in the last few years.
- Energy efficiency and "greenness" are of extreme importance now. Appliances which can bear the Energy Star label are good sellers. At this time there are only a few appliance categories for foodservice where there is energy star. The community is working to expand this list over the next few years.

Conclusions

The commercial and institutional food service sector represents an important – **and growing** -- market for the natural gas industry. According to the National Restaurant Association (NRA), there are approximately 525,000 commercial food service establishments nationwide with annual sales of $580 billion.

State-level characteristics on four key states – New York, Massachusetts, Rhode Island, and New Hampshire – indicate a market size of 56,900 commercial foodservice locations with annual sales in excess of $43 billion. Using a nominal value of 3.4 percent of sales, annual utility costs (electricity, natural gas, water, etc) exceeds $1.4 billion in these four states (and approaches $20 billion nationally).

According to Energy Information Agency (EIA) survey data, commercial foodservice customers have 2.2 times the energy intensity (Btu/ft^2) of the average commercial customer. Audits conducted by Southern California Gas and Piedmont Gas found that natural gas sales to commercial foodservice customers account for 12 percent of the volume of gas sold, but comprised a healthy 19 percent of their profits.

In terms of new equipment, the estimated annual sales of new commercial foodservice equipment totaled about $1.2 billion in 2006. Of this, about 69 percent was natural gas-based products – indicating a strong market position for natural gas relative to electricity. The report provides further analysis of sales by product category and, an important consideration, the availability of Energy Star-rated products.

While a significant and growing market, there are continual threats and opportunities to assess within the commercial food service market segment, including:

- Natural gas market share is currently strong and holding against electric market share. New electric products; perceptions of electric as clean, simple, and reliable; and growing electric energy efficiency programs represent potential threats. There is also a market perception that electric equipment is more advanced or higher end than gas equipment.
- Natural gas is perceived as more cost-effective by users, with current electric-to-natural gas price ratios of 4.5:1 or higher. A typical restaurant is paying over twice as much annually for electricity than natural gas – underscoring the perception of natural gas as being cost effective.
- Rising labor, food, and energy costs are motivating foodservice providers to seek new and innovative equipment designs that could save operating costs through productivity improvements and speedier delivery.
- **Labor issues are a dominanting factor in this sector** – the major issues are obtaining and retaining quality workers, labor costs, and productivity. Increased labor turnover motivates foodservice providers to seek methods or equipment to improve the working environment for employees in terms of comfort, ease of equipment usage, and cleaning.
- Key purchase factors for new equipment include price, efficiency (operating costs), after-sales support, and productivity improvement. Equipment obsolescence and deterioration is typically the main reason to buy new equipment. One of the problems with old gas equipment is that is lasts for many years and restaurants do not tend to replace equipment until is total breaks down

instead of updating to new equipment. Getting information to users about the cost and energy saving associated with new equipment is lacking.

- Trends toward healthier and/or more environmentally responsible eating habits can influence the market, but the economic benefits/effects are not fully understood by the industry.
- The industry is concerned about lower emissions standards (including NO_x and particulates) – especially where such requirements have been imposed on residential appliances.
- The green movement is a threat to natural gas. Consumer surveys show that electric is perceived as being more green, possibly due to the site-based efficiency claims. There is an opportunity to position the new gas equipment as green through consumer education - identifying the financial and environmental benefits.

References

Czachorski, M. and Leslie, N., "Source Energy and Emission Factors for Building Energy Consumption," Gas Technology Institute for American Gas Foundation, Nov. 2009.

Energy Information Agency, "2003 Commercial Buildings Energy Consumption Survey," www.eia.doe.gov.

Environmental Protection Agency, Energy Star www.energystar.gov.

Frable, F., "Rethermalize it," Nation's Restaurant News, Oct. 8, 2007.

Fryett, D.K., "So, What's Going On Out There In The Food Service Industry That We Need To Know About," Final Report, Gas Food Equipment Network (2008).

Gas Food Equipment Network, "Cooking Up Greener Solutions, Spring 2009 Newsletter.

Melink, S., "Kitchen Hoods Using Demand Ventilation," ASHRAE Journal, Dec. 2003.

National Restaurant Association, "2010 Restaurant Industry Forecast," (2010).

National Restaurant Association and Deloitte, "Restaurant Industry Operations Report (2006/2007 Edition).

Nevius, M., Eldridge, R., and Krouk, J., "The State of the Efficiency Program Industry Budgets, Expenditures, and Impacts 2009," Consortium for Energy Efficiency, March 5, 2010.

USEPA, "Energy Star for Commercial Kitchens: Helping Customers Manage Costs," Energy Star publication (June 30, 2009).

van Straten, G. and Brown, S., "Keeping Cooks in the Kitchen: Solving the Makeup Air Dilemma," ASHRAE Journal, June 2003.

Appendix A: Market Survey Results

Key Issues	Issue / Question	Colburn & Guyette response	Clevenger Foster LaVallee response	Trimark response	Kittredge response	Perkins response	May Food Service response
	What type of business is this?	Colleges, healthcare facilities, institutions. C&G do not design many restaurants; dealers have a foothold and do designs for free to sell equipment.	CFL does big commercial and institutional jobs; also does more chain and restaurant work than typical consultants.	Largest dealer in US; also Trimark conducts engineering for restaurants and hotels.	Full service dealer of commercial kitchen equipment including engineering and sales	Dealer and design firm for restaurants, health care, institutions, etc.	Equipment distributor and design firm for food & beverage operations, institutions, etc.
	What product lines do they have (we only care about cooking and warewashing equipment)?	C&G does the research and specs equipment for clients by brand and model. They use gas wherever possible (high market share). Gas is more efficient and quicker (higher food output).	N/A	Large selection of equipment and brands	Offer products of most major manufacturers	Perkins specs equipment for their clients.	Full line of commercial foodservice equipment
	Profile sales of gas vs. electric equipment						
	What are the actual sales of gas equipment / Actual numbers	N/A	N/A	N/A	N/A		
	Share of market/sales of gas vs. electric	Sees no change in share; still predominantly gas in their market.	Sees no significant change in market share between gas and electric	Predominantly gas in the Northeast	Gas is predominant.		
	Is this share ratio changing, and if so, why?	No	No	No. Electric energy cost is high which limits sales of electric equipment. Also, most chefs prefer gas because of better control and higher output.	No	No change seen; equipment is almost always gas.	No change seen in market share
	Why gas share is what it is						
	Who specs fuel type and what are the key criteria (availability, cost, ventilation, reliability, etc.)	C&G uses gas wherever possible. They use electric with recirculating ventilation systems by necessity in limited applications.	CFL specs equipment (make and model) in consultation with the owner. CFL gets information from trade shows, equipment reps, AutoQuotes, etc. Usually specifies gas whenever gas is available. In situations without venting, electric is used.	Trimark works with their clients to spec the optimum equipment; also sells equipment to projects where the design is done by A&E firms and Consultants.	Replacement equipment nearly always utilizes the same fuel; utility changeover is very expensive and a hassle for an operating facility. Gas is usually specified when available; viewed as cheaper.	Perkins specs gas almost exclusively. Small markets are developing for unique electric equipment such as induction cooktops. However, induction currently is offered only in one or two station countertop units, no induction ranges are currently sold in the US (some may be coming from Europe).	May does the site design and specs the equipment by fuel type, make, model, etc. Gas is used almost exclusively in the Northeast except for very limited applications of electric equipment.
	What are the respective roles of consultants, dealers, manufacturers, utilities, etc.?	Big jobs use consultants; usually brought in by the A&E firm responsible for the project. Some projects like nursing homes use dealers but this may be changing as well.	Consultants typically are brought in by architects and A&E firms on large jobs (80 – 90% of their business). Dealers tend to do restaurant work in return for the equipment business. However, CFL also markets to the chains and restaurants; they do more of this work than most consultants.	Trimark, because of its size, has test kitchens where customers can prepare their food products with different types of equipment to determine what is best for their needs.	Consultants are hired by A&E's and architects for big jobs. Project subcontractors may include Kittredge who bids on supplying suites of equipment. Restaurants use Kittredge and its showrooms to purchase equipment. Kittredge does engineering for restaurants and offers a rebate on purchased equipment.		Customers rely on May for recommendations on equipment.
!	What is the level of participation of utilities, gas and electric. Is one doing a better job?	Utilities (gas or electric) aren't really involved; would be helpful if they were. C&G gets its information from manufacturers and trade journals	Utilities (gas or electric) provide no assistance to CFL. They could use help, especially in the area of codes and standards. Codes are becoming more varied across the country and restrictive. CFL could use one consistent set of up-to-date data. One specific problem area mentioned was requirements for flex connectors.	Rebates for Energy Star (currently up to $1000 for a fryer) help with the sale of high efficiency equipment. Bob believes the West Coast utilities still support the sale of gas with test kitchens and information; the East Coast utilities never did much and now do less.	GasNetworks does a good job of offering and advertising rebates in New England. The electric utilities have been much slower to offer rebates. However, it is like "pulling teeth" to get any assistance from utilities.	Utilities currently are providing $1000 rebates for high efficiency fryers.	Utilities really are no help at all. May is very disappointed that utilities are not more active in providing assistance and information on programs such as rebates.
	Is the current energy situation affecting share?	No	No. The fuel choice decision is based on the availability of gas; not energy cost.	No, electric cost is still higher than gas.	People are forgetting about energy and worrying about the economy	No, fuel cost drives the business and gas remains cheaper than electricity.	No
	Is the current world economic crisis impacting sales?	Not yet, but it appears there is a slowdown coming on new construction.	Yes, the current recession is slowing building projects.	Absolutely, the chains are experiencing a significant downturn. Franchisees cannot secure financing.	Yes	Across the board.	Yes, definitely.
	What is perception of gas equipment (vs. electric) / Cost	Electric equipment is higher cost	Gas equipment is more expensive in some equipment categories; less expensive in others.	Gas equipment is perceived as less costly, although in reality it is not always so. Electronics have added cost.	Gas is viewed as less expensive.	Gas	Gas equipment costs less.

Key Issues	Issue / Question	Colburn & Guyette response	Clevenger Foster LaVallee response	Trimark response	Kittredge response	Perkins response	May Food Service response
	What is perception of gas equipment (vs. electric) / Reliability	On par with the newer products; electric used to be less reliable	Better in some categories (ranges) and worse in others (kettles, combi-ovens and braising pans). However, the gas equipment manufacturers have done a good job improving equipment reliability	Even	Gas viewed as more reliable	Gas	Gas equipment is more reliable.
	What is perception of gas equipment (vs. electric) / Cook Quality	Gas is better	Depends on the application; electric braising was better but gas has improved. Some chefs prefer electric in specialized applications (griddle range and induction) so there is some small penetration of dual fuel kitchens	Gas is better	Gas is viewed as better overall. Some segments, such as bakers, prefer electric deck and convection ovens for better baked product quality.	Gas	Gas is better.
	What is perception of gas equipment (vs. electric) / Efficiency	Gas is higher	No perceived difference.	Gasis viewed as higher but because of energy cost.	Dan believes electric products are more efficient at getting the energy to the food but admits most of his customers only are concerned with energy cost which is lower for gas.	Gas	Gas is more efficient.
	What is perception of gas equipment (vs. electric) / Output	Gas is better	Same or greater for gas.	Even	Gas is better	Gas	Gas is higher
!	What is perception of gas equipment (vs. electric) / Other issues including Venting	Electric is used if ventless systems are required	Venting is a major issue. For example, it prevents the use of gas booster heaters for warewashing in many applications. Without adequate venting, electric equipment is specified to prevent any potential problems.	Gas requires more ventilation and this is an issue. To expand, some facilities will add electric equipment to the current suite of gas products to eliminate the need to add more hood space.	Venting is a growing issue for all types and applications. Code officials and fire inspectors are requiring similar venting regardless of fuel type. Hoods are expensive. Even table top cooktops (bottled gas or induction) now need ventilation. Electric ignition is required in Massachusetts (though subject to fire inspector interpretation)	There is virtually no call for electric equipment other than small products (toasters) and induction cooktops which is desired by some sophisticated chefs.	Ventilation is not really an issue for the vast majority of applications since cooking requires venting regardless of fuel type.
!	For costumers that prefer electric, why?	Can avoid ventilation cost. Also, certain applications use specialized cooking equipment (induction). New microwave/convection ovens are ventless and cook well; they fill a niche.	Regulations, safety (important in schools), desire for induction. Electric speed ovens (TurboChef) are impinging on gas in settings such as Dunkin Donuts for sandwich preparation. 20 years ago, a gas grill and hood would have been used. Codes and regulations could accelerate this trend – a potential dark cloud for gas.	Electric technology has improved more than gas lately. Speed-cook ovens and induction ranges are impressive and have potential to grow electric market share.	See above; also some churches like electric because of safety.	Applications where gas is not available or ventilation may be an issue.	Kiosk applications may require electric equipment where venting is an issue.
	Is there a significant trend in fuel choice by segment?	No	No.	No	No	No	No
	Who do users rely on for information before buying equipment	In this segment, on the consultants who rely on manufacturers and trade journals	Consultants and dealers.	Dealers and manufacturers reps. Reps have taken up the slack from utilities and now are much more sophisticated with test kitchens, data, etc.	N/A		Dealers and designers. Some operators rely on this advice and really do not get involved. Others, like chains, are very much involved in the purchase decision.
	What can be done to grow gas share						
	What would cause the decision of gas vs. electric to change in the future	N/A	See above.	N/A	If users start to accept (believe) the efficiency benefit of electric and the fact that electric equipment can be cheaper to operate in some circumstances		Large increase in gas cost.

Key Issues	Issue / Question	Colburn & Guyette response	Clevenger Foster LaVallee response	Trimark response	Kittredge response	Perkins response	May Food Service response
!	What can manufacturers/utilities do to influence that decision	N/A	Utilities or a national association (AGA, GTI, etc.) could help by providing a national data base on codes and regulations. Foster mentioned a particular problem in New York City where ConEd, the gas supplier, has decided to maintain low pressure service in high rise buildings. This requires a $50K compressor system for food service applications costing $100K, not a cost effective solution. Therefore, electric is being used. Also, the new electronic controls monitor gas pressure and shut the equipment down if the pressure drops below specs. Older equipment used to keep operating at lower output.	N/A	N/A		
!	Are there opportunities for gas in steamers and warewashing equipment?	C&G uses steamer and kettle combinations that utilize gas-fired boilers. Countertop steamers are electric and have the advantage or being more portable. C&G never specs gas for warewashing equipment; gas-fired boosters are hard to get approved. This is a growth opportunity for gas.	CFL sees an opportunity for large steam generators that can function under a hood and provide steam to several appliances (kettles, booster heater, etc.). Currently, plant steam is used but there is a trend to decentralize steam plants in buildings such as hospitals. Gas booster heaters aren't being widely used because they are hard to vent and restricted by codes.	There are problems with gas boilers in the Northeast because of high iron content in the water. Gas booster heaters for warewashing really are not popular because of the need for venting and the perception that electric is easier to locate, cheaper, and more reliable.	Ventilation and cost restricts the use of gas boosters for warewashing. Dan didn't see any promising additional opportunities for gas boosters or steam generators.	There is an opportunity for gas booster heaters if they can be made more reliable and venting can be more easily accomplished. Electric boosters require very heavy electric service (80 - 100 Amp, 3 Phase).	There are opportunities for booster heaters if gas equipment becomes more reliable, less expensive and more efficient.
	Is the Green movement good or bad for gas?	There is a perception that gas is greener.	Good for gas.	Not sure.	Good for gas; as a result, gas companies are aggressively marketing rebates	Not fuel specific; more the desire for higher efficiency.	Don't know.
!	What design improvements are needed for gas equipment (Efficiency, Cleanability, Performance, Price, etc.)	There is a need for electronic ignition in all gas equipment. The new ventilation systems turn off the gas supply when they are shut down. Electronic ignition is now required in some areas (Massachusetts)	The gas industry has done a good job overall with equipment. An additional needed design improvement is auto-shutdown for gas ranges. Currently ranges in many applications are turned on and left on. Also see above suggestion on steam generators	N/A	N/A	Pilotless ignition is being required by some codes. Electronic ignition systems have never been reliable in gas food service equipment; need improvement.	None come to mind.

Appendix B: National Restaurant Association Data Sheets

NATIONAL RESTAURANT ASSOCIATION®

2010 Restaurant Industry

Pocket Factbook

2010 Industry Sales Projection **$580 billion**

	2010 Sales (billion $)
Commercial	$ 530.4
Eating places	388.5
Bars and taverns	18.8
Managed services	40.9
Lodging place restaurants	26.9
Retail, vending, recreation, mobile	55.2
Other	$ 49.7

Restaurants
An Essential Part of Daily Life

- Restaurants will provide more than 70 billion meal and snack occasions in 2010.
- On a typical day in America in 2010, more than 130 million people will be foodservice patrons.
- 44% of adults say restaurants are an essential part of their lifestyles.
- 65% of adults say their favorite restaurant foods provide flavor and taste sensations that can't easily be duplicated in their home kitchens.

Restaurants
Small Businesses with a Large Impact on our Nation's Economy

- Restaurant-industry sales are forecast to advance 2.5% in 2010 and equal 4% of the U.S. gross domestic product.
- The overall economic impact of the restaurant industry is expected to exceed $1.5 trillion in 2010.
- Every dollar spent by consumers in restaurants generates an additional $2.05 spent in the nation's economy.
- Each additional dollar spent in restaurants generates an additional $0.82 in household earnings throughout the economy.
- Every additional $1 million in restaurant sales generates 34 jobs for the economy.
- Eating-and-drinking places are mostly small businesses. Ninety-one percent have fewer than 50 employees.
- More than seven of 10 eating- and drinking-place establishments are single-unit operations.
- Average unit sales in 2007 were $866,000 at fullservice restaurants and $717,000 at quickservice restaurants.

Restaurants
Cornerstone of Career Opportunities

- The restaurant industry employs about 12.7 million people, or 9% of the U.S. workforce.
- The restaurant industry is expected to add 1.3 million jobs over the next decade, with employment reaching 14 million by 2020.
- Nearly half of all adults have worked in the restaurant industry at some point in their lives, and more than one in four adults got their first job experience in a restaurant.
- Eating-and-drinking places are extremely labor-intensive — sales per full-time-equivalent non-supervisory employee were $75,826 in 2008. That's much lower than most other industries.
- One-quarter of eating- and drinking-place firms are owned by women, 15% by Asians, 8% by Hispanics and 4% by African-Americans.
- Eating-and-drinking places employ more minority managers than any other industry.
- The number of foodservice managers is projected to increase 8% from 2010 to 2020.
- Fifty-eight percent of first-line supervisors/managers of food preparation and service workers in 2008 were women, 14% were of Hispanic origin and 14% were African-American.

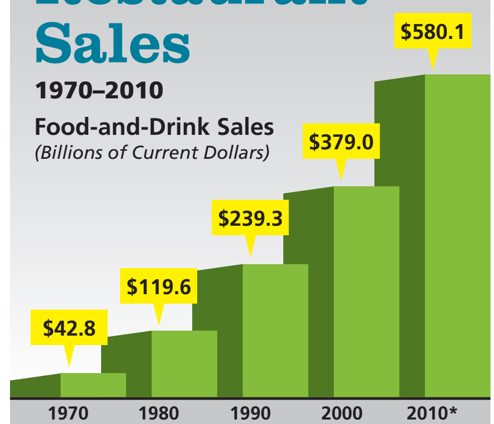
Restaurant Industry Share of the Food Dollar

1955 Present

Total Restaurant Industry Employment

* Projected

Restaurant Sales
1970–2010
Food-and-Drink Sales
(Billions of Current Dollars)



* Projected

Restaurants by the Numbers

- **$1.6 billion** Restaurant-industry sales on a typical day in 2010.
- **40** Percent of adults who agree that purchasing meals from restaurants and take-out and delivery places makes them more productive in their day-to-day life.
- **73** Percent of adults who say they try to eat healthier now at restaurants than they did two years ago.
- **57** Percent of adults who say they are likely to make a restaurant choice based on how much a restaurant supports charitable activities and the local community.
- **78** Percent of adults who say they would like to receive restaurant gift cards or certificates on gift occasions.
- **59** Percent of adults who say there are more restaurants they enjoy going to now than there were two years ago.
- **52** Percent of adults who say they would be more likely to patronize a restaurant if it offered a customer loyalty and reward program.
- **$2,698** Average household expenditure for food away from home in 2008.
- **29** Percent of adults who say purchasing take-out food is essential to the way they live.
- **54** Percent of adults who say they would be likely to use an option of delivery directly to their home or office if offered by a fullservice restaurant.
- **78** Percent of adults who agree that going out to a restaurant with family or friends gives them an opportunity to socialize and is a better way to make use of their leisure time than cooking and cleaning up.
- **63** Percent of adults who say the quality of restaurant meals is better than it was two years ago.
- **56** Percent of adults who say they are more likely to visit a restaurant that offers food grown or raised in an organic or environmentally friendly way.
- **70** Percent of adults who say they are more likely to visit a restaurant that offers locally produced food items.

1200 17th St. NW, Washington, DC 20036 | (202) 331-5900 | E-mail: askus@restaurant.org | www.restaurant.org

NATIONAL RESTAURANT ASSOCIATION® www.restaurant.org/research

New York
Restaurant Industry at a Glance

New York's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in New York, and their sales generate tremendous tax revenues for the state.

The contribution of New York's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

New York Restaurants by the Numbers

LOCATIONS

In 2007, there were **37,354** eating-and-drinking places in New York.

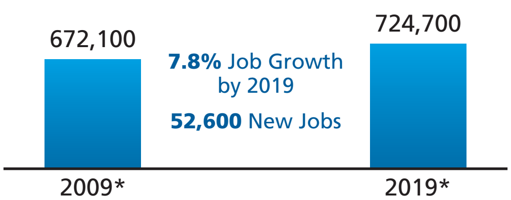
STATE ECONOMY

Every $1 spent in New York's restaurants generates an additional **$.98 in sales** for New York's economy.

Each additional $1 million spent in New York's eating-and-drinking places generates an additional **23.4 jobs** in New York.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **8 percent** of total employment in New York.

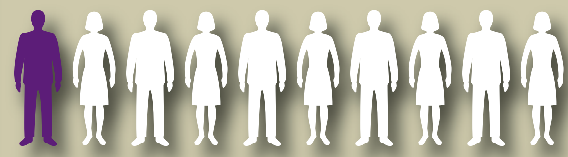
SALES

In 2009, New York's restaurants will register **$27.8 billion** in sales.*

* projected

America's Restaurants: By the Numbers

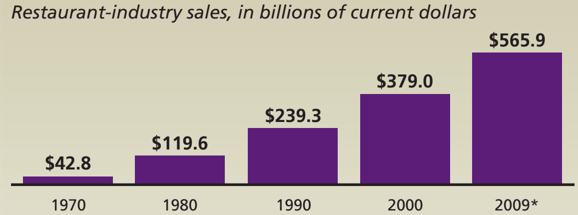
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION®
www.restaurant.org

NEW YORK STATE RESTAURANT ASSOCIATION
We serve you
www.nysra.org

New York's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	Timothy H. Bishop (D)	1,350	17,431
2	Steve Israel (D)	1,225	15,812
3	Peter King (R)	1,357	17,513
4	Carolyn McCarthy (D)	1,436	18,534
5	Gary L. Ackerman (D)	973	12,560
6	Gregory W. Meeks (D)	476	6,151
7	Joseph Crowley (D)	919	11,866
8	Jerrold Nadler (D)	4,401	56,812
9	Anthony Weiner (D)	801	10,342
10	Edolphus Towns (D)	453	5,851
11	Yvette D. Clarke (D)	525	6,777
12	Nydia Velazquez (D)	975	12,587
13	Michael E. McMahon (D)	893	11,526
14	Carolyn Maloney (D)	2,559	33,039
15	Charles B. Rangel (D)	616	7,947
16	Jose Serrano (D)	446	5,756
17	Eliot Engel (D)	903	11,662
18	Nita M. Lowey (D)	1,465	18,915
19	John J. Hall (D)	1,129	14,574
20	*Vacant Seat*	1,352	17,459
21	Paul Tonko (D)	1,602	20,684
22	Maurice D. Hinchey (D)	1,722	22,235
23	John M. McHugh (R)	1,399	18,057
24	Michael A. Arcuri (D)	1,308	16,887
25	Daniel B. Maffei (D)	1,365	17,622
26	Christopher John Lee (R)	1,325	17,105
27	Brian Higgins (D)	1,651	21,310
28	Louise McIntosh Slaughter (D)	1,348	17,404
29	Eric J. J. Massa (D)	1,378	17,785
	TOTAL	**37,354**	**482,200**

***** Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®

www.restaurant.org

NEW YORK STATE RESTAURANT ASSOCIATION
We serve you

www.nysra.org

Massachusetts

Restaurant Industry at a Glance

Massachusetts's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in Massachusetts, and their sales generate tremendous tax revenues for the state.

The contribution of Massachusetts's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

Massachusetts Restaurants by the Numbers

LOCATIONS

In 2007, there were **14,088** eating-and-drinking places in Massachusetts.

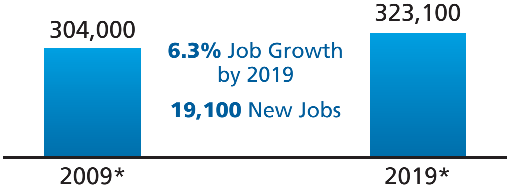
STATE ECONOMY

Every $1 spent in Massachusetts's restaurants generates an additional **$1.02 in sales** for Massachusetts's economy.

Each additional $1 million spent in Massachusetts's eating-and-drinking places generates an additional **24.1 jobs** in Massachusetts.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **9 percent** of total employment in Massachusetts.

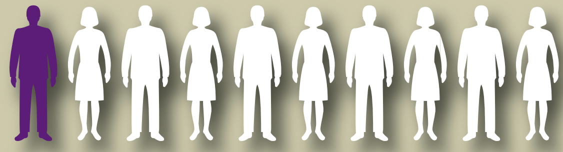
SALES

In 2009, Massachusetts's restaurants will register **$11.8 billion** in sales.*

* projected

America's Restaurants: By the Numbers

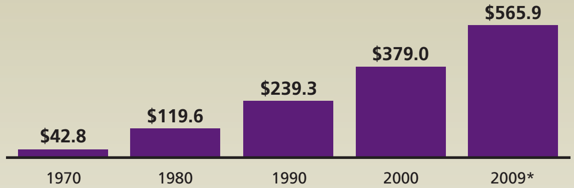
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION® — www.restaurant.org

MRA Massachusetts Restaurant Association — www.marestaurantassoc.org

Massachusetts's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	John W. Olver (D)	1,449	22,613
2	Richard E. Neal (D)	1,307	20,399
3	James P. McGovern (D)	1,483	23,132
4	Barney Frank (D)	943	14,706
5	Niki Tsongas (D)	1,211	18,893
6	John F. Tierney (D)	1,537	23,980
7	Edward J. Markey (D)	805	12,561
8	Michael Capuano (D)	1,926	30,053
9	Stephen F. Lynch (D)	1,521	23,738
10	William Delahunt (D)	1,905	29,724
	TOTAL	**14,088**	**219,800**

***** Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®

MRA Massachusetts Restaurant Association

www.restaurant.org **www.marestaurantassoc.org**

www.restaurant.org/research

Rhode Island

Restaurant Industry at a Glance

Rhode Island's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in Rhode Island, and their sales generate tremendous tax revenues for the state.

The contribution of Rhode Island's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

Rhode Island Restaurants by the Numbers

LOCATIONS

In 2007, there were **2,663** eating-and-drinking places in Rhode Island.

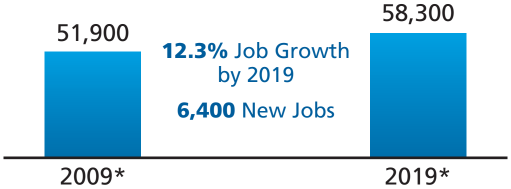
STATE ECONOMY

Every $1 spent in Rhode Island's restaurants generates an additional **$.85 in sales** for Rhode Island's economy.

Each additional $1 million spent in Rhode Island's eating-and-drinking places generates an additional **24.7 jobs** in Rhode Island.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **11 percent** of total employment in Rhode Island.

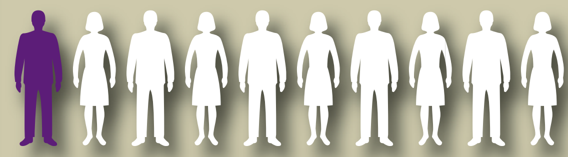
SALES

In 2009, Rhode Island's restaurants will register **$1.8 billion** in sales.*

* projected

America's Restaurants: By the Numbers

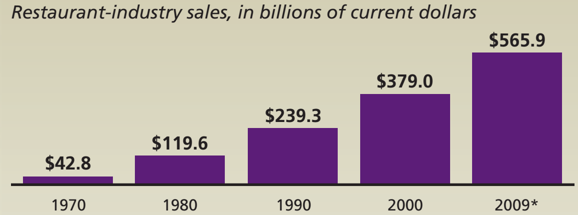
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION
www.restaurant.org

RI Hospitality Association
RI Hospitality Education Foundation
Voice of Rhode Island's Lodging, Restaurant and Tourism Industry
www.rihospitality.org

Rhode Island's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	Patrick J. Kennedy (D)	1,259	18,535
2	James R. Langevin (D)	1,404	20,665
	TOTAL	**2,663**	**39,200**

* Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®

www.restaurant.org

RI HOSPITALITY ASSOCIATION
RI HOSPITALITY EDUCATION FOUNDATION
Voice of Rhode Island's Lodging, Restaurant and Tourism Industry

www.rihospitality.org

NATIONAL RESTAURANT ASSOCIATION | www.restaurant.org/research

New Hampshire
Restaurant Industry at a Glance

New Hampshire's restaurants are an increasingly important part of the state's economy. Restaurants are a key driver of employment in New Hampshire, and their sales generate tremendous tax revenues for the state.

The contribution of New Hampshire's restaurants extends far beyond the jobs they create, the careers they build and the revenues they generate. America's restaurants today are leaders in nutrition and healthy living, sustainability and social responsibility, and entrepreneurship and business opportunities.

For more information visit www.restaurant.org.

New Hampshire Restaurants by the Numbers

LOCATIONS

In 2007, there were **2,824** eating-and-drinking places in New Hampshire.

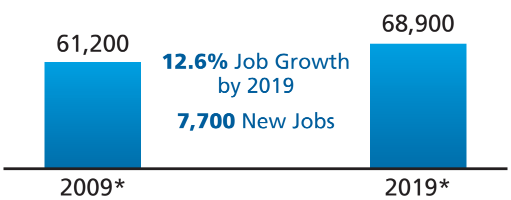
STATE ECONOMY

Every $1 spent in New Hampshire's restaurants generates an additional **$.84 in sales** for New Hampshire's economy.

Each additional $1 million spent in New Hampshire's eating-and-drinking places generates an additional **22.9 jobs** in New Hampshire.

JOBS

Restaurant and Foodservice **Employment**



Restaurant jobs represent **9 percent** of total employment in New Hampshire.

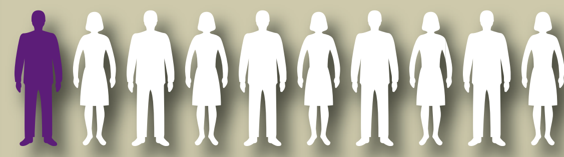
SALES

In 2009, New Hampshire's restaurants will register **$2.1 billion** in sales.*

* projected

America's Restaurants: By the Numbers

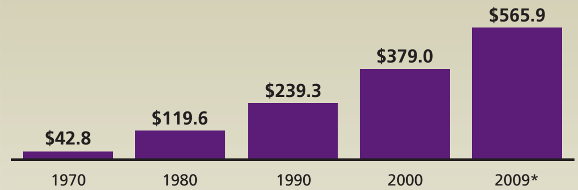
Almost **1 in 10** working Americans are restaurant employees



Restaurants' **share of the food dollar** is rising

Annual industry sales exceed a **half-trillion dollars**

Restaurant-industry sales, in billions of current dollars



* projected
Source: National Restaurant Association

Did you know?

- **More than one out of four** American adults got their first job in a restaurant.
- **Nearly half of all Americans** have worked in a restaurant at some point in their working careers.
- America's eating-and-drinking places employ **more minority managers** than any other industry.

Sources: Figures are based on National Restaurant Association research and data from federal and state government agencies.

See www.restaurant.org/research/state for more information

NATIONAL RESTAURANT ASSOCIATION | NHLRA NEW HAMPSHIRE LODGING & RESTAURANT ASSOCIATION

www.restaurant.org | www.nhlra.com

New Hampshire's Restaurants:
Impact by Congressional District

Cong. Dist.	U.S. Representative	Restaurant Establishments*	Restaurant Employees*
1	Carol Shea-Porter (D)	1,528	23,973
2	Paul W. Hodes (D)	1,296	20,327
	TOTAL	**2,824**	**44,300**

***** Estimates are for eating-and-drinking place establishments and employees in 2007. "Eating-and-drinking places" is a Census designation that represents about three-fourths of all restaurant and foodservice employment.

Source: National Restaurant Association, based on data from the Bureau of Labor Statistics and U.S. Census Bureau.

NATIONAL RESTAURANT ASSOCIATION®
www.restaurant.org

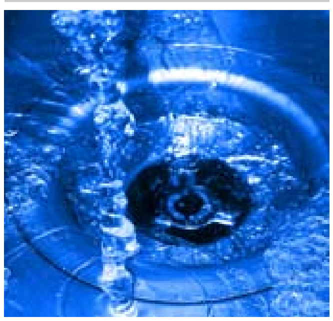
NHLRA
NEW HAMPSHIRE LODGING & RESTAURANT ASSOCIATION
www.nhlra.com

Appendix C: Commercial Foodservice Publications

ENERGY STAR

ENERGY STAR® Guide for Restaurants

Putting Energy into Profit



EPA
United States
Environmental Protection
Agency

LEARN MORE AT energystar.gov

ENERGY STAR®, a U.S. Environmental Protection Agency program, helps us all save money and protect our environment through energy efficient products and practices. For more information, visit www.energystar.gov.

Contents Page

IN PARTNERSHIP WITH

PG&E Food Service Technology Center is the industry leader in commercial kitchen energy efficiency and appliance-performance testing as well as a leading source of expertise in commercial kitchen ventilation and sustainable building design.

National Restaurant Association's Conserve initiative explores conservation efforts in restaurants around the nation and offers suggestions and resources to help operators reduce their costs and improve their environmental performance.

ACKNOWLEDGEMENTS

This best-practices guide was created with the assistance of California's four investor-owned utilities (Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison). These energy suppliers are working together to provide comprehensive energy efficiency resources for California's food service industry, including, but not limited to, the following resources: rebates for cooking and refrigeration equipment, food service specific seminars and workshops, Web tools, energy audits, appliance testing, and energy education centers. The California energy-efficiency research and educational programs are funded by California ratepayers under the auspices of the California Public Utilities Commission and are administered by the four investor-owned utilities.

Southern California Gas Company — A Sempra Energy utility®
www.socalgas.com/business

PG&E®
www.pge.com/fstc

SDGE — A Sempra Energy utility®
www.sdge.com/foodservice

SOUTHERN CALIFORNIA EDISON® — An EDISON INTERNATIONAL® Company
www.sce.com/CTAC

Disclaimer: all energy, water, and monetary savings listed in this document are based upon average savings for end users and are provided for educational purposes only. Actual energy savings might vary based on use and other factors.

FIVE EASY STEPS TO SAVE ENERGY AND WATER

1 *Install compact fluorescent lamps* (CFLs) in your walk-in refrigerators and kitchen ventilation hoods (and throughout your restaurant where appropriate).

2 *Install a high-efficiency pre-rinse spray valve* in your dishroom and save hundreds of dollars a year!

3 *Fix water leaks immediately*—especially hot water leaks: wasted water, sewer, and water heating costs can add up to hundreds of dollars a year.

4 *Perform walk-in refrigerator maintenance:* check and replace door gaskets; clean evaporator and condenser coils; check refrigerant charge.

5 *Replace worn-out cooking and refrigeration equipment* with ENERGY STAR qualified models!

Get additional easy to implement tips at: http://conserve.restaurant.org

Energy efficiency is a sound business practice that improves profitability, reduces greenhouse gas emissions, and conserves resources. This guide is designed to help your restaurant save energy and water, protect our Earth, and boost your bottom line.

ENERGY EFFICIENCY AND YOUR RESTAURANT

Restaurants use about 2.5 times more energy per square foot than other commercial buildings.

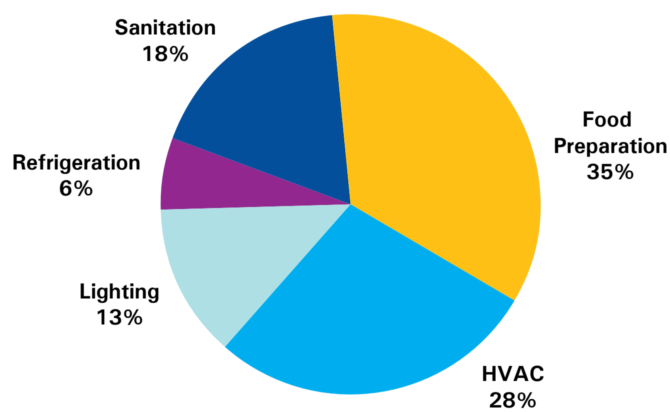
Energy costs have been increasing at a rate of 6 to 8 percent per year. Investing in energy efficiency is the best way to protect your business against rising energy prices.

Most commercial kitchen appliances are energy intensive. For instance, a typical electric deep fat fryer uses more than 11,000 kilowatt-hours (kWh) of energy per year which could cost you more than $1,100 in electricity.

You can reduce your restaurant's energy consumption by following the **Cost Saving Tips** outlined below and throughout this guide:

- Buy ENERGY STAR qualified appliances. If you're in the market for new equipment, think in terms of life-cycle costs, which include purchase price, annual energy costs, and other long-term costs associated with the equipment. High-efficiency appliances could cost more upfront, but significantly lower utility bills can make up for the price difference. Be sure to ask your dealer or kitchen designer to supply you with ENERGY STAR qualified equipment.
- Cut idle time. If you leave your equipment ON when it is not performing useful work, it costs you money. Implement a startup/shutdown plan to make sure you are using only the equipment that you need, when you need it.
- Maintain and repair. Leaky walk-in refrigerator gaskets, freezer doors that do not shut, cooking appliances that have lost their knobs—all these "energy leaks" add up to money wasted each month. Don't let everyday wear and tear drive up your energy bills.

Example of the Average Energy Consumption in a Full-service Restaurant
(British Thermal Units [Btu])



- Cook wisely. Ovens tend to be more efficient than rotisseries; griddles tend to be more efficient than broilers. Examine your cooking methods and menu; find ways to rely on your more energy-efficient appliances to cook for your customers.
- Recalibrate to stay efficient. The performance of your kitchen equipment changes over time. Thermostats and control systems can fail, fall out of calibration, or simply become readjusted. Take the time to do a regular thermostat check on your appliances, refrigeration, dish machines, and hot water heaters and reset them to the correct operating temperature.

COOKING APPLIANCES

When replacing old appliances or buying new ones, look beyond the sticker price. Buying and installing equipment that has earned the ENERGY STAR could trim hundreds of dollars from your annual utility bills. In order to realize the most savings from your ENERGY STAR qualified equipment you must train your staff to use energy wisely by following good operating practices such as those in the **Cost-Saving Tips** that follow.

Steamers

Steam cookers provide an effective way to batch-cook food but generating steam is an energy-intensive process. ENERGY STAR qualified steamers have a sealed cooking cavity that consumes a fraction of the energy and water required by traditional open systems. In many cases the dollar savings are so great that it makes sense to replace an existing steamer with an ENERGY STAR qualified one.

Cost-Saving Tips

- Look for the ENERGY STAR
- Close the door
- Use the timer
- Cut idle time
- Maintain & repair

Good practices can save:

$250 to $350 in annual energy costs for a traditional, electric, open-system steamer by eliminating an hour of idle time per day.

Buy an ENERGY STAR qualified connectionless steamer and save:

- $680 for water and sewer costs annually
- $510 for electricity annually (electric steamer), or
- $390 for gas annually (gas steamer)

Equating to an average $1,190 total savings for an electric steamer or $1,070 total savings for a gas steamer (some restaurants with high commercial sewer costs can save hundreds of dollars more annually)

Fryers

Energy-efficient fryers that have earned the ENERGY STAR offer shorter cook times, faster temperature recovery times, and ultimately higher pound-per-hour production rates through advanced burner and heat exchanger designs. Some models also offer an insulated fry pot, which reduces standby losses, giving the fryer a lower idle energy rate.

Cost-Saving Tips

- Look for the ENERGY STAR
- Cut idle time & turn off back-up fryers when possible
- Recalibrate

Good practices can save:

$250 annually for a gas fryer by cutting four hours of idle time per day.

Buy an ENERGY STAR qualified fryer and save:

- $120 for electricity annually (electric fryer), or
- $590 for gas annually (gas fryer)

Convection Ovens

Convection ovens are the industry standard due to faster cook-times produced by increased hot air movement inside the oven cavity. In addition, convection ovens are now eligible for ENERGY STAR qualification.

Cost-Saving Tips

- Look for the ENERGY STAR
- Cut idle time & turn off back-up ovens when possible
- Fully load the oven when cooking
- Replace seals & tighten hinges

Buy an ENERGY STAR qualified convection oven and save:

- $190 for electricity annually (electric oven), or
- $360 for gas annually (gas oven)

Griddles

Griddles are a versatile piece of equipment and a workhorse appliance found on most kitchen lines. Variations in efficiency, production capacity, and temperature uniformity make it important to choose wisely when shopping for a griddle. Many energy-efficient griddles can deliver both high production capacity and excellent temperature uniformity.

Cost-Saving Tips

- Look for the ENERGY STAR
- Cut idle time
- Recalibrate

Good practices can save:

$250 annually from a gas griddle by cutting three hours of idle time per day.

Buy an ENERGY STAR qualified griddle and save:

- $190 for electricity annually (electric griddle), or
- $175 for gas annually (gas griddle)

Holding Cabinets

ENERGY STAR hot food holding cabinets typically feature improved insulation, so heat stays in the cabinet and out of the kitchen. An insulated ENERGY STAR holding cabinet uses about half the energy consumed by an uninsulated cabinet. Other available features that could potentially save energy include magnetic door gaskets, auto-door closers, and dutch doors.

Cost-Saving Tips

- Look for the ENERGY STAR
- Shut off overnight
- Use the timer
- Replace missing or worn out control knobs

Good practices can save:

$500 annually by turning off an uninsulated holding cabinet when the kitchen is closed.

Buy an ENERGY STAR qualified holding cabinet and save:

- $340 to $960 annually for electricity

Combination Ovens

The combination oven is an extrememly versatile cooking platorm with the added bonus of a self-cleaning feature. Operating a combination oven in “steam” or “combination” mode typically uses more energy and water than operating in traditional convection mode. Use the oven’s programming capabilities to properly control different cooking modes to maximize energy efficiency and cost savings. Do your homework when buying a combination oven: the most efficient models will use about half as much energy and water as the inefficient models.

Good practices can save:

$400 to $800 annually off an electric combination oven by cutting out two hours of idle time per day.

If ENERGY STAR qualified models don’t exist for the type of equipment you’re looking for don’t worry: you still have options. Ask distributors and manufacturers for energy use information, and check online for equipment reviews. The California commercial food service incentive program is also a third party resource because, like ENERGY STAR, appliances that qualify must meet designated efficiency standards. The list of qualifying appliances can be found at: www.fishnick.com/saveenergy/rebates.

Broilers

Broilers are true kitchen workhorses but their dependability and simplicity come at a price: searing heat requires a great deal of energy and broilers have simple, non-thermostatic controls. This combination can make the broiler the most energy intensive appliance in the kitchen. For example, one gas broiler can use more energy than six gas fryers. A new generation of broilers incorporates better radiant designs, allowing the broiler to get the job done while consuming about 25 percent less energy.

Cost-Saving Tips

- Cut preheat time
- Turn off unneeded sections
- Reduce idle time
- Replace missing knobs

Good practices can save:

$600 annually by cutting out three hours of idle time per day.

Ranges

The range top is one of the most widely used pieces of equipment in restaurant kitchens. Ranges are manually controlled and can be energy guzzlers depending on how you operate them. A potential alternative to traditional range tops are induction ranges; they are more expensive but offer very high efficiency, rapid heat up, precise controls, and low maintenance.

Cost-Saving Tips

- Maintain and adjust burners
- Use a lid
- Cut idle time

REFRIGERATION SYSTEMS AND ICE MACHINES

Reach-In Refrigerators and Freezers

Compared to standard models, ENERGY STAR qualified commercial refrigerators and freezers can lead to energy savings of as much as 35 percent with a 1.3 year payback. Glass door refrigerators and freezers can now earn the ENERGY STAR too! Features that could potentially save energy include improved insulation and components such as high-efficiency compressors and motors.

Cost-Saving Tips

- Look for the ENERGY STAR
- Turn off door heaters when possible
- Clean coils
- Set defrost timers
- Replace worn gaskets

Buy ENERGY STAR qualified equipment and save:

- $200 for electricity annually (per solid door refrigerator)
- $140 for electricity annually (per solid door freezer)

Walk-In Refrigerators

Walk-in refrigerators are extremely important to any successful restaurant. Improve this equipment's energy performance with a few inexpensive upgrades and good practices, such as:

- Swapping out incandescent light bulbs for low-temperature ENERGY STAR qualified compact fluorescent lamps (CFLs) can reduce the lamps' heat output by 75 percent! (Look for the lowest possible "minimum start temperature" on the CFL box, e.g., zero degrees Fahrenheit.)
- Adding strip curtains and automatic door closers to your walk-in refrigerator: *they are inexpensive and easy-to-install.* Strip curtains can cut outside air infiltration by about 75 percent!
- Installing electronically commutated motors (ECM) on the evaporator and condenser fans reduces fan energy consumption by approximately two-thirds.

Cost-Saving Tips

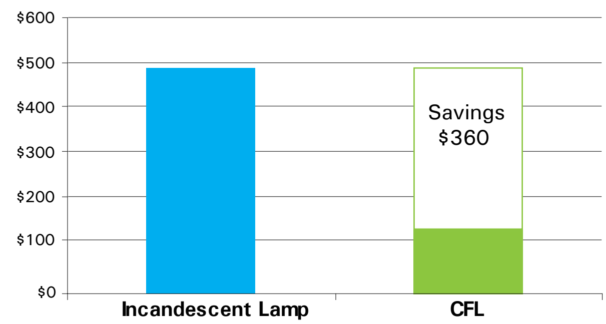
- Allow air circulation
- Insulate suction lines
- Check refrigerant charge
- Repair and realign doors
- Clean coils

LAMPS AND LIGHTING FIXTURES

In a typical restaurant, lights are usually on for 16 to 20 hours a day. For many areas in your restaurant, high-efficiency ENERGY STAR CFLs and lighting fixtures are your ticket to savings.

- Install ENERGY STAR qualified fixtures and CFLs in your dining area and reduce energy consumption and heat output by 75 percent.
- Install occupancy sensors in closets, storage rooms, break rooms, restrooms, and even walk-in refrigerators. Look for sealed, low-temperature-specific sensors for refrigerated environments.
- If your restaurant features linear fluorescent lighting with T12 lamps and magnetic ballasts it is time to upgrade. Switch to more efficient T8 or T5 lamps with electronic ballasts. Electronic ballasts typically have faster on-times and do not hum or flicker. Look for utility incentives for lighting upgrades in your area.
- Swap your old Open/Closed and EXIT signs with LED technology for electricity savings up to 80 percent.
- Visit www.energystar.gov/lighting for more cost-saving information.

Annual Savings After Replacing Eight Incandescent Lamps with Eight CFLs



CFL vs. Incandescent Light Bulbs

If each of the 945,000 restaurants in the United States replaced only one incandescent light bulb with a CFL, more than 630 million pounds of CO_2 emissions could be avoided each year (the annual greenhouse gas emissions from more than 52,000 passenger vehicles*), and the restaurant industry could save about $42.5 million annually.

*Source: EPA Greenhouse Gas Equivalencies Calculator: www.epa.gov/cleanenergy/energy-resources/calculator.html

Mercury and CFLs

CFLs contain a very small amount of mercury sealed within the glass tubing (approximately 4 milligrams). By comparison, older thermometers contain about 500 milligrams of mercury an amount equal to the mercury in 125 CFLs. No mercury is released when the bulbs are intact (not broken) or in use. For more information about recycling and disposing of CFLs visit: www.energystar.gov/mercury.

Ice Machines

Commercial ice machines that earn the ENERGY STAR are on average 15 percent more energy efficient and 10 percent more water efficient than standard models.

- Cut down on your daytime electricity demand by installing a timer and shifting ice production to nighttime off-peak hours.
- Bigger ice machines are typically more efficient than smaller ones, yet the price difference is usually not very large. Choose wisely and you could get twice the ice capacity at half the energy cost per pound of ice.
- Avoid water-cooled ice machines because of their high water cost, which make them significantly more expensive to operate. *Note: water-cooled ice machines do not currently qualify for ENERGY STAR.*

Cost-Saving Tips

- Look for the ENERGY STAR
- Clean the coils
- Keep the lid closed
- Adjust the purge water timer

Buy an ENERGY STAR qualified ice machine and save:

- $120 for electricity annually

HEATING, COOLING AND VENTILATION

Making smart decisions about your restaurant's heating, ventilating, and air conditioning (HVAC) system can have a big effect on your utility bills—and your customers' comfort.

Heating and Cooling Systems

Heating and cooling systems account for a large portion of your restaurant's annual energy use. For many restaurants, heating and cooling is second only to food preparation in terms of annual energy consumption.

Cost-Saving Tips

- Look for the ENERGY STAR
- Clean heat-transfer coils
- Replace air filters
- Consider an Energy Management System
- Repair broken duct work
- Recommission economizers

Energy use falls by 4 to 5 percent for every degree that you raise your cooling thermostat setpoint. Easing back on central cooling by only 3°F could trim air conditioning costs by 12 to 15 percent. Improve customer comfort by using an efficient ENERGY STAR qualified ceiling fan to compensate for the difference in air temperature. Ensure that your heating and cooling equipment is included in the start-up and shut down schedule to save even more.

Don't forget about the restroom! ENERGY STAR qualified ventilating fans use 70 percent less energy than standard models.

Buy ENERGY STAR qualified equipment and save:

- $1.70 per square foot over the life of the HVAC equipment ($4,250 for a 2,500 square foot restaurant; the same as $430 annually)
- $17 annually for electricity costs per ceiling fan
- $75 annually for electricity costs for ventilating fans that are run continuously

According to the Consortium for Energy Efficiency (CEE), at least 25 percent of all rooftop HVAC units are oversized, resulting in increased energy costs and equipment wear. Properly sized equipment dramatically cuts energy costs, increases the life of the equipment, and reduces greenhouse gas emissions.

Kitchen Ventilation

An unbalanced or poorly designed kitchen exhaust system can allow heat and smoke to spill into your kitchen, spelling trouble both for your restaurant's air quality and for your utility bills. Spillage leads to a hot, uncomfortable working environment and higher energy bills for air-conditioned kitchens.

- Cut down on spillage by adding inexpensive side panels to hoods.
- Push each cooking appliance as far back against the wall as possible to maximize hood overhang and close the air gap between the appliance and the wall.
- Install a demand-based exhaust control. It uses sensors to monitor your cooking and varies the exhaust fan speed to match your ventilation needs. Demand ventilation controls could reduce your exhaust system costs by anywhere from 30 to 50 percent and can be installed on either new equipment or retrofitted to existing hoods.

Learning More About Kitchen Ventilation

If you're getting ready to design a new kitchen or renovate an old one, check out "Improving Commercial Kitchen Ventilation System Performance," a two-part kitchen ventilation design guide written by the experts at PG&E FSTC and available at: www.fishnick.com/equipment/ckv/designguides.

Windows

Applying a clear, heat rejecting window film will help cut your cooling costs while making your dining room more comfortable. Use only high quality window film installed by a qualified professional.

Patio Heaters

The best approach to saving money with patio heaters is to cut back their use—both for hours of operation and for the number of patio heaters running at any given time. Patio heaters are radiant devices that heat up quickly so there is no reason to leave them running if a seating area is temporarily empty.

Good practices can save:

$530 per heater annually by cutting three hours of use per day

WATER AND WASTE MANAGEMENT

Water Use

Using water more efficiently preserves water supplies, saves money, and protects the environment. By conserving hot water you trim not one but two bills: one for the water and sewer and another for the electricity or natural gas used to heat the water used in bathroom faucets, kitchen sinks, and dishwashers.

Cost-Saving Tips

- Look for the ENERGY STAR and WaterSense label
- Add aerators
- Install WaterSense labeled toilets
- Repair leaks
- Reduce sink and tap usage

Similar to the ENERGY STAR, the WaterSense® label identifies water-efficient products and programs. WaterSense is a partnership program sponsored by EPA and additional information is available at: www.epa.gov/watersense.

look for WaterSense Meets EPA Criteria

Good practices can save:

$1,000 annually by turning down dipper wells and making sure they are OFF when the kitchen is closed

$1,000 annually by fixing leaks in sinks, mop-stations, and dishmachines

Look for WaterSense labeled equipment and use WaterSense irrigation partners to landscape your restaurant:

Bathroom faucets are 30 percent more water efficient

Landscaping with WaterSense irrigation partner could save you 15 percent compared to average watering bills

High-Efficiency Pre-Rinse Spray Valves

A high-efficiency, or low-flow, pre-rinse spray valve is one of the most cost-effective energy saving devices available to the foodservice operator. And it is easy to install! Just unscrew your old spray valve and screw in your new, water-efficient one.

In addition to minimizing hot water consumption, you can reduce both your water-heating and sewer expenditures per month. How? Typical spray valves can release hot water at a rate of three to four gallons of water per minute (gpm), while common high-efficiency units spray only 1.6 gpm or less without sacrificing cleaning power!

Buy a 1.6 gpm spray valve and save:

$300 to $350 annually for water, sewer, and natural gas costs annually (used one hour a day and compared to 3 gpm sprayer).

Additional information is available at: www.fishnick.com/equipment/sprayvalves.

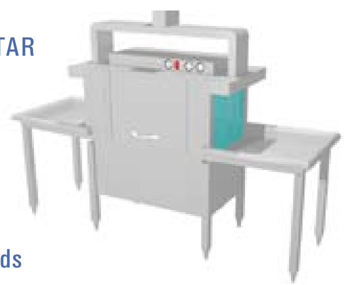
Dishwashers

From an operational standpoint, dishwashers are one of the most expensive pieces of equipment in your kitchen. Commercial dishwashers that have earned the ENERGY STAR are on average 25 percent more energy and water efficient than standard models.

- Run fully loaded dish racks through the dish machine. Cutting wash cycles could save you hundreds of dollars annually.
- Pay attention to your dishwasher's pressure gauge—if it's showing pressure above 25 psi, there is a good chance you are using much more water than is necessary. Most dishwashers require only around 20 psi.
- If you have a conveyor-style dishwasher, make sure you are using it in auto mode, which saves electricity by running the conveyor motor only when needed.

Cost-Saving Tips

- Look for the ENERGY STAR
- Turn off at night
- Replace torn wash curtains
- Repair leaks
- Replace worn spray heads



Buy an ENERGY STAR qualified dishwasher and save:

- $975 for electricity annually
- $200 for water annually

Waste Reduction Is Good Business

Waste reduction leads to increased operating efficiency and cost savings. Decreased solid waste generation reduces collection and disposal costs just as reducing electricity and water consumption reduces utility bills. Waste minimization also may reduce your purchasing costs for restaurant supplies.

Using recycling and composting bins, sustainable take-out containers, and "green" signage are all excellent ways to announce and to demonstrate to your customers your efforts to be more environmentally sustainable and aware.

For help identifying waste reduction opportunities please visit www.epa.gov/wastewise.

BEGIN THE PROCESS, LEARN MORE AND SAVE!

The best first step is to perform an energy audit on your facility. Energy service providers (utilities), state energy offices, and private sector product and service providers can assist you in identifying a trained professional to conduct your audit. However, comprehensive, affordable energy audits are not available everywhere in the country for commercial food service businesses.

To help address the lack of energy audits in many communities, ENERGY STAR provides free online tools and information to achieve energy savings. ENERGY STAR's basic guidance for self-assessments is part of the Guidelines for Energy Management, "Step 2: Assess Performance," at: www.energystar.gov/guidelines.

In addition, ENERGY STAR's Portfolio Manager software is designed to help businesses "benchmark" and track energy use, costs, and greenhouse gas emissions. Portfolio Manager also offers the option to track water use and renewable energy credits—all in a password protected online file. Portfolio Manager users can track multiple facilities independently or aggregate all the business locations into one file. Your restaurant can generate a Statement of Energy Performance which includes a "weather-normalized" kBtu/ft^2 energy use intensity calculation, associated greenhouse gas emissions and a national average for similar building types. Access to the software and free online training in use of Portfolio Manager is available at: www.energystar.gov/benchmark.

Once you have identified the areas of potential energy savings, decide which energy efficiency upgrades you want to install and what practices to initiate. If your finances and operating schedule make it impractical to perform all the upgrades at once, you can take a staged approached and install them as time and money allow.

Remember, having your **restaurant manager** 100 percent on board is absolutely key to saving your restaurant money and protecting the environment! Your best-laid energy-saving plans are only as good as the staff that is implementing them!

For more information, please consult the following online resources:

- ENERGY STAR Commercial Food Service: www.energystar.gov/cfs
- ENERGY STAR Restaurants: www.energystar.gov/restaurants
- ENERGY STAR Portfolio Manager: www.energystar.gov/benchmark
- PG&E Food Service Technology Center: www.fishnick.com
- National Restaurant Association Conserve: http://conserve.restaurant.org
- EPA WaterSense: www.epa.gov/watersense
- EPA WasteWise: www.epa.gov/wastewise

Find Monetary Incentives

ENERGY STAR CFS Incentive Finder: go to www.energystar.gov/cfs and click on “Special Offers” or go to www.energystar.gov/cfsrebate _ locator

December 2009

EPA 430-R-09-030

For more information visit www.energystar.gov.

Food Service Technology Center
Promoting Energy Efficiency in Food Service

conserve
solutions for sustainability

NATIONAL RESTAURANT ASSOCIATION®

energy
LEARN MORE AT energystar.gov

ENERGY STAR

ENERGY STAR® FOR COMMERCIAL KITCHENS: HELPING CUSTOMERS MANAGE COSTS

Buildings with restaurants and other food service operations are very energy intensive, consuming roughly 2.5 times the energy per square foot as other commercial buildings, or close to 250,000 British thermal units (Btu) of energy per square foot.[1] Energy efficiency program administrators can help these customers rein in operating costs while also reducing energy use, peak demand, and water use by promoting ENERGY STAR qualified commercial food service (CFS) equipment and other best practices. Utility cost savings of 10 to 30 percent are achievable without sacrificing service, quality, style or comfort—all while making significant contributions to a cleaner environment.[2] The U.S. Environmental Protection Agency (EPA) is working with about 50 efficiency program administrators throughout the nation to integrate ENERGY STAR qualified CFS equipment into their program offerings. EPA is providing this fact sheet to introduce more program administrators to ENERGY STAR and the savings opportunities in commercial kitchens, as well as to share best practices for program design, implementation, and evaluation based on the experiences of recent CFS programs.

DELIVERING SOLUTIONS IN COMMERCIAL KITCHENS

Promoting the installation of energy-efficient equipment in commercial kitchens is an important part of a comprehensive CFS program. It saves significant amounts of energy and offers meaningful financial benefits to the establishment. Utility costs are a major operating expense for the CFS industry, on the level of about one-half to almost parity with their profit margins—which, for a full service restaurant, is around 5 percent of sales.[3] Due to rising energy costs, CFS customers may be increasingly receptive to program administrator assistance for improving energy efficiency and reducing related utility bills. And the savings opportunities are significant: as much as 80 percent of the food service sector's $10 billion annual energy bill is expended on energy that does no useful work and a substantial portion of this waste is related to equipment inefficiencies.[4]

ENERGY STAR provides a comprehensive and cost-effective platform for promoting greater equipment efficiency and related best practices to CFS customers. ENERGY STAR currently identifies efficient products in eight product categories: hot food holding cabinets, solid door refrigerators and freezers, fryers, steam cookers, ice machines, commercial ovens, griddles, and dishwashers.

These energy-efficient products offer energy savings of 10 to 65 percent over standard models, depending upon the product category. Three of the product categories, commercial dishwashers, ice machines, and steam cookers, also offer water savings of up to 90 percent over standard models. Three CFS utility programs have earned ENERGY STAR awards for promoting these energy-saving products and are showing promising early returns. They include:

- California's four investor-owned utilities (IOUs)—Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), Southern California Gas Company (SCG), and San Diego Gas & Electric Company (SDG&E)—offer a coordinated statewide incentive program with strong early results, achieving annual electric savings of around 20.6 million kilowatt-hours (kWh) and annual natural gas savings of around 526,000 therms.[5]
- The Energy Trust of Oregon's (ETO) CFS program is achieving annual savings of nearly 1.2 million kWh and over 190,000 therms by partnering with dealers that sell CFS equipment directly to restaurants.[6]
- Wisconsin's Focus on Energy offers CFS customers a bonus incentive to encourage the purchase of multiple ENERGY STAR qualified products and is achieving annual electric savings of nearly 350,000 kWh and annual natural gas savings of nearly 22,000 therms.[7]

Outfitting an entire commercial kitchen with a suite of ENERGY STAR qualified equipment could save around 300 million Btus of energy and about $3,600 per year.

PROGRAM DESIGN AND IMPLEMENTATION

A key factor in effective program design is understanding the market barriers to greater adoption of energy-efficient equipment and developing strategies to overcome these barriers. Common barriers in the CFS market include:

- ***Hard-to-reach market***—The CFS market is highly fragmented, both in terms of equipment supply channels and end use sectors.
- ***Lack of readily available supply***—CFS equipment suppliers typically compete on low prices and therefore stock only a limited supply of energy-efficient products. This barrier is compounded by customers who make short-term purchasing decisions due to the need to replace equipment quickly when it fails.
- ***Incremental costs***—ENERGY STAR qualified CFS equipment is generally more expensive than standard efficiency equipment and can cost significantly more than refurbished models sold in the used equipment market.
- ***Lack of knowledge***—Equipment suppliers and end users might not be aware of energy-efficient products, might have misperceptions about tradeoffs between energy efficiency and performance, or both.

The following sections describe the CFS equipment market in further detail and discuss program strategies for addressing the key barriers listed above.

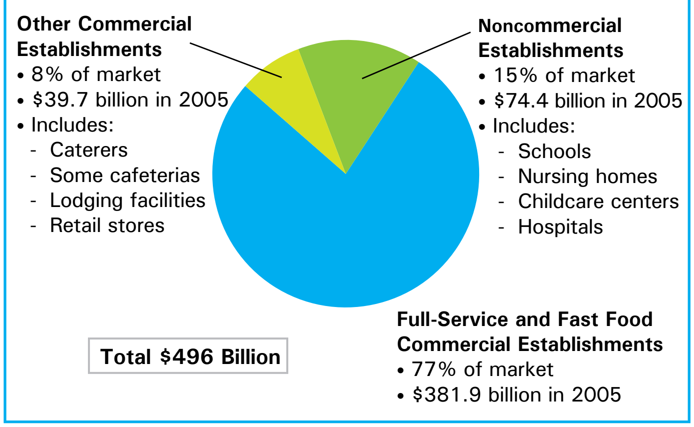
Understanding and Engaging the CFS Market

Foodservice establishments include commercial and noncommercial entities, diverse business sectors, and account for approximately $500 billion in expenditures for food consumed away from the home (e.g., meals and snacks for on-premise or immediate consumption). Commercial establishments—including full service restaurants, fast food outlets, caterers, some cafeterias, lodging facilities, and retail stores—account for about 85 percent of this total with full-service restaurants and fast food restaurants representing the two largest industry segments, accounting for 77 percent of expenditures for food consumed away from the home. Noncommercial foodservice operators—those that prepare and serve food as an adjunct service in institutional settings (e.g., schools, nursing homes, childcare centers, and hospitals)—account for the remaining 15 percent.[8]

In addition to the diverse business sectors that comprise the foodservice industry, the CFS equipment market is complicated by multiple equipment distribution channels including:

- Dealers that primarily sell to individual restaurants.
- Distributors that primarily supply bulk quantities to equipment dealers and sell commodity equipment (e.g., ice machines, counter-top fryers) directly to end users.

Breakdown of Consumer Expenditures for Food Consumed Away from Home in 2005



Source: *Adapted from U.S. Department of Agriculture Economic Research Service, Briefing Room: Food Marketing System in the United States.*

- Manufacturers that sell through manufacturer representatives (reps) but may also sell directly to large end users such as national restaurant chains.
- Consultants that assist in either designing new or renovating existing commercial kitchens, typically working with restaurant chains, hotels, hospitals, and universities.

(Additional information on supply channel actors and strategies for influencing them can be found in the text box on page 3).

Due to the complexity of the CFS market and potential for widespread variability between service territories, program administrators should consider conducting a market assessment to: 1) understand the major sectors and primary distribution channels influencing the CFS equipment market in their territory, 2) develop estimates of likely program uptake for each sector

ITW Food Equipment Group

2008 and 2009 ENERGY STAR Partner of the Year, ITW Food Equipment Group (ITW FEG)—the parent organization of independent companies such as Hobart, Stero, Vulcan, Traulsen, and Wittco—understands the importance of supporting customers in their drive to cut costs, use less water and consume less electricity, and has responded by offering 381 ENERGY STAR qualified CFS products.

> "ENERGY STAR plays an important role in helping foodservice operators and food retailers design a sustainable kitchen that's good for the environment and good for business in terms of efficiency, productivity and quality...Our partnership with ENERGY STAR enables us to emphasize the value of selecting equipment engineered for high efficiency and low water consumption."
>
> *—John McDonough, President of ITW FEG*

taking into account the uniqueness of each sector (e.g., while restaurants are often the largest segment, they are often the hardest segment to influence), and 3) establish program baseline conditions (e.g., what is the current market share for an efficient product, and what is the best estimate of market share over time absent a program). See related discussion under Measurement and Verification, page 7.

Another key best practice is to engage equipment suppliers and other key stakeholders, such as large and small restaurant customers and their trade associations, during program design. Engaging stakeholders early in the planning process can help program administrators better understand stakeholder business models and gauge receptivity to potential education, marketing, and incentive strategies.

Continuing this dialogue during program launch, particularly with supply-side market actors, is essential to ensuring that manufacturer reps, distributors, dealers, and businesses are familiar with program incentives, policies and procedures, and are able to effectively communicate the key benefits and features of qualified energy-efficient equipment to their customers. During these meetings, it is important to communicate both the mechanics of how the CFS program works and the business benefits of program participation.

An ENERGY STAR qualified commercial refrigerator can save a restaurant around $200 on energy costs per year. This may not seem like much until one considers the slim profit margins in the restaurant industry. If a restaurant operates with a profit margin of around 5 percent (the industry average), it will need to make roughly $4,000 in sales to earn $200 in profit.

Improving Availability of ENERGY STAR® Qualified Equipment

In the retrofit market, purchasing often occurs when existing equipment fails, and the top priority is getting new equipment online quickly. Decisions on product selection and purchase are usually driven by product availability, price, and advice from the equipment supplier. Unfortunately, many suppliers do not stock or promote efficient equipment due to price premiums that range from 10 to 85 percent, depending on product category.

The following are important strategies for motivating suppliers to sell and stock ENERGY STAR qualified equipment:

Make the business case—It is important to educate suppliers on the value proposition for promoting ENERGY STAR qualified CFS equipment to their customers. While efficient equipment may have

Supply Channel Actors

Dealers—Dealers primarily sell to individual restaurants, which is often the most difficult market to reach. Smaller dealers may join buying groups so they can compete more effectively with larger dealers. Many dealers display their products in showrooms and tend to stock lower-priced, popular models that are usually not energy-efficient. A dealer's main objective is usually to sell the products they have on hand, and they are generally more interested in attracting customers with low prices rather than emphasizing the overall value of higher-end products (e.g., lifetime cost savings). Given that many manufacturers offer sales incentives to move lower-end models, dealer incentives can be an effective strategy to promote stocking and sales of energy-efficient equipment.

Distributors—Distributors primarily supply bulk quantities of equipment to dealers and sell commodity equipment (e.g., ice machines, fryers) directly to end users. Since distributors usually supply dealers, developing a good working relationship with distributors helps funnel energy-efficient CFS products into dealer showrooms. In addition, some restaurant food distributors sell CFS equipment and should also receive program outreach.

Manufacturers and Reps—CFS equipment manufacturers generally sell through product reps, although manufacturers may also sell directly to large end users such as national restaurant chains. Though all supply channels gravitate toward inexpensive, fast-moving pieces of equipment, a key value proposition for engaging reps is the up-sell potential of high-value, high-efficiency equipment. Sales of high-quality products earn reps a higher commission and generate long-term value for the customer, often leading to repeat business.

Design Consultants—Design consultants assist in the planning and design of new or renovated commercial kitchens, typically working with large or chain-owned restaurants, hotels, universities, and hospitals. Conducting targeted outreach to design consultants helps to ensure that energy- and water-efficient CFS equipment is considered in these types of projects. Design consultants are typically focused on the overall design and aesthetics of the space and controlling project costs, and back-of-the-house equipment is often a low priority. In addition, they often have established relationships with buying groups and may receive incentives for selling lower-end equipment. Equipment quality and performance are key selling points for engaging design consultants.

a higher first cost, it costs less to operate. With today's rising energy costs, efficient equipment will continue delivering dividends through lower utility bills for years to come. It is also important to highlight non-energy benefits of efficient products such as water savings, reduced noise, reduced waste heat, and other quality and performance features. Businesses that can effectively up-sell higher-end equipment can increase their bottom line.

Sales incentives—Upstream incentives, including salesperson incentives or "spiffs," can be effective at motivating equipment suppliers to promote the multiple benefits of energy-efficient products, rather than steering customers to low-cost products, which is the norm. Puget Sound Energy (PSE) offers a $30 "spiff" for each completed incentive application submitted by an equipment supplier; San Diego Gas & Electric Company (SDG&E) offers a $25 spiff.

Program Highlight

Puget Sound Energy's $30 spiff rewards equipment suppliers for submitting completed incentive applications to the utility for processing on behalf of the customer. The supplier discounts the purchase price by the amount of PSE's customer rebate, so the customer receives an incentive at the point-of-purchase. Suppliers are reimbursed for the amount of the customer rebate, and get the $30 reward for their time and effort. This approach has led to higher turn-in rates for incentive applications, and fewer paperwork errors.

Provide program information—Providing easy access to up-to-date information about program offerings and procedures is essential to engaging and maintaining effective trade ally relationships. Initial kick-off workshops provide an opportunity to discuss the benefits of ENERGY STAR qualified CFS equipment and to inform participants of program requirements and incentive offerings. Conducting regular visits to trade ally showrooms/offices to discuss the program and distribute educational literature, point-of-purchase marketing materials, and incentive applications are also highly effective strategies for keeping trade allies informed. Other best practices include establishing a dedicated Web site and distributing electronic newsletters to keep equipment suppliers updated on program activities.

Offering Customer Incentives to Overcome First-Cost Barriers

The incremental cost of some ENERGY STAR qualified equipment can be a significant barrier to purchasing products. In general, the incremental cost is highest for fryers and hot food holding cabinets; moderately high for commercial dishwashers, refrigerators and freezers, and ice machines; and lowest for steam cookers.

Equipment rebates—To overcome the significant barrier of incremental cost, the majority of CFS programs offer prescriptive rebates for the purchase of qualified equipment. Program administrators typically set incentive levels at 50 percent or less of the incremental cost of purchasing the ENERGY STAR qualified model versus a standard efficiency model. There is, however, no set formula for success when choosing equipment rebate levels, and CFS programs are achieving success with a range of levels. As of August 2008, the following incentive ranges were available from the online ENERGY STAR CFS equipment incentive finder tool.

Table 1: Range of Incentives Offered by Program Sponsors (as of 5/09)*

Product	Incentive Range
Fryers	$150–$1,000
Hot food holding cabinets	$200–$500
Refrigerators and freezers	$50–$500
Steam cookers	$200–$1,500
Ice machines	$50–$600
Commercial dishwashers	$200–$2,000

Some programs, like Wisconsin's Focus on Energy, promote comprehensive kitchen efficiency upgrades by offering bonus incentives for the purchase of two or more pieces of qualified equipment. The customer is eligible for the usual per-unit equipment incentive, plus an additional $100 if they purchase two or more pieces of qualifying equipment, or $300 if they purchase three or more pieces of eligible equipment at a time. This strategy can be particularly effective when targeting commercial kitchen renovation and new construction opportunities.

The following are common best practices related to incentives:

- Tie incentive levels to ENERGY STAR specifications whenever possible to help customers easily identify products that qualify for rebates and to take advantage of the growing consumer awareness, market momentum, and supporting infrastructure provided by the program.
- Keep incentive application processes simple and straightforward.
- Maintain relatively consistent incentive levels from year to year, trending downward as market penetration increases.
- Ensure suppliers and buyers have easy access to a list of qualified models and related incentive levels. ENERGY STAR qualified product lists are available on each of the specific

* Note: *data include some programs offering incentives for equipment achieving higher efficiency levels than ENERGY STAR.*

product pages at *www.energystar.gov/cfs*. The California IOUs, which offer incentives for CFS equipment beyond ENERGY STAR qualified products, provide an online list of qualified equipment through PG&E's Food Service Technology Center (FSTC).

- Promote program and incentives through the online ENERGY STAR CFS equipment incentive finder tool (*www.energystar.gov/CFSrebate _ locator*).
- Educate customer call centers about program offerings, procedures, and where to direct customers for additional information.

Audits—Offering free or reduced-cost audits for commercial kitchen facilities is another form of incentive that can be useful for helping customers, particularly regional and national franchise chains, identify and correct operational inefficiencies, and for encouraging customers to take advantage of program rebate offerings when equipment purchases are needed. Customers are more likely to make smart decisions about CFS appliances if they have time to research options and secure the necessary capital to purchase new equipment. Many utilities offer audits to national restaurant chains as part of the menu of services they receive as managed accounts, and offer a higher level of support in helping such customers specify efficient equipment options for their facilities.

Audits can be offered for a nominal fee or at no cost to the customer. Some programs make a free audit contingent upon implementation of a minimum number of energy- and water-saving recommendations. Immediate energy savings benefits can be achieved by conducting direct installation of low-cost measures (e.g., high-efficiency pre-rinse spray valves, gaskets on refrigeration equipment, or compact fluorescent light bulbs).

Program Highlight

To effectively serve the diverse set of CFS market participants, the programs sponsored by the **California IOUs** offer an array of services, including site audits, equipment testing, and new restaurant plan review, as well as regular energy efficiency seminars for food service professionals.

Audits help to develop the customer relationship, increasing the likelihood that the customer will take advantage of program offerings when it comes time to replace equipment or conduct comprehensive facility upgrades. To ensure that the program is viewed as a credible resource, it is critical that auditors be knowledgeable about the unique challenges and business realities of CFS operations, and deliver realistic recommendations. A recent evaluation of the PG&E's FSTC found that in order to deliver the most value to food service operators, audit reports should include detailed information on costs and savings associated with the recommended improvements.[9]

Educating the Marketplace

Lack of knowledge about efficiency opportunities among end users and equipment suppliers, as well as misperceptions about tradeoffs between efficiency and performance, continue to inhibit greater adoption of energy-efficient equipment in the CFS market, despite improvements in this area since EPA introduced ENERGY STAR specifications for a variety of CFS products—as of May 2009, there are more than 98 ENERGY STAR CFS manufacturing partners and 2,600 qualified CFS products on the market.

The following strategies have been effective for getting information to end users to overcome these barriers:

Target marketing—Program information needs to be timely and relevant in order to motivate consumers to take action. For this reason, program administrators often develop targeted marketing strategies and messaging for each major market segment they are trying to reach—restaurants, hotels, schools, hospitals, etc.—taking into account business cycles and major industry events in timing promotions and outreach.

Training and equipment demos—Equipment suppliers may have little experience selling energy-efficient equipment, and they and their customers may be confused by different efficiency claims in the market or think energy efficiency comes with a tradeoff in productivity or product features. Equipment demonstrations and hands-on training can be particularly effective for persuading consumers that ENERGY STAR qualified CFS equipment comes with no tradeoffs in features or performance. Some programs have dedicated demonstration facilities for this purpose, while others work to assist suppliers in developing their own equipment demonstrations.

- PG&E's FSTC evaluation found that training seminars were a good way to build relationships with food service operators, leading to energy savings impacts over time.[10]
- New York State Energy Research and Development Authority's (NYSERDA) Small Commercial Kitchen Pilot successfully used cooperative marketing dollars to assist suppliers in developing their own equipment demonstrations (see text box on page 6).
- ETO gives an annual 45 minute sales training to CFS dealers to ensure sales staff understand the energy, monetary, and ancillary benefits of ENERGY STAR qualified CFS equipment.

Cooperative marketing—CFS programs create opportunities for cooperative advertising, showroom promotions and other collaborative marketing efforts with equipment suppliers. Programs often provide collateral marketing materials such as point-of-purchase banners, tags or stickers to identify rebate-eligible equipment, and informational flyers and brochures. Providing cooperative advertising funds is also an effective approach as it allows businesses the flexibility to market and advertise their ENERGY STAR qualified products in a way that is best aligned with their business model. For example, equipment suppliers that join

Program Highlight

ETO developed a highly successful document modeled after CFS dealers' handbooks (folders with equipment specification and sell sheets) that dealers take with them on the road. The handbooks contain all the relevant information that a dealer would need to sell ENERGY STAR equipment, such as:

- What is energy efficiency
- What is ENERGY STAR
- List of incentives available in Oregon
- A territory map showing where incentives are available
- Qualified product lists
- Tables listing the energy, water, and monetary savings for energy-efficient equipment (e.g., fryers, ice machines, refrigerators)
- Ancillary benefits of ENERGY STAR equipment
- Incentive application forms

Alliant Energy's trade ally network can be reimbursed for up to 50 percent of the cost of cooperative advertising, subject to utility pre-approval and other minimum requirements. For CFS products that save energy and water—commercial dishwashers, ice machines, and steam cookers—a growing number of energy and water utilities are pursuing opportunities for cooperative marketing, joint program implementation, or both.

Trade association outreach—CFS programs can leverage existing trade association networks to raise awareness of program opportunities and boost participation by customers and suppliers. Program administrators should consider joining the local restaurant association and trade associations serving food service equipment suppliers, as well as state restaurant associations. Membership in these organizations will keep program managers abreast of developments in the industry and alert them to outreach opportunities available through trade shows, meetings, and monthly publications. Informational seminars, industry conferences, and well-crafted articles are excellent ways of reaching service decision-makers. At these events, program administrators can also conduct informational seminars and display information and materials to publicize CFS program offerings.

Communications and outreach—A robust communications plan utilizing multiple channels including newsletters, targeted mailings, personal contact, seminars, and electronic communications increases awareness of program opportunities. Personal contact (i.e., "face time") is extremely important for implementing a successful program. Energy efficiency is a new concept in the CFS market and supply channel actors often need additional support from utilities before stocking, promoting, and selling energy-efficient CFS equipment. Program administrators can contact ENERGY STAR for assistance in identifying trade allies and developing outreach materials.

Program Highlights

1) **CenterPoint Energy** (MN) uses its Commercial Food Service Learning Center in Minnesota to provide hands-on education to trade allies about the benefits of high-efficiency equipment. CenterPoint is also a member of several food service trade associations and regularly attends the **Upper Midwest Restaurant Show.**

2) Distributor **Saratoga Restaurant Equipment Sales** (SRES) leveraged cooperative marketing opportunities through **NYSERDA's Small Commercial Kitchen Pilot** and increased sales of qualified equipment by 50 to 900%, depending on the product. Promotional efforts included a showroom event and equipment demonstration, hang tags on qualified equipment, and direct mail. SRES also streamlined the application process by filling out rebate paperwork on the customer's behalf.

3) As part of their program outreach activities, the four **California IOUs** attend the annual **Western Food Service and Hospitality Expo** in Los Angeles. The show is a great way for California program sponsors to engage with trade allies and to reach their key audience: restaurants.

Motivating Behavior Change and Continuous Energy Performance Improvement

In addition to purchasing energy and water efficient equipment, there are a number of operational best practices that program administrators can share with food service operators. The ENERGY STAR Restaurant Guide provides both short- and long-term recommendations for saving energy in commercial kitchens, equipment use and maintenance tips, and general energy savings tips, in addition to outlining the benefits of energy-efficient equipment installation. Program administrators can use this guide as part of education efforts with commercial kitchen customers to promote additional savings. EPA's Portfolio Manager tool can also be used to obtain a weather-normalized energy performance benchmarks for buildings, assisting food service operators in tracking their building's energy use and reducing it over time.

EPA also works cooperatively with the Consortium for Energy Efficiency (CEE) Commercial Kitchens Initiative. CEE is a nonprofit corporation whose membership includes utility, state, and nonprofit administrators of energy efficiency programming. The goal of the initiative is to define a high performance commercial kitchen package that CEE members can deliver to customers in targeted CFS sectors. A bundled whole-kitchen approach may be particularly appropriate for new construction or major renovation projects. For more information, please visit: *www.cee1.org/com/com-kit/com-kit-main.php3*

Program Highlight

PG&E has developed a Food Service Edition of the Smart Business Rebate Booklet identifying over $6,000 in rebates for the food service industry. The booklet provides information on nearly two dozen ways that PG&E can help customers save energy in commercial kitchens. The booklet tells customers how to apply for rebates, how to access education and training through PG&E's Food Service Technology Center, and how to develop an energy management plan using PG&E's online tool, SmartEnergy AnalyzerTM.

MEASUREMENT AND VERIFICATION

Measurement and verification (M&V) are central to the success of energy efficiency programs, and are used to assess the market during program design, monitor program performance during program implementation, validate program impacts, and justify continued investment in a program.

During the program planning and design phase it is important to establish a baseline and capture important data before it is lost.

Baseline Assessment

During the program planning process, it is useful to develop a baseline market assessment of the energy savings potential from commercial kitchens. This baseline will allow program managers to set realistic savings goals and design programs that are well-suited for the target market. Understanding market potential and the market penetration of energy-efficient CFS equipment is well worth the effort, providing valuable insights into how the program should be delivered, and what incentive levels would be cost-effective and successful at moving the market.

Many program administrators quantify kWh savings potential by customer segment. Some market assessments employ a survey process to develop baseline assumptions. At a minimum, a market assessment will identify the number of independently owned and franchised restaurants, hospitality businesses, and large institutional users of CFS equipment (e.g., hospitals, schools, prisons) within the service territory, and provide general information on the baseline equipment installed in such facilities. Growth projections for key end-use sectors and annual run time for qualified equipment are also useful metrics to include.

Program Tracking

Developing and maintaining a program tracking system is important for measuring program progress and tracking energy savings. Program administrators have found the following indicators useful in tracking program performance over time: energy savings (kWh and kW) from approved incentive applications; level of rebate activity by product type; level of rebate activity by customer type (restaurant, hospitality, etc.); trade ally participation; and program costs.

Incentive applications are an important source of information for collecting basic information not only to justify rebate payment, but also to inform future program impact evaluation. The following are commonly required inputs:

- Customer contact information
- Equipment cost
- Type of facility (restaurant, hotel, etc.)
- Number of qualified units installed
- Equipment type
- New installation or retrofit
- Manufacturer
- Proof of purchase (including serial number)
- Model number
- Trade ally contact information (if trade ally incentives are offered)

It is important to keep in mind the significant lag time between implementing a program and achieving program results. According to PG&E, CFS incentive programs take approximately 12 months to demonstrate changes in equipment stocking, selling, and purchasing behavior.

Process and Impact Evaluation

CFS programs are typically subject to two types of evaluations: process evaluation and impact evaluation. Process evaluations review program design and implementation to assess what elements of the program are working well and identify opportunities for improvement. Impact evaluations estimate the energy and demand savings that directly result from a program. The Model Energy Efficiency Program Impact Evaluation Guide, a resource of the National Action Plan for Energy Efficiency, is a useful resource for learning more and is available at *www.epa.gov/cleanenergy/documents/evaluation _ guide.pdf*

PROGRAM COST EFFECTIVENESS

ENERGY STAR qualified CFS equipment provides substantial savings opportunities for program administrators. While CFS programs can be operational within a two to four month period, given the diffuse nature of the distribution and purchasing patterns associated with this equipment, seeing significant progress in terms of program participation may take as long as one year.

Measure-level cost-effectiveness analysis, conducted during program planning, requires data on incremental measure cost, per-unit savings (kW, kWh, therms), annual hours of operation, and measure life. Program administrators typically base hours of operation assumptions on the type of facility where the equipment is installed (e.g., full service restaurant, quick service restaurant, hospital, school). As refrigeration measures are weather-sensitive,

Figure 1: Example of Co-Branded Marketing Document

ENERGY STAR supports development of co-branded marketing materials, like this flyer from **Wisconsin's Focus on Energy** highlighting the benefits of ENERGY STAR qualified equipment.

savings assumptions may vary based on the climate zone where the equipment is installed.

Measure-level data are available from a number of public sources, including the following:

- The Database for Energy-efficient Resources (DEER), maintained by the California Energy Commission and California Public Utilities Commission: *www.energy.ca.gov/deer*
- Program work papers filed by the California IOUs, available through the Energy Efficiency Groupware Application: *http://eega2006.cpuc.ca.gov*
- PG&E's FSTC Web site: *www.fishnick.com*
- NYSERDA also has a Deemed Savings Database, available by request

Table 2 presents program administrator cost (PAC) effectiveness results for three existing programs that provide incentives for ENERGY STAR qualified CFS equipment. These calculations only include the equipment incentive and administrative costs, but are estimated for the useful life of the equipment and discounted to net present value using 7 and 9 percent discount rates.

Program administrator costs are different, and usually lower than, total resource cost (TRC), which include the end users' marginal cost for purchasing energy-efficient equipment. For example, PG&E's PAC cost per kWh is estimated at $0.04 for both 7 and 9 percent discount rates; TRC is estimated

Table 2: Estimated Program Cost Effectiveness for Three Utilities[*]

	Pacific Gas & Electric Company[11] (PG&E)	Southern Minnesota Municipal Power Agency[12] (SMMPA)	Energy Trust of Oregon[13] (ETO)
Implementation Period (years)	2.75	2.00	4.00
Implementation Dates	01/06 to 09/08	05/06 to 05/09	05/05 to 04/09
Total Rebated Units	3,026	60	4,757
Gas	858	7	2,601[†]
Electric	2,168	53	2,156
Total Therms Saved	490,625	1,402	458,970
Total KWh Saved	13.3 million	183,147	3.4 million
Levelized CCE - Natural Gas ($/Therm)[o]	$1.06 –1.18	$1.54 – 1.70[◊]	$0.44 – 0.47[◊,†]
Levelized CCE - Electricity ($/kWh)[o]	0.04	$0.01[◊]	$0.10 – 0.11[◊]

* Levelized Cost of Conserved of Conserved Energy (CCE) estimates using the Program Administrator Cost Test (also known as the Utility Cost Test).

o Levelized CCE is presented using a range for discount rates of 7% and 9%.

◊ Administrative costs: for ETO and SMMPA an administrative cost of 11% was used in calculating CCE based on a published cap on administrative costs from the Oregon Public Utility Commission (www.energytrust.org/who/090323_Facts_EnergyTrust.pdf). PG&E data includes administrative costs supplied by the utility in program files and imbedded in measure level estimates.

† Includes 2,202 low-flow pre-rinse spray valves (PRSVs) provided free of charge to restaurants by ETO.

between $0.12 and $0.13 per kWh for the same discount rates (9 and 11 present respectively).11 The difference between these two estimates is the end users' added costs for purchasing the equipment. Utilities should analyze both PAC and TRC when deciding what types of equipment to incentivize.

ENERGY STAR SUPPORT FOR CFS PROGRAMS

In order to take full advantage of the ENERGY STAR platform for CFS programs, program administrators sign an ENERGY STAR Partnership Agreement with the government. The ENERGY STAR Program has an established national network of program administrators, equipment manufacturers, and marketing support firms that can provide advice and technical assistance during program start-up and implementation. Examples of support and resources include:

- **Specifications**—ENERGY STAR specifications currently cover six CFS equipment types, with new product categories evaluated every year. Information on new specifications and revisions to existing specifications is available at *www.energystar.gov/productdevelopment*.

Figure 2: Example of Co-Branded Incentive Booklet

Be creative when publicizing your programs! Southern Minnesota Municipal Power Agency created the Food Service Equipment Rebate booklet to showcase the comprehensive incentive program they developed for their 18 Member utilities. The booklet includes information on the utility's CFS equipment rebates, emphasizes ENERGY STAR's role in CFS market transformation, and provides product- and market-specific information for end users.

The Food Service Equipment Rebate booklet is available at: *http://www.SaveEnergyInBloomingPrairie.com/Upload/FoodServiceBooklet.pdf*

- **Marketing tools and resources**—Downloadable logos, equipment-related information, and educational tools like the ENERGY STAR Guide for Restaurants allow program administrators to customize a variety of marketing and informational materials, while using high-quality ENERGY STAR graphics and language that effectively describes how ENERGY STAR works in commercial kitchens (see figure 1 and 2).
- **Training resources**—A variety of materials are available to support program training activities, including customizable train-the-trainer presentations and opportunities for online or in-person training conducted by PG&E's FSTC (minimum participation requirements apply).
- **Partner matchmaking**—ENERGY STAR facilitates contacts between energy efficiency program administrators and manufacturers, equipment suppliers, and restaurant associations to support program marketing and outreach.
- **Savings calculators**—Spreadsheet tools estimate lifecycle energy, water, and cost savings for each category of ENERGY STAR qualified CFS equipment and are available at *www.energystar.gov/cfs* by clicking on the relevant product page.
- **Manufacturer and product lists**—Regularly-updated lists of equipment models that have earned the ENERGY STAR support rebate verification activities and are available at *www.energystar.gov/cfs* by clicking on the relevant product page.
- **Best practices tools**—Spreadsheet tools for quick service restaurants and full service restaurants estimate lifecycle energy and cost savings from additional energy-efficient food service equipment categories not currently covered by ENERGY STAR, and are available at *www.energystar.gov/cfs*.
- **CFS Equipment Incentive Finder**—Online database of available rebates for qualified equipment is searchable by zip code or by product type and is available at *www.energystar.gov/CFSrebate _ locator*.
- **CFS Program Guide**—Regularly-updated publication informs food service equipment suppliers about cross-promotional opportunities available through efficiency programs.
- **CFS newsletter**—Bimonthly electronic publication is distributed to industry associations, equipment suppliers, and efficiency program administrators highlighting efforts to promote ENERGY STAR qualified CFS equipment.
- **Case studies**—Success stories highlight commercial kitchens saving energy and money by leveraging energy efficiency programs and purchasing ENERGY STAR qualified equipment.

RESOURCES FOR ADDITIONAL INFORMATION

The following links are useful resources for energy efficiency program administrators that would like to learn more.

- ENERGY STAR for Commercial Food Service: *www.energystar.gov/cfs*

- ENERGY STAR for Restaurants: *www.energystar.gov/restaurants*
- ENERGY STAR Purchasing and Procurement with Product Savings Calculators: *www.energystar.gov/purchasing*
- ENERGY STAR Small Business Network: *www.energystar.gov/smallbiz*
- CEE Commercial Kitchens Initiative: *www.cee1.org/com/com-kit/com-kit-main.php3*
- PG&E's FSTC: *www.fishnick.com*
- GasNetworks: *www.gasnetworks.com/efficiency/pdf/Fryer_Rebate_Form_07_08.pdf*
- Green Restaurant Association: *www.dinegreen.com*
- National Restaurant Association: *www.restaurant.org*
- National Restaurant Association Conserve Initiative: *www.conserve.restaurant.org*
- North American Association of Food Equipment Manufacturers (NAFEM): *www.nafem.org*

PROGRAMS PROMOTING ENERGY STAR QUALIFIED CFS EQUIPMENT

Selected efficiency programs offering rebates for ENERGY STAR qualified CFS equipment include:

- Avista Utilities: *www.avistautilities.com/business/rebates/washington_idaho/Pages/incentive_7.aspx*
- The Energy Trust of Oregon: *www.energytrust.org/buildingefficiency/restaurants.html*
- MidAmerican Energy: *www.midamericanenergy.com/kitchen*
- New York State (NYSERDA): *www.nyserda.org/Commercial_Industrial/CommercialKitchens/default.asp*
- Pacific Gas & Electric Company: *www.pge.com/mybusiness/energysavingsrebates/incentivesbyindustry/hospitality*
- Puget Sound Energy: *www.pse.com/solutions/forbusiness/pages/comRebates.aspx?tab=4&chapter=4*
- San Diego Gas & Electric Company: *www.sdge.com/foodservice*
- Southern California Edison: *www.sce.com/RebatesandSavings/SmallBusiness/ExpressEfficiency/FoodServiceEquipment*
- Southern Minnesota Municipal Power Agency (SMMPA): *www.smmpa.org/members.asp?utility=59&service=326*
- Wisconsin's Focus on Energy: *www.focusonenergy.com/foodserviceincentives*

SOURCES

1 Consortium for Energy Efficiency. Commercial Kitchens Fact Sheet. Available at: *www.cee1.org/resrc/facts/comkit-fx.pdf*

2 PG&E Food Service Technology Center.

3 National Restaurant Association (2008). 2007/2008 Restaurant Industry Operations Report, as cited in National Restaurant Association, 2008 Restaurant Industry Forecast.

4 PG&E Food Service Technology Center.

5 California Public Utilities Commission (CPUC) (2008). Energy Efficiency Groupware Application, 4th Quarter 2007 E3 Calculators. Available at: *http://eega2006.cpuc.ca.gov*

6 Personal communication, Energy Trust of Oregon, July 9, 2008.

7 Personal communication, Wisconsin's Focus on Energy, July 16, 2008.

8 U.S. Department of Agriculture Economic Research Service. Briefing Room: Food Marketing System in the United States. Available at: *www.ers.usda.gov/Briefing/FoodMarketingSystem/foodservice.htm*

9 PA Consulting Group (2008). Pacific Gas & Electric: Process Evaluation and Strategic Assessment of the Food Service Technology Center. Available at: *www.calmac.org/publications/PGE_FSTC_Eval__Report_-_Final_Feb_14_2008.pdf*

10 PA Consulting Group (2008). Pacific Gas & Electric: Process Evaluation and Strategic Assessment of the Food Service Technology Center. Available at: *www.calmac.org/publications/PGE_FSTC_Eval__Report_-_Final_Feb_14_2008.pdf*

11 Pacific Gas and Electric Company. E-mail communication and data sharing, January 2009.

12 Southern Minnesota Municipal Power Agency. E-mail communication and data sharing, April 2009.

13 Energy Trust of Oregon. E-mail communication and data sharing, April 2009.

ENERGY STAR®, a program sponsored by the U.S. EPA and DOE, helps us all save money and protect our environment through energy-efficient products and practices. Learn more. Visit www.energystar.gov.

Date of Request: April 13, 2016 DPS Request No. DPS-426 JL-5
Due Date: April 25, 2016 KEDNY/ KEDLI Req. No. BULI-462

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, Sean Mongan

SUBJECT: **SALES PROMOTION EXPENSE - KEDLI**

Request:

Provide the following:

1. Identify and explain what sales promotion activities were performed by the Company (KEDLI) during the historic test year for the $1,040,000? Provide the cost breakdown in the same format as the information provided by the Company in Exhibit____(SPM-2).

2. What additional activities, if any, will be performed in the Rate Year and Data Years with the additional $950,000? Provide an updated Exhibit____SPM-2 with a breakdown of the sales promotion activities to reflect the total dollars to be spent by the Company for sales promotion activities in the Rate Year and Data Years, combining the historic sales promotion expenses of $1,040,000 and the requested sales promotion expenses of $950,000.

3. How will the additional sales promotion expense dollars requested by the Company help achieve the load reflected in the Company's sales forecast? Specifically, identify the level of customer additions and load growth expected if sales promotion expenses were cut to $0, left at the existing $1,040,000, and increased to $1,990,600 as requested by the Company. For each of these scenarios, identify the number of customers and additional load, anticipated to be added resulting from these sales promotion expenditures.

4. On p. 5 you state that sales promotion activities will promote cost effective load growth through incremental conversion and the retention of existing load. Explain how sales promotion expenses will contribute to net load growth through retention of existing load and identify which customer classes will directly benefit from these expenditures

5. The Neighborhood Expansion Program, case 14-G-0214, is set to expire on December 31, 2016. KEDLI requests a three-year extension of this successful program. Provide an explanation and examples of the metrics used by KEDLI to label the program as a success. Identify and explain what metrics does the Company propose be used to support this program as a successful program and provide any analysis of the costs/benefits of this program?

6. For the proposed residential rebate program, historically $46,000 and with a proposed incremental increase of $200,000, explain what does the Company propose to do with any unspent rebate dollars at the conclusion of the Rate Year and Data Years?

7. Provide the work papers supporting the $750 savings and the $210 incremental margin associated with a service line extension at the time of main replacement.

8. Provide the reports and data points the Company uses to monitor the success of its sales promotion payback over a nine-year period (*see*, KEDLI testimony p. 12).

Response:

1. Please see the following chart describing sales promotion activities in the Historic Test Year:

Channel	Description	KEDLI
Direct Mail*	Initial Direct Mail campaigns and follow-up initiatives	$595,419
Television	:10 TV Billboards on News 12 Long Island	$116,192
Co-Op Advertising	Plumber outreach postcards	$86,254
Digital/Mobile Ads	Digital and mobile ads to target people to convert on LI	$83,956
Sales Promotion	Residential Rebate Program-Sales Promotion	$46,800
Email	Email campaigns	$40,234
Outbound Telemarketing	Outbound Telemarketing for additional outreach/follow-up	$21,863
Construction Support	Marketing materials to support main replacement efforts	$8,325
Events	Tabling and Collateral material	$7,700
Plumber Outreach	Outreach materials for plumbers	$7,472
Sales Materials	Collateral material to help support Sales team	$6,874
Social Media	Full year of SEM and Facebook posts	$2,000
Website Content	Develop content on the website to drive conversions	$5,257
Door hangers	Door hangers to targeted areas to get them to convert	$4,895
Community meetings	Direct Mail and Collateral material	$3,968
Services not burning letters	Letters to Services not burning	$2,587
Employee Notifications	At-a Glance communications to employees	$850
Total Cost:		**$1,040,647**

Cost includes the printing and postage.

2. Please see the following chart showing total spending of $1,990,646 for the Rate Year and Data Years:

Channel	Description	KEDLI	Additional Spend	Total
Direct Mail*	Initial Direct Mail campaigns and follow-up initiatives	$595,419	$115,000	$710,419
Sales Promotion	Residential Rebates	$46,800	$450,000	$496,800
Television	:10 TV Billboards on News 12 Long Island	$116,192	$125,000	$241,192
Email	Email campaigns	$40,234	$103,000	$143,234
Outbound Telemarketing	Outbound Telemarketing for additional outreach	$21,863	$92,000	$113,863
Co-Op Advertising	Plumber outreach postcards	$86,254	$0	$86,254
Digital/Mobile Ads	Digital and mobile ads to target people to convert on LI	$83,956	$0	$83,956
Website Content	Develop content on the website to drive conversions	$5,257	$29,100	$34,357
Sales Materials	Collateral material to help support Sales team	$6,874	$14,200	$21,074
Construction Support	Marketing materials to support main replacement efforts	$8,325	4000	$12,325
Events	Tabling and Collateral material	$7,700	$3,700	$11,400
Plumber Outreach	Outreach materials for plumbers	$7,472	$3,000	$10,472
Community meetings	Direct Mail and Collateral material	$3,968	$5,000	$8,968
Social Media	Full year of SEM and Facebook posts	$2,000	$6,000	$8,000
Door hangers	Door hangers to targeted areas to get them to convert	$4,895	$0	$4,895
Services not burning	Letters to Services not burning	$2,587	$0	$2,587
Employee Notifications	At-a Glance communications to employees	$850	$0	$850

Cost includes the printing and postage.

3. The sales promotion expense promotes awareness, generates new leads and provides incentives to achieve the sales forecast. The level of additions associated with the identified levels of spending cannot be accurately forecast as the price difference between oil and natural gas and general economic conditions are larger drivers of added load and impact the outcome of the sales promotion expense.

4. Sales promotion activities help to promote the overall awareness of the value of natural gas service for both current and prospective customers. Although retention of existing customers is not presently a large issue, there are options for customers as their equipment breaks down or comes to the end of its useful life. The overall market messages that promote the value of gas help to keep a new gas appliance as a customer's first choice and may help to offset any messaging about new non-gas fired products. This messaging has a greater impact in the residential market based on volume of equipment turnover and number of alternatives.

5. The program is a success as it has provided access to natural gas to previously un-served areas that meet the density and initial connection requirements of the program. The program's metric for success is achieved when the Company is able to connect to an un-served area because a sufficient number of customers (as set forth in the program's guidelines) have chosen to connect for service. Longer term success will be based on the overall program portfolio achieving results that are consistent with tariff requirements. This will be supported with ongoing promotion and education of customers along the route of a Neighborhood Expansion main extension.

6. If a multi-year rate plan is adopted, any unspent funds will carry forward during the term of the rate plan and, upon conclusion of the plan, be refunded to customers if they are not used to provide rebates. If a one year case results, the Company would be willing to defer any unspent amount.

7. The estimated savings of $750 expected from the installation of a new service when a road or street is already open were derived from a comparison of contractor bids for both scenarios. The anticipated revenue of $210 from new residential non- heating customers is derived from a weighted average of the expected types of appliance and the Company's adjusted annual revenue net of fuel for each of those applications. It is projected that 75% of the new non-heat customer usage would be from either a new stove or dryer at $183 of annual New Delivery Revenue (NDR) each and 25% to be water heating at $279 NDR each. The weighted average NDR as shown in the testimony is derived as follows:

   (($183*75%) + ($279*25%)) = $207

   There are no workpapers associated with these calculations.

8. No specific reports are prepared or maintained to show the success of the sales promotional payback over the past nine years. However, in the response to question 8 of DPS-289, the Company provided the methodology and support for determining the payback for the Historic Test Year and Rate Year based on costs and expected revenue.

<u>Name of Respondent</u>: Keith Sperling, Christine Kivia/Chris Cavanagh

<u>Date of Reply</u>: April 25, 2016

Date of Request: April 13, 2016
Due Date: April 25, 2016

DPS Request No. DPS-427 JL-6
KEDNY/ KEDLI Req. No. BULI-463

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, Sean Mongan

SUBJECT: **SALES PROMOTION EXPENSE – KEDNY**

Request:

Provide the following:

1. Identify and explain what sales promotion activities were performed by the Company (KEDNY) during the historic test year for the cost of $557,081? Provide the cost breakdown in the same format as the information provided by the Company in Exhibit____(SPM-2)

2. Explain why sales promotion expenses beyond the historic level of $557,081 will not increase and describe whether this is consistent with your request for KEDLI?

3. How will the sales promotion expense dollars requested by the Company help achieve the load reflected in Company's sales forecast? Specifically, identify the level of customer additions and load growth expected if sales promotion expenses were cut to $0, left at the existing $557,081, increased beyond the requested level, and equivalent to those sales promotion dollars requested for KEDLI? For each of these scenarios, identify the number of customers and additional load, anticipated to be added resulting from these sales promotion expenditures.

4. You state that sales promotion activities will promote cost effective load growth through incremental conversion and the retention of existing load. Explain how sales promotion expenses will contribute to net load growth through retention of existing load and identify which customer classes will directly benefit from these expenditures?

5. Explain why the Company is not proposing a Neighborhood Expansion Program for KEDNY and provide any analysis or supporting documentation underlying the decision not to propose a Neighborhood Expansion Program.

6. On p. 9 of your KEDLI testimony you identified an approximate savings of $750 associated with a service line extension if it is done at the same time as a planned main replacement with a $210 incremental margin. Explain why the Company has not requested a similar customer rebate for customers located in the KEDNY service territory. What would the savings and additional margin be for customers converting from non-firm or no heat service classes to firm heating classes?

7. Provide the reports and data points the Company uses to monitor the success of its sales promotion payback over a nine-year period (*see*, KEDNY testimony p. 6).

Response:

1. Please see the following chart describing sales promotion activities in the Historic Test Year:

Channel	Description	KEDNY
Direct Mail*	Initial Direct Mail campaigns and follow-up initiatives	$390,472
Email	Email campaigns	$31,478
Sales Materials	Collateral material to help support Sales team	$8,743
Web site updates	Updates to the website with any updated forms	$1,880
Plumber Outreach	Outreach materials for plumbers	$67,514
Outbound Telemarketing	Outbound Telemarketing for additional outreach/follow-up	$56,994
Total Cost:		$557,081.00

**Cost includes the printing and postage.*

2. The market conditions in KEDNY's service territory are different than those in KEDLI's service territory. Unlike KEDLI, KEDNY's service territory has a high saturation of natural gas and new construction is driving the market. Therefore, KEDNY is not forecasting an incremental increase in sales promotion expense.

   The market conditions driving KEDLI's need for incremental sales promotion expenses are discussed in the testimony of Sean P. Mongan.

3. The sales promotion expense promotes awareness, generates new leads and provides incentives to achieve the sales forecast. The level of additions associated with the identified levels of spending cannot be accurately forecast as the price difference between oil and natural gas and general economic conditions are larger drivers of added load and impact the outcome of the sales promotion expense.

4. Sales promotion activities help to promote the overall awareness of the value of natural gas service for both current and prospective customers. Although retention of existing customers is not presently a large issue, there are options for customers as their equipment breaks down or comes to the end of its useful life. The overall market messages that promote the value of gas help to keep a new gas appliance as a customer's first choice and may help to offset any messaging about new non-gas fired products. This messaging has a greater impact in the residential market based on volume of equipment turnover and number of alternatives.

5. The Company is not proposing a Neighborhood Expansion Program for KEDNY because of the high saturation of natural gas in its service territory.

6. Because of the high saturation of natural gas in KEDNY's service territory, there is minimal opportunity to connect new customers in conjunction with the main replacement program. KEDNY will review the results of KEDLI's main replacement program and, if successful, would consider it at a later date. For the non-heat to heating conversions in KEDNY's residential market, the vast majority of customers do not require a new service. The decoupled revenue associated with a residential non-heat to heating conversion is $396.

7. No specific reports are prepared or maintained to show the success of the sales promotional payback over the past nine years. However, in the response to question 8 of DPS-289, the Company provided the methodology and support for determining the payback for the Historic Test Year and Rate Year based on costs and expected revenue.

Name of Respondent:	Date of Reply:
Keith Sperling/Christine Kiviat/Chris Cavanagh	April 25, 2016

Date of Request: April 14, 2016
Due Date: April 25, 2016

DPS Request No. DPS-435 JL-7
KEDNY/ KEDLI Req. No. BULI-471

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, Sean Mongan

SUBJECT: Natural Gas Vehicles - KEDNY

Request:

1. On p. 17 of your testimony, you identify that the price advantage that compressed natural gas (CNG) has enjoyed over gasoline fuel has declined in the last few years. Provide the average price for a CNG gasoline gallon equivalent and a gallon of gasoline for the past five years (2011 to 2015). Include the gasoline gallon equivalents (GGE) sold, by station, within KEDNYs service territory for the same five year period.

2. Provide information regarding the price advantage that CNG has enjoyed over diesel fuel and changes in that advantage in the last five years. Provide the average price for a CNG diesel gallon equivalent and a gallon of diesel fuel for the past five years (2011 to 2015). Include the diesel gallon equivalents (DGE) sold, by station, within KEDNYs service territory for the same five year period.

3. For the KEDNY service territory, has the Company developed information regarding the numbers and types of vehicles with the potential to convert from gasoline and /or diesel to CNG within its service territory? Has the Company developed or does it have access to information regarding the numbers and types of vehicles that have converted from gasoline or diesel and the level of displacement or elimination of the associated pollution by fuel type?

4. Identify the total number of individual CNG vehicles that have utilized CNG stations located in KEDNY's service territory. Provide the monthly and annual totals for the past five years (2011 through 2015).

5. On p. 17 of your testimony, you identify that government incentives and grants have been reduced or eliminated. Provide a listing of the individual incentives and grants provided by the government and the amount and timing of these program changes.

6. On p. 19 of your testimony, you identify the cost of the proposed Natural Gas Vehicle (NGV) incentive program would be capped at $475,000 annually to enable the Company to provide up to a $1,200 incentive for approximately 395 new NGVs. Has the Company evaluated the potential for NGV conversions within its service territory and developed a targeted marketing plan to acquire 395 vehicles per year? If so, provide a copy of the analyses developed by the companies. If not, what is the basis for the estimate of 395 NGVs?

7. What is the Company's plan to address unspent monies collected for this rebate program? Explain whether the plan addresses these unspent monies annually or over the term of a multi-year rate plan, were one to be adopted in this case?

Response:

1. Attachment 1 sets forth both the gallon gas equivalent and diesel gas equivalent sold, by station, within KEDNY's service territory for calendar year (CY) 2011 through CY 2015. National Grid does not set the price or have pricing information for Compressed National Gas (CNG) stations, with the exception of the Company-owned fueling station at JFK Airport that operated until March of 2015; that station sold CNG under SC-14 of the Company's tariff. The fuel sold at JFK was a relatively small volume and not representative of the market. The actual pricing at CNG stations is set by the station's operator. The Company has estimated the price differential for uncompressed gas that is compressed, treated and dispensed into vehicles. The second tab of Attachment 1 includes an estimate of the typical cost of fuel supplied to these CNG stations and an estimate of the fuel price differential for natural gas for CY 2011 through CY 2015.

2. Please see the response to question 1 and Attachment 1.

3. Because the Company does not manage retail fueling, it does not have specific information on the types of vehicles being fueled. Most CNG vehicles are now acquired new from original equipment manufacturers or their designated upfitters. The Company does not have specific data on the numbers or types of vehicles that have been converted or have the potential to convert. The types of vehicles being fueled can be inferred from customer information. Referring to the stations identified in Attachment 1, from observation, vehicles that utilize the National Grid-owned stations are typically medium or light-duty trucks, vans and sedans with occasional heavy-duty trucks. The majority of CNG dispensed in KEDNY's service territory is for public transit buses and municipal garbage trucks.

   The Company previously purchased fleet registration data from vendors. One such list, purchased in 2007, indicated that there were at least 98 commercial fleets based in KEDNY's service area each with 50 or more vehicles and more than 500 fleets of all sizes. There are in excess of 3,600 public transit buses in NYC and over 13,000 medallion taxis.

The environmental benefits of natural gas vehicles (NGVs) have been documented in a variety of studies by the USDOE, USEPA and others and will vary by vehicle type.[1] NGVs generally result in a reduction of greenhouse gases by as much as 25% over traditional fuels. NGVs also reduce criteria pollutants such as smog and acid-rain producing emissions (*e.g.,* NOx) by as much as 60%. In addition, NGVs that would otherwise have been fueled with diesel result in the elimination of up to 90% of particulate matter. For additional information on displacement or elimination of pollutants, please refer to Attachment 2, page 9 of the Executive Summary. At the current rate of use, CNG in NYC is estimated to avoid the emission of approximately 48,000 tons per year CO_2.

4. The Company does not have specific information on the types and numbers of individual vehicles using CNG stations. The first tab of Attachment 1 includes an estimate of the average numbers of vehicles using these stations based on typical annual usage of commercial vehicles. The average over the past five years is the equivalent of approximately 850 vehicles exclusively using these stations.

5. There have been significant changes in the incentives and grants available in NYS in recent years, including the following;

   a. Fueling equipment for natural gas, installed between January 1, 2015, and December 31, 2016, is eligible for a federal tax credit of 30% of the cost of a fueling station, not to exceed $30,000. This incentive has recently been as low as $1,000 while the original incentive was a tax deduction of $100,000 for an investment in a station and up to $25,000 for each vehicle.

   b. The NYS alternative fuels credit expired on December 31, 2010. As of January 2013, NYS reduced the new credit for each installation of property to the lesser of $5,000 or 50% of the cost of property. The credit previously was 50% of the cost of clean fuel refueling property limited by the Customer's tax. See NY Tax Law section 187-b.

   c. There currently is a federal Volumetric Excise Tax credit for alternative fuels valued at $0.50 per GGE. However, this credit expired three times and has been retroactively reinstated through 12/31/2016.[2]

   d. Federal grant funding is facilitated by the USDOE Clean Cities program. There was significant competitive federal grant funding available for vehicles and stations prior to and through the 2009 American Reinvestment and Recovery Act, but the Company is not aware of any significant federal funding opportunities since.

   e. The 2013 New York City Alternative Fuel Vehicle - Voucher Incentive Fund is managed by NYSERDA and has been extended. It offers up to 80% of the incremental cost of an

---

[1] See http://www.afdc.energy.gov/vehicles/natural_gas_emissions.html
[2] See http://www.afdc.energy.gov/laws/319

alternative fuel Class 3 to 8 truck or bus operating in NYC that meets certain qualifications. Vehicles operated by public agencies are not eligible. Funds have been awarded on a first-come first served basis. The program has a fixed budget and is expected to permanently close when any remaining funds are committed.[3]

6. A review of NYSERDA and EIA data indicated that CNG market share in NYS is about 0.5%[4] in terms of vehicle fuel. America's Natural Gas Alliance commissioned a detailed study in 2013 that estimated that a realistic potential of 6% market share for CNG was possible by 2035.[5] The Company has not yet developed a new marketing plan but will do so upon approval of the funding proposed in the case in collaboration with NGV developers operating in NYC and through direct interaction of the Company's sales force and the Empire Clean Cities organization.

   The target for the incentive will be to support the fuel equivalent of 395 light-or medium duty vehicles that utilize 1,500 GGE each annually. As the market data show, there is more potential than the incentive could support. Attachment 1 shows that NGV use in NYC has essentially been flat for the past five years. The proposed incentive could restore a growth rate of about 10% over the term of the rate plan in terms of fuel use at existing CNG stations.

7. If a multi-year rate plan is adopted, any unspent funds will carry forward during the term of the rate plan. If a one year case results, the Company would be willing to defer any unspent amount.

<u>Name of Respondent</u>:
Christopher Cavanagh/Keith Sperling

<u>Date of Reply</u>:
April 25, 2016

[3] See https://truck-vip.ny.gov/WhatisNYT-VIP.php
[4] See USEIA & Patterns and Trends New York State Energy Profiles: 1999-2013 Final Report, NYSERDA 2015
[5] See "U.S. and Canadian Natural Gas Vehicle Market Analysis: Natural Gas Vehicle, Industry Overview", p 9. America's Natural Gas Alliance & TIAX Corp. 2013 Included as Attachment 2.

U.S. and Canadian Natural Gas Vehicle Market Analysis:

Natural Gas Vehicle Industry Overview

Executive Summary

Published by America's Natural Gas Alliance

The opinions expressed within the Executive Summaries of Modules 1 and 2 of this market assessment are the work product of America's Natural Gas Alliance (ANGA) and participating American Gas Association (AGA) companies based upon data provided by TIAX LLC.

The Final Reports of Modules 1 through 5 are the work of TIAX LLC as a market assessment sponsored by ANGA with the support of participating AGA companies.

Executive Summary

Driving Into a Cleaner, Safer Future

America needs to increase its energy independence now

America urgently needs a new alternative energy solution. We must reduce our dependency on foreign sources of energy and implement an alternative transportation fuel that is reliable, safe, and affordable. The U.S.'s annual import bill approaches $350 billion, more than double what the federal government spends on education.[1] The transportation sector uses the bulk of our imported oil. Vehicles consumed 4.7 billion barrels of petroleum in 2010, even more than the 4.2 billion barrels of petroleum the country imported that year.[2]

Increasing use of domestic natural gas as a clean alternative fuel will help prevent North America from relying on regions of the world whose interests run counter to our own. Given events in the Middle East like the Gulf War and the prolonged conflict in Iraq as well as OPEC's continual control of petroleum supplies, we can practically gauge the health of U.S./Middle East diplomatic relations by the price at the pump.

Our current transportation portfolio carries societal costs

It's not just the price at the pump that should worry us. It's also the hidden costs we don't see when we slide our credit cards across the magnetic reader. Each time a driver refuels, the indirect cost of energy security adds an additional $0.46 per gallon or an average of $8.31 per vehicle.[3] You can see the costs of this premium in decreased national economic output, loss of national gross product, economic strain and volatility, oil supply shocks, prices spikes, supply disruption, and import costs.

Each time a driver refuels, the indirect cost of energy security adds an additional $0.46 per gallon or an average of $8.31 per vehicle.[3]

In addition, every transportation fuel carries a societal cost based on impacts from criteria pollutant emissions. Another societal cost of our transportation fuel results from GHG emissions. Monetization of these societal costs provides a means to assess the societal benefits of the alternative fuels considered. Across multiple vehicle segments, the societal costs for NGVs are lower than those for conventional transportation fuels. The net savings (of direct and societal costs) exceed $50,000 for some high fuel use applications and are comparable to saving 15 percent of lifetime costs. The savings for other applications may be less but are still significant.

The more we increase the use of domestic natural gas, the more these societal costs can be reduced.

1 Brian Riedel, "Federal Spending By the Numbers," June 1, 2010, http://www.heritage.org/research/reports/2010/06/federal-spending-by-the-numbers-2010, (October 12, 2011).
2 Energy Information Administration. "Annual Energy Review." October 19, 2011.
3 U.S. EPA, NHTSA. "Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis." EPA-420-R-10-009, p. 8-16. April 2010.

ES1 Energy Security Premium

The effect of imported overseas petroleum:

Energy Security Premium[4] $0.46 per gallon transportation fuel
Decreased economic output Loss of national gross product Economic strain and volatility Supply shocks and price spikes Supply disruption Import costs

ES2 Criteria Pollutants + GHG Costs

Our current total transportation portfolio bears societal costs:

Air Pollution Costs[5,6,7,8] $9,072 per ton NOx $270 per ton CO $7,401 per ton VOC $283,274 per ton PM2.5	**GHG Costs[9,10]** $23.13 per ton
Impacts from Criteria Pollutants	Impacts from GHG Emissions

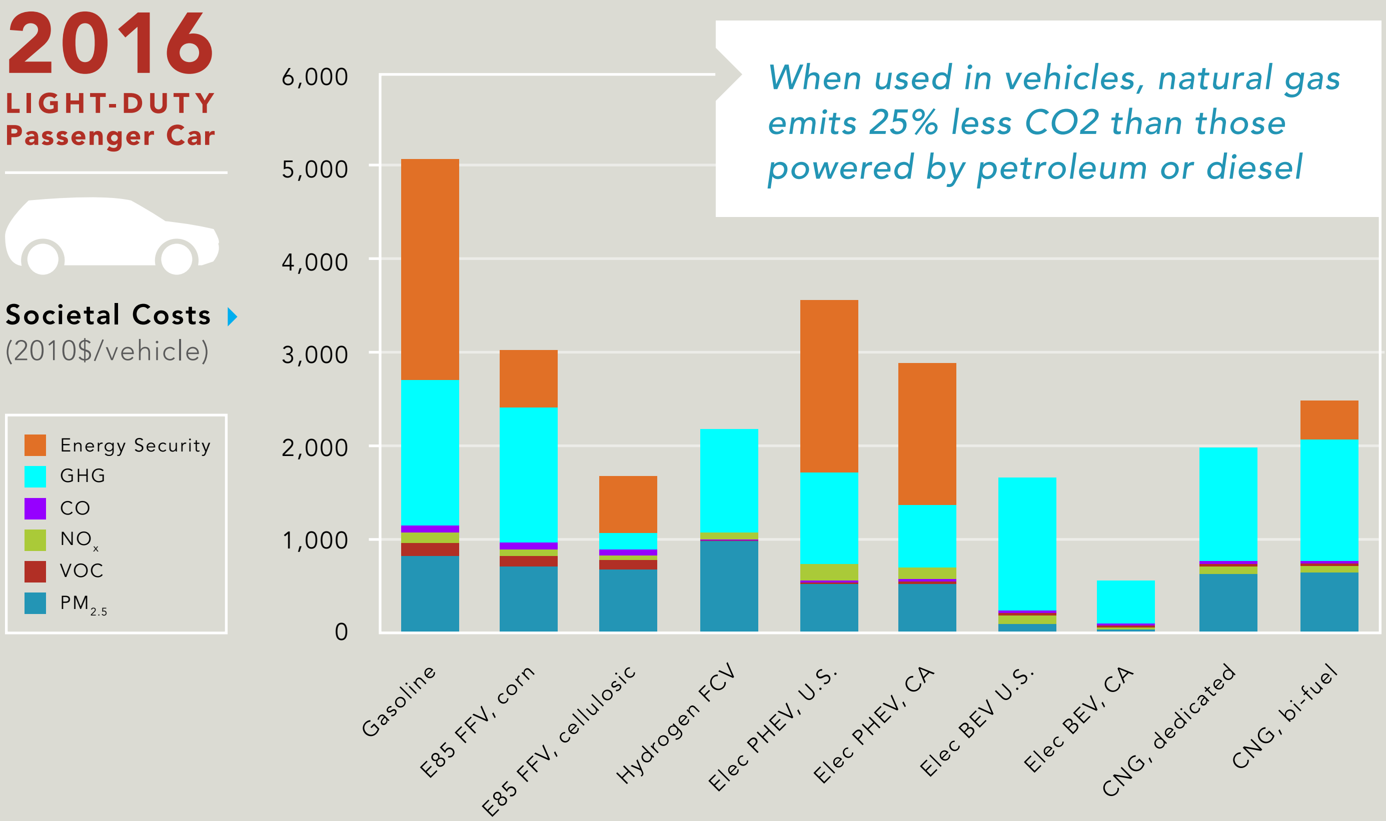
Current societal costs are estimated to add up to $0.99 per day for each 2010 passenger car on the road.[11,12,13,14,15,16] With an on-highway vehicle population of 255 million in the U.S., the costs related to transportation fuel pollution total upwards of $252 million dollars a day.[17]

Natural gas vehicles (NGVs) have less impact on energy and the environment, and the difference is dramatic. Conventionally-powered passenger cars carry a societal cost estimated at $5,100 per vehicle over their lifetime, while NGVs cost $2,000 to $2,500.

For medium-duty vans, hybrid package delivery vans, hybrid beverage trucks, transit buses, refuse haulers, and 18-wheeled tractor-trailers using diesel the societal costs are even greater. Over the lifetime of an 18-wheeler, these costs are estimated at $70,000. In comparison, the costs associated with an 18-wheeler using natural gas are $21,000 to $34,000. Regardless of a vehicle's size, the lifetime societal costs of NGVs will be lower than those of conventional vehicles.

> *Regardless of a vehicle's size, the lifetime societal costs of NGVs will be lower than those of conventional vehicles vehicles.*

4 U.S. EPA, NHTSA. "Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis." EPA-420-R-10-009, p. 8-16. April 2010.
5 Costs for NOx and VOCs include both direct emissions of these pollutants and their indirect emissions (as precursors to PM); all costs are given in 2010 U.S. dollars.
6 U.S. EPA, NHTSA. "Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis." EPA-420-R-10-009, p. 7-118. April 2010.
7 TIAX communication with N. Fann, EPA Office of Air Quality Planning & Standards, August/September 2010.
8 CEC. "Reducing California's Petroleum Dependence, Appendix A: Benefits of Reducing Demand for Gasoline and Diesel (Task 1)." P600-03-005A1, p. 3-27. September 2003.
9 U.S. Government. "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis, Under Executive Order 12866," p. 39. Interagency Working Group. February 2010.
10 U.S. EPA, NHTSA. "Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis." EPA-420-R-10-009, p. 7-128. April 2010.
11 Costs for NOx and VOCs include both direct emissions of these pollutants and their indirect emissions (as precursors to PM); all costs are given in 2010 U.S. dollars.Costs for NOx and VOCs include both direct emissions of these pollutants and their indirect emissions (as precursors to PM); all costs are given in 2010 U.S. dollars.
12 U.S. EPA, NHTSA. "Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis." EPA-420-R-10-009, p. 7-118. April 2010.
13 TIAX communication with N. Fann, EPA Office of Air Quality Planning & Standards, August/September 2010.
14 CEC. "Reducing California's Petroleum Dependence, Appendix A: Benefits of Reducing Demand for Gasoline and Diesel (Task 1)." P600-03-005A1, p. 3-27. September 2003.
15 U.S. Government. "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis, Under Executive Order 12866," p. 39. Interagency Working Group. February 2010.
16 U.S. EPA, NHTSA. "Final Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Regulatory Impact Analysis." EPA-420-R-10-009, p. 7-128. April 2010.
17 Research and Innovative Technology Administration, "Number of U.S. Aircraft, Vehicles, Vessels, and Other Conveyances (2008)," http://www.bts.gov/publications/national_transportation_statistics/html/table_01_11.html (October 6, 2011).



The advantages and opportunities of alternative fuels

Although driving small vehicles reduces fuel consumption, all vehicles in every class have gotten heavier and more powerful, small and large vehicles alike. However, many Americans want their minivans, SUVs, and trucks. As we continue to use energy in transportation, we need to find alternatives to the way we fuel our cars.

No matter what your political affiliation, we all agree on a basic problem: We must change our energy consumption. Former President George W. Bush explained that affordable energy is the key to our future:

"Keeping America competitive requires affordable energy. And here we have a serious problem: America is addicted to oil, which is often imported from unstable parts of the world. [...] By applying the talent and technology of America, this country can dramatically improve our environment, move beyond a petroleum-based economy and make our dependence on Middle Eastern oil a thing of the past." [18]

The Obama Administration shared these sentiments, and President Barack Obama stated:

"Our dependence on foreign oil threatens our national security, our environment and our economy. We must make the investments in clean energy sources that will put Americans back in control of our energy future, create millions of new jobs, and lay the foundation for long-term economic security." [19]

Fortunately, our overseas dependency on foreign sources of energy from geopolitically unstable regions of the world is a problem we can solve. We already recycle, tote canvas bags to the grocery store, and try to run our appliances in evening hours. Doesn't it logically follow then that the transportation industry offers consumers an amazing opportunity to impact their country, environment, and wallet with one purchasing decision?

18 President George W. Bush, "State of the Union Address: January 31, 2006," The Washington Post, http://www.washingtonpost.com/wp-dyn/content/article/2006/01/31/AR2006013101468.html, (October 3, 2011).
19 The White House, "Learn: Clean Energy Economy," http://m.whitehouse.gov/issues/energy-and-environment/new-foundation/learn, (October 3, 2011).

A better source of energy security and economic stability exists inside our borders

North America has a better energy source inside its borders, and the U.S. could pass Saudi Arabia and overtake Russia as the world's largest energy producer.[20] We can accelerate our energy independence by augmenting our petroleum supply with North American natural gas. NGVs and a natural gas fueling infrastructure can be the solution to our energy problems that minimizes damage to the environment. Switching to natural gas will also save North America millions of dollars in security costs related to defending access to international petroleum resources in geopolitically unstable regions of the world.

Natural gas is not a new fuel. We've used it since practically the beginning of time—the Chinese discovered natural gas in 600 BC and, around the first century, the first recorded use of natural gas in the home occurred in Persia (now Iran). In North America, natural gas use dates back as early as 1626.[21] It heats our homes and businesses, has many industrial applications, and generates electricity. Natural gas already accounts for 23.4% of the U.S. energy supply.[22]

Natural gas has served as a transportation fuel for more than six decades. It has mainly been applied to commercial vehicles like school buses and truck fleets that return to a central base at the end of a day. Fleet operators can economically build and maintain fueling stations at these central stations. It's also no coincidence that school buses have been a successful application, given the positive attribute of lower emissions.

We can accelerate our energy independence by augmenting our petroleum supply with North American natural gas.

Natural gas is an economical fuel option

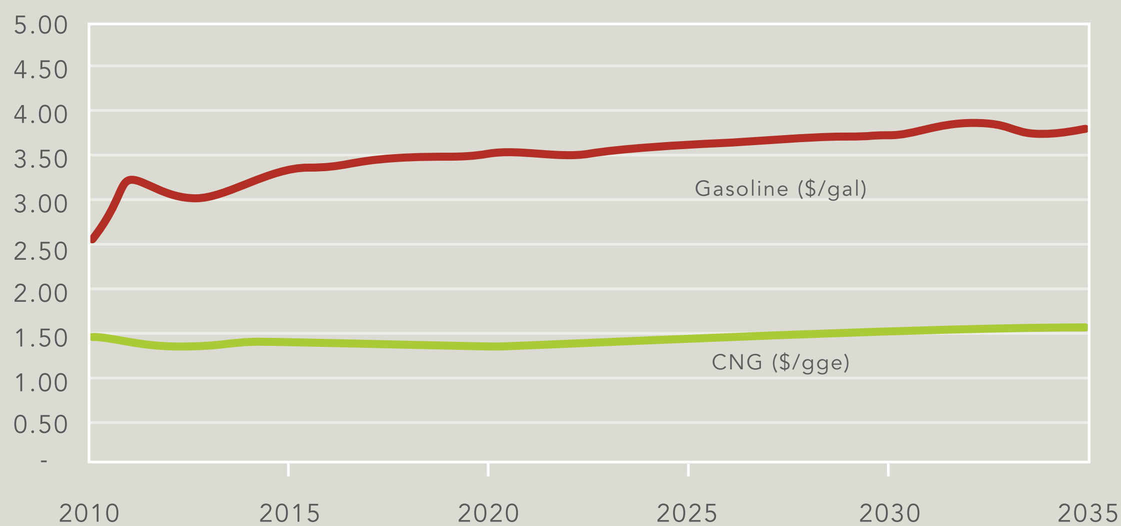
Despite the lack of a large natural gas fueling infrastructure for the public, consumption as a transportation fuel has increased steadily since 1997. During this period, the price of petroleum rose while the price of natural gas fell. As the exhibit below shows, this trend is continuing. Over the next 25 years, natural gas is expected to become even cheaper relative to petroleum.

The fuel cost differential between natural gas and gasoline is expected to reach over $2.00 per gasoline gallon equivalent (GGE) and over $3.00 per diesel gallon equivalent (DGE) between natural gas and diesel. For the average North American, who fills up his or her tank weekly, refueling with natural gas rather than petroleum would save approximately $32 per gas station visit. In a year, that's a $1,664 savings.

ES4

GGE Fuel Price At Pump
(2010$ per GGE)

Notes
1) Fuel prices are derived from the reference case in U.S. EIA "Annual Energy Outlook," 2012
2) Prices include federal and state taxes
3) Prices are adjusted for vehicle efficiency

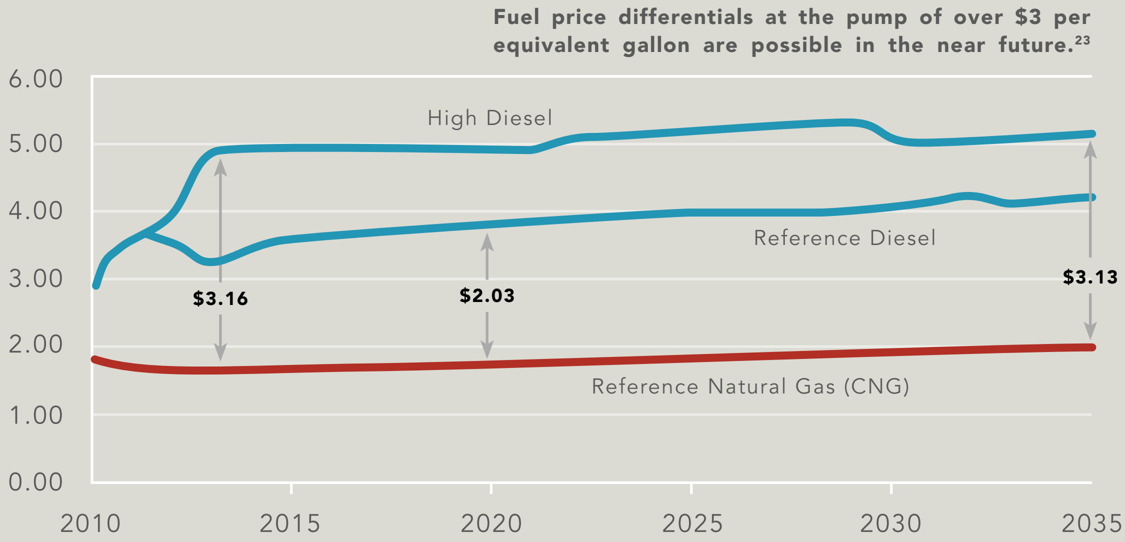


20 "History Zone", Pacific Gas & Electric, http://www.pge.com/microsite/safety_esw_ngsw/ngsw/more/history.html (October 3, 2011).
21 U.S. Energy Information Administration, "U.S. Primary Energy Flow by Source and Sector, 2009," www.eia.gov, http://www.eia.gov/totalenergy/data/annual/pecss_diagram.cfm, (October 3, 2011)
22 Energy Information Administration. "Annual Energy Outlook 2011" assessed at http://www.eia.doe.gov/forecasts/aeo/ on April 28, 2011.

ES5

DGE Fuel Price At Pump
(2010$ per DGE)

Notes
1) Fuel prices are derived from U.S. EIA "Annual Energy Outlook," 2012
2) Prices include federal and state taxes
3) Prices are adjusted for vehicle efficiency



Conventional fuel retailers, fleet fueling operators, and average drivers are accustomed to fueling vehicles with liquid fuels. Though natural gas is different from conventional fueling, it's simple to use and is widely used in transportation.

While liquid fuels like gasoline or diesel must be transported to stations via over-the-road trucks, compressed natural gas (CNG) is a natural gas fuel that is typically transported via an underground pipeline and then compressed to a higher pressure. While some investment is required to build a natural gas fueling infrastructure, it can use an already existing network of pipelines to reach stations. Additionally, CNG fueling stations can be designed to accommodate any situation—public or fleet fueling.

Natural gas is in abundant supply and offers price stability

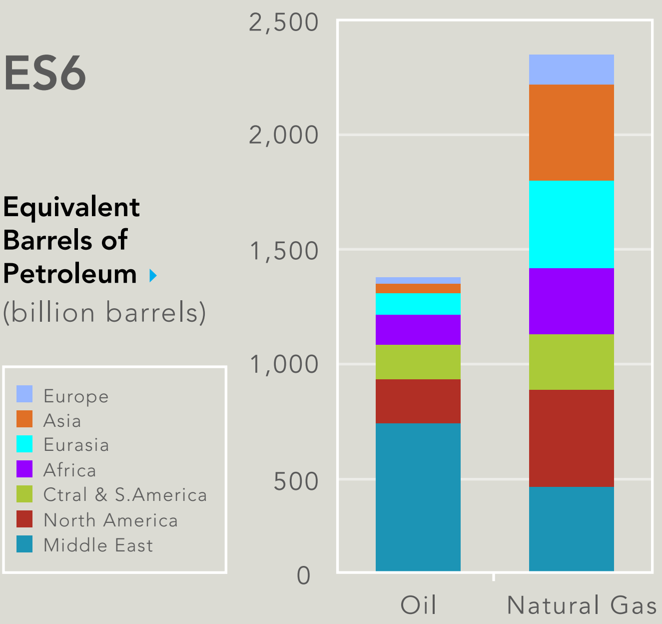
Now is the time for natural gas. Recent explorations for natural gas have found abundant supplies in North America, making natural gas even more plentiful than petroleum. Current global supplies of natural gas could sustain world demand, at current consumption, for 121 years versus 46 years for petroleum.[24]

There is enough natural gas in the U.S. and Canada to supply the current economy-wide uses of 24.3 trillion cubic feet (TCF) per year and support these markets as they expand.[25]

Current global supplies of natural gas could sustain world demand, at current consumption, for 121 years versus 46 years for petroleum.[24]

ES6

Equivalent Barrels of Petroleum
(billion barrels)



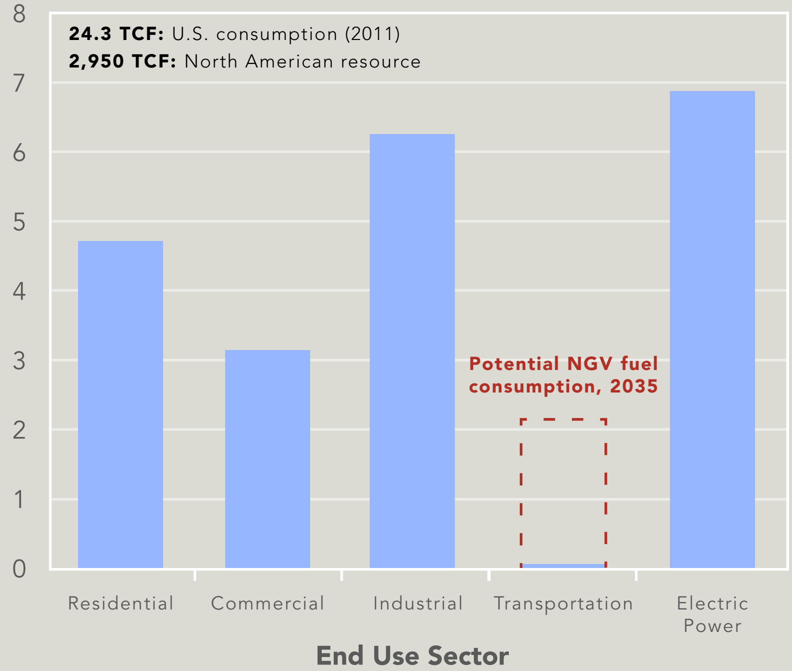
23 Energy Information Administration, "International Energy Outlook 2010-Natural Gas," DOE/EIA-0484(2009), July 27, 2010; http://www.eia.doe.gov/oiaf/ieo/nat_gas.html
24 Energy Information Administration, "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States," Release date: April 5, 2011, http://www.eia.doe.gov/analysis/studies/worldshalegas/
25 Energy Information Administration. "Natural Gas Consumption by End Use." http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm. Accessed January 2011.

ES7 Natural Gas Transportation Consumption

	2008	2035
Natural Gas Vehicles in U.S. (Millions)	0.13	16
Consumption (Trillion Cubic Feet-TCF)	0.05	2.2

ES8 Natural Gas Consumption (TCF)

Source [27]



The existing U.S. natural gas vehicle population is approximately 130 thousand (.05% of the on-highway vehicle population), and it consumes 364 million DGE of natural gas annually. If we made a commitment to NGVs, by 2035 we could have 16 million vehicles in the U.S. That amounts to 6% of the 2012 on-highway vehicle population, and it would displace 10% of the 2012 on-highway conventional/transportation fuel consumption.[26] At the same time, we could also increase the number of residences, businesses, and industries using natural gas for electricity.

Because North America is subject to changes in foreign energy policy, we constantly wrestle with fluctuating supply and volatile prices for foreign sources of energy from geopolitical unstable regions of the world. However, the abundance of our current and projected natural gas supplies would lead to stable prices for regionally sourced fuel. Price certainty would also allay some of our fears about domestic security. Among other benefits, this would translate into millions of dollars in fuel savings, fewer dollars leaving North America to pay for imports, and a smaller trade imbalance.

Replacing 6% of the vehicles on the highway with natural gas vehicles would displace 10% of conventional/transportation fuel consumption.

Natural gas is a safe, environmentally superior fuel

You might ask, since natural gas is a fuel, doesn't that mean it is harmful to the environment? With natural gas, our clean energy future may be closer than we think. When it's used to generate electricity, natural gas burns cleaner than other fossil fuels and releases fewer pollutants. It is an essential partner to the development of renewables because it provides clean, reliable power when the sun sets in the evening or the wind dies down.

26 See Scenario Analysis report of overall TIAX assessment for details and assumptions
27 See Market Segmentation and Scenario Analysis reports of overall TIAX assessment for NGV population and fuel consumption estimates and projections. Data from Energy Information Administration, "Natural Gas Consumption by End Use," http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm, accessed September 11, 2012; Energy Information Administration, "Natural Gas Year-in-Review 2009," July 2010; Massachusetts Institute of Technology, "The Future of Natural Gas," Interim Report, p. 7. 2010.

Natural gas is the answer that green energy proponents are searching for: it's a high octane, low carbon fuel. From a well to wheels analysis natural gas can emit 23% less CO_2 than gasoline passenger cars.[28] But that's just the beginning of its clean-energy profile. Using natural gas results in 46% reduction in NO_x emissions compared to pre 2010 diesel vehicles and virtually no sulfur dioxide, mercury, or particulate pollution. In most cases, natural gas can be a substitute for gasoline or diesel without many of the energy and environmental drawbacks.[29]

But to get an accurate picture of the environmental costs of different fuels, you need to look beyond tailpipe emissions. Using domestically sourced natural gas would mean we wouldn't have to use oil tankers to transport oil thousands of miles from the Middle East to North America.

The U.S. Environmental Protection Agency (EPA) has cited natural gas as a safe transportation fuel for several reasons including reduced flammability relative to petroleum, presence of onboard gas detectors, existence of tank safety valves, and periodic DOT tank inspections. Since it is non-toxic, natural gas poses no threat to land or water. In the event of a release, natural gas disperses rapidly (it is lighter than air) thus reducing ignition risks relative to gasoline.

Similarly, liquefied natural gas (LNG) readily evaporates if it is released in the air. If an LNG vehicle or station were damaged in a way that punctured fuel tanks, any spilled fuel would evaporate into the atmosphere much faster than gasoline or diesel, both of which pool on the ground.

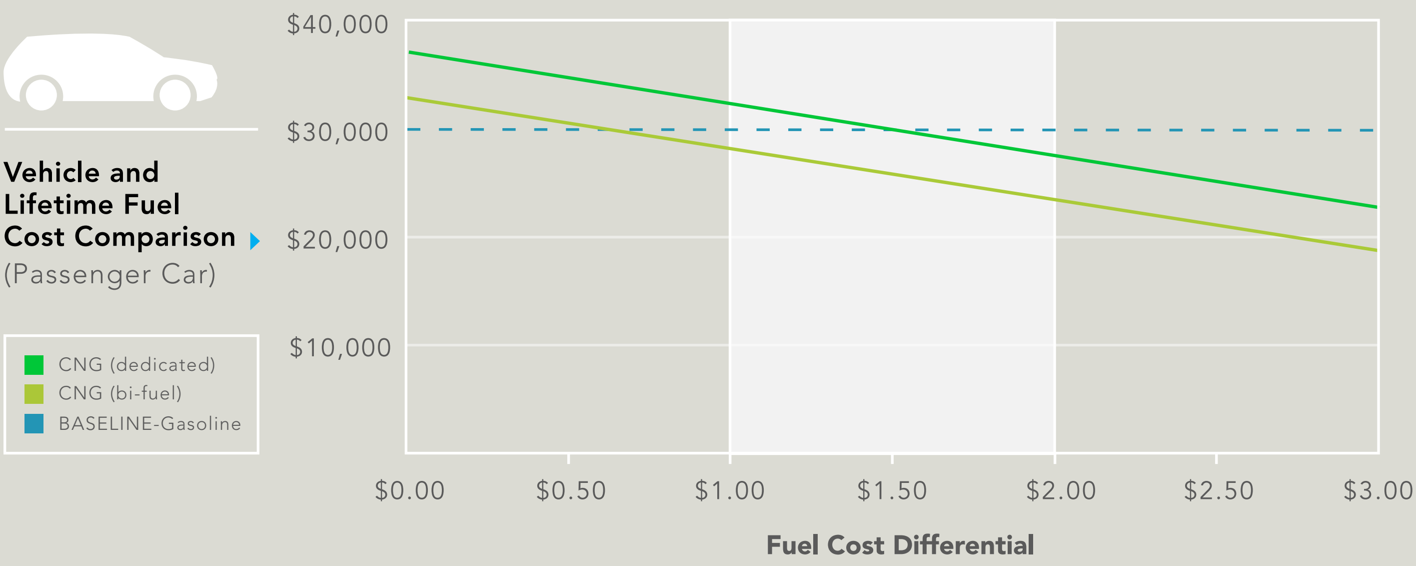
Because natural gas has been used in the North American vehicle fleet for many years, consumers are unlikely to face the specter of dramatic new, unforeseen dangers if market penetration increases.

NGVs have a lower total cost of ownership versus conventional vehicles

Natural gas is an economical and versatile fuel option. Even assuming a conservative fuel price differential at the pump of $1.50 per equivalent gallon, lifetime ownership costs for NGVs are generally lower than those of conventional vehicles. Lower fuel prices offset the higher costs of fuel storage in vehicles, enabling NGV owners to have reasonable payback periods.[30] As demand for petroleum increases, prices do the same. However, because of our vast natural gas supplies, increases in natural gas vehicles on the road will have little impact on the price of natural gas.

ES9

Vehicle and Lifetime Fuel Cost Comparison (Passenger Car)



28 U.S. Department of Energy, "Energy Efficiency and Renewable Energy: Alternative Fuels and Advanced Vehicles Data Center," http://www.afdc.energy.gov/afdc/vehicles/natural_gas_emissions.html, (November 17, 2011).ANGA, "Why Natural Gas: Clean," http://anga.us/why-natural-gas/clean, (October 3, 2011).
29 U.S. Environmental Protection Agency. "Clean Alternative Fuels: Compressed Natural Gas." http://eerc.ra.utk.edu/etcfc/docs/EPAFactSheet-cng.pdf. March 2002.
30 Lifetime costs include the cost of fuel over the vehicle's first-owner operating lifetime and reflect the vehicle application's operating characteristics. Hydrogen vehicle and fuels costs are projections only (not yet commercialized). See Comparative Analysis report of overall TIAX assessment for calculation details and assumptions.

NGV adoption is progressing in the commercial and consumer markets

Commercial Adoption
Several corporations and municipalities have already switched their fleets from petroleum to natural gas fuel (CNG in all applications), and they're already seeing savings in transportation costs and a reduction in harmful emissions. Among them:

UPS: By switching a portion of its fleet to compressed natural gas (CNG) vehicles and converting existing trucks, UPS reduced its carbon emissions significantly. It started this process in 2000, and its CNG trucks have traveled over 165 million miles since. A study by the National Renewable Energy Laboratory found UPS' CNG trucks yielded much lower emissions than the cleanest operating diesel trucks.[31]

Kansas City: In 1996, Kansas City, Missouri instituted a fleet-wide alternative fuel program for the city's large rigs and public transportation. The city started with six CNG-powered vehicles and has expanded to approximately 2,700. By switching much of their fleet to CNG, the city displaces nearly a half a million gallons of foreign oil each year. Kansas City has experienced not only 15% savings in fuel costs, but has also significantly lowered emissions. The EPA estimates the use of CNG in Kansas City will yield 90-97% lower carbon monoxide output, 35-60% lower nitrogen oxides emissions, and reductions in carbon dioxide output of 25%.[32]

Seattle: Seattle has quickly expanded its natural gas fleets to include both heavy-duty vehicles—garbage trucks—and light-duty taxis. In 2009, Waste Management of Seattle invested $29 million in 106 new CNG-fueled vehicles to replace diesel-run trucks. An independent environmental review determined Waste Management's equipment upgrade will reduce smog-causing NOx emissions by 97%, diesel particulate matter by 94%, and greenhouse gases by 20%.. It's also good news for residents—natural gas vehicles run cleaner and quieter.[33]

Seattle opened Washington's first large scale, public access CNG fueling station near the Sea-Tac Airport. The station is convenient for the 74 natural gas and hybrid vehicles in use at the airport as well as the fleet of taxis operated by the Seattle-Tacoma International Taxicab Association. All 166 Ford Crown Victoria cabs operated by the association are CNG-fueled. It's estimated that the cabs will produce 149 fewer tons of carbon monoxide and 24 fewer tons of nitrogen oxides each year than comparable petroleum-powered vehicles.[34]

With respect to NGVs, though the world is changing, the U.S. is not.

Consumer Adoption
Consumers already drive NGVs today, though the limited vehicle choices and uncertainty about refueling options holds many people back. Honda manufactures and sells limited volumes of the Civic Natural Gas, one of the cleanest vehicles in the world, and more manufacturers are re-entering the North American market, including Ford, GM, and Chrysler. As consumer demand increases, the market will expand, just as it has globally. Worldwide, consumers can choose from more than 40 models, and there are more than 12 million NGVs in operation. In the U.S., that number is just 120,000. With respect to NGVs, though the world is changing, the U.S. is not.

NGVs offer proven benefits and are the new frontier of North American prosperity

Natural gas means domestic jobs. By increasingly using NGVs in transportation, we will foster domestic jobs, create new manufacturing and construction opportunities, and stimulate economy-wide spending through consumer fuel savings.

Expanding North America's fueling infrastructure would add over 3.7 million jobs. Some, though not all, of these jobs would be temporary, but they are just the kinds of opportunities that Americans, specifically unemployed construction workers, need today.

31 ANGA, "Issues and Policies: Case Studies," http://anga.us/issues--policy/transportation/case-studies-, (October 3, 2011).
32 Ibid.
33 Ibid.
34 Ibid.

ES10 Building the natural gas transportation infrastructure will create jobs

Source [35]

	Light-Duty CNG	Medium and Heavy-duty CNG	Heavy-Duty LNG
Total number of new stations built by 2035	12,800	12,100	700
Spending Changes and employment impacts in transportation fuel sectors			
Job impacts (Full Time Employees) per station:	0.81	0.24	19.78
Overall job impacts (FTEs):	10,400	2,900	13,800
Capital and infrastructure expansion			
Job impacts (FTEs) per station built:	112	179	166
Overall job impacts (FTEs):	1,430,000	2,170,000	116,000

During this economic downturn, new shale plays across North America enabled the natural gas community to add jobs. According to IHS Global Insight, an independent research source, natural gas companies directly employed roughly 622,000 Americans in 2008 and indirectly sustained an additional 2.2 million jobs. But the economic benefits of natural gas extend well beyond job creation. In 2008 alone, natural gas contributed $385 billion to the U.S. economy and generated over $70 billion in direct income for workers. Its overall impact on the U.S. economy was $172 billion.[36]

Natural gas contributed $385 billion to our nation's economy and generated over $70 billion in direct income for workers.

In Canada, the natural gas industry has had a greater relative impact on the domestic economy. Every province has people whose jobs are related to natural gas. According to IHS Global Insight, nearly 600,000 Canadians worked in jobs supported by natural gas in 2008, contributing $106 billion to the nation's GDP. This economic impact exceeds the total GDP of all but four Canadian provinces that year. It accounts for 3.5% of all Canadian jobs and roughly 6.7% of Canada's overall GDP.[37]

According to IHS Global Insight, nearly 600,000 Canadians worked in jobs supported by natural gas in 2008, contributing $106 billion to the nation's GDP.

Natural gas jobs are filling the void left by the manufacturing, management, and technology sectors in Pennsylvania, Louisiana, and Alberta.

Pennsylvania: The Marcellus Shale, which is considered by experts to be the second largest shale gas formation in the world, is responsible for much for the state's natural gas job growth. A recent influx of natural gas activity in the state has quickly expanded the number of well-paying employment opportunities, ranging from manual labor to highly technical work. A 2010 Penn State study concluded that the Marcellus Shale could generate over $8 billion in economic value this year, $1 billion in state and local tax revenue and almost 100,000 jobs in 2011, just in Pennsylvania.[38]

35 Employment impacts based on IMPLAN Input-Output model and Jack Faucett Associate estimates. See Overview report of overall TIAX assessment.
36 ANGA, "Why Natural Gas: U.S. Benefits," http://anga.us/why-natural-gas/jobs/us-benefits, (October 3, 2011).
37 ANGA, "Why Natural Gas: Canada Benefits," http://anga.us/why-natural-gas/jobs/canada-benefits, (October 3, 2011).
38 ANGA, "Why Natural Gas: State-by-State," http://anga.us/why-natural-gas/jobs/us-benefits/state-by-state, (October 3, 2011).

Louisiana: The Haynesville Shale has helped boost the Louisiana economy during tough economic times. According to Dr. Loren Scott & Associates, which looked at about 70% of the exploration in the state, natural gas activities in the shale generated $10.6 billion in new economic activity and created more than 57,000 new jobs. It also generated $5.7 billion in new household earnings for Louisiana residents.[39]

Alberta: Over 16% of Alberta's employment was attributable to natural gas, with British Columbia (4.8%) the second largest beneficiary of Canada's natural gas abundance. Saskatchewan was third (4.5%). Natural gas supports 27.7% of Alberta's GDP, or $80 billion in total economic impact.[40]

Jump-starting NGV adoption

Even without broad adoption in the commercial transportation market and a minimal presence in the consumer market, natural gas is has made a significant economic impact in North America. Just imagine the opportunity we have to strengthen national security, grow our economy, reduce pollution, and lower greenhouse gas emissions if we make NGVs more widely available and affordable. This challenge will involve all of us but particularly the four major stakeholders in the NGV industry—end users, natural gas supply chain companies, vehicle and engine manufacturers, and government—all working together. There are some challenges to this goal but they are not insurmountable.

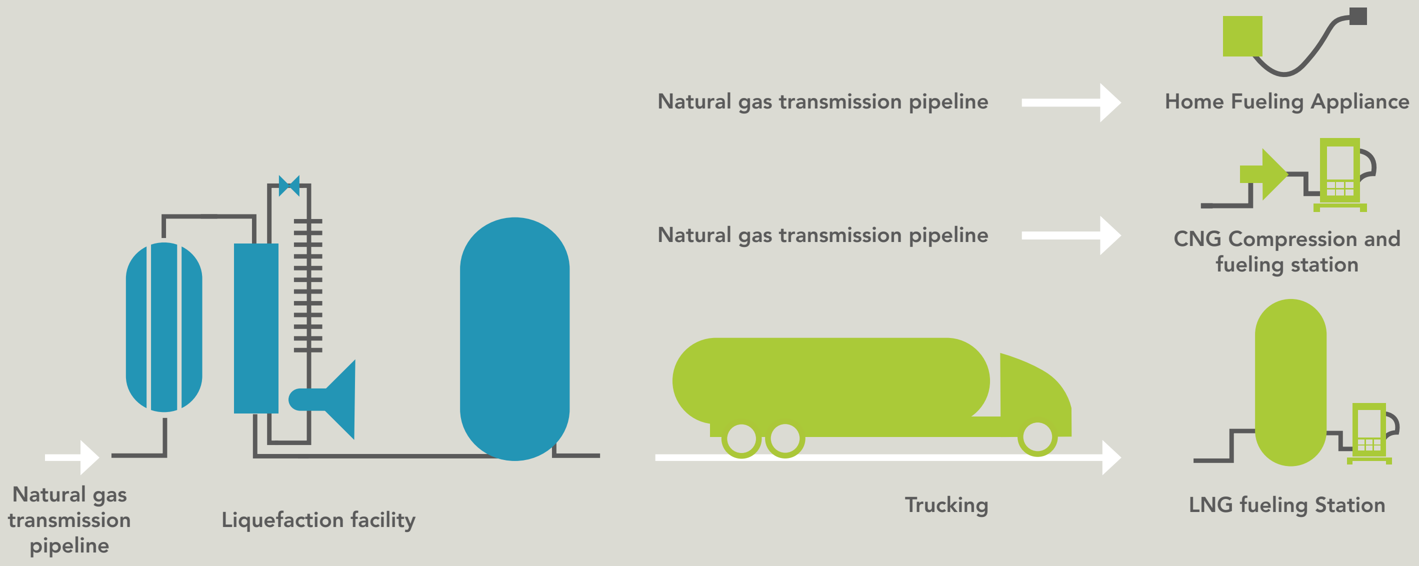
The average driver in the U.S. drives 29 miles per day, based on this statistic, early localized infrastructure can support this emerging consumer market, but it will take a paradigm shift in the consumer mindset.[41]

To drive demand, consumers need to be educated on vehicle and fueling options

Consumers and commercial stakeholders are becoming more interested in natural gas. General consumer interest in alternative vehicles is also growing, but consumers are driven by both price and convenience. NGVs will not become a viable transportation option without an efficient and affordable fueling infrastructure, affordable vehicles, and a level playing field among alternative vehicles if government incentives are necessary.

Uncertainty about the fueling infrastructure is the main concern swaying customer purchase decisions and keeping vehicle manufacturers from building more NGVs. It's a chicken and egg problem: consumers who consider buying an NGV don't see natural gas fueling stations lining the highway or visible at main intersections, so they assume that refueling will be inconvenient. But without a critical mass of NGVs on the road, the need for a fueling infrastructure does not seem critical.

ES11



39 ANGA, "Why Natural Gas: State-by-State," http://anga.us/why-natural-gas/jobs/us-benefits/state-by-state, (October 3, 2011).
40 ANGA, "Why Natural Gas: Canada Benefits," http://anga.us/why-natural-gas/jobs/canada-benefits, (October 3, 2011).
41 U.S. Department of Transportation Federal Highway Administration. "2009 National Household Travel Survey." http://nhts.ornl.gov. Accessed August 2012.

Building the fueling infrastructure

North America is in the process of establishing an efficient and affordable natural gas fueling infrastructure. Companies like UPS and Seattle Waste Management have been able to transition to natural gas quickly because they have dedicated fleets that return to a base. It's economical for them to develop small or large private fueling facilities for their exclusive use. Accommodating light and medium duty vehicles will require some changes in vehicle fueling systems, like an in-home fueling device—a home-based gas utility or personal fueling device approximately the size of a small chair that sits outside or inside—and accessible public fueling stations.

During this intermediate phase, government will work in partnership with the natural gas industry and fuel providers to begin developing a public natural gas fueling infrastructure that includes corridors connecting stations throughout regions.[42] This partnership is already underway. Through the American Recovery and Reinvestment Act of 2009, the Department of Energy funded 25 different projects for alternative fuel, infrastructure, and advanced technology vehicles, and 19 of these 25 projects included natural gas. These commitments include support for 140 new fueling stations.

Building the vehicles

When consumers make the decision to buy an NGV, these vehicles need to be readily available on showroom floors. The manufacturing process must begin with engine manufacturers who provide efficient technology for natural gas, develop, and commercialize a wider selection of natural gas engines to meet the increasing demand.

One way to ease into this new era is to design and adopt natural gas passenger cars and light-duty trucks as bi-fuel vehicles—using both natural gas and gasoline. These vehicles do not compromise tailpipe or evaporative emission performance. They are designed to meet daily driving requirements with natural gas and use gasoline for extended driving. Reducing onboard natural gas storage capacity reduces vehicle costs, and ensures a faster payback on initial NGV purchase costs. For the U.S. and Canadian retail consumer market, bi-fuel NGVs coupled with a small home fueling compressor would provide overnight access to natural gas and allow consumers to avoid daily trips to a natural gas fueling station. For heavy-duty trucks, dedicated natural gas systems make the most economic sense, as long as the fuel systems are properly sized to the particular needs of the fleet, thereby minimizing unnecessary incremental cost and weight.

Vehicle manufacturers must be financially motivated to continue to provide high quality NGVs that meet the same reliability and durability standards as gasoline and diesel products.

The newest NGV offerings have focused on the medium-duty market and targeted at the commercial working sector. In the future, we need to offer a wider selection of vehicles for the consumer market.

Creating a level playing field

The U.S. and Canada both have robust environmental policies to reduce air pollutant and GHG emissions associated with fuel production and vehicle operation. These policies have been marginally effective. Now, we need stronger energy policy or strategy supported by stakeholders to increase the use of natural gas in the transportation sector and reduce North America's dependency on foreign sources of energy from geopolitcally unstable regions of the world.

The integration of both environmental and energy policies can reduce petroleum use and emissions. These policies can also highlight the favorable lifetime economics and environmental aspects of NGVs to increase consumers' interest in alternatives to petroleum. The government can also play a role in leveling the playing field relative to other alternative fuels and vehicles, allowing for more market based adoption and avoidance of picking alternative fuel winners and losers. If policy makers decide to continue to offer purchase incentives for alternative fueled vehicles, they should do so on a level playing field.

The players in the natural gas ecosystem—vehicle manufacturers, government, and fuel suppliers—are ready to work together to make natural gas vehicles widely available, affordable, and simple to maintain. The missing piece is consumer demand and a desire to increase energy security. Now it is your turn; it's time to find out about the natural gas vehicle waiting for you. It's time for natural gas.

42 See Compressed Natural Gas Infrastructure and Liquefied Natural Gas Infrastructure reports of overall TIAX assessment for additional discussion of natural gas fueling infrastructure development.

U.S. and Canadian Natural Gas Vehicle Market Analysis:

Natural Gas Vehicle Industry Overview

Legal Disclaimer

This report was prepared by TIAX LLC for America's Natural Gas Alliance on terms specifically limiting TIAX's liability. Our conclusions are the result of the exercise of our best professional judgment based in part upon materials and information provided to us by our subcontractors and others.

TIAX accepts no duty of care or liability of any kind whatsoever to any third party, and no responsibility for damages or loss, if any, suffered by any third party, as a result of decisions made, or not made, or actions taken, or not taken, based on this document.
This report may be reproduced only in its entirety and only with the prior written consent of TIAX.

Table of Contents

Lower heating value energy conversion factors*

Diesel	129,488 Btu/gal
Gasoline	113,602 Btu/gal
Natural gas	113,602 Btu/GGE or 129,488 Btu/DGE (983 Btu/cubic foot)

*Argonne National Laboratory, "Greenhouse Gas and Regulated Emissions and Energy Use in Transportation," 1.8c. Note that lower heating values for fuels will vary by refinery. Lower heating value does not include the latent heat of vaporization of water vapor, whereas the higher heating value does. Lower heating value is used to represent the energy available for internal combustion engines, and higher heating value is used to represent energy available for external combustion engines (e.g., gas fired boiler for space heating).

Abbreviations

AGA	American Gas Association
ANGA	America's Natural Gas Alliance
B20	Blend of 20 percent biodiesel and 80 percent diesel
BCF	Billion cubic feet
BEV	Battery electric vehicle
CA	California
CAFE	Corporate Average Fuel Economy
CNG	Compressed natural gas
CO	Carbon monoxide
DEF	Diesel exhaust fluid (urea)
DGE	Diesel gallon equivalent (equals 131.7 cubic feet of natural gas)
DPF	Diesel particulate filter
E10	Blend of 10 percent ethanol, 90 percent gasoline
E85	Blend of 85 percent ethanol, 15 percent gasoline
EIA	Energy Information Administration
EPAct	Energy Policy Act
EPA	Environmental Protection Agency
FCV	Fuel cell vehicle
FTE	Full-time equivalent
gal	Gallon
GGE	Gasoline gallon equivalent (equals 115.6 cubic feet of natural gas)
H2	Hydrogen
HEV	Hybrid electric vehicle
LNG	Liquefied natural gas (1 gallon LNG equals 0.58 DGE)
LDC	Local distribution company (gas utility)
LPG	Liquefied petroleum gas
M85	Blend of 85 percent methanol, 15 percent gasoline
MPG	Miles per gallon
NGV	Natural gas vehicle
NHTSA	National Highway Safety Transportation Administration
NOx	Oxides of nitrogen
OEM	Original equipment manufacturer
OECD	Organization for Economic Co-operation and Development
OPEC	Organization of Petroleum Exporting Countries
PHEV	Plug-in hybrid vehicle
PM	Particulate matter
RFS	Renewable Fuel Standard
SCAQMD	South Coast Air Quality Management District
SCFM	Standard cubic feet per minute
SCR	Selective catalytic reduction
TCF	Trillion cubic feet
U.S.	United States
VOC	Volatile organic compound

Preface

To identify the most productive and effective means to increase the use of natural gas vehicles (NGVs) in the U.S. and Canada, the TIAX team has conducted a thorough and independent assessment of the NGV market. This assessment examines the key technical, economic, regulatory, social, and political drivers and challenges that shape this market. TIAX has partnered with The CARLAB, Clean Fuels Consulting, the Clean Vehicle Education Foundation, Jack Faucett Associates, the Natural Gas Vehicle Institute, and St. Croix Research to provide perspectives and insights into the development of the future NGV market.

TIAX's overall approach relies on six key stages:

- Segmentation of the vehicle market
- Identification of market decision drivers
- Assessment of market development actions
- Analysis of competing technologies
- Analysis of market scenarios
- Integration of overall market development opportunities

The market perspectives, for which decision drivers and opportunities have been identified and assessed are: light-, medium-, and heavy-duty vehicle ownership; light-, medium-, and heavy-duty vehicle manufacturing; compressed and liquefied natural gas infrastructure; and government.

Drawing on the respective expertise of each team member, TIAX presents an integrated assessment of the U.S. and Canadian NGV market in a collection of eight reports. Each report is capable of standing alone while integrating the data, ideas, and themes of the other seven reports. The collection of reports in this TIAX analysis of the NGV market is funded by America's Natural Gas Alliance (ANGA) and further supported by participating members of the American Gas Association (AGA).

Introduction

The NGV market and its prospects for a long-term, sustainable future are described from the perspectives of four major stakeholders: End Users, Natural Gas Supply Chain Companies, Vehicle and Engine Manufacturers, and Government, all of whom have significant opportunities in the NGV market.

The four major stakeholders that have a key role in bringing about these changes in transportation are: 1) end users, 2) natural gas supply chain companies, 3) vehicle and engine manufacturers, and 4) government.

- **End users** purchase and operate vehicles and provide the market demand for natural gas vehicles (NGVs). Acceptance of NGVs by end users will depend on the value proposition offered by the vehicles, including lifetime economics, attribute tradeoffs, vehicle availability, fueling convenience, and other incentives.

- **Natural gas supply chain companies** include gas producers, pipeline companies, local distribution companies (gas utilities/LDCs), and fueling station operators. Together, they establish and operate the infrastructure needed to supply natural gas to the transportation market. Having the most knowledge of and greatest familiarity with natural gas, these companies may also greatly benefit the NGV market by helping in the education and training of and outreach to other industry players, which aids in the distribution of market risk.

- **Vehicle and engine manufacturers** provide NGV and engine offerings to meet the requirements of the end users. Because these requirements vary by vehicle application, NGVs may be better suited to some applications than others.

- **Government** is entrusted with the general welfare of society and can undertake measures to correct market failures, including the classic example of environmental costs that are not included in full product costs that negatively impact society as a whole.

Other needed stakeholders in the NGV industry include vehicle component and infrastructure equipment suppliers, who enable the four major stakeholders to operate in the NGV market.

Chapter 1

What do we pay for our current transportation energy?

The high cost and risk of foreign energy dependency

Our transportation system relies on imported fuel

The transportation sector, specifically vehicles that operate using gasoline or diesel, uses mostly foreign sources of energy. In 2010, vehicles consumed a total of 4.7 billion barrels of petroleum, 4.2 billion barrels of which were imported.[1]

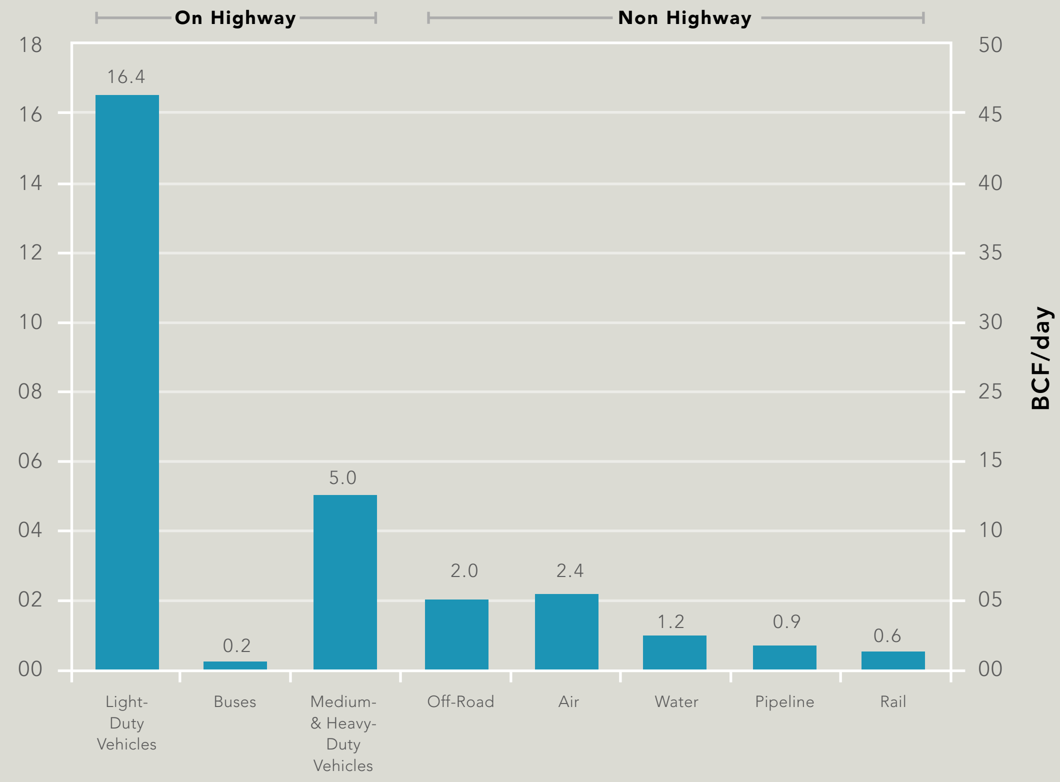
Passenger and light-duty trucks dominate energy use, but off-road and non-highway uses consume significant energy per vehicle. Vehicles vary in their fuel consumption and efficiency. The North American vehicle fleet is very diverse, composed of relatively standardized vehicles such as pickup trucks and passenger cars, as well as highly specialized vehicles such as beverage trucks and refuse haulers. Within the on-road market, the light- and medium-duty vehicle market segments are predominantly composed of mass-produced vehicles in a few common configurations. Heavy-duty, on-road vehicles are built for specific applications and are generally built-to-order for each customer, as is equipment in the off-road and non-highway sectors.

As the graphics below show, in the on-road segment, light-duty vehicles are the most fuel-efficient vehicles and use the least fuel per vehicle on an annual basis. Medium- and heavy-duty vehicles are less fuel efficient and consume more fuel annually per vehicle, especially in specific applications, making their total cost of ownership very sensitive to fuel price. Passenger and light-duty trucks dominate energy use, but off-road and non-highway uses consume significant energy per vehicle/application.[2] Despite increasing fuel efficiency of light, medium, and heavy-duty vehicles, the U.S. transportation system continues to rely significantly on foreign sources of energy from geopolitically unstable regions of the world and cannot be satisfied with domestic sources alone.

1 Energy Information Administration. "Annual Energy Review." October 19, 2011.
2 U.S. Census Bureau Foreign Trade Division. "U.S. Imports of Crude Oil." http://www.census.gov/foreign-trade/statistics/historical/petr.pdf. Accessed October 2010.

Passenger and light-duty trucks dominate energy use; non-highway uses consume significant energy per vehicle/application[3]

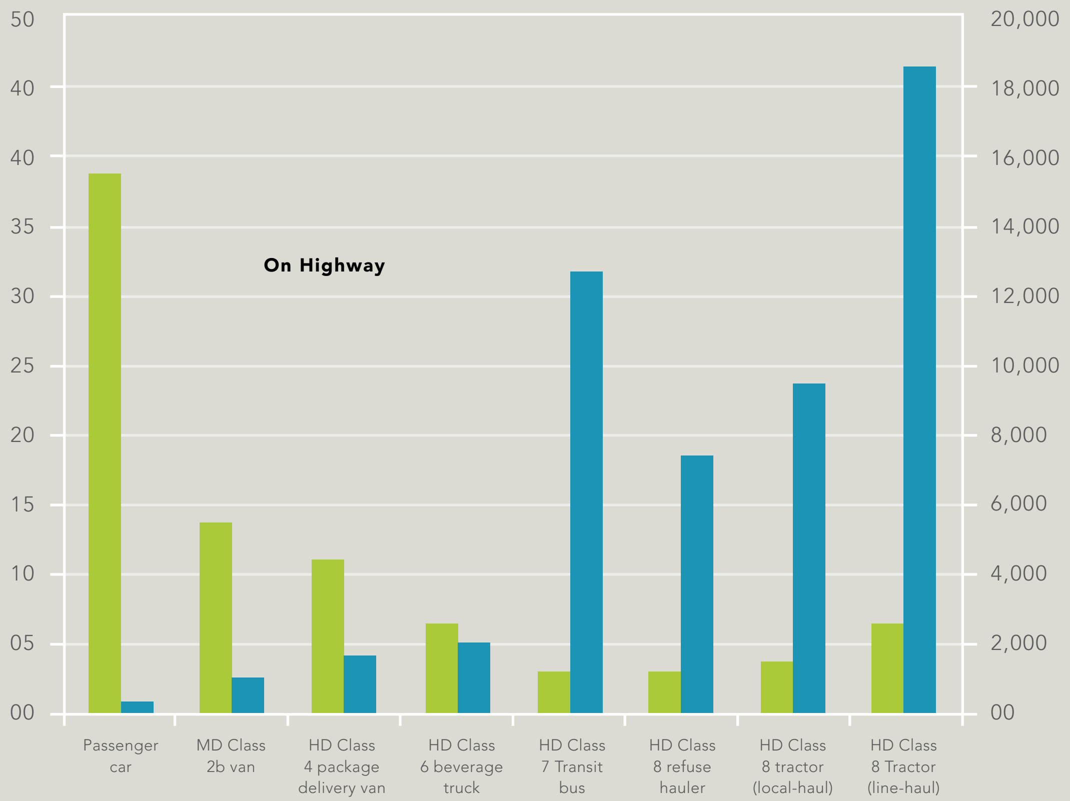
Annual Fuel Consumption by Sector (quads)



Light-duty vehicles have low annual mileage and high fuel economy; heavy-duty vehicles have high annual mileage and lower fuel economy[4]

Fuel Economy (mpg)

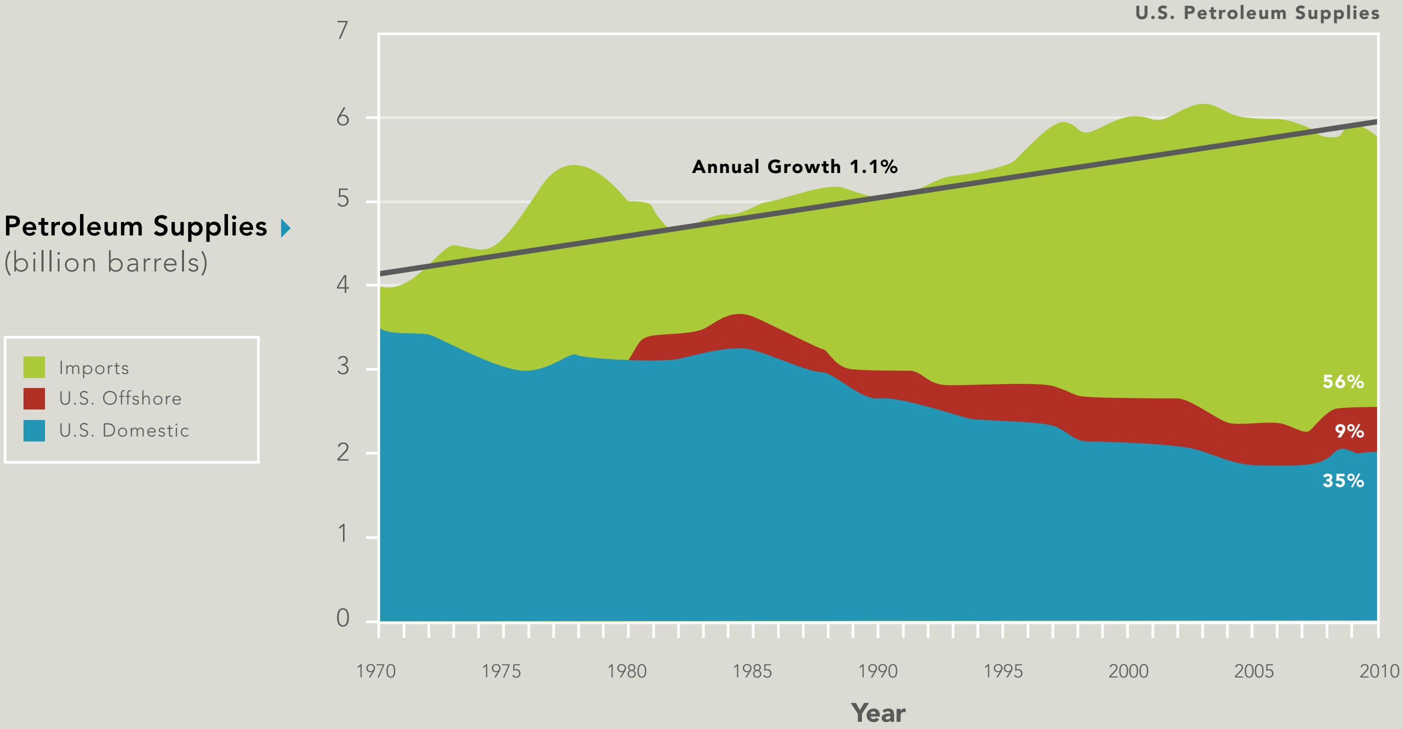
Average Annual Fuel Consumption (gal/year/vehicle)



3 2008 data from DOE Transportation Energy Data Book - http://cta.ornl.gov/data/index.shtml
4 See Market Segmentation report of overall TIAX assessment for additional descriptions of these market segments.

U.S. petroleum supplies[5]

Petroleum Supplies
(billion barrels)



For commercial and fleet vehicle operators, whose total cost of doing business is significantly influenced by small changes in fuel price, both volatility of, and increase in, petroleum prices can have a large negative impact. From the consumer perspective, this cost is reflected in the price per gallon at the retail pump. Because fuel price to date has generally represented a small fraction of total lifetime vehicle costs, private vehicle use has been relatively insensitive to fuel price.

If alternative fuel vehicle technology can be proven economically and become more available, conventional fuel prices will eventually move consumers to lower costs alternatives. Leveraging and communicating the potential of natural gas is a critical component of this shift. With abundant domestic natural gas, proven technology, and overall lower ownership costs, consumers will move natural gas into the marketplace and allow the North American economy to hedge against widespread impacts of unstable sources of foreign energy.

5 Data from Energy Information Administration, "Crude Oil Production," http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm, accessed September 11, 2012; Energy Information Administration, "U.S. Crude Oil Supply & Disposition," http://www.eia.gov/dnav/pet/pet_sum_crdsnd_k_a.htm, accessed September 11, 2012.

Chapter 2

How can NGVs and a supporting natural gas infrastructure enable energy independence?

A reliable source of energy security and economic stability exists inside our borders

North America can reduce its dependence on imported petroleum by tapping into the supply of natural gas. Several recent developments make this the right time to look at natural gas as a viable and sustainable option for widespread use in transportation. First, recent discoveries of abundant and domestic natural gas supplies have resolved questions relating to supply constraints. Secondly, NGV technologies are maturing. Thirdly, the United States and Canada are experiencing a widespread push for increasing energy security.

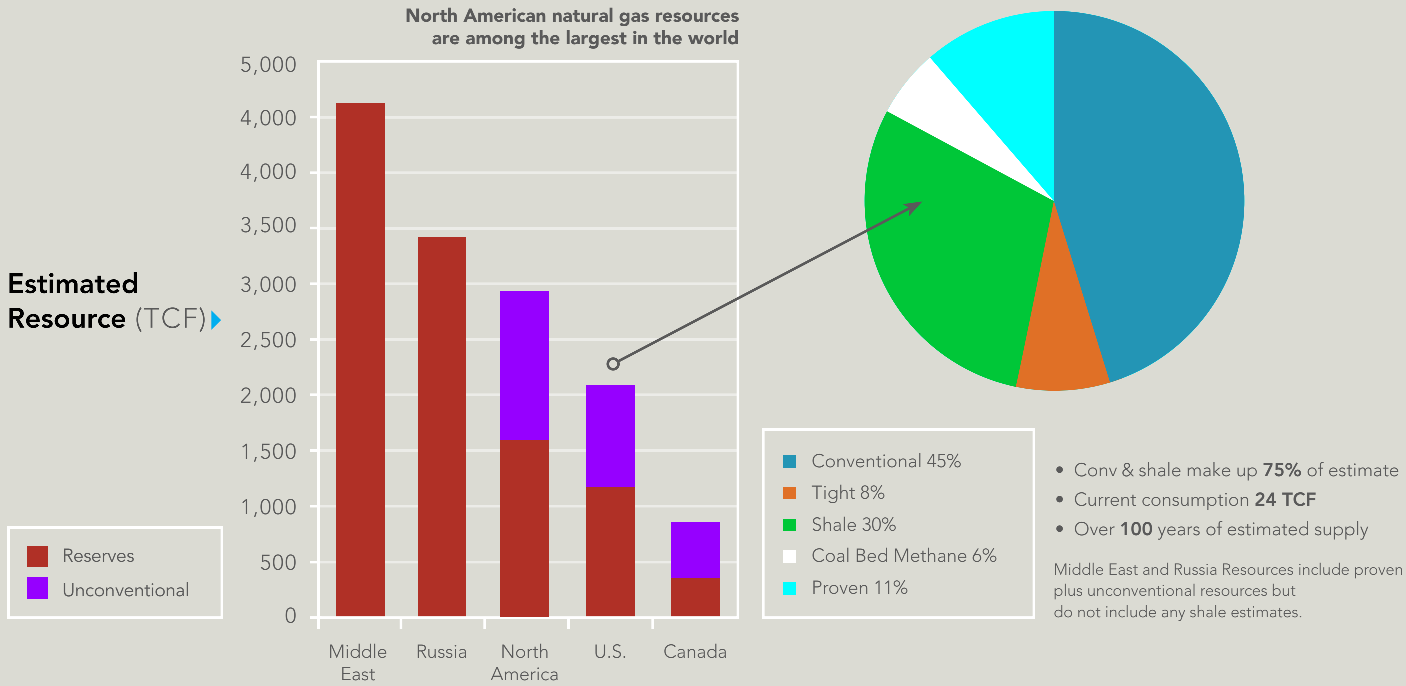
From mature supply and rising prices to abundance and affordability

Not long ago, it appeared that conventional North American domestic natural gas supplies had begun to reach maturity. This perceived limited supply drove up prices, and demand stagnated as consumers switched to other energy sources. Due to high prices, suppliers (particularly in the U.S.) sought new natural gas sources, including planned liquefied natural gas (LNG) terminals, and increased exploration. This lack of North American supply was seen as a non-starter for considering natural gas as an alternative to foreign petroleum in the transportation sector. At this time, natural gas was being used for residential, commercial, and power generation markets. However, expanding its use in transportation would only take away from using clean natural gas in these segments.

Natural gas supply changed radically beginning in the early 2000s with the introduction of advanced drilling technologies and pressure pumping services that could economically produce natural gas from the vast resources in North America. Overnight, the supply went from projections of shortages to oversupply. This changed the opportunity for using natural gas as a transportation fuel. Currently, North America's natural gas resources are among the largest in the world, approaching 3,000 trillion cubic feet (TCF). Current U.S. consumption is about 24 TCF[6], suggesting over 100 years of supply.

6 Energy Information Administration. "Natural Gas Consumption by End Use." http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm. Accessed September 11, 2012.

U.S. and Canadian natural gas resources are among the largest in the world[7]



The abundance of natural gas makes it an attractive transportation fuel option

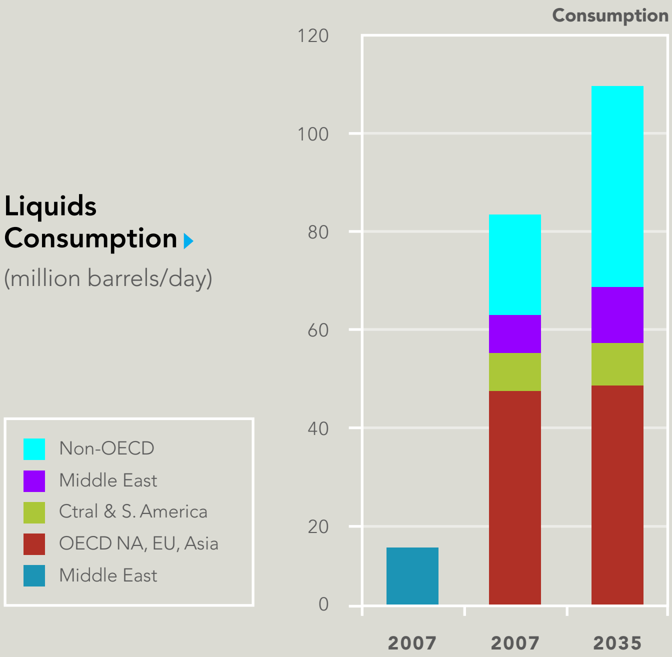
The North American natural gas supply is estimated (on an energy equivalent basis) at 500 billion barrels. The annual U.S. transportation consumption is 14 million barrels per day, compared to world consumption of over 80 million barrels per day. The total U.S. transportation demand is projected to increase to 16.2 million barrels per day in 2035. Little future growth in consumption is from the Organisation for Economic Co-operation and Development (OECD) countries, but significant growth is projected from developing (non-OECD) countries.

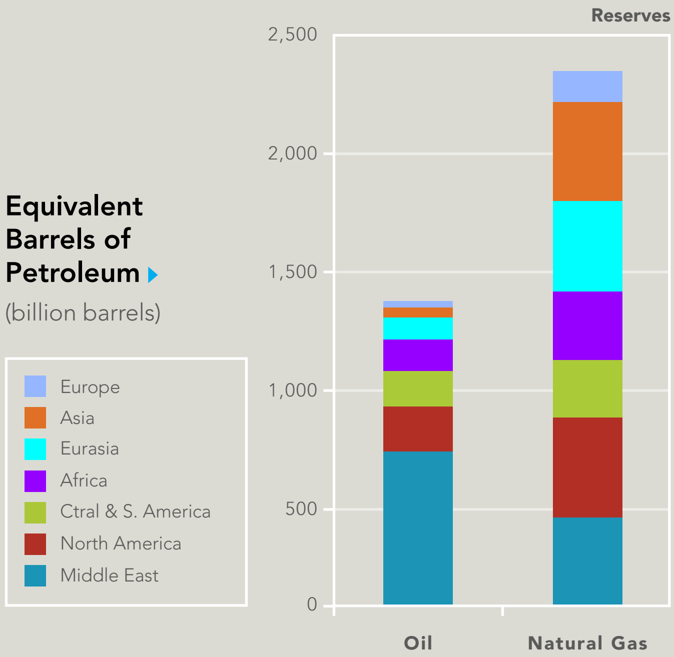
Natural gas can resolve a petroleum supply/demand imbalance

The worldwide supply of natural gas far outweighs the worldwide supply of petroleum. World petroleum resources are estimated at 1,350 billion barrels, and world natural gas resources are estimated (on an energy equivalent basis) at 2,260 billion barrels. At current consumption rates, these resources would last 46 and 121 years, respectively, and fewer years at projected future utilization rates. More importantly, from the perspective of domestically supplied and available fuels, natural gas resources in North America are 2.6 times greater than petroleum resources.

7 Data from Energy Information Administration, DOE/EIA-0484(2009), July 27, 2010; "Worldwide Look at Reserves and Production," Oil & Gas Journal 105(48), December 24, 2009.

Worldwide petroleum consumption and reserves[8]





As illustrated above, worldwide petroleum consumption is projected to remain relatively flat in North America, Europe, and Asia while increasing substantially in non-OECD countries and the Middle East (left). While petroleum reserves are concentrated in the Middle East, natural gas reserves are more widely distributed and are greater than petroleum (right). Even with fuel efficiency standards, increased demand from other parts of the world will increase pressure on petroleum prices for North American consumers and consumers around the world.

We have sufficient natural gas supply for both current & projected uses

Expanding natural gas applications can occur without limiting supply to current uses. Today, natural gas in North America is used primarily in sectors other than transportation, specifically, residential and commercial heating, industrial processes, and electric power generation. Combined, all U.S. sectors use 24.3 TCF of natural gas annually[9]. Of that amount, annual natural gas use in the transportation sector is 0.05 TCF. Given the extent of the North American natural gas resource, estimated at over 2,950 TCF[10], the supply of natural gas is sufficient to supply both the transportation and non-transportation sectors even as the NGV market expands.

8 Data from Energy Information Administration, DOE/EIA-0484(2009), July 27, 2010; "Worldwide Look at Reserves and Production," Oil & Gas Journal 105(48), December 24, 2009.
9 Energy Information Administration. "Natural Gas Consumption by End Use." http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm. Accessed September 11, 2012.
10 Massachusetts Institute of Technology. "The Future of Natural Gas." Interim Report, p. 7. 2010.

Current supplies of natural gas are sufficient for future natural gas demands[11]

Natural Gas Consumption
(TCF)

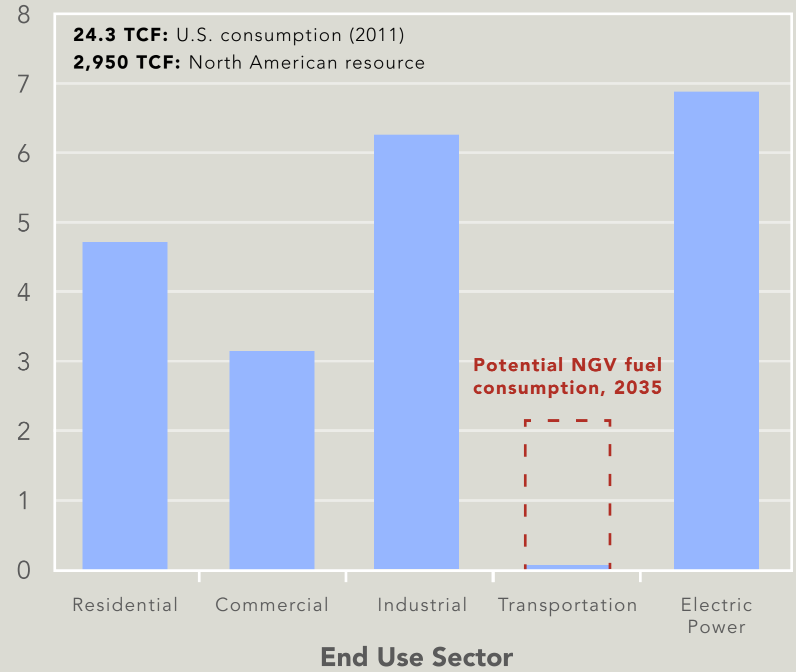
Estimated U.S. NGV population, current:
100,118-154,466 vehicles
(0.04-0.06% of 2012 on-highway vehicle population)

Estimated annual U.S. NGV fuel consumption, current:
361-366 million DGE
(0.05 TCF or 0.2% of 2012 on-highway consumption)

Potential U.S. NGV population, 2035:
16 million vehicles
(6% of 2012 on-highway vehicle population)

Potential annual U.S. NGV fuel consumption, 2035:
17 billion DGE
(2.2 TCF or 10% of 2012 on-highway consumption)

Source [28]

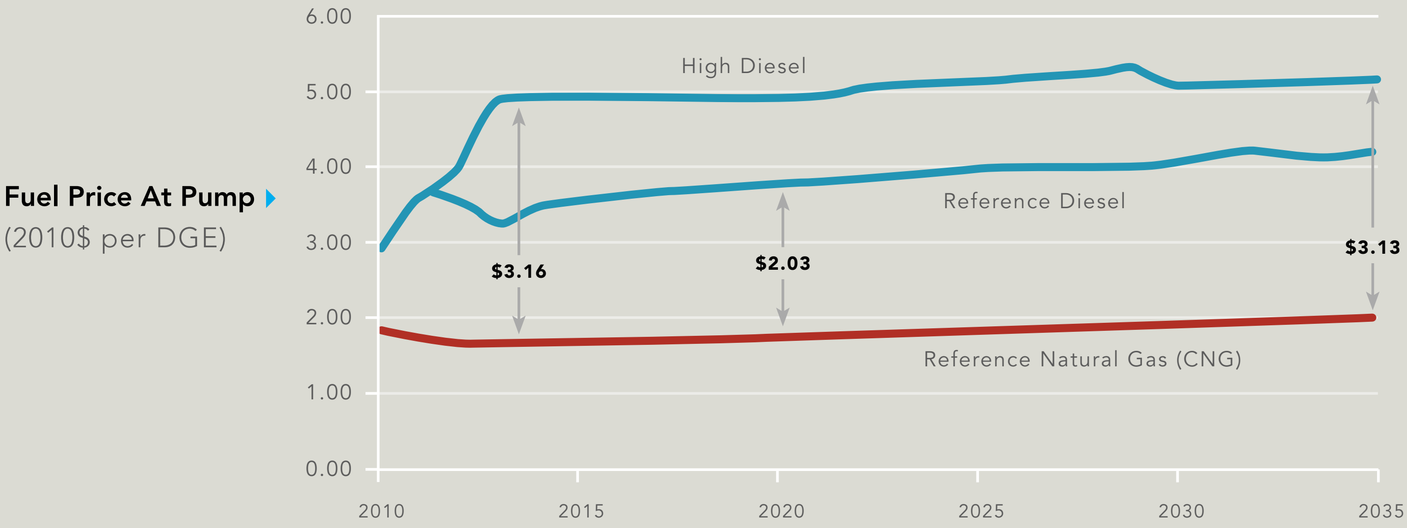


Natural gas is an economical fuel

Natural gas prices are gradually diverging from petroleum prices, making natural gas use in cars and trucks far more economical than gasoline or diesel fuels. NGVs cost more than conventional vehicles, but these higher costs are usually offset by lower fuel prices. The Energy Information Administration (EIA) projects natural gas pump price differentials of $1.00 to over $3.00 per diesel gallon equivalent (DGE) over the next 25 years. These savings are attributable to increasing petroleum prices, driven by increasing global demand and decreasing global supply, and stable natural gas prices, due to reliable domestic fuel resources. As shown in the following graph, natural gas is less expensive (on an energy basis) than conventional fuels. Fuel price differentials at the pump of over $3.00 per gallon are possible in the near future.

11 See Market Segmentation and Scenario Analysis reports of overall TIAX assessment for NGV population and fuel consumption estimates and projections. Data from Energy Information Administration, "Natural Gas Navigator," http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm, accessed January 2011; Energy Information Administration, "Natural Gas Year-in-Review 2009," July 2010; Massachusetts Institute of Technology, "The Future of Natural Gas," Interim Report, p. 7. 2010

Future natural gas/diesel price differentials[12]

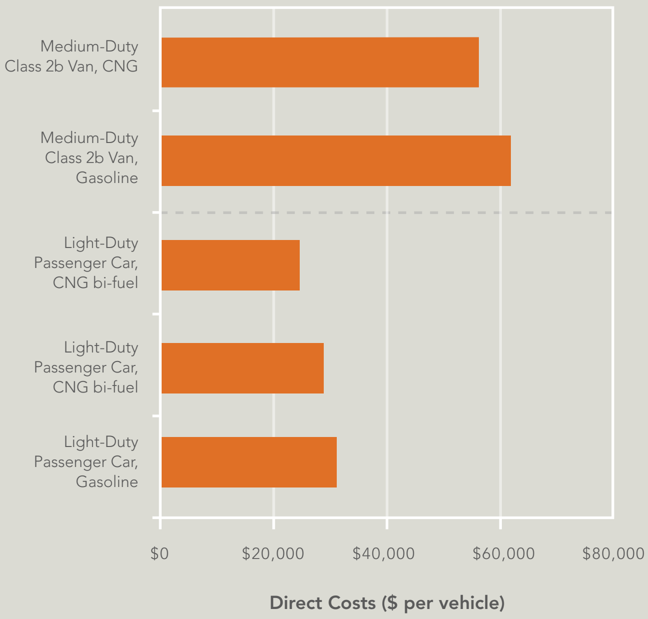


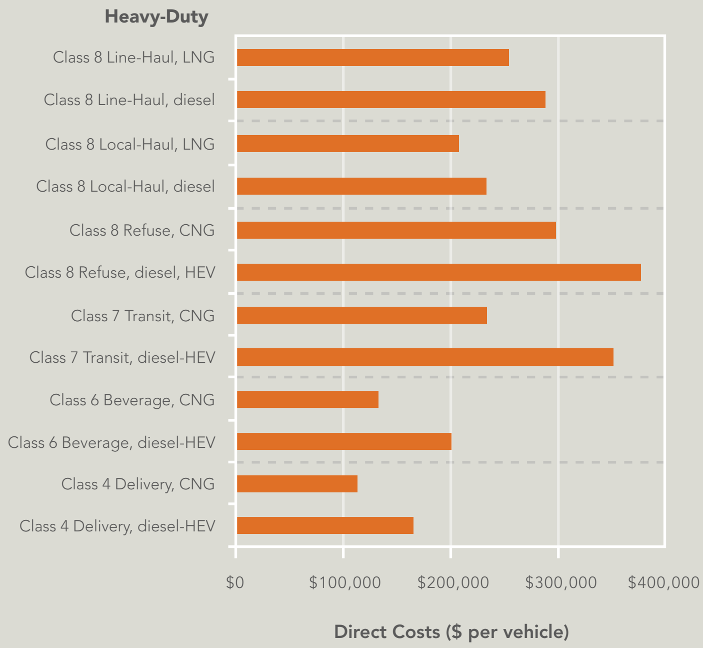
Direct costs for natural gas vehicles compare favorably to conventional vehicles

Estimates of vehicle ownership costs include vehicle costs, fuel and other operating and maintenance costs, residual value, insurance, and financing costs. The illustration below shows estimated ownership costs for various vehicle applications. These costs include only vehicle and fuel costs; all other costs are assumed to be the same for NGVs and conventional vehicles. These lifetime costs are referred to as direct costs. For each vehicle application, NGVs are compared to conventional baselines. The baseline configurations project possible improvements with advanced engine and driveline technology, such as hybridization. Thus, the comparison uses the next generation advanced conventional technologies. Even with this assumption and a conservative pump price differential of $1.50 per equivalent gallon, direct costs for NGVs are lower in nearly every vehicle application. With higher differentials, NGVs offer even greater savings.

12 Energy Information Administration. "Annual Energy Outlook 2012." June 2012.

Direct vehicle costs, by vehicle and fuel type[13]





Natural gas vehicles compare favorably to other alternative vehicles

Not all alternative vehicle ownership costs are equal. Ethanol and biodiesel blends can be used with existing technology without modification and do not require added vehicle costs. Natural gas and electric technologies have higher vehicle costs because they require more expensive storage systems—high-pressure or cryogenic tanks for natural gas and hydrogen and batteries for electric platforms. Fuel costs are lower for natural gas and electricity, projected to be the same for hydrogen, and the same or higher for biofuels. Infrastructure requirements also differ. Home refueling is primarily an option for electricity and natural gas, whereas blended fuels need few changes. Natural gas, hydrogen, electric, and E85 require the development of public fueling. Private fueling applies mostly to fleets using natural gas, biodiesel, or, in the future, hydrogen. Despite these differences, when contrasting NGV costs and fueling needs to those of other alternative vehicles, NGVs compare favorably.

13 See Comparative Analysis report of overall TIAX assessment for calculations of direct and societal costs of various vehicle technologies.

Comparison of alternative fuel vehicle and fuel costs to conventional

Alternative Fuels	Vehicle Costs	Fuel Costs
Ethanol blend (E10)	Same	Same
Ethanol (E85)	Same	Same
Plug-in hybrid electric vehicle (PHEV)	More	Less
Battery electric vehicle (BEV)	More	Less
Hydrogen fuel cell vehicle (FCV)	More	Same
Light-duty NGV	More	Less
Heavy-duty NGV	More	Less
Biodiesel (B20)	Same	More

The line-up of NGVs is limited today but consumer demand could expand offerings

The options for NGVs in the light-, medium-, and heavy-duty vehicle segments are currently limited. However, recognizing the growing potential of NGVs, vehicle and engine manufacturers have shown interest in producing NGVs. Original equipment manufacturer (OEM) products are small in number, though recent announcements by major automakers demonstrate renewed interest in expanding NGV offerings. The Honda Civic Natural Gas is the only OEM passenger car available at present. GMC, Chevrolet, VPG, and Ford currently offer NGV products, either as turn-key NGVs or conversion-ready NGVs. For light- and medium-duty segments, conversion companies currently offer a variety of options for converting existing engines. These vehicles typically offer the same or similar warranties and features that end users expect from OEMs.

For heavy-duty segments, in which vehicles are built according to customer specifications, the availability of NGVs depends on the availability of natural gas engines that meet the power and torque requirements of specific vehicle applications. For example, a refuse truck that requires a 10-liter engine for its particular duty cycle may not have a natural gas option in the near term, unless the purchaser is willing to accept a vehicle with a 9- or 11-liter engine. In the near term, it appears that natural gas engines will not be available for heavy-duty vehicles that require engines in the 10- and 14-liter ranges. However, heavy-duty engine OEMs have expanded their offerings to a wider range of engine sizes in recent years and are continuing to do so.

For light- and medium-duty vehicles, up to seven OEM and OEM conversion-ready NGVs are currently available. For heavy-duty vehicles, up to six engines may be available, but natural gas choices for specific vehicle segments may be limited. The currently available vehicles are listed on the next page:

Current NGV Lineup[14]

Light- and Medium-Duty:

OEM Turn-Key NGVs

GMC Savana

Chevrolet Express

Honda Civic GX

VPG MV-1

OEM Conversion-Ready NGVs

Ford Transit Connect

Ford E- Series

Ford F150- Series

Heavy-Duty

	7L Emission Solutions/ International Truck 7.6 L Phoenix	8L Landi Renzo USA/ Baytech 8.1 L	9L Cummins Westport 8.9 L ISL G	10L	11L Doosan Infracore America 11 L GK12	12L Cummins Westport 11.9 L ISX G	13L Navistar 13 L Maxx-Force	14L	15L Westport Innovations 15 L GX
Heavy-duty truck	●				●		●		
Transit bus		●	●		●				
School bus		●							
Over-the-road coach							●		
Refuse / utility truck				●	●				
Drayage						●			●
Vocational		●				●			

HD NG Engine Currently Available
HD NG Engine Expected Near Term
● Indicates New or Additional Engine Needed

14 Illustrations courtesy of their respective manufacturers. See Light- and Medium-Duty Vehicle Ownership and Production and Heavy-Duty Vehicle Ownership and Production reports of overall TIAX assessment for details.

Short range vehicles can benefit from natural gas immediately

Transit buses, refuse haulers, and package delivery vehicles have had the strongest market drivers for adopting natural gas. These applications are also well suited to the use of natural gas based on their market enabling features of short range and return-to-base duty cycles. Additionally, depending on the fuel capacity and typical range, fuel type is important. Vehicles that carry more than 80 DGE are more suited to liquid natural gas (LNG), whereas vehicles with less than 80 DGE often use compressed natural gas (CNG). Thus, vehicles with ranges greater than 300 miles (e.g., line- or regional-haul tractors) are primarily suited for LNG, while with less range than 300 miles use CNG.

NGVs must keep pace with efficiency improvements in the conventional market

The current NGV market supports a limited number of vehicle offerings. Growth of the market could be influenced by lower vehicle ownership costs and by future regulations. Either of these factors would increase demand for natural gas engines and vehicles. Suppliers will need to be ready to provide products that include improvements to engine and vehicle efficiencies to this expanding market.

Natural gas is expected to compete well against diesel hybrid technologies in many sectors. Furthermore, with cost reductions, hybrid natural gas drivetrains could be competitive. With the focus on lower carbon dioxide emissions, diesel engine efficiency will also be improving. Similarly, gasoline technologies will be improving with technologies like direct injection, which may or may not be applicable to natural gas engines. Any increase in efficiency of conventionally fueled engines and vehicles without similar increases in natural gas technology will reduce the competitiveness of NGVs. This may result in lower fuel prices being required to compete. In addition to product improvements, engine and vehicle manufacturers should continue to educate dealers on the maintenance and servicing of NGVs as well as the benefits of NGVs.

One key question that remains for NGVs is whether they can keep pace with higher engine efficiency improvements for conventional fuel engines and therefore remain competitive as technologies evolve. Nevertheless, even with limited offerings of engines and vehicles, there are enough products available today to support expansion of the NGV market. As the market grows, more products will be demanded.

Chapter 3

Who will benefit from expansion of NGVs?

Natural gas vehicles can create millions of jobs

Natural gas creates domestic jobs. Increasing the use of natural gas in transportation has significant potential to impact national employment by displacing foreign petroleum jobs, establishing new manufacturing and construction opportunities, and stimulating economy-wide spending through fuel savings to the consumer. Jobs may be permanent, such as those established to support increased economy-wide spending, or temporary, such as those established for the duration of a particular construction project.

Expanding North America's fueling infrastructure would create a cumulative total of over 3.7 million jobs by 2035. While some of these jobs would be temporary, they provide opportunities that Americans need today:

Expanding the natural gas infrastructure is expected to create jobs[15]

	Light-Duty CNG	Medium and Heavy-duty CNG	Heavy-Duty LNG
Total number of new stations built by 2035[a]	12,800	12,100	700
Spending Changes and employment impacts in transportation fuel sectors			
Job impacts (FTEs) per station:	0.81	0.24	19.78
Overall job impacts (FTEs):[b]	10,400	2,900	13,800
Capital and infrastructure expansion			
Job impacts (FTEs) per station built:	112	179	166
Overall job impacts (FTEs):[c]	1,430,000	2,170,000	116,000

a - Based on potential market projections as detailed in the Scenario Analysis report of the overall TIAX assessment.
b - These jobs are permanent jobs across the economy.
c - These jobs are created for the duration of the manufacturing/construction project only; cumulative number in 2035 is presented.

15 Employment impacts based on IMPLAN Input-Output model and Jack Faucett Associates estimates; see Appendix

The societal benefits of NGVs compensate for higher direct costs

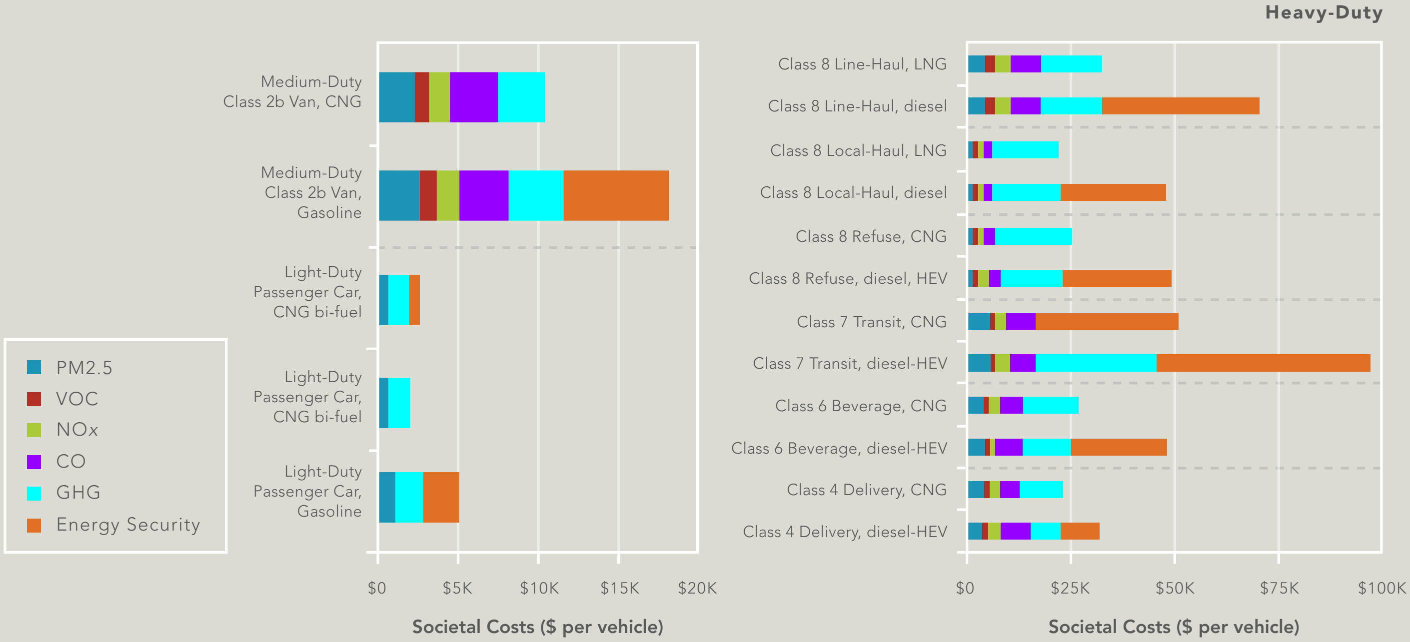
In addition to direct costs, the increased use of natural gas also results in fewer indirect costs to society as a whole. One of these reduced costs is the energy security premium, which has been estimated at approximately $0.462 per gallon.[16] Energy security can be defined as protecting the economy against significant increases and volatility in energy costs, which have contributed to U.S. recessions since the 1970s.

In addition, every transportation fuel carries a societal cost based on impacts to human health by criteria pollutant emissions. These costs are different for each fuel. The more use of natural gas as a transportation fuel, the more these societal costs can be reduced. The third societal cost of fuel use results from GHG emissions, which impact human health, property, agricultural productivity, and ecosystems.

Monetization of these societal costs provides a means to assess the societal benefits of the alternative fuels considered. The charts below demonstrate that, across multiple vehicle segments, the societal costs for NGVs are lower than those for conventional fuels. The net savings (of direct and societal costs) exceed $50,000 for some high fuel use applications and are comparable to saving 15 percent of lifetime costs. The savings for other applications may be less but are still significant. One way to capture these societal cost savings is by providing vehicle incentives to buy down the initial cost of the more expensive technology, noting that the total ownership costs of NGVs may be less than those of conventional vehicles due to lifetime fuel savings. This is currently done in several states and was recently part of federal programs as well.

16 See Comparative Analysis report of overall TIAX assessment for additional discussion of energy security and societal cost monetization.

Societal costs of various vehicles, by fuel type[17]



Note: Direct costs above include vehicle and lifetime fuel costs, assuming a $1.50 per equivalent gallon pump price differential. As indicated in Figure 2.3-1, the differential may be as high as $4.00 per equivalent gallon, which significantly lowers the relative direct costs of NGVs.

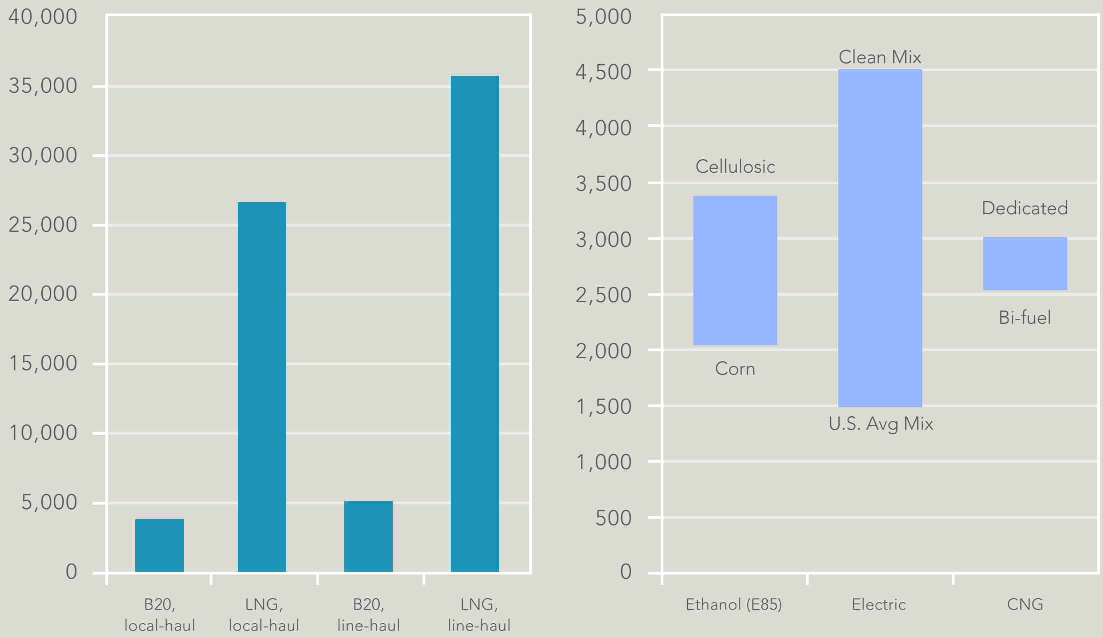
Heavy-duty NGVs deliver the greatest societal benefits

In understanding the societal costs of conventional and natural gas vehicles, this report monetizes the societal and indirect costs associated with various fuels and technologies. It focuses on those with the largest impact: local urban pollution, GHG emissions, and energy security. Emissions and energy use were determined using a full fuel cycle methodology, and the values of these externalities were calculated from accepted estimates used by federal agencies. The figure below shows two examples of the societal benefits of using alternative fuels compared with advanced gasoline and diesel technologies. For passenger cars, NGVs are essentially comparable to ethanol and electric options. In heavy-duty NGVs, high fuel use leads to greater societal benefits. The value of these benefits, applied as incentives, may help move the NGV market forward.

17 See Comparative Analysis report of overall TIAX assessment for calculations of direct and societal costs of various vehicle technologies.

Societal costs of various transportation fuels[18]

Societal Cost Savings Compared to Conventional Vehicle ($)



Energy policy to date has not decreased transportation fuel consumption

Americans experienced the first petroleum price shock in 1974 when the Organization of Petroleum Exporting Countries (OPEC) embargoed petroleum to the U.S. Its price more than doubled, and Americans experienced shortages at local fueling stations. The second "petroquake" occurred in 1979 with the Iranian War and petroleum again being embargoed. These two events resulted in the first of a series of Energy Policy Acts (EPActs) (Figure 6.1-1). The Corporate Average Fuel Economy (CAFE) standards of the first act approximately doubled fuel economy of new vehicles and were one of the reasons fuel prices fell in the early 1980s.

Although a number of other global events affected the price of petroleum over the next several decades, as world demand slowly increased, the price of petroleum reached a new high in 2008. Increasing petroleum prices have been associated with U.S. recessions; although each U.S. President responded to the energy crisis, there were no standards or regulations implemented to reduce fuel consumption in the transportation sector (other than CAFE and the more recent fuel economy and GHG standards).

The policy approach of the time was to let market forces regulate energy prices. This was a reasonably successful policy for providing consumers with relatively low and stable fuel prices from 1985 to the early 2000s. This policy also resulted in the U.S. importing more and more petroleum to meet the growing demand associated with population and economic expansion. The chart below details significant energy milestones and government energy policy introductions:

18 See Comparative Analysis report of overall TIAX assessment for societal cost calculation details and assumptions.

Date	Energy Milestones
1973	Yom Kippur War, OPEC petroleum embargo, Project Independence (self sufficient by 1980)
1975	Energy Policy and Conservation Act
1977	Carter signs DOE Organization Act
1978	National Energy Act-Energy Tax Act
1979	Iran War, 2nd oil crisis, decontrol of oil prices
1980	Energy Security Act
1981	Decontrol of crude and refined product prices
1988	Alternative Motor Fuel Act
1990	Gulf War
1992	EP Act 1992
2001	“9-11" Terrorist Attack
2003	Iraq War
2005	Gulf hurricanes—Katrina, Rita
2005	EP Act
2007	EISA
2008	Great Recession

Environmental standards are decreasing emissions and need to keep pace with fuel consumption

In response to health effects of local pollution (ozone, carbon monoxide, oxides of nitrogen (NOx), particulate matter (PM), and lead)[19], the U.S. federal government established the EPA and empowered it through the Clean Air Act (CAA) and its Amendments (CAAA) to set ever tighter fuel and vehicle standards to help regions comply with health-based ambient air quality standards. A number of programs that resulted from this overall policy are also shown in the table.

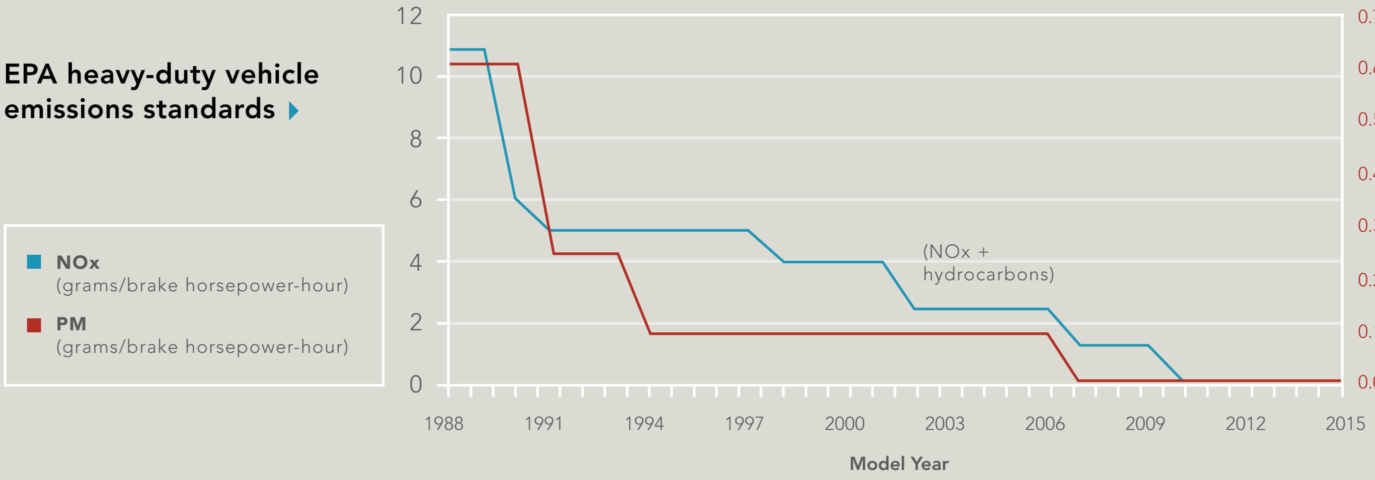
19 Health effects of these pollutants include respiratory and cardiovascular diseases.

Date	Environmental Milestones
1970	EPA opens, Clean Air Act passes
1971	EPA sets National Ambient Air Quality Standards
1973	EPA starts lead phase-out
1975	EPA requires catalysts on vehicles
1977	CAAA passed
1985	EPA sets new limit on lead in gasoline; expands air toxins program
1988	EPA sets standards for underground tanks
1989	Exxon Valdez oil spill
1990	CAAA of 1990
1993	Wintertime Oxygenated Fuel Program
1994	Phase in cleaner car standards
1995	Reformulated Gasoline Standard
2002	Diesel NO_x and PM standards
2005	RFS
2006	Ultra low sulfur diesel fuel
2007	Tighter diesel NO_x and 90% PM standards
2007	RFS II
2010	90% control of NO_x PM diesel

The environmental policy of the 1970s (the Clean Air Act) was much different than the energy policy in that affected industries were mandated to reduce emissions. In general, the philosophy was to set performance standards and let industry determine the most cost-effective ways to comply. The result has been a dramatic decrease in fuel and vehicle emissions and substantial improvement in air quality, as evidenced in the graphic below. However, economic expansion continues to put pressure on achieving and maintaining air quality in many regions of the U.S. In addition, the finding that climate change is a serious threat to human health requires additional reductions in GHG emissions—promoting improved fuel economy and lower carbon fuels.

EPA emissions standards[20]

EPA heavy-duty vehicle emissions standards



Economists agree that policy intervention is needed when market forces do not account for the full costs of using a technology, such as the societal damages caused by vehicle emissions. In the past, this has justified the use of incentives to correct for this market imperfection. However, except for incentives in the various EPA acts and the mandates in the Renewable Fuel Standard (RFS), there has not been a clear objective to reduce the U.S. dependence on foreign sources of energy from geopolitically unstable regions of the world, despite growing evidence that the costs of this dependence are not fully accounted for in the fuel price.

Where energy and environmental policies have been unsuccessful, NGVs can succeed in increasing our energy security

Despite the volatility of our energy prices and warnings about the dangers of climate change, energy and environmental policy has not significantly affected transportation fuel consumption. As global demand for petroleum grows, North American dependence on foreign petroleum from geopolitically unstable regions of the world becomes an increasing vulnerability. Recent discoveries of abundant and domestic natural gas supplies coupled with the maturity of NGV technologies makes natural gas a viable and sustainable option for widespread use in transportation. NGVs can provide lower overall operating costs, reduced air pollutant and GHG emissions, and reduced petroleum consumption, as well as offer significant job creation opportunities. Given these factors, North America is currently in a position to make radical changes in its approach to fuel sources for transportation.

NGVs offer proven benefits and are the new frontier of North American prosperity

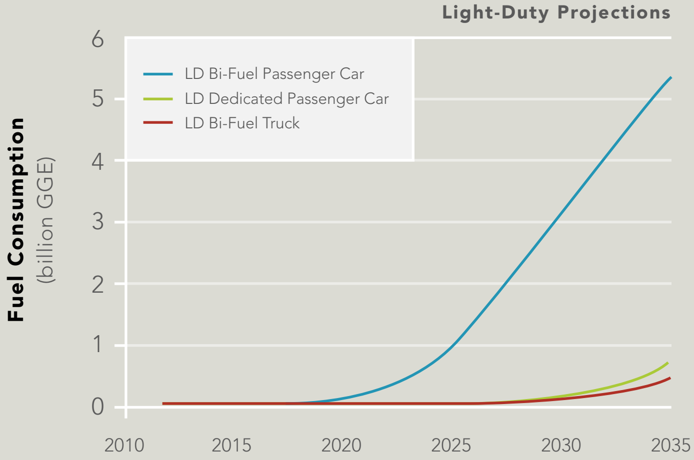
Proliferation of NGVs establishes a new market for natural gas

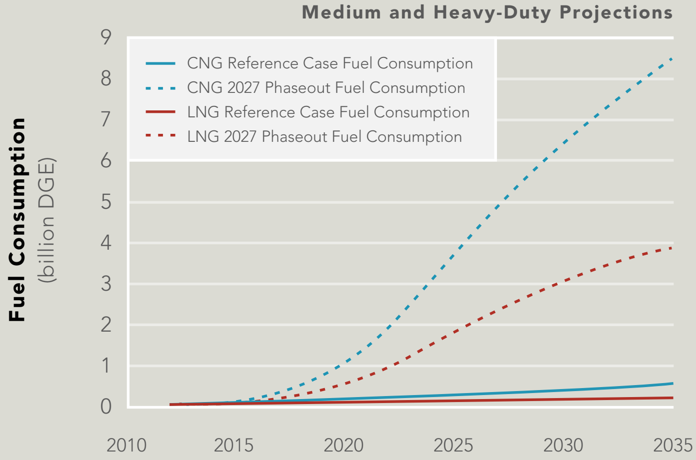
The NGV market can be considered to have three main components: the light-duty CNG market, the medium- and heavy-duty CNG market, and the heavy-duty LNG market. Medium- and heavy-duty vehicles are grouped in the same market because they are employed in commercial applications, whereas the light-duty vehicles are also employed for personal use.

Under an aggressive expansion scenario, by 2035, the NGV market may potentially enable the consumption of 5.5 billion GGE of CNG in the light-duty market and 8.5 billion DGE of CNG and 3.9 billion DGE of LNG in the medium- and heavy-duty markets. Together, this consumption equals 2.2 TCF of natural gas annually and is approximately 30 percent of the current natural gas consumption in the power generation sector. This level of use in the transportation sector represents a significant new market for natural gas. The increase in fuel required to power a growing NGV market is shown below:

20 Data from DieselNet, "Emission Standards: USA: Heavy-Duty Truck and Bus Engines," http://www.dieselnet.com/standards/us/hd.php, accessed October 2010;

Prospective fuel consumption in light, medium, and heavy duty vehicles[21]





Natural gas also offers profitable opportunities for players in the natural gas supply chain

The transportation sector offers significant market potential for natural gas supply chain companies. The business case for gas producers, pipeline companies, gas utility companies, and fueling station operators depends on reliable natural gas throughput and reasonable profit margins over costs. Because all of these individual companies are part of the same supply chain, they must work together to provide compelling natural gas prices at the pump. As such, it is critical to the long-term sustainability of the natural gas transportation market that these entities cooperate with one another to efficiently deliver natural gas to transportation customers. In order for each of these entities to remain in the NGV market, each must see a reasonable business case.

Making vehicles ready for natural gas creates new business opportunities for manufacturers and suppliers

End user vehicle requirements vary widely depending on the application in which vehicles are used. Different end use applications need different vehicle attributes and place varying levels of importance on these attributes. Aligning NGV characteristics with required attributes determines whether NGVs are a viable option for end users. Some characteristics of various vehicle segments are conducive to the use of natural gas while others require tradeoffs in order to gain the benefits of natural gas. Transit, refuse, school buses, and heavy-duty package delivery vehicles have the most favorable characteristics, and not surprisingly, these applications currently dominate NGV use, along with light-duty fleet applications. Other applications are considering or currently trying NGVs, including local- and regional-haul tractors.

The table below summarizes current suitability of different vehicles for natural gas. It also provides insight into the work that will be required to bring products to market.[22]

21 See Scenario Analysis report of overall TIAX assessment for details and assumptions.
22 See Market Segmentation report of overall TIAX assessment for additional discussion of vehicle segment characteristics.

Vehicle Segment	Range	Base	Fueling Infrastructure	Vehicle Availability	Fuel Cost Sensitivity	Environmental Policies
Passenger Car/Light Truck (Retail)	Good	Good	Fair	Fair	Weak	Fair
Passenger Car/Light Truck (Commercial)	Fair	Good	Good	Fair	Weak	Fair
Medium-Duty Private and Commercial Van/Truck	Good	Good	Good	Fair	Fair	Fair
Heavy-Duty: Package Delivery	Good	Good	Good	Weak	Good	Good
Heavy-Duty: Utility Trucks	Good	Good	Good	Fair	Fair	Fair
Heavy-Duty: Beverage Truck	Good	Good	Fair	Fair	Fair	Fair
Heavy-Duty: School Bus	Good	Good	Good	Fair	Weak	Good
Heavy-Duty: Transit Bus	Good	Good	Good	Good	Good	Good
Heavy-Duty: Refuse Trucks	Good	Good	Good	Good	Good	Good
Heavy-Duty: Local-Haul Tractor	Good	Fair	Fair	Fair	Good	Fair
Heavy-Duty: Line Haul-Truck Tractor	Weak	Weak	Weak	Weak	Good	Fair
Off-road Service/Utility Vehicles	Fair	Good	Good	Fair	Fair	Fair
Construction Equiptment	Weak	Weak	Weak	Weak	Weak	Weak
Mining Equiptment	Weak	Good	Good	Weak	Good	Weak

Good Fair Weak

Definitions*

Good:
1- Strongly enables the use of NGVs with the current state of the NGV market, or
2- Provides significant benefits from the use of NGVs

Fair:
1- Provides limited options to enable the use of NGVs or needs additional development, or (2) Provides modest benefits from the use of NGVs

Weak:
1-Requires significant additional development to enable the use of NGVs, or
2-Provides no benefits from the use of NGVs or increases overall costs

*Note that the assessment of any criterion for any application as good, fair, or weak is subject to change as the markets and various external pressures change

Legend:
For each vehicle segment, six criteria are identified that align with characteristics that are suitable for natural gas. These are described below. Ratings of good, fair and weak are assigned to identify the best markets for NGVs.

"Range" describes the typical daily operating range of vehicles in a particular application. In most applications, whether on-road or off-road, it is preferred by vehicle users that the vehicle carry enough fuel to operate for several days or be able to miss a typical refueling event without running out of fuel. This provides the user with some margin of safety if daily operations deviate from the norm. At a minimum, it is assumed that a vehicle must carry enough fuel to work through an entire shift or typical day of operation.

"Base" refers to the location where the vehicle is parked or stored when not in operation. Return-to-base applications, where the vehicle is returned to the same location each day, are the most conducive to NGV use because they allow for daily refueling, thereby minimizing onboard fuel storage requirements. These return-to-base applications often include centralized maintenance facilities and staff, allowing a few trained technicians to support numerous NGVs.

"Fueling Infrastructure" describes the typical method of refueling employed for a particular vehicle application as well as the potential for adding natural gas capability. Fleets that fuel their vehicles at fleet yards or operations centers (e.g., warehouses and ports) are best positioned to use nearby public fueling stations or install fleet-controlled natural gas fueling equipment.

"Vehicle Availability" describes the number and types of vehicles currently available for a particular application. In general, more vehicle and engine options ensure that NGVs will be suitable for users within an application. Original equipment manufacturer (OEM) options provide a single responsible party for warranty and service, making these offerings more appealing.

"Fuel Cost Sensitivity" considers the relative importance of fuel costs to vehicle purchase and operating costs. In general, high fuel consumption applications are highly sensitive to fuel costs. Low fuel consumption applications tend to be more sensitive to purchase and maintenance costs.

"Environmental Policies" as a criterion attempts to describe whether vehicle users within a particular application are sufficiently motivated by internal policies or external regulations to make vehicle purchase decisions based on the relative environmental impacts of the vehicles.

Chapter 4

How can we make NGVs more available and affordable?

Making NGVs more available and affordable will involve all of the four major stakeholders in the NGV industry—end users, natural gas supply chain companies, vehicle and engine manufacturers and government—working together. Each has a specific role, as well as significant opportunities for gain, in the NGV market:

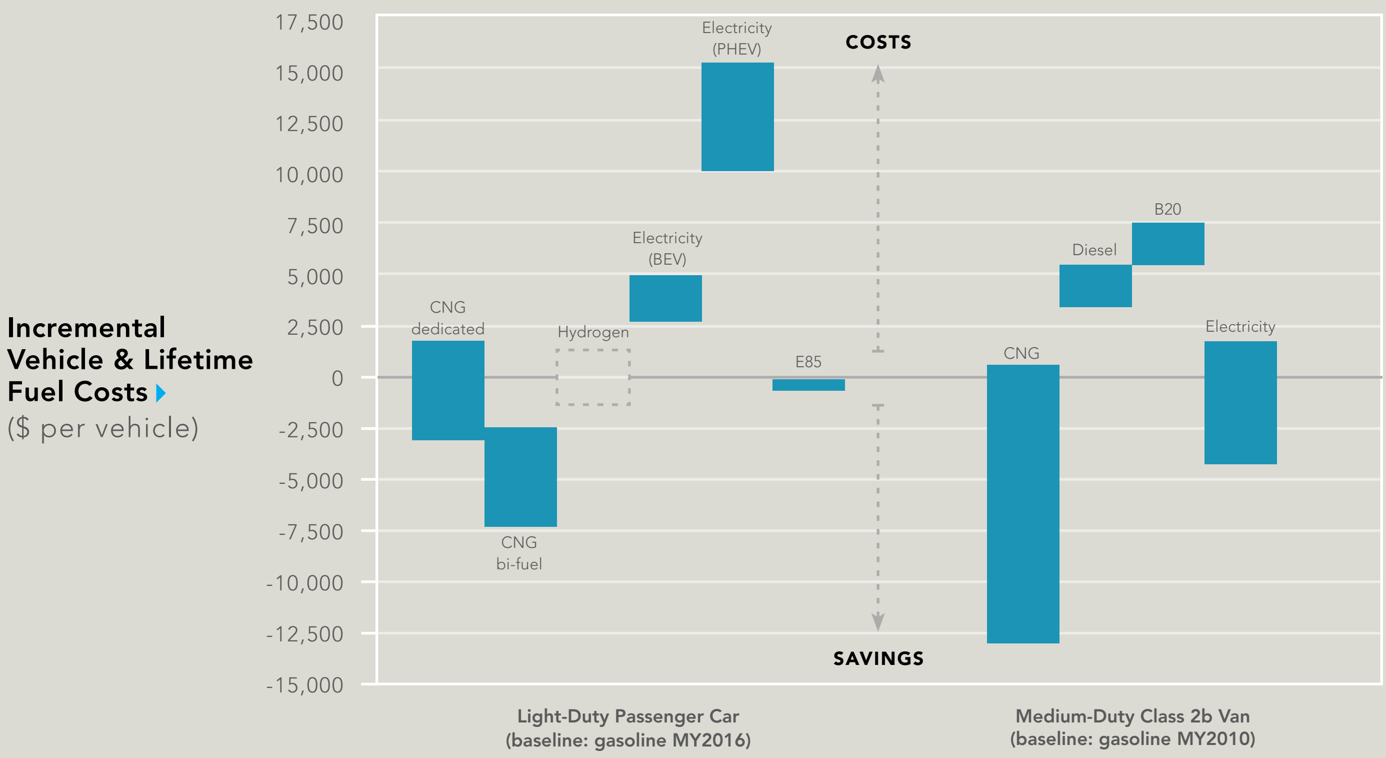
Major NGV Stakeholder	Role in NGV Market
End users	Provide demand for NGVs and natural gas fuel
Natural gas supply companies	Supply natural gas to transportation market; establish and operate fueling infrastructure; help in the education and training of and outreach to the other industry stakeholders to dispute market risk
Vehicle & engine manufacturers	Provide NGV offerings meeting the requirements of end users
Government	Level the playing field relative to other alternative fuels and vehicles and avoid picking alternative fuel winners and losers

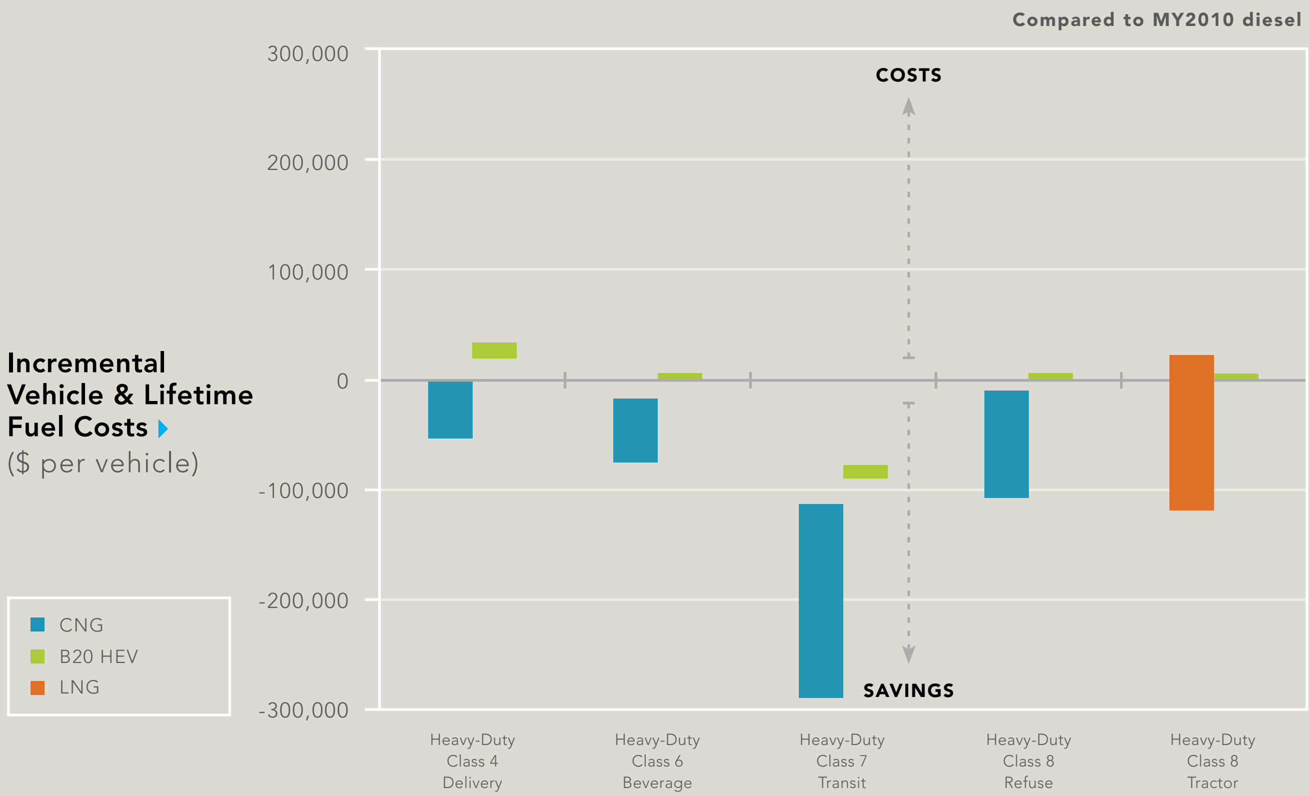
Building a foundation for NGVs: End users need affordable options

End-user vehicle purchase decisions focus primarily on three criteria: potential savings, fueling infrastructure availability, and vehicle choices. Whether end users rely on public fueling infrastructure or are capable of accessing a home fueling appliance[23], the availability of infrastructure drives the vehicle purchase decision. End users' purchase decisions will be influenced by the relative lifetime costs or savings offered by various technology options compared to gasoline and diesel vehicles. The table below presents information on the existing fueling infrastructure by fuel type. Adoption of NGVs is also highly dependent on engine and vehicle availability.

23 An in-home fueling device is a home-based gas utility or personal fueling device. It would be approximately the size of a small chair and could sit outdoors or indoors.

Lifetime fuel costs by vehicle and fuel type[24]





24 Lifetime costs include the cost of fuel over the vehicle's first-owner operating lifetime and reflect the vehicle application's operating characteristics. See Comparative Analysis report of overall TIAX assessment for calculation details and assumptions.

Rising fuel costs and environmental concerns attract consumers to NGVs

There are six criteria that drive end-user purchase decisions: range, base, refueling infrastructure, vehicular availability, fuel cost sensitivity, and environmental policies. In general, economic, environmental, and social pressures influence vehicle purchase decisions. These pressures will ultimately dictate which market segments seek alternatives to traditional petroleum fuels and what alternative fuels they select. Of the six criteria used to evaluate the various market segments as previously discussed, two of these criteria represent market drivers that incentivize or discourage the acceptance of alternative fuels. These criteria are sensitivity to fuel cost and environmental policies and represent economic and environmental/social pressures respectively. While not complete or exhaustive, these two criteria are important and reflect those markets that have seen the greatest penetration of NGVs.

Consumer demand for NGVs depends on their value proposition, which depends on initial vehicle costs, expected fuel savings, vehicle incentives, vehicle and fueling infrastructure availability, and other non-financial motivators, such as carpool lane access or a "green" image. They want sufficiently large and constant fuel cost differentials and reasonable initial vehicle costs relative to their discounting of future fuel savings.

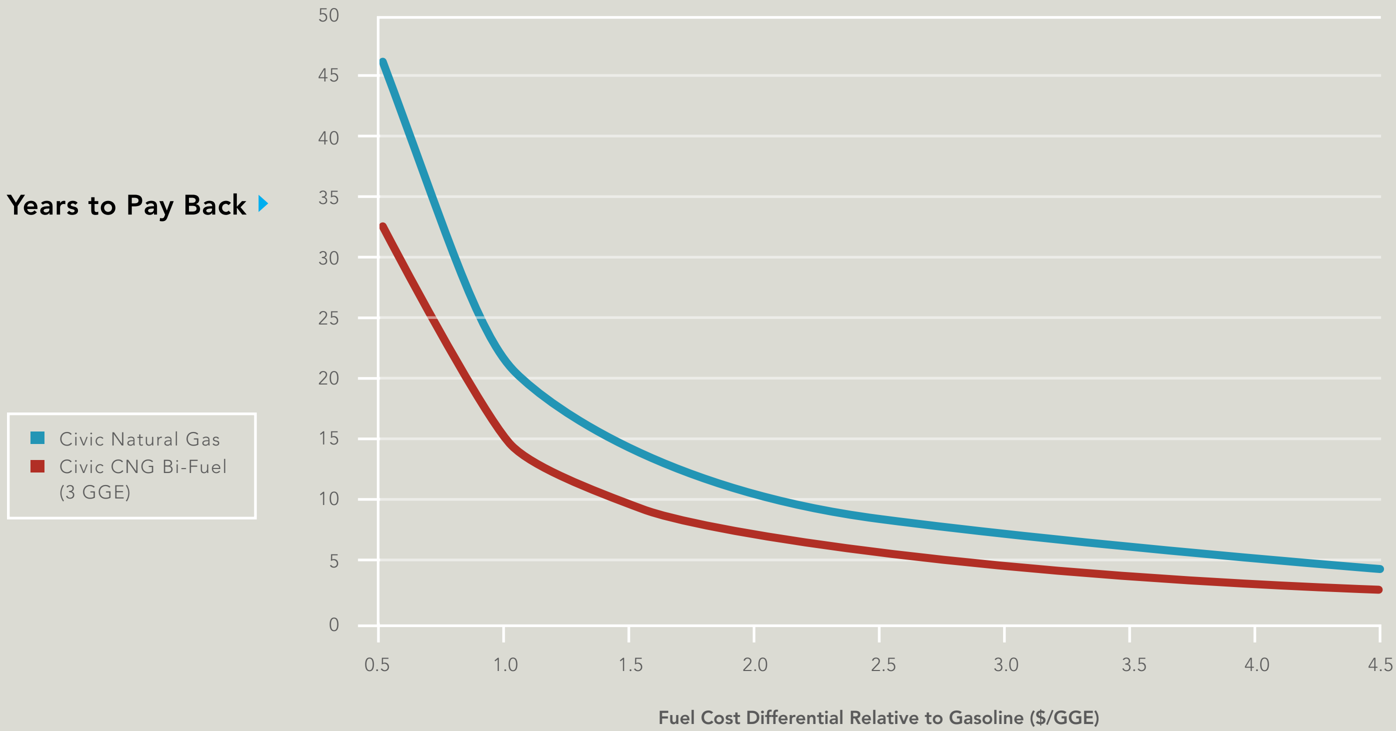
Consumers consider payback timeframe when making a purchase decision

Years-to-payback is the main economic indicator end-users focus on when determining the attractiveness of an NGV. This is defined as the number of years required to achieve payback on higher initial vehicle costs through fuel savings. It is a function of the pump price differential between natural gas and petroleum fuels, as well as incentives for vehicle purchase, including tax credits and rebates. Because there are several competing vehicle technology options to choose from, end users should weigh the relative merits of conventional and other alternative fuel vehicles against those of NGVs in their purchase decisions.

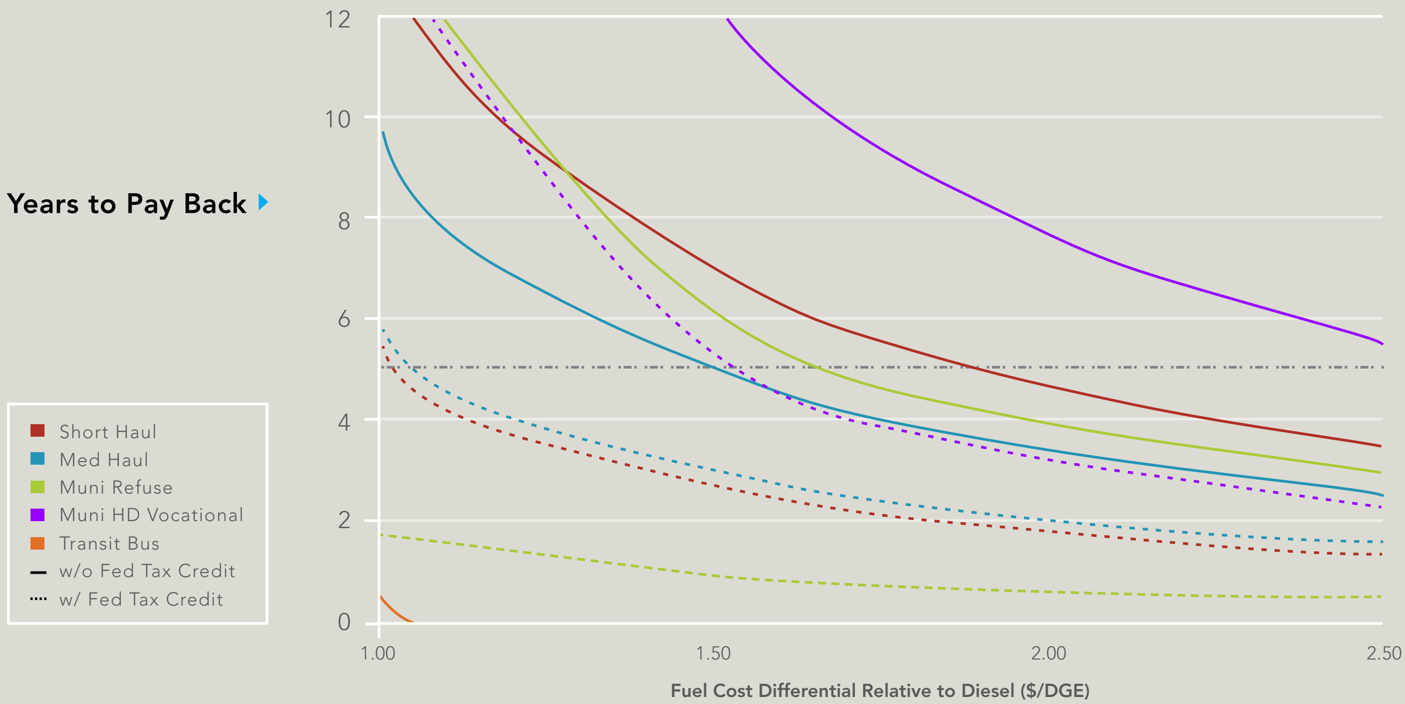
Though the duration of vehicle ownership may be much longer, the payback period required by consumers may be three to five years, so the value proposition hinges on whether the combination of fuel price differentials and incentives allows such a payback period, if any. In the light-duty personal use vehicle market, typical driving cycles may allow the option of using small natural gas capacity bi-fuel NGVs[25] (operating on both natural gas and gasoline), which attains payback more quickly than dedicated NGVs. If consumers see a value proposition for NGVs, whether in the personal use market or the commercial fleet market, manufacturers have indicated that they will be "fast followers" into this market.

25 On the order of 3 GGE of natural gas capacity; see Light- and Medium-Duty Vehicle Ownership and Production report of overall TIAX assessment for details.

Years-to-payback for a Honda Civic Natural Gas and a bi-fuel model[26]



Years-to-payback for heavy-duty NGVs[27]



26 See Light- and Medium-Duty Vehicle Ownership and Production report of overall TIAX assessment for details and assumptions of payback analyses.
27 See Heavy-Duty Vehicle Ownership and Production report of overall TIAX assessment for details and assumptions of payback analyses.

Building a foundation for NGVs: Manufacturers need a viable marketplace

Consumer demand, profitability and supporting regulations will drive vehicle and engine manufacturers' activity

Vehicle and engine manufacturers across the light, medium, and heavy-duty segments are driven by three key factors: consumer demand, profitability, and regulations. As detailed above, to capture consumer demand, manufacturers must play a role in garnering rebates. The attractiveness of natural gas to vehicle and engine manufacturers will depend on how well it can meet the standards and the cost of producing natural gas vehicles and engines compared to other options that meet the same standards.

Manufacturers' profitability depends on the costs of developing a natural gas version of their products and the volume of vehicles or engines over which these development costs can be amortized. Light-duty vehicle OEMs are estimated to require volumes of 50,000 to 60,000 units for NGVs to be considered "at scale,". For OEMs with existing CNG experience, the cost of developing a new, ground up natural gas powertrain is estimated to require $50 million in incremental costs. Heavy-duty vehicle OEMs reported the need for annual sales of approximately 1,000 to 10,000 units to justify expanded investments in the North American NGV market, estimating costs to develop and commercialize natural gas versions of their vehicles at $100,000 to $3.5 million, depending on the vehicle type and previous natural gas vehicle design. Heavy-duty engine OEMs reported the need for annual sales of approximately 10,000 units worldwide and estimated costs to develop and commercialize natural gas versions of their engines at $2 to $10 million also depending on the extent of base engine modifications.

Finally, regulations influence manufacturers to produce certain vehicles and engines. As air pollutant and GHG emissions standards are expected to grow more stringent, vehicle offerings will need to meet these standards. In the near term, air pollutant emissions standards and fuel economy standards will drive light-, medium-, and heavy-duty vehicle production.

Natural gas requires an efficient fueling infrastructure

Consumers see natural gas as a viable transportation option but fueling infrastructure is lacking

Natural gas is a mature and proven technology that can hold its own with other fuels across a range of vehicle segments but will require significant expansion of infrastructure to be widely accepted. The figure below presents a comparison of vehicle ownership costs in seven market segments for both baseline and alternative fuel types.

Comparison of consumer considerations for alternative fuel vehicles[28]

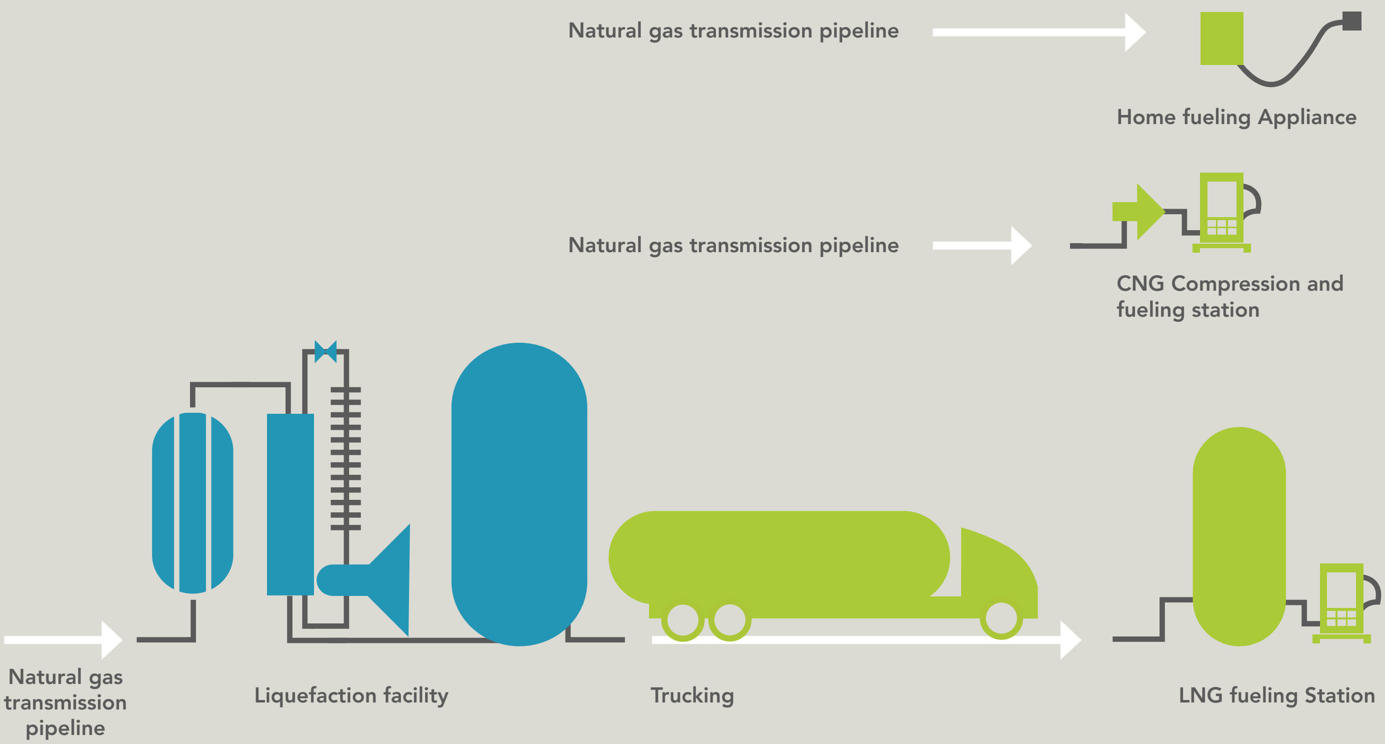
Vehicle Technology	Number of U.S. Stations	Primarily Used In:			Consumer Perception
		Light-Duty	Med-Duty	Heavy-Duty	
Gasoline	118,756	O	O		Familiar technology; for medium-duty vehicles, may be more economically attractive than the 2010 compliant diesel technologies emissions
Diesel	32,000		O	O	Familiar and efficient; new diesel technology may be costly
E85	2,544	O			Generally, unaware that vehicles may already be an FFV; E85 price may not be enough to motivate acceptance of lower energy content and station availability
CNG	1,091	O	O	O	Mature and proven technology that may be more economically attractive than advanced gasoline or diesel technologies
Biodiesel	679		O	O	Quality-controlled B20 accepted by many manufacturers; potential issues at cold temperatures and fuel price
Electricity	12,542	O	O	O	Can help enhance green image; economics may be favorable if battery costs meet expectations
Hydrogen	54	O			Significant interest, but not yet commercially available
LNG	58			O	Can help enhance green image; economics may be favorable for high fuel use applications

The discoveries of significant natural gas resources expand natural gas use from heating and power generation to include transportation. However, significant investments aimed at establishing a cohesive network of fueling stations are required. In order for the transportation market to access this supply of natural gas, the appropriate infrastructure must be in place to fuel vehicles.

The required infrastructure for CNG and LNG differs from that of gasoline and diesel. For CNG, natural gas is supplied to the fueling station or home garage via pipeline and compressed before it is dispensed as vehicle fuel. For LNG, natural gas is supplied to a liquefaction facility via pipeline, where it is cooled and liquefied into LNG and transported by truck to fueling stations, as the following diagram shows:

28 U.S. Census Bureau, "Economic Census," 2007; Alternative Fuels and Advanced Vehicles Data Center, "Alternative Fueling Station Counts by State," http://www.afdc.energy.gov/fuels/stations_counts.html, July 31, 2012; TIAX LLC, "SCR-Urea Implementation Strategies Update," prepared for Engine Manufacturers Association, 2006

Natural gas fueling options[29]



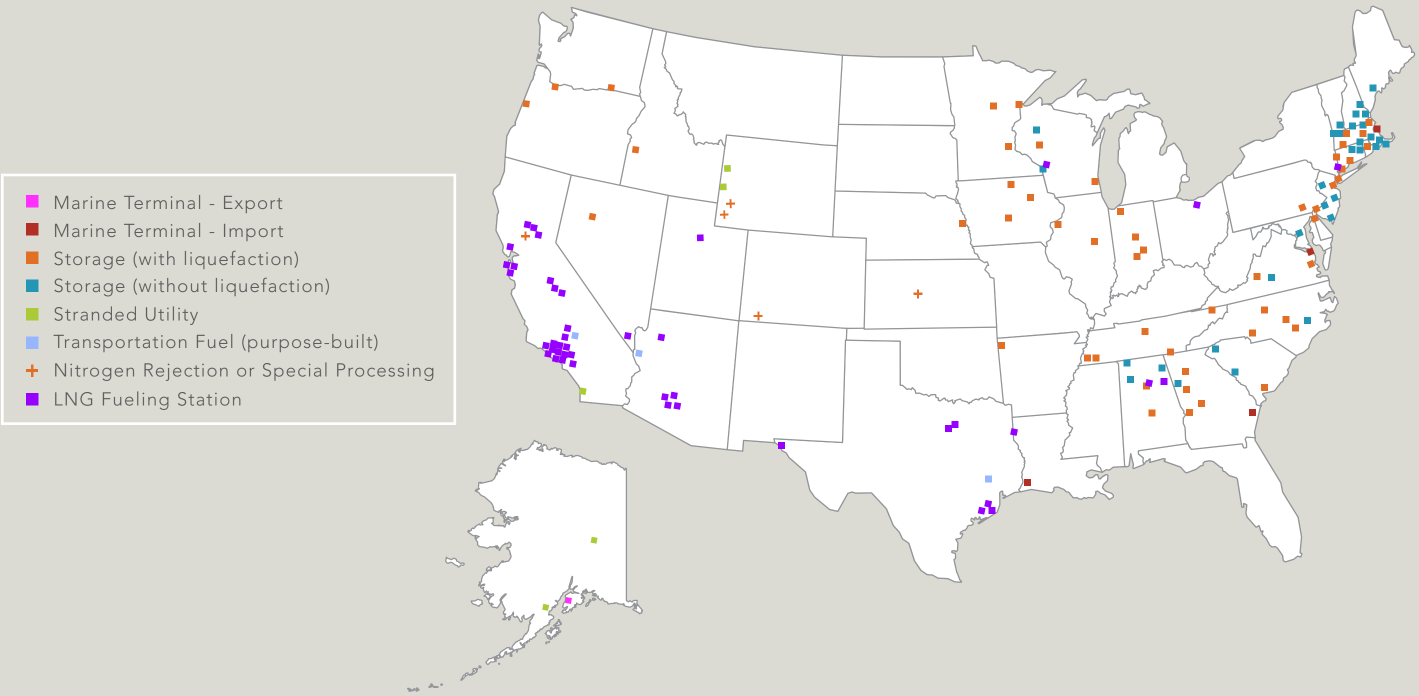
Initially, the current infrastructure can be leveraged in the natural gas supply chain

Several approaches have been used to establish natural gas fueling infrastructure. For example, a gas utility company may decide to build a station to serve its own NGV fleet as well as provide natural gas for public access. A transit agency or large commercial fleet may decide to build a station to fuel its NGV fleet and may or may not offer natural gas for public access. Alternatively, an independent fuel retailer may decide to build a station to serve the public at large. Combined, the various approaches to building infrastructure have resulted in 1,091 CNG and 58 LNG stations to date in the U.S.[30] It is important to note that a regional hub-and-spoke approach to building up natural gas infrastructure can be effective in establishing a fueling network, but purely private fleet stations may not help in this regard.

To achieve the reliable throughput needed by natural gas supply chain companies, the expansion strategy for natural gas infrastructure should be focused and incorporate growth potential. The transition between low demand in the near term and higher demand in the long term may be bridged by leveraging current stations and liquefaction facilities. Most, if not all, stations at present are operating below maximum capacity and thus are able to support significant growth of the NGV market in the near term. (Location, however, may be limiting.) As shown in the map below, liquefaction facilities exist across the U.S., even in areas where LNG stations do not yet exist

29 See Compressed Natural Gas Infrastructure and Liquefied Natural Gas Infrastructure reports of overall TIAX assessment for additional discussion of natural gas supply chains for transportation.
30 Alternative Fuels and Advanced Vehicles Data Center. “Alternative Fueling Station Counts by State.” http://www.afdc.energy.gov/fuels/stations_counts.html. July 31, 2012.

Current U.S. LNG fueling infrastructure[31]



Only three liquefaction facilities currently serve the transportation market, though LNG is produced for other purposes in various areas. Leveraging this remaining liquefaction capacity can support a regional expansion model of natural gas infrastructure development. Though these facilities do not specifically serve the transportation market, they can help meet demand for LNG as new LNG infrastructure is being developed. Furthermore, building stations with modularized natural gas capacity, such that additional compressors, tanks, and/or dispensers can be easily added as needed at a later date, can help match capacity to throughput and offer more favorable return on investment.

Future fueling infrastructure requirements differ depending on NGVs types

At the systems level, the expansion strategy for CNG and LNG may differ slightly, depending on the vehicle segments being targeted. Growth of the fueling infrastructure network for both CNG and LNG may be based on first establishing regional centers then connecting regional centers to allow expansion. For LNG, regional/line-haul tractors will require a complete corridor before they can be placed into long-distance service, and thus pre-planning of the location of these corridors will be important to infrastructure development. Finally, because the pipeline infrastructure is currently designed to serve heating and power generation needs, pipeline companies must ensure that the distribution infrastructure will be capable of handling increased volumes for transportation.

31 See Liquefied Natural Gas Infrastructure report of overall TIAX assessment for additional discussion of the various types of LNG facilities.

A North American natural gas fueling infrastructure requires significant investments

While some of the existing fueling infrastructure can be used for an expanding NGV market, large investments are needed to expand the fueling infrastructure to support its growth. The cost of establishing a CNG station may range from $675,000 for a time-fill station dispensing 1,320 DGE in a ten-hour period to $1,000,000 for a fast-fill station dispensing 200 DGE in a one-hour period. The cost of establishing an LNG station may range from $2.25 to $7.5 million for dispensing capacities of 4 to 20 million DGE per year. The LNG pathway also requires constructing liquefaction facilities, which may cost on the order of $30 million per facility with capacity of approximately 100,000 LNG gallons per day[32]. In order for these investments to be reasonable, the throughput of natural gas must grow quickly enough to offer favorable return on investment and justify costs.

Vehicle suppliers and natural gas supply chain companies must collaborate

The natural gas supply chain includes production companies, pipeline companies, LDCs, and private companies. To grow the NGV market, these companies will have to provide a cost-effective fuel that meets fuel quality and supply expectations similar to those provided by the petroleum supply chain. By 2035, aggressive expansion of the NGV market may potentially enable the equivalent of 2.2 TCF of natural gas to be consumed annually in transportation. Work has started on building an infrastructure to compete with petroleum, but much more work will be required to scale up this initial effort to effectively cover a much broader range of vehicle applications—from light-duty passenger cars to over-the-road trucks. This much broader adoption of NGVs can be a major growth market for the industry.

To support this emerging market, the supply chain companies will have to work closely with other stakeholders to develop the business cases for using natural gas. This will include working with government and other stakeholders to develop a comprehensive energy and environmental policy, working with engine and vehicle manufactures to improve their NGV offerings, and working with users to make sure their fueling requirements are met. A major focus of the supply chain companies should be on developing a robust, cost-competitive fueling infrastructure throughout the U.S. and Canada. This will require private firms working with regulated entities and equipment and construction companies to execute a plan to bring natural gas to the transportation market. The table below spells out the specific actions that vehicle suppliers and natural gas supply chain companies must take in order to grow the NGV market:

32 See Compressed Natural Gas Infrastructure and Liquefied Natural Gas Infrastructures reports of overall TIAX assessment for additional details of vehicle throughput and fuel volume.

Vehicle suppliers' steps going forward to provide NGVs to the commercial and retail vehicle markets:

Engine Manufacturers:

Provide most efficient technology for natural gas

2. Continue to evaluate cost-effective applications of advanced diesel engine technologies to natural gas engines

3. Develop and commercialize wider selection of natural gas engines and ratings to meet the increasing demand

Vehicle Manufacturers:

1. Continue to provide a quality natural gas vehicle to customers meeting the same reliability, durability as gasoline and diesel products

2. Continue to train and educate dealers on the service and maintenance of natural gas vehicles as well as the benefits of NGVs

3. Work with equipment suppliers to drive down the costs of natural gas vehicle components

Natural gas supply chain companies' steps going forward to provide natural gas to commercial and retail customers:

Fuel Supply Chain:

1. Work to match fueling station throughput to vehicle demand

- a. Pipeline infrastructure
- b. Liquefaction facilities
- c. Local fueling stations

2. Develop successful business cases for infrastructure development

3. Use government fuel infrastructure incentives to connect regions

4. Promote competition to reduce costs of CNG and LNG supply to end-users

5. Work with equipment suppliers to develop cost effective, modular station designs to drive down cost of designing, building, and operating natural gas fueling stations

Government can level the playing field to make NGVs more affordable

For the NGV market to grow, each major market player will need to take steps to promote the use of natural gas. The higher incremental cost of NGVs is one reason that natural gas tends to rely on regulations and incentives rather than fuel cost differential. In particular, the infrastructure costs associated with installing private natural gas fueling stations can be prohibitive for many small fleets without funding assistance to offset costs. In addition, the incremental cost of NGVs can prevent adoption in low fuel consumption applications where the return on investment is low.

A level playing field among alternatives can make NGVs more affordable.

Government intervention is critical to support new fuel alternatives that are more expensive for consumers. For example, no vehicle incentives are needed for fuels that do not have increased costs, whereas vehicle incentives may be recommended for those that do. Similarly, no incentives are needed for fuels that are less expensive on an energy basis or that are currently mandated through existing standards. The table below shows how policy might be structured to reflect the differences between alternative fuels:

Alternative Fuel	Vehicle Costs	Fuel Costs	infrastructure Needs			Incentive Needs		
			Home	Public	Private	Vehicle	Fuel	Infra-structure
Ethanol blend (E10)	Same	Same	No	No	No	No	No	No
Ethanol (E85)	Same	Same	No	Yes	No	No	Yes	Yes
Plug-in hybrid electric vehicle (PHEV)	More	Less	Yes	Some	No	Yes	No	Yes
Battery electric vehicle (BEV)	More	Less	Yes	Some	No	Yes	No	Yes
Hydrogen fuel cell vehicle (FCV)	More	Same	No	Yes	Yes	Yes	Yes	Yes
Light-duty NGV	More	Less	Yes	Yes	No	Yes	No	Yes
Heavy-duty NGV	More	Less	No	Yes	Yes	Yes	No	Yes
Biodiesel (B20)	Same	More	No	Yes	Yes	No	No?	No

The growth of NGVs over the past twenty years has been driven by environmental objectives of lowering fuel and vehicle emissions—particularly those produced by heavy-duty diesel vehicles.

EPAct helped drive the purchase of NGVs and the establishment of natural gas fueling stations. Regions having the most success at increasing the use of NGVs were those that required alternative fuels but at the same time provided incentives for users to purchase the higher cost technologies. The South Coast Air Quality Management District (SCAQMD) "1190" fleet rules are a good example of requiring the use of alternative fuels in fleets such as transit and refuse as a way to reduce NOx and PM emissions from diesel engines. Using local and state funding, SCAQMD was able to provide incentives to those complying with the regulations.

Federal and state agencies are developing regulations to control GHG emissions. At the federal level, EPA is working with the U.S. Department of Transportation to regulate GHG emissions for light- and heavy-duty vehicles. To date, these regulations have primarily focused on increasing fuel economy and not on the use of low carbon fuels. An exception to this is California and other states that are developing a low carbon fuel standard to encourage the use of alternative fuels that will decrease carbon emissions and increase energy security. Increased CAFE standards will also help to increase the use of alternatives. Going forward, there needs to be a consensus on reducing transportation energy consumption above and beyond that is achievable through increased efficiency alone. Furthermore, government policy, supported by stakeholders, should reflect parity for the various alternative fuels, each of which has different requirements as indicated earlier in this report. The current renewable fuels standard is a step in the right direction but is specific to biofuels. A broader stakeholder-supported regulation is needed to include not only efficiency and biofuels but also other low carbon fuel sources like natural gas. The specific actions that the government and end users must take in order to grow the NGV market are outlined below:

Government steps going forward to encourage the use of natural gas in the transportation sector:

1. Develop consensus on objectives and policies to increase energy security

2. Integrate energy objectives and policies with environmental objectives and polices

3. Evaluate and select policy instruments to achieve environmental and energy objectives

4. Do not wait for "silver bullet" technologies.

5. Level the playing field by evaluating alternative fuels based on needs and benefits

6. Set performance standards for increasing use of alternative, domestic fuels in government fleets to avoid "picking winners" and to allow for industry to comply cost-effectively

7. Continue to educate consumers through Clean Cities program

Commercial and retail car, truck, and bus purchasers' steps going forward on the use of natural gas as a transportation fuel:

1. Make use of information, funding, and incentives available from natural gas suppliers, vehicle suppliers, and government to evaluate the benefit of NGVs to company's operation.

2. Work with similar industries in region to evaluate and aggregate demand to justify public natural gas stations.

3. Work with vehicle suppliers to expand availability of NGV products—vehicle and performance characteristics

Any regulation developed should be structured to allow the affected industries the flexibility to meet the regulations as cost-effectively as possible. Lastly, government organizations are very effective at disseminating unbiased information on alternatives. The U.S. Clean Cities program has been particularly effective in this regard and should be leveraged to continue providing information on NGVs as well as other alternatives.

End users should make use of the information provided by the government and vendors to make business decisions on the savings possible with NGVs. Users should also work with similar industries to help natural gas fuel providers to aggregate demand in various locations and regions. Finally, users should provide feedback to engine and vehicle manufacturers as well as suppliers regarding needed product improvements and expansion of product offerings

This page intentionally left blank

Appendix: Job Impacts Analysis

This analysis covers three scenarios (light-duty CNG, medium- and heavy-duty CNG, and heavy-duty LNG) involving expansion of the supply of natural gas as a transportation fuel, as well as the construction of the necessary infrastructure (including stations, processing plants and heavy-duty trucks) to support that expansion. Employment impacts vary with the scale of additional spending that occurs within sectors. For this analysis, the results are reported as the impact associated with each additional station. These numbers should be understood as averages, however, and they take into account the assumption that a significant expansion is modeled. These numbers would be less reliable in the case of an expansion on a very small scale (involving only a few new stations and a few thousand new vehicles).

Employment impacts are expressed in full-time equivalent units (FTEs) of employment. An FTE represents the level of employment equal to a single full-time employee working forty hours per week. The use of FTEs as a measure does not imply that the employees under consideration are full-time employees, however. Two or more employees may be employed on a part-time basis, and their total employment may comprise a single FTE.

Employment impacts from infrastructure expansion

Infrastructure expansion for the provision of expanded supplies of natural gas requires significant spending on fueling stations, processing facilities and additional heavy-duty tanker vehicles to carry supply not deliverable through the existing natural gas pipeline network. In addition, incremental capital costs are anticipated for the construction of vehicles capable of using natural gas as a transportation fuel.

In the three scenarios under consideration, the assumptions regarding the capital costs of infrastructure and vehicles are expressed as the costs associated with each additional natural gas fueling station. As such, the vehicle costs represent the additional fleet that can be supported by a single additional fueling station. The processing plant costs represent that share of a single plant's output sold by a single additional fueling station. The truck and pipeline costs are the cost to supply a single station.

The full infrastructure expansion costs are shown in Table A-1.

Table A-1. Assumptions and Costs of Capital and Infrastructure

	Light-Duty CNG	Medium and Heavy-duty CNG	Heavy-Duty LNG
Fueling Station Construction			
Units	1	1	1
Cost/unit ($millions)	$1.00	$1.00	$0.77
Total Cost ($millions)	$1.00	$1.00	$0.77
Processing / Liquefaction Facility Construction			
Units	0	0	0.1
Cost/unit ($millions)	$31.8	$31.8	$31.8
Total Cost ($millions)	$0	$0	$3.18
LNG Distribution Trucks			
Units	0	0	1
Cost/unit ($millions)	$0.345	$0.345	$0.345
Total Cost ($millions)	$0	$0	$0.345
Supported Vehicle Fleet			
Units	2,300 (LDVs)	34 (Class 3) 200 (Class 4-6) 47 (Class 7-8)	114 (Class 7-8)
Incremental Vehicle Cost/unit ($millions)	$0.002916	$0.017 (Class 3) $0.040 (Class 4-6) $0.060 (Class 7-8)	$0.060 (class 7-8)
Total Cost ($millions)	**$6.71**	**$11.40**	**$6.84**

To produce employment impacts, these final demand values were converted to associated employment levels per station through the use of input-output multipliers. These employment multipliers are developed as part of macroeconomic modeling tools and utilized to determine the specific employment impacts of changes in spending in particular sectors.

Employment multipliers for the construction and heavy manufacturing sectors were taken from the IMPLAN Input-Output Model, a macroeconomic modeling tool. Employment multipliers are expressed as the number of FTEs created for each $1 million in final demand directed to a given sector. The IMPLAN employment multiplier for the construction sector is 15.95, indicating that the model assumes that 15.95 FTEs are created for every $1 million of spending in the construction sector. The employment multiplier for manufacturing is 14.28. This slightly lower number indicates that manufacturing is slightly less labor-intensive per dollar of spending in the sector than construction.

Employment impacts in specific sectors are derived from the product of the spending in a given sector and its corresponding employment multiplier. Table A-2 shows the estimates of employment impacts from natural-gas infrastructure expansion (again, measured per fueling station).

Table A-2. Employment Impacts from Capital and Infrastructure

	Light-Duty CNG	Medium and Heavy-duty CNG	Heavy-Duty LNG
Fueling Station Construction			
Employment Impacts	15.95	15.95	12.28
Processing/Liquefaction Facility Construction			
Employment Impacts	0	0	50.72
LNG Distribution Trucks			
Employment Impacts	0	0	4.93
Supported Vehicle Fleet			
Employment Impacts	95.77	162.76	97.68
Overall Job Impacts (FTEs) per Station:	**111.72**	**178.71**	**165.60**

These numbers refer to the years in which the spending occurs. The additional employment created by this expenditure would disappear when the construction and manufacturing was completed.

Employment impacts from transportation fuel sales

Employment impacts from the increased use of natural gas fuels are affected by both the growth in employment created from expanded spending on natural gas as well as losses in employment caused by spending shifting away from the petroleum sector. Importantly, because the scope of the job impacts is domestic, petroleum jobs lost outside of the country are not counted as losses to the domestic economy; in essence, the effect is a shift of foreign petroleum jobs to domestic natural gas jobs. The overall net impact is positive – the increased use of natural gas under these scenarios creates more employment than it displaces.

An important component of these job impacts is driven by the fact that natural gas has historically been, and is projected to be, approximately 45 percent cheaper than gasoline or diesel when measured per unit of energy. For this analysis, which is prospective, price projections for the near future were selected. The averages of the projected prices for all three fuels for the next five years were taken from the Department of Energy's "Annual Energy Outlook," published in March 2010. The prices assumed are in the table below, and are expressed in both GGE and DGE (Table A-3).

Table A-3. Fuel Prices[33]

	CNG/LNG	Gasoline	Diesel
GGE	$1.37	$2.81	$2.34
DGE	$1.56	$2.91	$2.86

Because the additional energy used from natural gas was similar in quantity to the energy left unused from petroleum fuels, the shift from consumption of gasoline and diesel to the consumption of natural gas presents a net savings to the consumer. This has two conflicting impacts on employment. First, employment from the direct provision of fuel goes down, because natural gas is less labor-intensive to provide and because less money enters that sector than leaves the petroleum sector. Second, economy-wide employment rises as a result of increased spending triggered by the additional money available as a result of fuel savings.

Employment Multipliers

Accurate assessment of the impacts of spending on CNG and LNG as transportation fuels required the development of customized employment multipliers. The IMPLAN and REMI macroeconomic models use historical data, and have not developed sector-specific multipliers for the large-scale provision of natural gas as a transportation fuel. Multipliers exist for provision of natural gas for heat and power generation, but these multipliers do not take into account the additional labor involved in distributing transportation fuels (especially liquid fuels) to fueling stations, or the additional labor involved in maintaining and operating retail fueling facilities.

For CNG, analysts began with the employment multiplier established in IMPLAN for the natural gas utility sector, which is 5.57 jobs/$million in final demand. Analysts treated this level as a lower bound, and then made assumptions regarding additional labor requirements regarding the distribution and retail components of CNG as a transportation fuel. This produced a custom employment multiplier of 9.18 jobs/$million in final demand.

For LNG, which must be distributed in the same manner as conventional gasoline and diesel fuel, analysts used the employment multiplier of petroleum fuels (12.8 FTE/$million in final demand) as a benchmark from which to start. Analysts then adjusted the distribution to take into account that LNG contains only 58 percent of the energy per unit volume that diesel fuel contains. This lower energy content requires significant additional transportation resources to transport the same amount of energy to the fueling station. Analysts developed an estimate of the share of the employment multipliers dedicated to distribution, and adjusted for the scenario stipulations regarding total amounts of energy produced and displaced, to arrive at a custom employment multiplier for LNG of 15.6 FTE/$million in final demand.

Table A-4 displays the scenario assumptions, corresponding spending changes, and employment multipliers for transportation fuel sales.

33 Source: U.S. Energy Information Administration "Annual Energy Outlook," 2010, averages of projected prices for 2011 to 2015

Table A-4. Spending Changes and Employment Impacts, Transportation Fuel Sectors

	Light-Duty CNG	Medium and Heavy-duty CNG	Heavy-Duty LNG
Natural Gas Fuel Sales Growth			
Final Demand Change	$0.88	$1.59	$2.99
Employment Multiplier	9.185	9.185	15.60
FTEs Created	8.12	14.61	46.70
Petroleum Fuel Sales Displacement			
Final Demand Change	-$1.77	-$2.92	-$5.53
Employment Multiplier	12.8	12.8	12.8
FTEs created	-22.70	-37.40	-70.76
Increased Non-Fuel Spending			
Final Demand Change	$0.89	$1.33	$2.53
Employment Multiplier	17.3	17.3	17.3
FTEs created	15.39	23.03	43.85
Overall Job impacts (FTEs) Per Station per Year:	**0.81**	**0.24**	**19.78**

These results indicate that the scenario seeking to expand the use of LNG in the heavy-duty sector produces the largest ongoing positive job impact. Because LNG provision is more labor-intensive, expansion of LNG has a larger positive impact on employment. All three scenarios demonstrate the benefits to the overall economy of savings from using natural gas in place of petroleum. In all three cases, the scenario produces greater positive employment impacts outside the natural gas sector than within it – entirely through creating significant energy savings to the transportation sector.

This assessment was sponsored by America's Natural Gas Alliance with the support of participating American Gas Association companies.

For questions, please contact:

TIAX LLC
20813 Stevens Creek Blvd, Suite 250
Cupertino, CA 95014

http://www.tiaxllc.com/services/

The opinions expressed within the Executive Summaries of Modules 1 and 2 of this market assessment are the work product of America's Natural Gas Alliance (ANGA) and participating American Gas Association (AGA) companies based upon data provided by TIAX LLC.

The Final Reports of Modules 1 through 5 are the work of TIAX LLC as a market assessment sponsored by ANGA with the support of participating AGA companies.

Date of Request: April 15, 2016
Due Date: April 25, 2016

DPS Request No. DPS-443 JS-7
KEDNY/ KEDLI Req. No. BULI-478

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, John Sano

TO: National Grid, Revenue Requirements Panel

SUBJECT: Geothermal/Solar Technologies

Request:

1) Do the Companies currently have any programs to assist customers in pursuing geothermal or solar thermal technologies?

2) Do the Companies have any information on the potential for those two technologies in their service territories, specifically information that describes the potential in terms of numbers of customers and potential thermal load displaced expressed in dekatherm equivalents?

3) Do any of the Companies' affiliates have any incentive programs aimed at these technologies?

Response:

1)

The Companies do not currently have any programs to specifically assist customers in pursing geothermal or solar thermal technologies. However, an unregulated National Grid affiliate, National Grid Energy Management, offers installation services for solar thermal systems.

2)

The Companies do not have a resource assessment on the potential for those two technologies in their service territories.

3)

At present, no National Grid affiliate has any incentive program specifically aimed at these technologies.

<u>Name of Respondent</u>:
Chris Cavanagh/Keith Sperling

<u>Date of Reply</u>:
April 25, 2016

Date of Request: April 22, 2016
Due Date: May 2, 2016

DPS Request No. DPS-460 CS-1
KEDNY/ KEDLI Req. No. BULI-568

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, Claude Semexant

TO: National Grid, GIOP

SUBJECT: Chromatographs – KEDNY & KEDLI

Request:

The Following questions refer to the forecasts of Gas System Reinforcement Program for KEDNY, as listed in Exhibit__ (GIOP-4):

1) Provide the total number and the location(s) of the existing Chromatographs for both Companies (KEDNY and KEDLI).

2) Provide the total number and location(s) of Chromatographs installed in the last five years for both Companies KEDNY and KEDLI.

3) Provide the justification for the three additional chromatographs in the Company (KEDNY) gas system reinforcement program.

4) Describe the methodology used to calculate the billing zone determinant(s) for both Companies KEDNY and KEDLI. Provide all supporting documentation for the underlying calculation.

    a. Describe and explain how this information has been communicated to customers.

5) Provide the locations of the billing zones for both Companies KEDNY and KEDLI, on a system map.

Response:

1) and 2)

Please refer to the table below:

Company	***Location***	***Purpose***	***Installed in the Last 5 Years***
KEDNY	Cambria Heights	Therm Billing Zone # 9	No
KEDNY	Transco Linden Mix	Supply	No
KEDNY	Maspeth Station	Therm Billing Zone # 1	Yes - Replacement
KEDNY	Newtown Transfer	Supply	No
KEDNY	LaGuardia	Therm Billing Zone # 1	No
KEDNY	Fresh Kills	Supply	No
KEDNY	Tetco Goethals	Supply	Planned
KEDNY	Transco	Supply	No
KEDNY	Cubit Power	Therm Billing	Planned
KEDNY	North Queens	Therm Billing	Planned
KEDNY	Chelsea Gate	Therm Billing	Planned
KEDNY	Brooklyn Navy Yard	Therm Billing	Yes
KEDNY	KIAC JFK CoGen	Therm Billing Zone # 2	Yes
KEDNY	Newtown Creek Biogas	Supply	Planned
KEDNY	Brooklyn Narrows	Supply	Yes
KEDNY	NYPA Kent	Therm Billing	No
KEDNY	NYPA 23 Street	Therm Billing	No
KEDNY	NYPA Pouch	Therm Billing	No
KEDNY	Gowanus Power	Therm Billing	No
KEDNY	Narrows Power	Therm Billing	No
KEDNY	Arthur Kill Power Plant	Therm Billing	No
KEDNY	South Gate	Therm Billing Zone # 8	No
KEDNY	Pratt (Visy Paper)	Therm Billing	No
KEDNY	Canarsie	Therm Billing Zone # 2	No
KEDNY	Citizens	Therm Billing Zone # 2	No
KEDNY	Floyd Bennett Field	Supply	Yes
KEDNY	Kew Gardens	Therm Billing	Planned
KEDNY	Downtown Brooklyn	Therm Billing	Planned
KEDLI	Long Beach M&R Station	Therm Billing Zone # 1	No
KEDLI	South Commack M&R Station	Therm Billing Zone # 3	No
KEDLI	Lake Success Meter Station	Supply	No
KEDLI	NYPA Holtsville	Therm Billing	No
KEDLI	EF Barrett Power Station	Therm Billing	No
KEDLI	Glenwood	Therm Billing	No
KEDLI	Port Jefferson	Therm Billing	No
KEDLI	Northport	Therm Billing	No
KEDLI	NYPA Pilgrim	Therm Billing	No
KEDLI	Freeport	Therm Billing	No
KEDLI	NDEC	Therm Billing	No
KEDLI	Caithness	Therm Billing	No
KEDLI	Far Rockaway	Therm Billing	No
KEDLI	Calpine	Therm Billing	No

"Therm billing" listed without a zone refers to billing to a single customer such as a power plant. To calculate the BTU values for KEDLI zone 2 and KEDNY zones 3, 4, 5, 6, 7, and 10, see the Companies' response to Question 4 below. "Planned" refers to chromatographs that are going to be installed in the near future. “Supply” refers to the chromatograph sites that are for gas quality purposes where there is no direct customer but the site supplies gas to areas leading into direct customer feeds.

3. The additional chromatographs in KEDNY’s gas system reinforcement program are for three new regulator stations. The Company installs standard gas monitoring/regulating equipment at these stations, such as telemetering, heaters, regulators, filters and chromatographs. The chromatographs will monitor gas heating value and quality at these new sources of gas into the distribution system.

4. For KEDNY, the heating value of gas the Company receives at its city gates is measured by gas chromatographs located at:

- Transcontinental Gas Pipe Line (“Transco”) stations in Linden, NJ, and Floyd Bennett Field

- Texas Eastern Transmission Pipeline (“Tetco”) station in Goethals, Staten Island

In addition, KEDNY has installed gas chromatographs on its distribution system at the following large metering stations: LaGuardia, Maspeth, Citizens, Canarsie, the Staten Island Landfill Plant, and South Staten Island gate station.

There are also gas chromatographs at transfer metering stations at the following locations:

- Cambria Heights – the point of transfer between KeySpan Gas East Corporation d/b/a National Grid (“KEDLI”) and KEDNY
- Newtown – the point of transfer between Con Ed and KEDNY.

Lastly, large customers (*i.e.,* power plants) either have a BTU measuring device located at their site or use the readings from a specific BTU measuring device on the system. These customers are billed in accordance with the heating value measured by these devices.

KEDNY performed an engineering study using the GL Noble Denton SynerGEE (Stoner) Model that established ten therm billing zones within the Company’s service territory.

Four therm billing zones within the boroughs of Brooklyn and Queens together constitute the vast majority of the Company’s service territory. These include:

- Zone 1, the Northern zone
- Zone 2, the Central zone
- Zone 3, the Southern zone
- Zone 9, the Eastern zone.

Southern Zone 3 extends from Brooklyn into Staten Island where it represents the majority of the Staten Island. At the extreme southern end of Staten Island, Zone 8 is influenced by the gas received from the Staten Island Landfill Plant and is measured by a gas chromatograph at South Staten Island gate station. When there is no flow into Zone 8 through South Staten Island gate station (typically above 40°F average temperatures), all of Staten Island is treated as Zone 3.

To determine the thermal conversion factor for each zone, KEDNY first computes each day the overall heating value of gas received into its service territory. To do this, the Company takes the measured heating value of the gas supplies received at each city gate and transfer metering station, and multiplies those heating values by the associated metered volumes to compute the total dekatherm quantity received. The average system heating value is next computed by dividing the total quantity received in dekatherms by the total volume received in Mcf.

Second, KEDNY computes the thermal conversion factors for Zones 1, 2, 8, and 9 using the same approach described above. The measured heating value of the gas chromatograph(s) located within each zone is multiplied by the associated metered volumes to compute total dekatherms received into each zone. The Company then divides the computed dekatherm quantity received by the metered Mcf volume received to arrive at the thermal conversion factor for each zone.

Zone 3 is determined as the difference between the overall KEDNY distribution system heating value and that of Zones 1, 2, 8 and 9.

The thermal conversion factors for Zones 4 to 10, which are transitional zones that account for variances in transmission system flows, are then established as follows:

- Zone 4 receives the lower of Zone 1 or 2
- Zone 5 receives the lower of Zone 1 or 9
- Zone 6 receives the lower of Zone 2 or 3
- Zone 7 receives the lower of Zone 3 or 8
- Zone 10 receives the lower of Zone 2 or 9

With the exception of large customers that are assigned to a specific BTU measuring device, the calculated thermal content of the gas is then applied uniformly to all customers within a particular zone.

For KEDLI, a similar engineering study was performed using the GL Noble Denton SynerGEE (Stoner) Model that established three therm billing zones within the Company's service territory. These zones account for the difference in heating value between supplies received at the Long Beach, NY city gate on the Transcontinental Gas Pipe Line ("Transco") and the South Commack, NY city gate on the Iroquois Gas Transmission System ("Iroquois").

The zone boundaries are such that Zone 1 comprises the western end of the Company's service territory, Zone 3 comprises the eastern end of the service territory, and Zone 2 is a transitional zone located between Zones 1 and 3. The engineering study determined that Zone 2 receives Transco supply in the winter (November 1st through March 31st) and Iroquois supply in the summer (April 1st through October 31st).

The Zone 1 conversion factor is set each day based on the gas chromatograph measured heating value of gas received at the Transco Long Beach city gate. Similarly, the Zone 3 conversion factor is based on the gas chromatograph measured heating value of gas received at the Iroquois South Commack city gate. The Zone 2 conversion factor is equal to Zone 1 during the winter and Zone 3 during the summer.

The calculated thermal content of the gas is applied uniformly to all customers within a particular zone with the exception of large customers (*i.e.*, power plants) that have a BTU measuring device located at their site. These customers are billed in accordance with the heating value measured by the local devices.

a. On the front of the customer bill, the therm factor used to covert usage from CCF to therms is specified. The back of the bill in a section titled "Understanding Terms On Your Bill" defines CCF, thermal factor and therms. A representative copy of a KEDNY bill is provided as Attachment 1. The language on the KEDLI bill is the same.

5. Attachment 2 is the currently available map for the Brooklyn Queens Area of KEDNY. This map does not reflect the latest addition of zones 9 and 10 to Queens and the associated revision of the other zones in the Brooklyn Queens area. Attachment 3 is the currently available map for the Staten Island area of KEDNY. Attachment 4 is the currently available map for KEDLI.

Name of Respondent:
Peter Metzdorff
Stephen Greco
Eric Aprigliano

Date of Reply:
May 2, 2016

nationalgrid

2014143

0200007000000

**C 078 053945

Please Pay
Upon Receipt
86.05 H

Account Number

Tear here
Please mail this part of bill with your payment.

Make checks payable to National Grid.
Write your account number on check.

Service To	Account Number	Next Meter Reading	Bill Date
		Jun 20 '14	May 22 '14
	Rate 1B Res. Heating	For Customer Assistance Please call (718) 643-4050	

CURRENT BILL ITEMIZED

In 30 days you used 47 therms:

May 22 2014 reading ACTUAL	5633
Apr 22 2014 reading ACTUAL	5588
CCF Used for METER#	45
Thermal Factor	x1.0363
Total therms used	47

Your Cost is determined as follows:

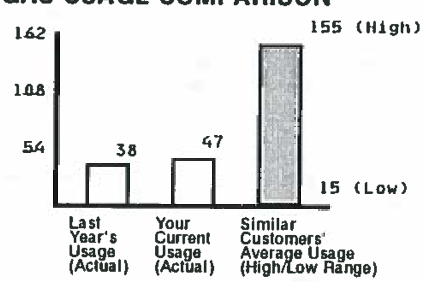
Minimum Charge (First 3.0 therms or less)	$20.77
Next 44.0 @ $.5901	25.96
Delivery Rate Adjustment: @ $.08021 /therm	3.77
System Benefits Charge: @ $.02370 /therm	1.11
MTA Surcharge	.10
GAS DELIVERY CHARGE	$51.71
GAS SUPPLY CHARGE @ $.63360 /therm	29.78
MTA Surcharge	.06
4.5000 % Sales Tax	1.34
Supply Subtotal	$31.18
4.5000 % Sales Tax on Gas Delivery	2.33
Bill. Charge (incl. tax & surchg)	.83
TOTAL CURRENT CHARGES	$86.05

SUMMARY OF CHARGES

Total Current Charges	$86.05
Amount Due Last Bill	138.08
Your Total Payments Since Last Bill. Thank You!	-138.08
Please Pay Upon Receipt	$86.05

If payment received after 06/14/2014 a late payment charge of $1.29 (1.5% of outstanding charges) may be added.

YOUR GAS USAGE COMPARISON



During this period the average temperature

IMPORTANT MESSAGES

The Billing Charge, now shown separately, is not charged when you buy gas supply from an ESCO that includes its charges on our bills; one of several savings opportunities. It has been separated from the Minimum Charge, which has been reduced, so there is no effect on your overall cost.

Your unique online Access Code is:
We're online, anytime! View and pay your bill, check your balance, submit meter readings. The code above provides free, instant access with "My Account" - visit www.nationalgridus.com. Many automated services are also available at the telephone number above.

nationalgrid www.nationalgridus.com

See back for definitions of terms used in this bill and more information.

Bill Payment
Bills may be paid at any National Grid Customer Service Center on weekdays from 8:30 a.m. to 5:00 p.m. or at Authorized Payment Locations in Brooklyn, Queens, and Staten Island. A list of locations is available online and upon request.

DirectPay Service
Have your bill payments transferred automatically from your checking or savings account. Enroll online or call.

National Grid
P.O. Box 11741
Newark, NJ 07101-9839

Moving?
Please give 10 days' notice when moving.
Make your move easier - open or close an account at **www.nationalgridus.com.**

Tear here

Please be sure the address above appears in the return envelope window.
For greater convenience, pay your bill online, anytime, at : **www.nationalgridus.com**

Tear here

Billing or Service Questions
***Call (718) 643-4050** or visit a National Grid Customer Service Center. Call us first! Most questions can be answered by telephone. Please speak to a Supervisor if you need additional help. If you prefer to write include a note with your payment and mail to: National Grid, Attn: Customer Correspondence, One MetroTech Center,16th Floor, Brooklyn, NY 11201.

Billing Rate Schedule:
Your billing rate is shown on the front. A complete rate schedule is available upon request.

Customer Service Centers:
Open weekdays from 8:30 a.m. to 5:00 p.m.
Brooklyn
-One MetroTech Center (Jay St. near Willoughby St.)
-1535 Pitkin Avenue
Queens
-89-67 162nd Street
Staten Island
- 2031 Forest Avenue (Corner of Maple Pkwy)

Special Customer Services:
Hearing or Speech-Impaired Customers
Call TTY Line (718) 237-2857
Services for Sight Impaired Customers
Braille and large print bills are available.
Senior Citizen/Disabled Customer Programs
Financial Assistance Programs
Call (718) 403-2171

Visit National Grid Online:
Check your latest account status, view and pay your bill, or provide a meter reading, 24 hours a day, 7 days a week at **www.nationalgrid.us.com.**

Payment Address:
Our payment address is: National Grid, P.O. Box 11741, Newark, NJ 07101-9839

Statement of Account:
A comprehensive statement of your account showing your past use and bills is available online or upon request.

Notice About Electronic Check Conversion:
When you mail a check as payment, you authorize us to use information from your check to withdraw funds from your account either as a one-time electronic fund transfer (EFT) or as a check transaction.

When we process an EFT, funds may be withdrawn from your account as soon as the same day we receive your payment and your financial institution will not return the check to you.

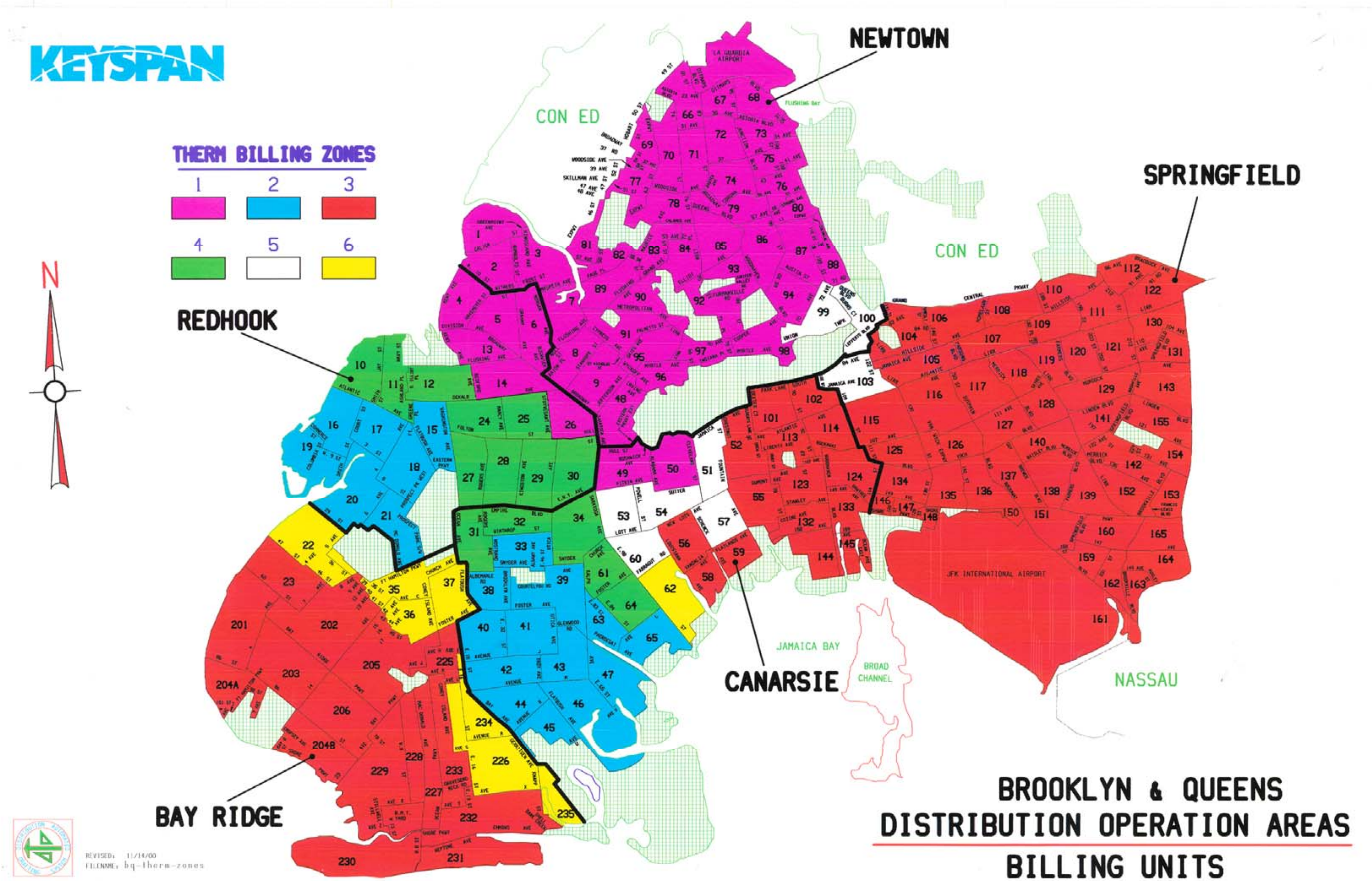
Understanding Terms On Your Bill:
CCF: The unit of gas volume (100 cubic feet) as measured by your meter.
Thermal Factor: The factor that converts the quantity of gas used (CCF) to a quality measurement (Therms).
Therm: A unit of heat content equal to 100,000 British Thermal Units (BTU). A BTU represents the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. The number of CCFs is multiplied by a conversion factor to determine the therms used. The number of therms is used to determine the gas charges on your bill.
Fixed Factor Multiplier: Due to their design, some meters record a fraction of the total usage. The multiplier is used to convert the recorded meter reading on these types of meters to total actual consumption.

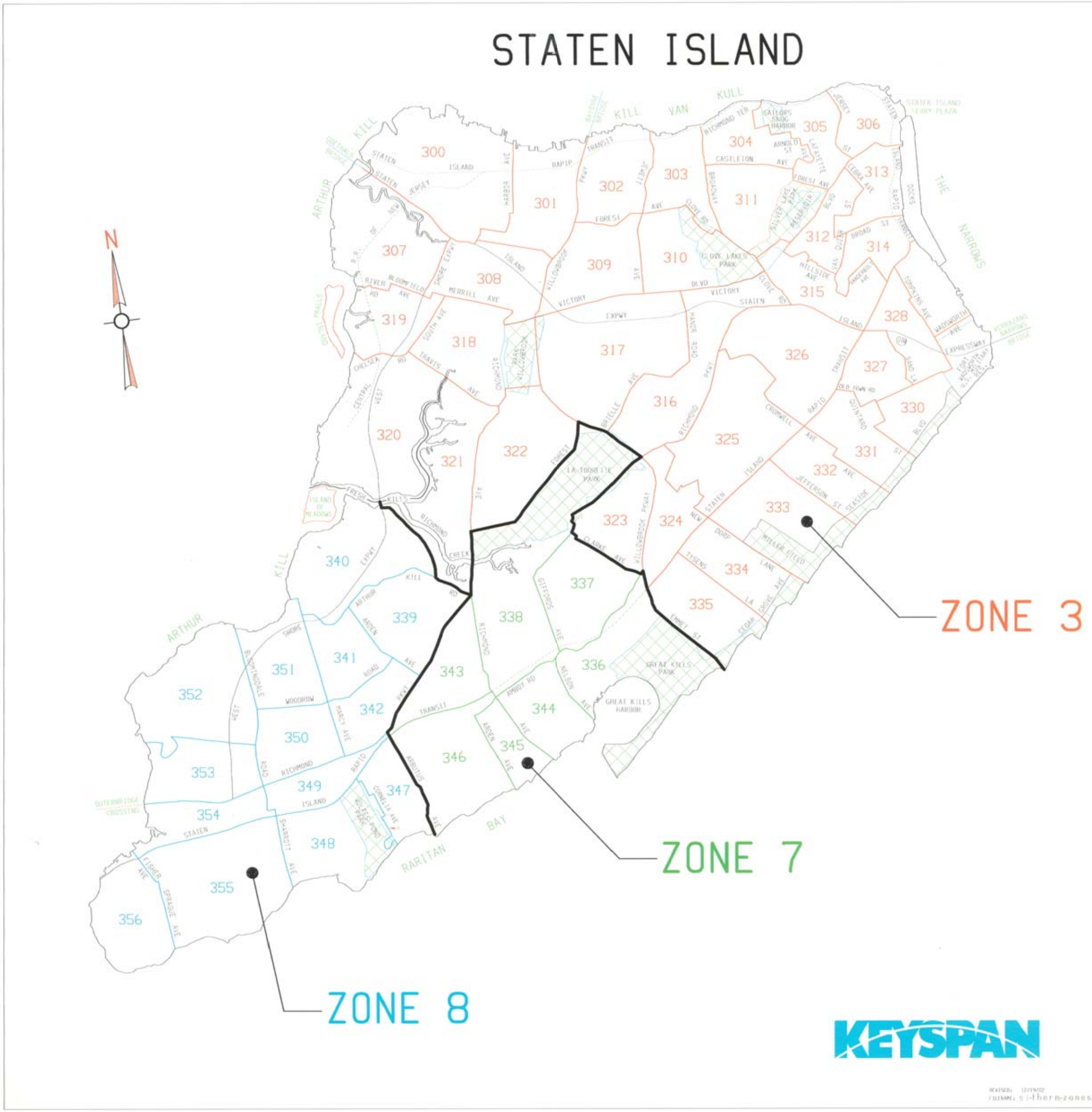
Gas Delivery Charge: The **Minimum Charge** is a fixed charge prorated for the number of days of service. The **Billing Charge** reflects costs associated with issuing bills and processing payments. If you buy gas supply from an ESCO who does not bill its charges separately, you avoid the Billing Charge. The **Delivery Rate Adjustment** includes the Incremental State Assessment Surcharge (in accordance with NYS Public Service Law Section 18-a), the Site Investigation and Remediation Surcharge (recovers deferred site remediation costs) and weather-related debits and/or credits (heating customers only). The **System Benefits Charge** recovers the cost of energy efficiency programs. It also includes State and City Gross Receipts Tax (4.548% Residential; 2.407% Commercial).

Gas Delivery Adjustment: The cost of storing and transporting natural gas. It also includes Gross Receipts Tax (2.407%).

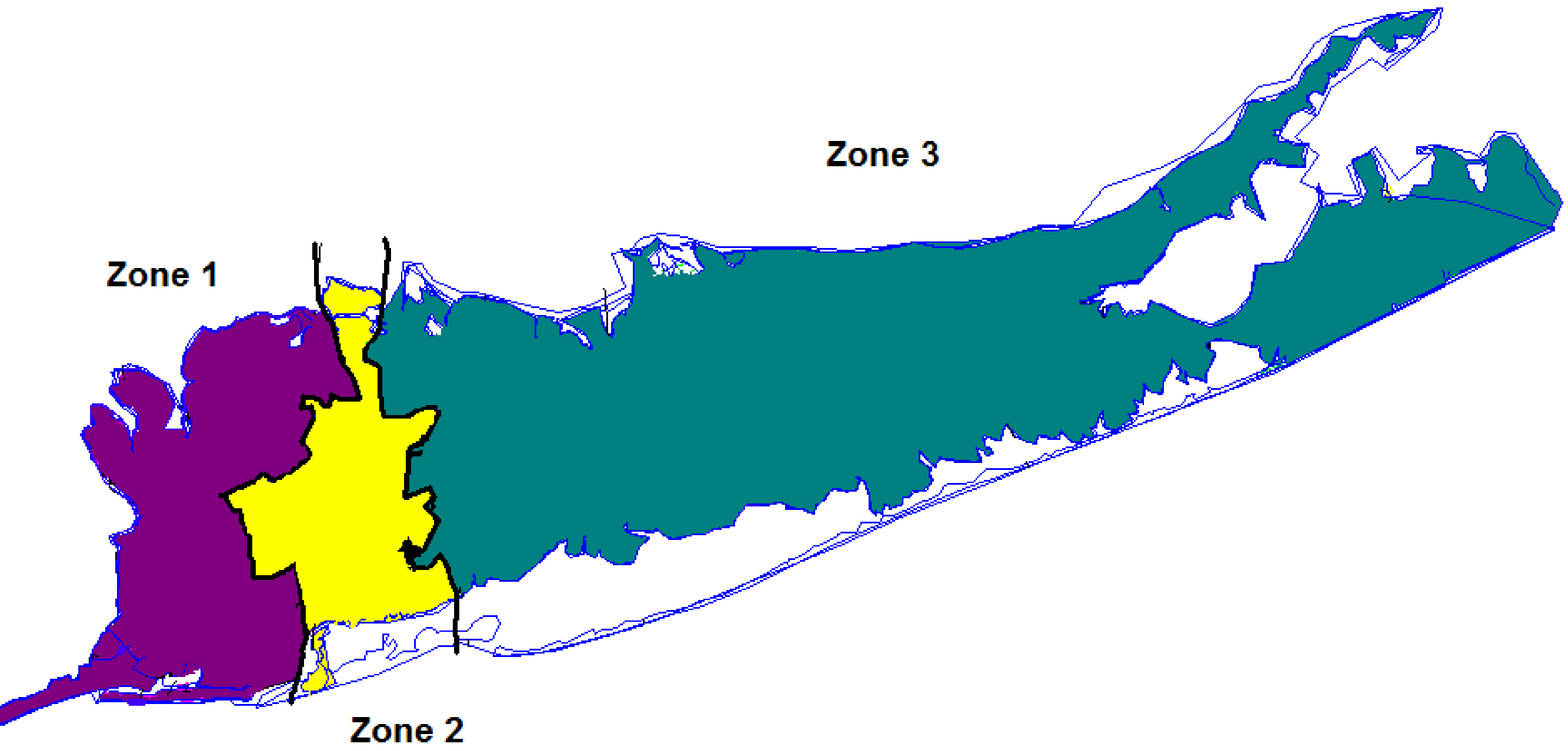
Gas Supply Charge: A charge to reflect the Company's cost of gas purchased from suppliers and transporting the gas to the Company's distribution system. If you choose an alternate supplier, the price will be what you agree upon with that supplier. It also includes Gross Receipts Tax (2.407%).

MTA Surcharge: State imposed taxes on utilities to maintain mass transit fares.
Sales Tax: The Company is required to collect state and local sales tax in all NY State counties. Some school districts also impose sales tax.


KEYSPAN
THERM BILLING ZONES
1 2 3
4 5 6
N
NEWTOWN
SPRINGFIELD
REDHOOK
CANARSIE
BAY RIDGE
CON ED
CON ED
NASSAU
JAMAICA BAY
BROAD CHANNEL
JFK INTERNATIONAL AIRPORT
LA GUARDIA AIRPORT
BROOKLYN & QUEENS
DISTRIBUTION OPERATION AREAS
BILLING UNITS
REVISED: 11/14/00
FILENAME: bq-therm-zones


STATEN ISLAND
N
ZONE 3
ZONE 7
ZONE 8
KEYSPAN
KILL VAN KULL
ARTHUR KILL
THE NARROWS
RARITAN BAY
300
301
302
303
304
305
306
307
308
309
310
311
312
313
314
315
316
317
318
319
320
321
322
323
324
325
326
327
328
330
331
332
333
334
335
336
337
338
339
340
341
342
343
344
345
346
347
348
349
350
351
352
353
354
355
356

KEDLI Therm Zones



Date of Request: May 2, 2016
Due Date: May 12, 2016

DPS Request No. DPS-476 CS-3
KEDNY/ KEDLI Req. No. BULI-618

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, Claude Semexant

TO: National Grid, Sean Mongan

SUBJECT: **SALES PROMOTION EXPENSE - KEDNY**

Request:

1. On p. 7 of your KEDLI testimony, you identified that there are more than 400,000 residential and commercial structures in KEDLI's service territory without gas service, and another 100,000 non-heat customers. Does KEDNY have similar statistics for its service territory and to the extent that the Company has this information, distinguish between those residential and commercial structures in KEDNY's service territory that are located along existing mains and those that will require an extension to serve their needs.

2. Referring to the Companies' response to information request DPS-426, Question 2, the response shows Sales Promotion Costs associated with residential rebates regarding KEDLI, however, there is no such detail shown in the Companies' response to information request DPS-427 regarding KEDNY. Explain why rebates are not being used in the KEDNY service territory.

Response:

1. The Company regularly produces a "saturation study" that uses public real estate data and gas account information to estimate the gas conversion potential as a function of the approximate distance to main. The table below shows an excerpt from that analysis for KEDNY's service territory.

KEDNY		Commercial	Multi-Family	Residential	Total
Non Heat	ON MAIN	12,122	5,804	65,664	**83,590**
Prospects	ON MAIN*	14,069	2,762	16,865	33,696

Gas Saturation Study as of July 2015 * All buildings in NYC are assumed On Main

2. Rebates for gas conversions are utilized in KEDNY's service territory, but at a significantly lower level due to the following:

   - high saturation of natural gas in the territory; and
   - new construction is driving the market.

   The Historic Test Year shown in Mr. Mongan's testimony (Exhibit __ SPM-1) included spending on rebates of $94,900, which was for conversions. Since the vast majority of customers in KEDNY's service territory do not require a new service in connection with a conversion, no incremental spending for rebates in NYC is proposed except for the proposed incentive for NGVs. Where rebates are used to promote conversions, such rebates are predominantly provided in the Multifamily market.

Name of Respondent:
Keith Sperling/Chris Cavanagh

Date of Reply:
May 9, 2016

Date of Request: May 5, 2016 DPS Request No. DPS-482 JS-10
Due Date: May 16, 2016 KEDNY/ KEDLI Req. No. BULI-627

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, John Sano

TO: National Grid, GIOP

SUBJECT: Information Systems Issues – Gas Transportation Information System (GTIS)

Request:

Referring to the Companies' response to information request DPS-350, Staff requested and received the year-to-date fiscal year budgeted versus actual expenditure amounts related to the GTIS system, temporary bulletin board, and staffing modifications during implementation of the GTIS system beginning in 2006. See the table of information provided below:

GTIS Financials ($000) as of February 29, 2016						
FY	**O&M**			**Capital**		
	Sanctioned	**Spent**	**Variance**	**Sanctioned**	**Spent**	**Variance**
FY10	196.0	2.1	(193.9)	600.0	599.0	(1.0)
FY11	202.0	64.2	(137.8)	2,500.0	2,500.0	826.5
FY12	23.0	3.1	(20.0)	2,820.0	3,014.1	194.2
FY13	24.0	14.7	(9.3)	1,779.0	775.0	(1,004.0)
FY14	404.0	293.5	(110.5)	1,110.0	1,631.1	521.1
FY15	81.0	43.3	(37.7)	7,044.0	4,635.0	(2,409.0)
FY16	267.0	134.5	(132.5)	4,852.0	4,215.0	(637.0)
Total	1,197.0	555.4	(641.6)	20,705.0	17,369.2	(3,335.8)
FY17	365.0			995.0		

Note that the total capital spend in the table above includes the $10.150 million for Customer Choice ESCO Gas project discussed in the Testimony of the Revenue Requirements Panel, as well as additional costs from other GTIS projects besides the Customer Choice ESCO Gas project

1. The Company notes the total capital spent is $17.369 million, and that is made up of costs for the Customer Choice ESCO Gas project as well as costs from other GTIS projects. The service company rent expense schedules, contained in Exhibit __ (RRP-11CU), Workpapers to Exhibit RRP-3CU, Schedule 9, Workpaper 2 for both KEDNY and KEDLI a listing of all the information services (IS) capital projects, the assets held at the service company level, and the costs expected to be incurred in rate year for either new or existing IS projects, and those that are included in the O&M rent expense cost element as well. Provide a list identifying every project (by line item) from both the attached KEDLI listing and the similar that comprises the $17.369 million shown in the table above.

2. For each project identified in response to question (1) above, provide a breakdown of costs in a format similar to the table above. The information should be broken down by specific project, and by year. Provide the information separately for KEDLI and KEDNY.

<u>Response</u>:

1) and 2)

Please see Attachment 1 for the projects that comprise $17,804,287 million in total capital spend for GTIS projects from FY2010 through February 2016. Please note that the Companies erroneously provided a total capital spend of $17.369 million in response to DPS-350. A total capital spend of $17,804,287 is reflected in the general ledger for GTIS projects, including the Customer Choice ESCO Gas project.

In the course of preparing Attachment 1, the Companies identified certain existing Service Company assets/projects that were not included in Exhibit __ (RRP-11-CU), Workpapers to Exhibit ___ (RRP-CU), Schedule 9, Workpaper 2 for both KEDNY and KEDLI. Attachment 2 identifies the missing projects and the total rent expense impact to KEDNY and KEDLI. The missing projects included three work orders for the GTIS project performed as part of investments INVP 1182 and INVP 1182B that delivered an early version of GTIS.
.

Work Order	INVP#	Total US Spend
1TXFER00099	1182	$3,866,615
900000124369	1182	$1,780,960
900000124375	1182B	$1,675,640

An updated Exhibit __ (RRP-11CU), Workpapers to Exhibit ___ (RRP-3CU), Schedule 9, Workpaper 2 is also included in Attachment 2.

With respect to the Customer Choice ESCO gas project in particular, of the $17,804,287 included in Attachment 1, only $10,150,478 relates to the total capital spend for the Customer Choice ESCO Gas project as shown in Exhibit_(RRP-11CU), Workpapers to RRP-3CU, Schedule 9, Workpaper 2 (line 10). In their Corrections and Updates filings, the Companies made a further adjustment to remove their share of $521,285 representing the AFUDC amount for project delays from the initial target GTIS implementation date of November 1, 2014 through the anticipated implementation date of April 30, 2016. As a result of this adjustment, the Companies' rent expense for the Customer Choice ESCO Gas project is based on a total US spend of $9,629,193.

<u>Name of Respondent</u>:
Christophe Chirol
Thomas Gill

<u>Date of Reply</u>:
May 16, 2016

GTIS Financials - INVP1182

	OPEX			CAPEX		
	Sanctioned	Spent	Variance	Sanctioned	Spent	Variance
FY10	$ 196,000	$ 192,236	$ (3,764)	$ 600,000	$ 599,000	$ (1,000)
FY11	$ 202,000	$ 64,156	$ (137,844)	$ 1,673,000	$ 2,028,588	$ 355,588
FY12	$ 23,000	$ 3,050	$ (19,950)	$ 2,820,000	$ 2,927,964	$ 107,964
FY13			$ -		$ 81,622	$ 81,622
FY14			$ -		$ -	$ -
FY15			$ -		$ 10,401	$ 10,401
Total	$ 421,000	$ 259,442	$ (161,558)	$ 5,093,000	$ 5,647,575	$ 554,575

GTIS Financials - INVP1182B

	OPEX			CAPEX		
	Sanctioned	Spent	Variance	Sanctioned	Spent	Variance
FY13 (Oct&Mar)	$ 24,000	$ 30,284	$ 6,284	$ 1,779,000	$ 1,644,095	$ (134,905)
FY14		$ 305	$ 305		$ 31,545	$ 31,545
Total	$ 24,000	$ 30,589	$ 6,589	$ 1,779,000	$ 1,675,640	$ (103,360)

GTIS Financials - INVP3564 (as of February 29th, 2016)

	OPEX			CAPEX		
	Sanctioned	Spent	Variance	Sanctioned	Spent	Variance
FY14	$ 404,000	$ 293,452	$ (110,548)	$ 1,110,000	$ 1,631,147	$ 521,147
FY15	$ 81,000	$ 43,257	$ (37,743)	$ 7,044,000	$ 4,634,955	$ (2,409,045)
FY16	$ 267,000	$ 134,455	$ (132,545)	$ 4,852,000	$ 4,214,970	$ (637,030)
Total	$ 752,000	$ 471,163	$ (280,837)	$ 13,006,000	$ 10,481,072	$ (2,524,928)

KeySpan Gas East Corporation
d/b/a National Grid
The Brooklyn Union Gas Company
d/b/a National Grid NY
Case 16-G-0058 and 16-G-0059
Attachment 2 to DPS-482 JS-10 BULI-627

GTIS Financials - INVP1182

	OPEX			CAPEX		
	Sanctioned	Spent	Variance	Sanctioned	Spent	Variance
FY10	$ 196,000	$ 192,236	$ (3,764)	$ 600,000	$ 599,000	$ (1,000)
FY11	$ 202,000	$ 64,156	$ (137,844)	$ 1,673,000	$ 2,028,588	$ 355,588
FY12	$ 23,000	$ 3,050	$ (19,950)	$ 2,820,000	$ 2,927,964	$ 107,964
FY13			$ -		$ 81,622	$ 81,622
FY14			$ -		$ -	$ -
FY15			$ -		$ 10,401	$ 10,401
Total	$ 421,000	$ 259,442	$ (161,558)	$ 5,093,000	$ 5,647,575	$ 554,575

GTIS Financials - INVP1182B

	OPEX			CAPEX		
	Sanctioned	Spent	Variance	Sanctioned	Spent	Variance
FY13 (Oct&Mar)	$ 24,000	$ 30,284	$ 6,284	$ 1,779,000	$ 1,644,095	$ (134,905)
FY14		$ 305	$ 305		$ 31,545	$ 31,545
Total	$ 24,000	$ 30,589	$ 6,589	$ 1,779,000	$ 1,675,640	$ (103,360)

GTIS Financials - INVP3564 (as of February 29th, 2016)

	OPEX			CAPEX		
	Sanctioned	Spent	Variance	Sanctioned	Spent	Variance
FY14	$ 404,000	$ 293,452	$ (110,548)	$ 1,110,000	$ 1,631,147	$ 521,147
FY15	$ 81,000	$ 43,257	$ (37,743)	$ 7,044,000	$ 4,634,955	$ (2,409,045)
FY16	$ 267,000	$ 134,455	$ (132,545)	$ 4,852,000	$ 4,214,970	$ (637,030)
Total	$ 752,000	$ 471,163	$ (280,837)	$ 13,006,000	$ 10,481,072	$ (2,524,928)

KeySpan Gas East Corporation
d/b/a National Grid
The Brooklyn Union Gas Company
d/b/a National Grid NY
Case 16-G-0058 and 16-G-0059
Attachment X to DPS-482 JS-10 BULI-627

Missing Projects Adjustment - Service Company Rents

Information Systems Projects (As Reported in DPS-395)

	Rate Year 1	Data Year 1	Data Year 2
KEDNY	$ 13,623,116	$ 13,810,462	$ 15,842,291
KEDLI	$ 9,053,489	$ 9,225,013	$ 10,362,599
Total	**$ 22,676,604**	**$ 23,035,474**	**$ 26,204,890**

Information Systems Projects (With Missing Projects)

	Rate Year 1	Data Year 1	Data Year 2
KEDNY	$ 16,099,834	$ 16,049,098	$ 17,268,746
KEDLI	$ 10,415,299	$ 10,435,048	$ 11,169,813
Total	**$ 26,515,133**	**$ 26,484,146**	**$ 28,438,559**

Information Systems Projects (Difference)

	Rate Year 1	Data Year 1	Data Year 2
KEDNY	$ 2,476,719	$ 2,238,636	$ 1,426,455
KEDLI	$ 1,361,810	$ 1,210,036	$ 807,215
Total	**$ 3,838,529**	**$ 3,448,672**	**$ 2,233,670**

KeySpan Gas East Corporation
d/b/a National Grid
The Brooklyn Union Gas Company
d/b/a National Grid NY
Case 16-G-0058 and 16-G-0059
Attachment X to DPS-482 JS-10 BULI-627

		KEDNY	Rate Year	Data Year 1	Data Year 2
1TXFER00099	GAS SCADA Upgrade/Modernize	38.38%	$ 112,432	$ -	$ -
1TXFER00099	GTIS	68.37%	$ 420,727	$ 398,256	$ 162,039
90000124369	GTIS	38.38%	$ 120,888	$ 115,078	$ 109,268
90000124368	Meter Route Consolidation	38.38%	$ 27,410	$ 26,071	$ 24,732
90000124375	GTIS	58.10%	$ 169,421	$ 161,146	$ 152,870
90000104112	IN1656-CUST.Systems Agent desktop	68.37%	$ 1,145,726	$ 1,085,073	$ 612,320
90000106246	IN2330 ETRM Repl Nucleus-Gas Benef	30.66%	$ 298,244	$ 282,593	$ 203,142
90000124371	IN2366 LI CNI Direct HW Upgrade	68.37%	$ 8,126	$ 7,737	$ 7,348
90000144051	INVP2960C GridForce SaaS Phase 2	30.66%	$ 173,745	$ 162,683	$ 154,736
			$ 2,476,719	**$ 2,238,636**	**$ 1,426,455**

		KEDLI	Rate Year	Data Year 1	Data Year 2
1TXFER00099	GAS SCADA Upgrade/Modernize	28.55%	$ 83,635	$ -	$ -
1TXFER00099	GTIS	31.63%	$ 194,641	$ 184,245	$ 74,964
90000124369	GTIS	28.55%	$ 89,926	$ 85,604	$ 81,282
90000124368	Meter Route Consolidation	28.55%	$ 20,389	$ 19,394	$ 18,398
90000124375	GTIS	30.27%	$ 88,268	$ 83,957	$ 79,645
90000104112	IN1656-CUST.Systems Agent desktop	31.63%	$ 530,047	$ 501,987	$ 283,278
90000106246	IN2330 ETRM Repl Nucleus-Gas Benef	22.81%	$ 221,883	$ 210,240	$ 151,130
90000124371	IN2366 LI CNI Direct HW Upgrade	31.63%	$ 3,759	$ 3,579	$ 3,399
90000144051	INVP2960C GridForce SaaS Phase 2	22.81%	$ 129,261	$ 121,030	$ 115,119
			$ 1,361,810	**$ 1,210,036**	**$ 807,215**
	Total Impact		**$ 3,838,529**	**$ 3,448,672**	**$ 2,233,670**

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service Date	(f) Amortization Period
1	DMS/OMS Replacement	1185	$60,613,682	G198		$66,772,709	1/1/2016	84
2	Gas GIS Consolidation	2577	$2,213,069	G210		$5,573,069	4/1/2019	84
3	AMAG Upgrades	1172	$3,698,542	G020		$5,991,812	10/1/2016	84
4	US CNI DKMS	3019A	$249,414	G098	(249,414)	$0	3/1/2017	84
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84
6	NE GAS LEAKS RECHECKS	3136	$1,244,826	G310		$1,788,826	8/1/2016	84
7	CI Services Foundation	3492	$2,197,232	G020		$2,644,306	2/1/2016	84
8	US CNI Frame Relay Replacement	2495H	$6,071,268	G210		$6,398,268	12/1/2015	84
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84
10	Customer Choice ESCO Gas	3564	$7,774,478	C225	(521,285)	$9,629,193	4/1/2016	84
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84
12	Challenge the Limits XML	3375B	$603,192	C179		$603,192	10/1/2015	84
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$661	G020		$1,240,600	9/1/2016	84
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84
17	CNI Network Security - (Cyber Security)	3614B7	$556,501	G020		$3,801,588	9/1/2016	84
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$144,307	G020		$1,362,769	6/1/2016	84
19	CNI Patch Management - (Cyber Security)	3614B11	$3,903	G020	(3,903)	$0	1/1/2099	84
20	CNI Network Security Controls - (Cyber Security)	3614B13	$4,206	G020	(4,206)	$0	1/1/2099	84
21	CNI SIEM - (Cyber Security)	3614B14	$0	G020		$1,106,000	9/1/2016	84
22	Enterprise Network Security - (Cyber Security)	3614D1	$3,000,805	G020		$5,946,273	9/1/2016	84
23	Network Risk & Compliance - (Cyber Security)	3614D2	$2,363	G020	(2,363)	$0	1/1/2099	84
24	Security Operations Center - (Cyber Security)	3614E2	$27,818	G020		$1,461,890	4/1/2016	84
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$0	G020		$121,600	4/1/2016	84
26	Security Reference Architecture - (Cyber Security)	3614G1	$0	G020		$60,800	9/1/2016	84
27	Cyber Security prioritised investments - (Cyber Security)	3614	$0	G020		$725,146	9/1/2016	84
28	NY Retail Access	3839	$2,088,663	G170		$2,872,399	12/1/2016	84
29	US Web Initiatives 2	3600B	$3,402,522	C175		$3,831,522	2/1/2016	84
30	Capitalized Asset Replacement	3617C	$882,109	G084		$935,395	4/1/2016	84
31	UNY Capitalized Asset Replacement	3617D	$134,169	G003		$265,077	4/1/2016	84
32	DSNY Capitalized Equipment Installs - Physical Security	3617B		G235		$475,000	4/1/2016	84
33	Pelco Video System Conversion - Physical Security	3841		G077		$480,000	4/1/2016	84
34	NMPC C-Cure Conversion to AMAG	3853	$485,308	G003		$1,182,427	3/1/2017	84
35	EHR1 - PMO		$6,218,548	G012		$8,928,548	12/1/2015	84
36	EHR1 - Supply Chain		$10,339,439	G012		$14,769,439	12/1/2015	84
37	EHR1 - Finance		$15,565,346	G012		$16,145,346	12/1/2015	84
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84
39	EHR1 - Payroll		$10,937,165	G012		$12,187,165	12/1/2015	84
40	EHR1 - BPS		$5,115,257	5020		$9,915,257	12/1/2015	84
41	Customer Storm Outage Credit Program	3859	$165,018	5210	(165,018)	$0	3/1/2015	84
42	US CNI GMS SCADA Upgrade	3737	$41,564	C210		$5,739,504	1/1/2019	84
43	US Desktop Refresh	2927	$5,813,532	G020		$7,430,690	3/1/2016	48
44	Internet Explorer Upgrade	3644	$137,061	G020		$300,090	3/1/2016	84
45	Mobile Device for PTO	3883	$242,471	G173		$2,442,471	9/1/2016	48
46	SMI Conversion Mobilization	3896	$402,655	G020		$2,187,292	7/1/2016	84
47	S005242 M112 Systemic Improvement		$843,635	G012		$3,500,000	3/1/2016	12
48	Cadency Account Reconciliation Tool		$146,894	G012		$146,894	3/1/2016	12
49	Soft Off Program	4024	$836,485	C207		$1,278,485	2/1/2016	84
50	LI CSS Stabilization	4133	$0	5230		$847,000	3/1/2016	84
51	Mobile Capture of Data Fusion	4102	$0	G207		$1,580,000	10/1/2016	84
52	Gas GIS Upgrade	2577C	$0	G210		$1,200,000	10/1/2016	84
53	NY Pipeline Safety CMS Regulatory Compliance	3882	$0	G207		$3,374,000	10/1/2016	84
54	Massachusetts Gas 4 Hour Appointment Window	4074	$32,254	C310		$166,254	3/1/2016	84
55	Voice Record Elec Control Rooms	3851	$0	G186		$2,300,000	12/1/2016	84
56	Team Center Replacement or Upgrade	3958	$0	G236		$600,000	10/1/2016	84
57	US CNI NY EMS-Conversion to MPLS	3970	$0	G181		$160,000	5/1/2016	84
58	Legacy VSTIG Migration and Decommission	3538		G020		$1,501,788	9/1/2017	84
59	Remote Net Metering	4124		G194		$910,000	9/1/2016	84
60	RI Renewable Energy Growth	4055	$318,786	5360E		$673,000	4/1/2016	84
61	US Mobile Device Refresh	2935		G173		$4,000,000	4/1/2017	48
62	US Mobile Device Refresh	2935		G173		$0	4/1/2018	48
63	US Mobile Device Refresh	2935		G173		$0	4/1/2019	48
64	KEDNY AMR Project - FDM Interface to CRIS	4183		5220		$356,000	9/1/2016	84
65	Cross Company Customer System Enhancements	4172		C246		$9,143,000	9/1/2016	84
66	New Redundant SCC	3840		G020		$900,000	3/1/2017	84
67	Capitalized Asset Replacement - Physical Security	3617C		G084		$736,000	4/1/2017	84
68	Capitalized Asset Replacement - Physical Security	3617C		G084		$0	4/1/2018	84
69	Capitalized Asset Replacement - Physical Security	3617C		G084		$0	4/1/2019	84
70	Capitalized Asset Replacement - Physical Security	3617C		G084		$0	4/1/2020	84
71	UNY Capitalized Asset Replacement - Physical Security	3617D		G003		$482,000	4/1/2017	84
72	UNY Capitalized Asset Replacement - Physical Security	3617D		G003		$0	4/1/2018	84
73	UNY Capitalized Asset Replacement - Physical Security	3617D		G003		$0	4/1/2019	84
74	UNY Capitalized Asset Replacement - Physical Security	3617D		G003		$0	4/1/2020	84
75	DSNY Capitalized Equipment Installs - Physical Security	3617B		G235		$649,000	4/1/2017	84
76	DSNY Capitalized Equipment Installs - Physical Security	3617B		G235		$0	4/1/2018	84
77	DSNY Capitalized Equipment Installs - Physical Security	3617B		G235		$0	4/1/2019	84
78	DSNY Capitalized Equipment Installs - Physical Security	3617B		G235		$0	4/1/2020	84
80	Field PC Refresh	2935	$49,570	5230		$963,188	2/1/2016	48
81	Field PC Refresh	2935	$155,070	5220		$1,417,990	1/1/2016	72
82	Access Violation (& Regulation) Management	3922		G020		$290,000	4/1/2017	84
83	Active Directory Upgrade	4287		G020		$350,000	4/1/2017	84
84	Advanced Analytics	3902		G020		$0	4/1/2019	84
85	US CNI Intrusion Detection and Prevention - Phase 1 (Cyber Security)	3863		G020		$350,000	4/1/2018	84
86	US CNI Intrusion Detection and Prevention - Phase 2 (Cyber Security)	3863		G020		$0	4/1/2020	84
87	Risk Based Authentication (Cyber Security)	3863		G020		$235,080	6/1/2017	84
88	Enhanced Phishing Protection (Cyber Security)	3863		G020		$120,000	8/1/2017	84
89	Security Incident Management (SIEM) 4 (Cyber Security)	3863		G020		$0	5/1/2019	84
90	Security Incident Management (SIEM) 5 (Cyber Security)	3863		G020		$0	5/1/2020	84
91	Identity & Access Management - Role Based Access Management (Cyber Security)	3863		G020		$1,650,000	10/1/2017	84
92	Identity & Access Management - Fine Grain Access Management (Cyber Security)	3863		G020		$0	4/1/2018	84
93	Identity & Access Management - Privileged Access Management (Cyber Security)	3863		G020		$0	4/1/2019	84
94	Identity & Access Management - Shared Area Access Management (Cyber Security)	3863		G020		$0	4/1/2020	84
95	US CNI Security Enhancements - CSP 2 - Phase 1 (Cyber Security)	3863		G020		$990,000	11/1/2018	84
96	US CNI Security Enhancements - CSP 2 - Phase 2 (Cyber Security)	3863		G020		$0	11/1/2021	84
97	Big Data Security Analytics - Phase 1 (Cyber Security)	3863		G020		$1,155,388	5/1/2019	84
98	Big Data Security Analytics - Phase 2 (Cyber Security)	3863		G020		$0	5/1/2021	84
99	Enhanced DLP Gateway and Endpoint (Cyber Security)	3863		G020		$1,305,780	12/1/2017	84
100	Cloud Security (Cyber Security)	3863		G020		$1,460,000	5/1/2017	84
101	Situational Intelligence & Cyber Intelligence - Phase 1 (Cyber Security)	3863		G020		$100,000	11/1/2017	84
102	Situational Intelligence & Cyber Intelligence - Phase 2 (Cyber Security)	3863		G020		$0	11/1/2019	84
103	IT/OT Discovery & Implementation - Phase 1 (Cyber Security)	3863		G020		$0	10/1/2019	84
104	IT/OT Discovery & Implementation - Phase 2 (Cyber Security)	3863		G020		$0	10/1/2021	84
105	vStig Scaling - Upgrades (Cyber Security)	3863		G020		$0	8/1/2018	84
106	Domain Based Security - Phase 1 (Cyber Security)	3863		G020		$0	4/1/2019	84
107	Domain Based Security - Phase 2 (Cyber Security)	3863		G020		$0	4/1/2020	84
108	Security Research Lab (Cyber Security)	3863		G020		$0	4/1/2020	84
109	Threat Behavior Modeling (Cyber Security)	3863		G020		$800,000	3/1/2017	84
110	Enterprise Content Management (ECM) - Archiving	1134		G020		$0	4/1/2020	84
111	Enterprise Content Management (ECM) Foundation Services (US only) - Upgrade	3995		G020		$0	4/1/2020	84
112	Global Audit System Replacement	3673		G020		$0	3/1/2020	84
113	Global Governance, Risk & Compliance	2940		G020		$0	6/1/2019	84
114	HRIS Strategy Transformation Program	4144		G020		$0	4/1/2021	84
115	IS Legacy Systems Archiving & Decommission	3631		G020		$0	7/1/2020	84
116	Mobility - Mobile Application Development Platform (MADP) (US only)	3996		G020		$0	3/1/2019	84
117	Mobility - Mobile Device Management (MDM) System	3430		G020		$100,000	3/1/2017	84
118	Office 365	3999		G020		$0	10/1/2019	84
119	RAS Re-Platform/Mobile	4269		G020		$400,000	4/1/2017	84
120	Desktop XP to Win7	4308		G020		$5,960,000	4/1/2018	84
121	Talent Management	3674		G020		$0	10/1/2020	84
122	UPS Replacement for Data Communication Closets	4003		G020		$0	4/1/2019	84
123	US Global Security TWIC Compliance	4023		G020		$270,000	4/1/2018	84
124	US Network Improvements	4289		G020		$350,000	4/1/2017	84
125	VC Room/Mobile Refresh	3424		G020		$0	4/1/2019	84
126	VSTIG Hardware Refresh	4274		G020		$300,000	4/1/2017	84
127	VSTIG upgrade Phase 2	4280		G020		$2,600,000	4/1/2017	84
128	VSTIG upgrade Phase 3	4266		G020		$1,300,000	4/1/2017	84
129	Wireless Network Expansion	3425		G020		$1,600,000	6/1/2017	84
130	Mandated Customer Systems Projects - FY16	4094		C173		$828,000	4/1/2016	84
131	Mandated Customer Systems Projects - FY17	4207		C173		$4,000,000	4/1/2017	84
132	Mandated Customer Systems Projects - FY18	4207		C173		$0	4/1/2018	84
133	Mandated Customer Systems Projects - FY19	4207		C173		$0	4/1/2019	84
134	Mandated Customer Systems Projects - FY20	4207		C173		$0	4/1/2020	84
135	Customer Contact Center / SDC Technology Upgrade Implement Solution	3932		C173		$1,403,000	4/1/2019	84
136	Meter To Cash Value Added Enhancements	3869		C173		$0	4/1/2019	84
137	Meter To Cash Value Added Enhancements	3869		C173		$0	4/1/2020	84
138	Credit & Collections Gap Analysis and Protections	4211		C173		$0	4/1/2019	84
139	Eliminate SSN from Customer Systems	4216		C173		$0	4/1/2019	84
140	Credit and Collections - Bad Debt Mitigation Initiatives	[illegible]		C173		$0	4/1/2018	84

Service Company Capital Software allocated to Operating Companies at Rate Expense

#	Investment Name	ISOP #	Inception to Date	Bill Pool	Adjustments	Total US Spend	In Service Date	Amortization Period		
110	Enterprise Content Management (ECM) - Archiving	1134	$0	G020		$0	4/1/2020	84	$ -	$ -
111	Enterprise Content Management (ECM) Foundation Services (US only) - Upgrade	3995	$0	G020		$0	4/1/2020	84	$ -	$ -
112	Global Audit System Replacement	3673	$0	G020		$0	3/1/2020	84	$ -	$ -
113	Global Governance, Risk & Compliance	2940	$0	G020		$0	6/1/2019	84	$ -	$ -
114	HRIS Strategy Transformation Program	4144	$0	G020		$0	4/1/2021	84	$ -	$ -
115	IS Legacy Systems Archiving & Decommission	3631	$0	G020		$0	7/1/2020	84	$ -	$ -
116	Mobility - Mobile Application Development Platform (MADP) (US only)	3996	$0	G020		$0	3/1/2019	84	$ -	$ -
117	Mobility - Mobile Device Management (MDM) System	3430	$100,000	G020		$100,000	3/1/2017	84	$ 88,095	$ 73,810
118	Office 365	3999	$0	G020		$4,300,000	10/1/2019	84	$ -	$ -
119	RAS Re-Platform/Mobile	4269	$400,000	G020		$400,000	4/1/2017	84	$ 357,143	$ 300,000
120	Desktop XP to Win7	4308	$5,960,000	G020		$11,040,000	4/1/2018	84	$ -	$ 9,857,143
121	Talent Management	3674	$0	G020		$0	10/1/2020	84	$ -	$ -
122	UPS Replacement for Data Communication Closets	4003	$0	G020		$0	4/1/2019	84	$ -	$ -
123	US Global Security TWIC Compliance	4023	$270,000	G020		$1,080,000	4/1/2018	84	$ -	$ 964,286
124	US Network Improvements	4289	$350,000	G020		$350,000	4/1/2017	84	$ 312,500	$ 262,500
125	VC Room/Mobile Refresh	3424	$0	G020		$0	4/1/2019	84	$ -	$ -
126	VSTIG Hardware Refresh	4274	$300,000	G020		$300,000	4/1/2017	84	$ 267,857	$ 225,000
127	VSTIG upgrade Phase 2	4280	$2,600,000	G020		$2,600,000	4/1/2017	84	$ 2,321,429	$ 1,950,000
128	VSTIG upgrade Phase 3	4266	$1,300,000	G020		$1,300,000	4/1/2017	84	$ 1,160,714	$ 975,000
129	Wireless Network Expansion	3425	$1,600,000	G020		$1,600,000	6/1/2017	84	$ 1,466,667	$ 1,238,095
130	Mandated Customer Systems Projects - FY16	4094	$828,000	C173		$828,000	4/1/2016	84	$ 621,000	$ 502,714
131	Mandated Customer Systems Projects - FY17	4207	$4,000,000	C173		$4,000,000	4/1/2017	84	$ 3,571,429	$ 3,000,000
132	Mandated Customer Systems Projects - FY18	4207	$0	C173		$4,000,000	4/1/2018	84	$ -	$ 3,571,429
133	Mandated Customer Systems Projects - FY19	4207	$0	C173		$0	4/1/2019	84	$ -	$ -
134	Mandated Customer Systems Projects - FY20	4207	$0	C173		$0	4/1/2020	84	$ -	$ -
135	Customer Contact Center / SDC Technology Upgrade Implement Solution	3932	$1,403,000	C173		$8,417,000	4/1/2019	84	$ -	$ -
136	Meter To Cash Value Added Enhancements	3869	$0	C173		$0	4/1/2019	84	$ -	$ -
137	Meter To Cash Value Added Enhancements	3869	$0	C173		$0	4/1/2020	84	$ -	$ -
138	Credit & Collections Gap Analysis and Protections	4211	$0	C173		$0	4/1/2019	84	$ -	$ -
139	Eliminate SSN from Customer Systems	4216	$0	C173		$0	4/1/2019	84	$ -	$ -
140	Credit and Collections - Bad Debt Mitigation Initiatives	2959	$0	C173		$400,000	4/1/2018	84	$ -	$ 357,143
141	Distributed Generation Application Tracking	3941	$600,000	C173		$600,000	12/1/2016	84	$ 507,143	$ 421,429
142	Customer Interaction Channels	4139	$0	C173		$0	4/1/2020	84	$ -	$ -
143	Mandated Customer Choice Systems Projects	4196	$3,100,000	C173		$3,100,000	4/1/2017	84	$ 2,767,857	$ 2,325,000
144	Operational Requirements and Upgrades for Procurement & Supply Chain (US SAP)	4169	$0	G020		$0	4/1/2020	84	$ -	$ -
145	Enhancement Release - EHR-H2R	4170	$0	G020		$0	4/1/2020	84	$ -	$ -
146	Enhancement Release - EHR-Non-Utility Billing	4171	$0	G020		$0	4/1/2020	84	$ -	$ -
147	Enhancement Release - EHR-Xfunc	4165	$0	G020		$0	4/1/2020	84	$ -	$ -
148	PII Project - Security & Controls	4168	$0	G020		$0	4/1/2019	84	$ -	$ -
149	US SAP: Business Planning Consolidation - HANA	4217	$3,500,000	G020		$3,500,000	4/1/2017	84	$ 3,125,000	$ 2,625,000
150	Blanket Work Order Pilot	4218	$0	G020		$0	4/1/2019	84	$ -	$ -
151	PowerPlan Module Enhancements	4220	$0	G020		$0	4/1/2019	84	$ -	$ -
152	US SAP: Improve Performance Reporting	4221	$0	G020		$0	12/1/2018	84	$ -	$ -
153	US Gas Enablement IS Component (US Front Office)	2575	$0	G210		$0	3/31/2023	84	$ -	$ -
154	US Operations Infrastructure Minor Works Improvement	3716	$0	G173		$1,000,000	3/31/2018	84	$ -	$ 892,857
155	New Medical System	3718	$800,000	G020		$1,100,000	10/31/2017	84	$ 1,073,810	$ 916,667
156	Electric and Gas Service Fulfillment Web Portal	3946	$0	G173		$0	1/31/2021	84	$ -	$ -
157	NY Gas Audit Work Mgmt and Time Reporting	3953	$0	G207		$0	11/30/2021	84	$ -	$ -
158	Migrate NYS DMV Inspection Stations to LAN	3954	$0	G207		$0	3/31/2020	84	$ -	$ -
159	Wi-Fi for Fleet Service Diagnostic Laptops	3956	$0	G173		$0	2/1/2020	84	$ -	$ -
160	ISI Follow Up Work Creation in WMS and Customer System	3961	$0	G210		$0	9/30/2021	84	$ -	$ -
161	Contract Management Modernization	4151	$0	G198		$0	1/31/2020	84	$ -	$ -
162	Ageing System Stabization/Upgrades/Replacements	4188	$1,500,000	G020		$1,500,000	3/31/2017	84	$ 1,339,286	$ 1,125,000
163	Gas Outage Management System (GOMS)	4237	$0	G210		$0	3/31/2021	84	$ -	$ -
164	Operations Performance Management, Data Management, and Reporting	4247	$0	G210		$0	3/31/2020	84	$ -	$ -
165	Gas Services Database	3948/3949	$0	G207		$940,000	3/31/2018	84	$ -	$ 839,286
166	Document Management System Replacement	3985	$4,040,000	G020		$4,040,000	5/31/2017	84	$ 3,703,333	$ 3,126,190
167	Cascade Electric Application Upgrade Project	3986	$0	G198		$460,000	3/31/2018	84	$ -	$ 410,714
168	EJ Ward Upgrade	3955	$350,000	G107		$600,000	4/1/2018	84	$ -	$ 535,714
169	Double Pole Management Database upgrade	4045	$432,000	G198		$432,000	3/31/2017	84	$ 385,714	$ 324,000
170	NY REV Clifton Park Demo Information Systems Readiness	4298	$650,000	G181		$650,000	4/1/2017	84	$ 580,357	$ 487,500
171	US CNI GMS-SCADA Upgrade and Consolidation	3737	$4,540,000	G210		$10,166,000	10/1/2020	84	$ -	$ -
172	US CNI GMS-Downstate NY and LI Upgrade End-Of-Life Verizon Back-up Communication	3730	$0	G225		$1,200,000	4/1/2018	84	$ -	$ 1,071,429
173	US CNI-Infrastructure Reliability and Security Enhancements	2881	$0	G020		$600,000	3/31/2022	84	$ -	$ -
174	US CNI Tech Services-Data Center Capacity Expansion	2909	$0	G020		$0	3/18/2020	84	$ -	$ -
175	US CNI GMS-Operator Workstation Operating System	3965	$0	G210		$820,000	3/18/2018	84	$ -	$ 732,143
176	US Control-Wires Down for Massachusetts and NY	4044	$0	G186		$5,560,000	11/19/2019	84	$ -	$ -
177	US Control-NE Electric Control Center Video Wall	3966	$0	G305		$650,000	3/18/2018	84	$ -	$ 580,357
178	US MDS - Itron Enterprise Edition (IEE) Consolidation	3486	$0	G173		$1,119,000	4/1/2021	84	$ -	$ -
179	US CNI EMS and OMS-Critical Component System Refresh	4190	$0	G198		$0	3/31/2021	84	$ -	$ -
180	US CNI EMS NY/NE-Transmission Outage Application (TOA) End-of-Life Replacement	4191	$0	G220		$0	3/31/2019	84	$ -	$ -
181	US Control-Electronic Bulletin Board Gas Trading Day Changes	4244	$2,200,000	G210		$2,200,000	3/31/2016	84	$ 1,650,000	$ 1,335,714
	Subtotal		$ 327,804,227			$ 394,443,853	########		$203,721,227	$192,267,536

$	8,151,422	Rate Year IS Projects

$	7,897,675	Existing IS Projects
$	16,049,098	Total RY 18 IS Projects
$	16,099,834	RY 17 IS Projects
$	(50,737)	Adjustment

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service Date	(f) Amortization Period	(g) 12/31/2018 Balance	(h) 12/31/2019 Balance
1	DMS/OMS Replacement	1185	$66,772,709	G198		$66,772,709	1/1/2016	84	$ 38,155,834	$ 28,616,875
2	Gas GIS Consolidation	2577	$10,283,069	G210		$11,633,069	4/1/2019	84	$ -	$ 10,386,668
3	AMAG Upgrades	1172	$5,991,812	G020		$5,991,812	10/1/2016	84	$ 4,065,872	$ 3,209,899
4	US CNI DKMS	3019A	$0	G098		$0	3/1/2017	84	$ 0	$ 0
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84	$ 258,135	$ 161,335
6	NE GAS LEAKS RECHECKS	3136	$1,788,826	G310		$1,788,826	8/1/2016	84	$ 1,171,255	$ 915,708
7	CI Services Foundation	3492	$2,644,306	G020		$2,644,306	2/1/2016	84	$ 1,542,512	$ 1,164,754
8	US CNI Frame Relay Replacement	2495H	$6,398,268	G210		$6,398,268	12/1/2015	84	$ 3,579,983	$ 2,665,945
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84	$ 1,250,117	$ 924,000
10	Customer Choice ESCO Gas	3564	$9,629,193	C225		$9,629,193	4/1/2016	84	$ 5,846,296	$ 4,470,697
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84	$ -	$ -
12	Challenge the Limits XML	3375B	$603,192	G179		$603,192	10/1/2015	84	$ 323,139	$ 236,968
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84	$ 205,726	$ 150,866
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84	$ 894,514	$ 666,127
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$1,240,600	G020		$1,240,600	9/1/2016	84	$ 827,067	$ 649,838
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84	$ -	$ -
17	CNI Network Security - (Cyber Security)	3614B7	$3,801,588	G020		$3,801,588	9/1/2016	84	$ 2,534,392	$ 1,991,308
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$1,362,769	G020		$1,362,769	6/1/2016	84	$ 859,842	$ 665,161
19	CNI Patch Management - (Cyber Security)	3614B11	$0	G020		$0	1/1/2099	84	$ -	$ -
20	CNI Network Security Controls - (Cyber Security)	3614B13	$0	G020		$0	1/1/2099	84	$ -	$ -
21	CNI SIEM - (Cyber Security)	3614B14	$1,106,000	G020		$1,106,000	9/1/2016	84	$ 737,333	$ 579,333
22	Enterprise Network Security - (Cyber Security)	3614D1	$5,946,273	G020		$5,946,273	9/1/2016	84	$ 3,964,182	$ 3,114,715
23	Network Risk & Compliance - (Cyber Security)	3614D2	$0	G020		$0	1/1/2099	84	$ -	$ -
24	Security Operations Center - (Cyber Security)	3614E2	$1,461,890	G020		$1,461,890	4/1/2016	84	$ 887,576	$ 678,735
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$121,600	G020		$121,600	4/1/2016	84	$ 73,829	$ 56,457
26	Security Reference Architecture - (Cyber Security)	3614G1	$60,800	G020		$60,800	9/1/2016	84	$ 40,533	$ 31,848
27	Cyber Security prioritised investments - (Cyber Security)	3614	$725,146	G020		$725,146	9/1/2016	84	$ 483,431	$ 379,838
28	NY Retail Access	3839	$2,872,399	G170		$2,872,399	12/1/2016	84	$ 2,017,519	$ 1,607,176
29	US Web Initiatives 2	3600B	$3,831,522	C175		$3,831,522	2/1/2016	84	$ 2,235,055	$ 1,687,694
30	Capitalized Asset Replacement	3617C	$935,395	G084		$935,395	4/1/2016	84	$ 567,919	$ 434,291
31	UNY Capitalized Asset Replacement	3617D	$265,077	G003		$265,077	4/1/2016	84	$ 160,940	$ 123,072
32	DSNY Capitalized Equipment Installs - Physical Security	3617B	$475,000	G235		$475,000	4/1/2016	84	$ 288,393	$ 220,536
33	Pelco Video System Conversion - Physical Security	3841	$480,000	G077		$480,000	4/1/2016	84	$ 291,429	$ 222,857
34	NMPC C-Cure Conversion to AMAG	3853	$1,182,427	G003		$1,182,427	3/1/2017	84	$ 872,744	$ 703,826
35	EHR1 - PMO		$8,928,548	G012		$8,928,548	12/1/2015	84	$ 4,995,735	$ 3,720,228
36	EHR1 - Supply Chain		$14,769,439	G012		$14,769,439	12/1/2015	84	$ 8,263,853	$ 6,153,933
37	EHR1 - Finance		$16,145,346	G012		$16,145,346	12/1/2015	84	$ 9,033,705	$ 6,727,227
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84	$ 1,350,867	$ 1,005,965
39	EHR1 - Payroll		$12,187,165	G012		$12,187,165	12/1/2015	84	$ 6,819,009	$ 5,077,986
40	EHR1 - BPS		$9,915,257	5020		$9,915,257	12/1/2015	84	$ 5,547,823	$ 4,131,357
41	Customer Storm Outage Credit Program	3859	$0	5210		$0	3/1/2015	84	$ 0	$ 0
42	US CNI GMS SCADA Upgrade	3737	$11,369,504	C210		$17,079,504	1/1/2019	84	$ -	$ 14,639,575
43	US Desktop Refresh	2927	$7,430,690	G020		$7,430,690	3/1/2016	48	$ 2,167,285	$ 309,612
44	Internet Explorer Upgrade	3644	$300,090	G020		$300,090	3/1/2016	84	$ 178,625	$ 135,755
45	Mobile Device for PTO	3883	$2,442,471	G173		$2,442,471	9/1/2016	48	$ 1,017,696	$ 407,079
46	SMI Conversion Mobilization	3896	$2,187,292	G020		$2,187,292	7/1/2016	84	$ 1,406,116	$ 1,093,646
47	S005242 M112 Systemic Improvement		$3,500,000	G012		$3,500,000	3/1/2016	12	$ -	$ -
48	Cadency Account Reconciliation Tool		$146,894	G012		$146,894	3/1/2016	12	$ -	$ -
49	Soft Off Program	4024	$1,278,485	C207		$1,278,485	2/1/2016	84	$ 745,783	$ 563,142
50	LI CSS Stabilization	4133	$847,000	5230		$847,000	3/1/2016	84	$ 504,167	$ 383,167
51	Mobile Capture of Data Fusion	4102	$1,580,000	G207		$1,580,000	10/1/2016	84	$ 1,072,143	$ 846,429
52	Gas GIS Upgrade	2577C	$1,200,000	G210		$1,200,000	10/1/2016	84	$ 814,286	$ 642,857
53	NY Pipeline Safety CMS Regulatory Compliance	3882	$3,374,000	G207		$3,374,000	10/1/2016	84	$ 2,289,500	$ 1,807,500
54	Massachusetts Gas 4 Hour Appointment Window	4074	$166,254	C310		$166,254	3/1/2016	84	$ 98,961	$ 75,210
55	Voice Record Elec Control Rooms	3851	$2,300,000	G186		$2,300,000	12/1/2016	84	$ 1,615,476	$ 1,286,905
56	Team Center Replacement or Upgrade	3958	$600,000	G236		$600,000	10/1/2016	84	$ 407,143	$ 321,429
57	US CNI NY EMS-Conversion to MPLS	3970	$160,000	G181		$160,000	5/1/2016	84	$ 99,048	$ 76,190
58	Legacy VSTIG Migration and Decommission	3538	$1,551,788	G020		$1,551,788	9/1/2017	84	$ 1,256,209	$ 1,034,525
59	Remote Net Metering	4124	$910,000	G194		$910,000	9/1/2016	84	$ 606,667	$ 476,667
60	RI Renewable Energy Growth	4055	$673,000	5360E		$673,000	4/1/2016	84	$ 408,607	$ 312,464
61	US Mobile Device Refresh	2935	$4,000,000	G173		$4,000,000	4/1/2017	48	$ 2,250,000	$ 1,250,000
62	US Mobile Device Refresh	2935	$2,000,000	G173		$2,000,000	4/1/2018	48	$ 1,625,000	$ 1,125,000
63	US Mobile Device Refresh	2935	$0	G173		$2,000,000	4/1/2019	48	$ -	$ 1,625,000
64	KEDNY AMR Project - FDM Interface to CRIS	4183	$356,000	5220		$356,000	9/1/2016	84	$ 237,333	$ 186,476
65	Cross Company Customer System Enhancements	4172	$9,143,000	C246		$9,143,000	9/1/2016	84	$ 6,095,333	$ 4,789,190
66	New Redundant SCC	3840	$900,000	G020		$900,000	3/1/2017	84	$ 664,286	$ 535,714
67	Capitalized Asset Replacement - Physical Security	3617C	$736,000	G084		$736,000	4/1/2017	84	$ 552,000	$ 446,857
68	Capitalized Asset Replacement - Physical Security	3617C	$797,000	G084		$797,000	4/1/2018	84	$ 711,607	$ 597,750
69	Capitalized Asset Replacement - Physical Security	3617C	$0	G084		$870,000	4/1/2019	84	$ -	$ 776,786
70	Capitalized Asset Replacement - Physical Security	3617C	$0	G084		$0	4/1/2020	84	$ -	$ -
71	UNY Capitalized Asset Replacement - Physical Security	3617D	$482,000	G003		$482,000	4/1/2017	84	$ 361,500	$ 292,643
72	UNY Capitalized Asset Replacement - Physical Security	3617D	$621,000	G003		$621,000	4/1/2018	84	$ 554,464	$ 465,750
73	UNY Capitalized Asset Replacement - Physical Security	3617D	$0	G003		$729,000	4/1/2019	84	$ -	$ 650,893
74	UNY Capitalized Asset Replacement - Physical Security	3617D	$0	G003		$0	4/1/2020	84	$ -	$ -
75	DSNY Capitalized Equipment Installs - Physical Security	3617B	$649,000	G235		$649,000	4/1/2017	84	$ 486,750	$ 394,036
76	DSNY Capitalized Equipment Installs - Physical Security	3617B	$701,000	G235		$701,000	4/1/2018	84	$ 625,893	$ 525,750
77	DSNY Capitalized Equipment Installs - Physical Security	3617B	$0	G235		$766,000	4/1/2019	84	$ -	$ 683,929
78	DSNY Capitalized Equipment Installs - Physical Security	3617B	$0	G235		$0	4/1/2020	84	$ -	$ -
80	Field PC Refresh	2935	$963,188	5230		$963,188	2/1/2016	48	$ 260,863	$ 20,066
81	Field PC Refresh	2935	$1,417,990	5220		$1,417,990	1/1/2016	72	$ 708,995	$ 472,663
82	Access Violation (& Regulation) Management	3922	$290,000	G020		$290,000	4/1/2017	84	$ 217,500	$ 176,071
83	Active Directory Upgrade	4287	$350,000	G020		$350,000	4/1/2017	84	$ 262,500	$ 212,500
84	Advanced Analytics	3902	$0	G020		$300,000	4/1/2019	84	$ -	$ 267,857
85	US CNI Intrusion Detection and Prevention - Phase 1 (Cyber Security)	3863	$550,000	G020		$550,000	4/1/2018	84	$ 491,071	$ 412,500
86	US CNI Intrusion Detection and Prevention - Phase 2 (Cyber Security)	3863	$0	G020		$300,000	4/1/2020	84	$ -	$ -
87	Risk Based Authentication (Cyber Security)	3863	$235,080	G020		$235,080	6/1/2017	84	$ 181,907	$ 148,324
88	Enhanced Phishing Protection (Cyber Security)	3863	$120,000	G020		$120,000	8/1/2017	84	$ 95,714	$ 78,571
89	Security Incident Management (SIEM) 4 (Cyber Security)	3863	$633,150	G020		$1,266,300	5/1/2019	84	$ -	$ 1,145,700
90	Security Incident Management (SIEM) 5 (Cyber Security)	3863	$0	G020		$0	5/1/2020	84	$ -	$ -
91	Identity & Access Management - Role Based Access Management (Cyber Security)	3863	$1,650,000	G020		$1,650,000	10/1/2017	84	$ 1,355,357	$ 1,119,643
92	Identity & Access Management - Fine Grain Access Management (Cyber Security)	3863	$1,650,000	G020		$1,650,000	4/1/2018	84	$ 1,473,214	$ 1,237,500
93	Identity & Access Management - Privileged Access Management (Cyber Security)	3863	$0	G020		$1,740,000	4/1/2019	84	$ -	$ 1,553,571
94	Identity & Access Management - Shared Area Access Management (Cyber Security)	3863	$0	G020		$0	4/1/2020	84	$ -	$ -
95	US CNI Security Enhancements - CSP 2 - Phase 1 (Cyber Security)	3863	$2,640,000	G020		$2,640,000	11/1/2018	84	$ 2,577,143	$ 2,200,000
96	US CNI Security Enhancements - CSP 2 - Phase 2 (Cyber Security)	3863	$0	G020		$0	11/1/2021	84	$ -	$ -
97	Big Data Security Analytics - Phase 1 (Cyber Security)	3863	$3,466,164	G020		$5,776,940	5/1/2019	84	$ -	$ 5,226,755
98	Big Data Security Analytics - Phase 2 (Cyber Security)	3863	$0	G020		$0	5/1/2021	84	$ -	$ -
99	Enhanced DLP Gateway and Endpoint (Cyber Security)	3863	$2,238,480	G020		$2,238,480	12/1/2017	84	$ 1,892,049	$ 1,572,266
100	Cloud Security (Cyber Security)	3863	$1,460,000	G020		$1,460,000	5/1/2017	84	$ 1,112,381	$ 903,810
101	Situational Intelligence & Cyber Intelligence - Phase 1 (Cyber Security)	3863	$100,000	G020		$100,000	11/1/2017	84	$ 83,333	$ 69,048
102	Situational Intelligence & Cyber Intelligence - Phase 2 (Cyber Security)	3863	$0	G020		$100,000	11/1/2019	84	$ -	$ 97,619
103	IT/OT Discovery & Implementation - Phase 1 (Cyber Security)	3863	$3,300,000	G020		$5,500,000	10/1/2019	84	$ -	$ 5,303,571
104	IT/OT Discovery & Implementation - Phase 2 (Cyber Security)	3863	$0	G020		$0	10/1/2021	84	$ -	$ -
105	vStig Scaling - Upgrades (Cyber Security)	3863	$1,000,000	G020		$1,000,000	8/1/2018	84	$ 940,476	$ 797,619
106	Domain Based Security - Phase 1 (Cyber Security)	3863	$0	G020		$800,000	4/1/2019	84	$ -	$ 714,286
107	Domain Based Security - Phase 2 (Cyber Security)	3863	$0	G020		$0	4/1/2020	84	$ -	$ -
108	Security Research Lab (Cyber Security)	3863	$325,000	G020		$325,000	4/1/2020	84	$ -	$ -
109	Threat Behavior Modeling (Cyber Security)	3863	$800,000	G020		$800,000	3/1/2017	84	$ 590,476	$ 476,190
110	Enterprise Content Management (ECM) - Archiving	1134	$0	G020		$0	4/1/2020	84	$ -	$ -
111	Enterprise Content Management (ECM) Foundation Services (US only) - Upgrade	3995	$0	G020		$0	4/1/2020	84	$ -	$ -
112	Global Audit System Replacement	3673	$0	G020		$200,000	3/1/2020	84	$ -	$ -
113	Global Governance, Risk & Compliance	2940	$0	G020		$480,000	6/1/2019	84	$ -	$ 440,000
114	HRIS Strategy Transformation Program	4144	$0	G020		$15,265,000	4/1/2021	84	$ -	$ -
115	IS Legacy Systems Archiving & Decommission	3631	$0	G020		$0	7/1/2020	84	$ -	$ -
116	Mobility - Mobile Application Development Platform (MADP) (US only)	3996	$0	G020		$500,000	3/1/2019	84	$ -	$ 440,476
117	Mobility - Mobile Device Management (MDM) System	3430	$100,000	G020		$100,000	3/1/2017	84	$ 73,810	$ 59,524
118	Office 365	3999	$4,300,000	G020		$4,700,000	10/1/2019	84	$ -	$ 4,532,143

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service	(f) Amortization Period	(g) 12/31/2016 Balance	(h) 12/31/2017 Balance
1	DMS/OMS Replacement	1185	$60,613,682	G198		$66,772,709	1/1/2016	84	$ 57,233,751	$ 47,694,792
2	Gas GIS Consolidation	2577	$2,213,069	G210		$5,573,069	4/1/2019	84	$ -	$ -
3	AMAG Upgrades	1172	$3,698,542	G020		$5,991,812	10/1/2016	84	$ 5,777,818	$ 4,921,845
4	US CNI DKMS	3019A	$249,414	G098	-$249,414	$0	3/1/2017	84	$ -	$ 0
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84	$ 451,737	$ 354,936
6	NE GAS LEAKS RECHECKS	3136	$1,244,826	G310		$1,788,826	8/1/2016	84	$ 1,682,348	$ 1,426,802
7	CI Services Foundation	3492	$2,197,232	G020		$2,644,306	2/1/2016	84	$ 2,298,028	$ 1,920,270
8	US CNI Frame Relay Replacement	2495H	$6,071,268	G210		$6,398,268	12/1/2015	84	$ 5,408,060	$ 4,494,022
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84	$ 1,902,352	$ 1,576,235
10	Customer Choice ESCO Gas	3564	$7,774,478	C225	-$521,285	$9,629,193	4/1/2016	84	$ 8,597,494	$ 7,221,895
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84	$ -	$ -
12	Challenge the Limits XML	3375B	$603,192	G179		$603,192	10/1/2015	84	$ 495,479	$ 409,309
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84	$ 315,447	$ 260,587
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84	$ 1,351,287	$ 1,122,900
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$661	G020		$1,240,600	9/1/2016	84	$ 1,181,524	$ 1,004,296
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84	$ -	$ -
17	CNI Network Security - (Cyber Security)	3614B7	$556,501	G020		$3,801,588	9/1/2016	84	$ 3,620,560	$ 3,077,476
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$144,307	G020		$1,362,769	6/1/2016	84	$ 1,249,205	$ 1,054,524
19	CNI Patch Management - (Cyber Security)	3614B11	$3,903	G020	-$3,903	$0	1/1/2099	84	$ -	$ -
20	CNI Network Security Controls - (Cyber Security)	3614B13	$4,206	G020	-$4,206	$0	1/1/2099	84	$ -	$ -
21	CNI SIEM - (Cyber Security)	3614B14	$0	G020		$1,106,000	9/1/2016	84	$ 1,053,333	$ 895,333
22	Enterprise Network Security - (Cyber Security)	3614D1	$3,000,805	G020		$5,946,273	9/1/2016	84	$ 5,663,117	$ 4,813,650
23	Network Risk & Compliance - (Cyber Security)	3614D2	$2,363	G020	-$2,363	$0	1/1/2099	84	$ -	$ -
24	Security Operations Center - (Cyber Security)	3614E2	$27,818	G020		$1,461,890	4/1/2016	84	$ 1,305,259	$ 1,096,417
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$0	G020		$121,600	4/1/2016	84	$ 108,571	$ 91,200
26	Security Reference Architecture - (Cyber Security)	3614G1	$0	G020		$60,800	9/1/2016	84	$ 57,905	$ 49,219
27	Cyber Security prioritised investments - (Cyber Security)	3614	$0	G020		$725,146	9/1/2016	84	$ 690,615	$ 587,023
28	NY Retail Access	3839	$2,088,663	G170		$2,872,399	12/1/2016	84	$ 2,838,204	$ 2,427,861
29	US Web Initiatives 2	3600B	$3,402,522	C175		$3,831,522	2/1/2016	84	$ 3,329,775	$ 2,782,415
30	Capitalized Asset Replacement	3617C	$882,109	G084		$935,395	4/1/2016	84	$ 835,175	$ 701,547
31	UNY Capitalized Asset Replacement	3617D	$134,169	G003		$265,077	4/1/2016	84	$ 236,676	$ 198,808
32	DSNY Capitalized Equipment Installs - Physical Security	3617B		G235		$475,000	4/1/2016	84	$ 424,107	$ 356,250
33	Pelco Video System Conversion - Physical Security	3841		G077		$480,000	4/1/2016	84	$ 428,571	$ 360,000
34	NMPC C-Cure Conversion to AMAG	3853	$485,308	G003		$1,182,427	3/1/2017	84	$ -	$ 1,041,662
35	EHR1 - PMO		$6,218,548	G012		$8,928,548	12/1/2015	84	$ 7,546,749	$ 6,271,242
36	EHR1 - Supply Chain		$10,339,439	G012		$14,769,439	12/1/2015	84	$ 12,483,692	$ 10,373,772
37	EHR1 - Finance		$15,565,346	G012		$16,145,346	12/1/2015	84	$ 13,646,661	$ 11,340,183
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84	$ 2,040,672	$ 1,695,769
39	EHR1 - Payroll		$10,937,165	G012		$12,187,165	12/1/2015	84	$ 10,301,056	$ 8,560,033
40	EHR1 - BPS		$5,115,257	5020		$9,915,257	12/1/2015	84	$ 8,380,753	$ 6,964,288
41	Customer Storm Outage Credit Program	3859	$165,018	5210	-$165,018	$0	3/1/2015	84	$ 0	$ 0
42	US CNI GMS SCADA Upgrade	3737	$41,564	C210		$5,739,504	1/1/2019	84	$ -	$ -
43	US Desktop Refresh	2927	$5,813,532	G020		$7,430,690	3/1/2016	48	$ 5,882,629	$ 4,024,957
44	Internet Explorer Upgrade	3644	$137,061	G020		$300,090	3/1/2016	84	$ 264,365	$ 221,495
45	Mobile Device for PTO	3883	$242,471	G173		$2,442,471	9/1/2016	48	$ 2,238,932	$ 1,628,314
46	SMI Conversion Mobilization	3896	$402,655	G020		$2,187,292	7/1/2016	84	$ 2,031,057	$ 1,718,586
47	S005242 M112 Systemic Improvement		$843,635	G012		$3,500,000	3/1/2016	12	$ 583,333	$ -
48	Cadency Account Reconciliation Tool		$146,894	G012		$146,894	3/1/2016	12	$ 24,482	$ -
49	Soft Off Program	4024	$836,485	C207		$1,278,485	2/1/2016	84	$ 1,111,064	$ 928,423
50	LI CSS Stabilization	4133	$0	5230		$847,000	3/1/2016	84	$ 746,167	$ 625,167

[illegible]

Total	#########	$ (6,382,909)	$ 13,670,747	#########		$ 1,145,031	$ 3,337,075	$ -	$136,428,012

$ 4,482,106 Rate Year IS Projects

(j) 9.9500% Service Co	(k) = (i)*(j) Rate Year Return	(l) = (-ac) RY Return on Accum Taxes	(m) = (k) + (l) Total Return	(n) Rate Year Amortization	(o) 5230G KEDLI Allocation	(p) = (m)*(n) KEDLI Rate Year Rent-Return	(q) = (n)*(o) KEDLI Rate Year Rent - Depn	(r) Amortization Period	Tax Expensing	(s) Bonus Depreciation	(t) Cumulative Tax Depreciation 12/31/2016 Balance
9.9500%	$251	($101)	$150	$5,046	0.00%	$ -	$ -	36	$47,097	$0	$ 47,097
9.9500%	$2,064	($830)	$1,234	$41,480	0.00%	$ -	$ -	36		$217,772	$ 435,545
9.9500%	$31,747	($12,762)	$18,985	$225,222	0.00%	$ -	$ -	36		$1,576,557	$ 1,576,557
9.9500%	$3,138	($1,262)	$1,877	$63,083	0.00%	$ -	$ -	36		$294,386	$ 588,773
9.9500%	$1,395	($561)	$834	$28,037	0.00%	$ -	$ -	36		$196,258	$ 392,515
9.9500%	$21,165	($8,508)	$12,656	$150,148	0.00%	$ -	$ -	36		$1,051,038	$ 1,051,038
9.9500%	$12,228	($4,915)	$7,312	$73,734	8.68%	$ 634.69	$ 6,400.14	36		$258,070	$ 516,140
9.9500%	$397	($160)	$238	$1,115	0.00%	$ -	$ -	36		$3,901	$ 7,803
9.9500%	$7,586	($3,050)	$4,536	$11,436	8.68%	$ 393.76	$ 992.65	36		$57,180	$ 114,360
9.9500%	$4,317	($1,735)	$2,582	$52,066	0.00%	$ -	$ -	36		$364,462	$ 364,462
9.9500%	$428	($172)	$256	$8,606	8.68%	$ 22.22	$ 747.04	36		$180,736	$ 361,473
9.9500%	$181,792	($73,081)	$108,712	$3,654,120	0.00%	$ -	$ -	36	$28,900,771	$0	$ 28,900,771
9.9500%	$18,798	($7,557)	$11,241	$113,356	6.98%	$ 784.64	$ 7,912.24	36		$396,745	$ 793,491
9.9500%	$34,019	($13,676)	$20,344	$273,522	0.00%	$ -	$ -	36	$546,007	$1,368,648	$ 1,914,655
9.9500%	$29,813	($11,985)	$17,828	$179,778	6.98%	$ 1,244.41	$ 12,548.50	36	$772,466	$242,990	$ 1,258,446
9.9500%	$22,512	($9,050)	$13,462	$135,753	8.68%	$ 1,168.54	$ 11,783.36	36		$475,135	$ 950,271
9.9500%	$9,866	($3,966)	$5,900	$29,747	0.00%	$ -	$ -	36		$104,115	$ 208,231
9.9500%	$3,351	($1,347)	$2,004	$9,184	0.00%	$ -	$ -	36		$32,143	$ 64,286
9.9500%	$1,876,513	($742,856)	$1,133,657	$3,901,951	0.00%	$ -	$ -	36	$23,863,614	$1,725,020	$ 26,738,532

[illegible]

9.9500%	$3,885	($1,562)	$2,323	$9,562	31.63%	$ 734.81	$ 3,024.38	36		$33,466	$ 66,932
9.9500%	$202,251	($71,140)	$131,111	$435,573	22.81%	$ 29,906.47	$ 99,354.15	36		$1,524,505	$ 2,540,740
Total	#########	$ (9,935,184)	$ 15,325,494	#########		$ 1,272,993	$ 4,660,199		#########	$225,478,898	$ 514,758,776

$ 5,933,193 Existing IS Projects

$ 10,415,299 Total RY 17 IS Projects
$ 6,317,433 Test Year IS Projects
$ 4,097,866 Adjustment

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service	(f) Amortization Period	(g) 12/31/2017 Balance	(h) 12/31/2018 Balance	(i) = (g+h)/2 Average Balance	(j) 9.9500% Service Co Return
1	DMS/OMS Replacement	1185	$66,772,709	G198		$66,772,709	1/1/2016	84	$ 47,694,792	$ 38,155,834	$ 42,925,313	9.9500%
2	Gas GIS Consolidation	2577	$5,573,069	G210		$10,283,069	4/1/2019	84	$ -	$ -	$ -	9.9500%
3	AMAG Upgrades	1172	$5,991,812	G020		$5,991,812	10/1/2016	84	$ 4,921,845	$ 4,065,872	$ 4,493,859	9.9500%
4	US CNI DKMS	3019A	$0	G098		$0	3/1/2017	84	$ 0	$ 0	$ 0	9.9500%
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84	$ 354,936	$ 258,135	$ 306,536	9.9500%
6	NE GAS LEAKS RECHECKS	3136	$1,788,826	G310		$1,788,826	8/1/2016	84	$ 1,426,802	$ 1,171,255	$ 1,299,028	9.9500%
7	CI Services Foundation	3492	$2,644,306	G020		$2,644,306	2/1/2016	84	$ 1,920,270	$ 1,542,512	$ 1,731,391	9.9500%
8	US CNI Frame Relay Replacement	2495H	$6,398,268	G210		$6,398,268	12/1/2015	84	$ 4,494,022	$ 3,579,983	$ 4,037,002	9.9500%
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84	$ 1,576,235	$ 1,250,117	$ 1,413,176	9.9500%
10	Customer Choice ESCO Gas	3564	$9,629,193	C225		$9,629,193	4/1/2016	84	$ 7,221,895	$ 5,846,296	$ 6,534,095	9.9500%
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84	$ -	$ -	$ -	9.9500%
12	Challenge the Limits XML	3375B	$603,192	G179		$603,192	10/1/2015	84	$ 409,309	$ 323,139	$ 366,224	9.9500%
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84	$ 260,587	$ 205,726	$ 233,157	9.9500%
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84	$ 1,122,900	$ 894,514	$ 1,008,707	9.9500%
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$1,240,600	G020		$1,240,600	9/1/2016	84	$ 1,004,296	$ 827,067	$ 915,681	9.9500%
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84	$ -	$ -	$ -	9.9500%
17	CNI Network Security - (Cyber Security)	3614B7	$3,801,588	G020		$3,801,588	9/1/2016	84	$ 3,077,476	$ 2,534,392	$ 2,805,934	9.9500%
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$1,362,769	G020		$1,362,769	6/1/2016	84	$ 1,054,524	$ 859,842	$ 957,183	9.9500%
19	CNI Patch Management - (Cyber Security)	3614B11	$0	G020		$0	1/1/2099	84	$ -	$ -	$ -	9.9500%
20	CNI Network Security Controls - (Cyber Security)	3614B13	$0	G020		$0	1/1/2099	84	$ -	$ -	$ -	9.9500%
21	CNI SIEM - (Cyber Security)	3614B14	$1,106,000	G020		$1,106,000	9/1/2016	84	$ 895,333	$ 737,333	$ 816,333	9.9500%
22	Enterprise Network Security - (Cyber Security)	3614D1	$5,946,273	G020		$5,946,273	9/1/2016	84	$ 4,813,650	$ 3,964,182	$ 4,388,916	9.9500%
23	Network Risk & Compliance - (Cyber Security)	3614D2	$0	G020		$0	1/1/2099	84	$ -	$ -	$ -	9.9500%
24	Security Operations Center - (Cyber Security)	3614E2	$1,461,890	G020		$1,461,890	4/1/2016	84	$ 1,096,417	$ 887,576	$ 991,997	9.9500%
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$121,600	G020		$121,600	4/1/2016	84	$ 91,200	$ 73,829	$ 82,514	9.9500%
26	Security Reference Architecture - (Cyber Security)	3614G1	$60,800	G020		$60,800	9/1/2016	84	$ 49,219	$ 40,533	$ 44,876	9.9500%
27	Cyber Security prioritised investments - (Cyber Security)	3614	$725,146	G020		$725,146	9/1/2016	84	$ 587,023	$ 483,431	$ 535,227	9.9500%
28	NY Retail Access	3839	$2,872,399	G170		$2,872,399	12/1/2016	84	$ 2,427,861	$ 2,017,519	$ 2,222,690	9.9500%
29	US Web Initiatives 2	3600B	$3,831,522	C175		$3,831,522	2/1/2016	84	$ 2,782,415	$ 2,235,055	$ 2,508,735	9.9500%
30	Capitalized Asset Replacement	3617C	$935,395	G084		$935,395	4/1/2016	84	$ 701,547	$ 567,919	$ 634,733	9.9500%
31	UNY Capitalized Asset Replacement	3617D	$265,077	G003		$265,077	4/1/2016	84	$ 198,808	$ 160,940	$ 179,874	9.9500%
32	DSNY Capitalized Equipment Installs - Physical Security	3617B	$475,000	G235		$475,000	4/1/2016	84	$ 356,250	$ 288,393	$ 322,321	9.9500%
33	Pelco Video System Conversion - Physical Security	3841	$480,000	G077		$480,000	4/1/2016	84	$ 360,000	$ 291,429	$ 325,714	9.9500%
34	NMPC C-Cure Conversion to AMAG	3853	$1,182,427	G003		$1,182,427	3/1/2017	84	$ 1,041,662	$ 872,744	$ 957,203	9.9500%
35	EHR1 - PMO		$8,928,548	G012		$8,928,548	12/1/2015	84	$ 6,271,242	$ 4,995,735	$ 5,633,489	9.9500%

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service	(f) Amortization Period	(g) 12/31/2018 Balance
1	DMS/OMS Replacement	1185	$66,772,709	G198		$66,772,709	1/1/2016	84	$ 38,155,834
2	Gas GIS Consolidation	2577	$10,283,069	G210		$11,633,069	4/1/2019	84	$ -
3	AMAG Upgrades	1172	$5,991,812	G020		$5,991,812	10/1/2016	84	$ 4,065,87[illegible]
4	US CNI DKMS	3019A	$0	G098		$0	3/1/2017	84	$
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84	$ 258,13[illegible]
6	NE GAS LEAKS RECHECKS	3136	$1,788,826	G310		$1,788,826	8/1/2016	84	$ 1,171,25[illegible]
7	CI Services Foundation	3492	$2,644,306	G020		$2,644,306	2/1/2016	84	$ 1,542,51[illegible]
8	US CNI Frame Relay Replacement	2495H	$6,398,268	G210		$6,398,268	12/1/2015	84	$ 3,579,98[illegible]
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84	$ 1,250,11[illegible]
10	Customer Choice ESCO Gas	3564	$9,629,193	C225		$9,629,193	4/1/2016	84	$ 5,846,29[illegible]
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84	$ -
12	Challenge the Limits XML	3375B	$603,192	G179		$603,192	10/1/2015	84	$ 323,13[illegible]
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84	$ 205,72[illegible]
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84	$ 894,51[illegible]
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$1,240,600	G020		$1,240,600	9/1/2016	84	$ 827,06[illegible]
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84	$ -
17	CNI Network Security - (Cyber Security)	3614B7	$3,801,588	G020		$3,801,588	9/1/2016	84	$ 2,534,39[illegible]
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$1,362,769	G020		$1,362,769	6/1/2016	84	$ 859,84[illegible]
19	CNI Patch Management - (Cyber Security)	3614B11	$0	G020		$0	1/1/2099	84	$ -
20	CNI Network Security Controls - (Cyber Security)	3614B13	$0	G020		$0	1/1/2099	84	$ -
21	CNI SIEM - (Cyber Security)	3614B14	$1,106,000	G020		$1,106,000	9/1/2016	84	$ 737,33[illegible]
22	Enterprise Network Security - (Cyber Security)	3614D1	$5,946,273	G020		$5,946,273	9/1/2016	84	$ 3,964,18[illegible]
23	Network Risk & Compliance - (Cyber Security)	3614D2	$0	G020		$0	1/1/2099	84	$ -
24	Security Operations Center - (Cyber Security)	3614E2	$1,461,890	G020		$1,461,890	4/1/2016	84	$ 887,57[illegible]
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$121,600	G020		$121,600	4/1/2016	84	$ 73,82[illegible]
26	Security Reference Architecture - (Cyber Security)	3614G1	$60,800	G020		$60,800	9/1/2016	84	$ 40,53[illegible]
27	Cyber Security prioritised investments - (Cyber Security)	3614	$725,146	G020		$725,146	9/1/2016	84	$ 483,43[illegible]
28	NY Retail Access	3839	$2,872,399	G170		$2,872,399	12/1/2016	84	$ 2,017,51[illegible]
29	US Web Initiatives 2	3600B	$3,831,522	C175		$3,831,522	2/1/2016	84	$ 2,235,05[illegible]
30	Capitalized Asset Replacement	3617C	$935,395	G084		$935,395	4/1/2016	84	$ 567,91[illegible]
31	UNY Capitalized Asset Replacement	3617D	$265,077	G003		$265,077	4/1/2016	84	$ 160,94[illegible]
32	DSNY Capitalized Equipment Installs - Physical Security	3617B	$475,000	G235		$475,000	4/1/2016	84	$ 288,39[illegible]
33	Pelco Video System Conversion - Physical Security	3841	$480,000	G077		$480,000	4/1/2016	84	$ 291,42[illegible]
34	NMPC C-Cure Conversion to AMAG	3853	$1,182,427	G003		$1,182,427	3/1/2017	84	$ 872,74[illegible]
35	EHR1 - PMO		$8,928,548	G012		$8,928,548	12/1/2015	84	$ 4,995,73[illegible]
36	EHR1 - Supply Chain		$14,769,439	G012		$14,769,439	12/1/2015	84	$ 8,263,85[illegible]
37	EHR1 - Finance		$16,145,346	G012		$16,145,346	12/1/2015	84	$ 9,033,70[illegible]
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84	$ 1,350,86[illegible]
39	EHR1 - Payroll		$12,187,165	G012		$12,187,165	12/1/2015	84	$ 6,819,00[illegible]
40	EHR1 - BPS		$9,915,257	5020		$9,915,257	12/1/2015	84	$ 5,547,82[illegible]
41	Customer Storm Outage Credit Program	3859	$0	5210		$0	3/1/2015	84	$
42	US CNI GMS SCADA Upgrade	3737	$11,369,504	C210		$17,079,504	1/1/2019	84	$ -
43	US Desktop Refresh	2927	$7,430,690	G020		$7,430,690	3/1/2016	48	$ 2,167,28[illegible]
44	Internet Explorer Upgrade	3644	$300,090	G020		$300,090	3/1/2016	84	$ 178,62[illegible]
45	Mobile Device for PTO	3883	$2,442,471	G173		$2,442,471	9/1/2016	48	$ 1,017,69[illegible]

[illegible]

Totals														
#########	$ (7,622,947)	#########	$ 53,671,210		$ 1,240,933	$ 5,138,322		$ -	$177,383,406	$314,137,717	$348,755,727	$ 331,446,722		

$ 6,379,255 Rate Year IS Projects

(k) = (i)*(j) Rate Year Return	(l) = (-ac) RY Return on Accum Taxes	(m) = (k) + (l) Total Return	(n) Rate Year Amortization	(o) 5230G KEDLI Allocation	(p) = (m)* (n) KEDLI Rate Year Rent-Return	(q) = (n)* (o) KEDLI Rate Year Rent - Depn	(r) Amortization Period	Cumulative Tax Depreciation Tax Expensing	(s) Bonus Depreciation	(t) 12/31/2018 Balance	(u) 12/31/2019 Balance	(v) = (t) + (u)/2 Average Balance
$0	$0	$0	$0	0.00%	$ -	$ -	36	$47,097	$0	47,097	47,097	$47,097
$0	$0	$0	$0	0.00%	$ -	$ -	36		$217,772	435,545	435,545	$435,545
$0	$0	$0	$0	0.00%	$ -	$ -	36		$1,576,557	1,576,557	1,576,557	$1,576,557
$0	$0	$0	$0	0.00%	$ -	$ -	36		$294,386	588,773	588,773	$588,773
$0	$0	$0	$0	0.00%	$ -	$ -	36		$196,258	392,515	392,515	$392,515
$0	$0	$0	$0	0.00%	$ -	$ -	36		$1,051,038	1,051,038	1,051,038	$1,051,038
$611	($246)	$366	$12,289	8.68%	$ 31.73	$ 1,066.69	36		$258,070	516,140	516,140	$516,140
$176	($71)	$105	$1,115	0.00%	$ -	$ -	36		$3,901	7,803	7,803	$7,803
$5,310	($2,135)	$3,175	$11,436	8.68%	$ 275.63	$ 992.65	36		$57,180	114,360	114,360	$114,360
$0	$0	$0	$0	0.00%	$ -	$ -	36		$364,462	364,462	364,462	$364,462
$0	$0	$0	$0	8.68%	$ -	$ -	36		$180,736	361,473	361,473	$361,473
$0	$0	$0	$0	0.00%	$ -	$ -	36	$28,900,771	$0	28,900,771	28,900,771	$28,900,771
$940	($378)	$562	$18,893	6.98%	$ 39.23	$ 1,318.71	36		$396,745	793,491	793,491	$793,491
$0	$0	$0	$0	0.00%	$ -	$ -	36	$546,007	$1,368,648	1,914,655	1,914,655	$1,914,655
$1,491	($599)	$891	$29,963	6.98%	$ 62.22	$ 2,091.42	36	$772,466	$242,990	1,258,446	1,258,446	$1,258,446
$1,126	($452)	$673	$22,625	8.68%	$ 58.43	$ 1,963.89	36		$475,135	950,271	950,271	$950,271
$3,946	($1,586)	$2,360	$29,747	0.00%	$ -	$ -	36		$104,115	208,231	208,231	$208,231
$1,523	($612)	$911	$9,184	0.00%	$ -	$ -	36		$32,143	64,286	64,286	$64,286
$1,100,025	($442,210)	$657,815	$3,901,951	0.00%	$ -	$ -	36	$23,863,614	$1,725,020	27,313,654	27,313,654	$27,313,654
$6,042	($2,429)	$3,613	$36,436	0.00%	$ -	$ -	36		$127,528	255,055	255,055	$255,055
$12,869	($5,173)	$7,695	$258,664	0.00%	$ -	$ -	36	$3,330,245	$507,653	4,345,552	4,345,552	$4,345,552
$8,807	($3,540)	$5,266	$44,255	0.00%	$ -	$ -	36		$154,893	309,785	309,785	$309,785
$102,421	($41,173)	$61,248	$411,744	8.58%	$ 5,255.07	$ 35,327.61	36		$1,441,103	2,882,206	2,882,206	$2,882,206
$184,599	($74,209)	$110,390	$428,138	8.68%	$ 9,581.86	$ 37,162.38	36	$122,333	$2,079,524	4,281,380	4,281,380	$4,281,380
$0	$0	$0	$0	6.98%	$ -	$ -	36		$312,721	312,721	312,721	$312,721
$0	$0	$0	$0	6.98%	$ -	$ -	36		$313,244	313,244	313,244	$313,244
$537	($216)	$321	$10,790	0.00%	$ -	$ -	36		$226,583	453,167	453,167	$453,167
$0	$0	$0	$0	0.00%	$ -	$ -	36		$180,122	360,244	360,244	$360,244
$1,687	($678)	$1,009	$33,912	0.00%	$ -	$ -	36		$284,858	569,716	569,716	$569,716
$1,175	($472)	$703	$23,615	0.00%	$ -	$ -	36		$123,979	247,958	247,958	$247,958
$0	$0	$0	$0	8.68%	$ -	$ -	36		$136,700	273,401	273,401	$273,401
$151,573	($60,932)	$90,641	$304,669	8.68%	$ 7,867.60	$ 26,445.28	36	$3,046,691	$0	3,046,691	3,046,691	$3,046,691
$6,825	($2,743)	$4,081	$13,064	8.68%	$ 354.24	$ 1,133.99	36		$65,322	130,644	130,644	$130,644
$2,181	($877)	$1,304	$43,834	8.68%	$ 113.19	$ 3,804.75	36		$263,001	526,002	526,002	$526,002
$13,466	($5,413)	$8,053	$101,503	0.00%	$ -	$ -	36		$355,260	710,520	710,520	$710,520
$3,087	($1,241)	$1,846	$62,053	0.00%	$ -	$ -	36		$289,582	579,164	579,164	$579,164

[illegible]

$0	$0	$0	$0	8.68%	$ -	$ -	36		$1,207,479	1,207,479	1,207,479	$1,207,479
$463	($186)	$277	$2,938	0.00%	$ -	$ -	36		$10,283	20,566	20,566	$20,566
$0	$0	$0	$0	0.00%	$ -	$ -	36		$313,523	313,523	313,523	$313,523
$0	$0	$0	$0	8.68%	$ -	$ -	36		$1,005,232	2,010,464	2,010,464	$2,010,464
$0	$0	$0	$0	28.55%	$ 0.00	$ -	36		$89	178	178	$178
$11,969	($4,812)	$7,158	$240,589	0.00%	$ -	$ -	36		$1,122,750	2,245,499	2,245,499	$2,245,499
$0	$0	$0	$0	0.00%	$ -	$ -	36		$3,705,869	7,411,737	7,411,737	$7,411,737
$0	$0	$0	$0	28.55%	$ -	$ -	36		$1,493,520	2,987,041	2,987,041	$2,987,041
$11,450	($4,603)	$6,847	$230,156	31.63%	$ 2,165.78	$ 72,798.23	36		$1,933,307	3,866,615	3,866,615	$3,866,615
$50,630	($20,353)	$30,277	$254,423	28.55%	$ 8,644.03	$ 72,637.72	36		$890,480	1,780,960	1,780,960	$1,780,960
$9,722	($3,908)	$5,814	$58,626	28.55%	$ 1,659.86	$ 16,737.79	36		$205,192	410,384	410,384	$410,384
$39,697	($15,958)	$23,739	$239,377	30.27%	$ 7,185.69	$ 72,459.48	36		$837,820	1,675,640	1,675,640	$1,675,640
$0	$0	$0	$0	30.27%	$ -	$ -	36		$2,702,821	5,405,642	5,405,642	$5,405,642
$43,269	($17,394)	$25,875	$869,723	31.63%	$ 8,184.17	$ 275,093.45	36		$5,218,339	10,436,678	10,436,678	$10,436,678
$32,010	($12,868)	$19,142	$643,420	22.81%	$ 4,366.31	$ 146,764.16	36		$3,002,628	6,005,256	6,005,256	$6,005,256
$1,982	($797)	$1,185	$9,562	31.63%	$ 374.90	$ 3,024.38	36		$33,466	66,932	66,932	$66,932
$115,572	($46,460)	$69,112	$435,573	22.81%	$ 15,764.46	$ 99,354.15	36		$1,524,505	3,049,009	3,049,009	$3,049,009
#########	$ (5,988,567)	$ 8,908,366	$ 47,709,903		$ 727,615	$ 4,062,943		$ 86,553,649	$225,478,898	$525,739,474	$525,739,474	$ 525,739,474

$ 4,790,558 Existing IS Projects

$ 11,169,813 Total RY 19 IS Projects
$ 10,435,048 RY 18 IS Projects
$ 734,765 Adjustment

KeySpan Gas East Corporation
d/b/a National Grid
The Brooklyn Union Gas Company
d/b/a National Grid NY
Case 16-G-0058 and 16-G-0059
Attachment 2 to DPS-482 JS-10 BULI-627

Missing Projects Adjustment - Service Company Rents

Information Systems Projects (As Reported in DPS-395)

	Rate Year 1	Data Year 1	Data Year 2
KEDNY	$ 13,623,116	$ 13,810,462	$ 15,842,291
KEDLI	$ 9,053,489	$ 9,225,013	$ 10,362,599
Total	**$ 22,676,604**	**$ 23,035,474**	**$ 26,204,890**

Information Systems Projects (With Missing Projects)

	Rate Year 1	Data Year 1	Data Year 2
KEDNY	$ 16,099,834	$ 16,049,098	$ 17,268,746
KEDLI	$ 10,415,299	$ 10,435,048	$ 11,169,813
Total	**$ 26,515,133**	**$ 26,484,146**	**$ 28,438,559**

Information Systems Projects (Difference)

	Rate Year 1	Data Year 1	Data Year 2
KEDNY	$ 2,476,719	$ 2,238,636	$ 1,426,455
KEDLI	$ 1,361,810	$ 1,210,036	$ 807,215
Total	**$ 3,838,529**	**$ 3,448,672**	**$ 2,233,670**

KeySpan Gas East Corporation
d/b/a National Grid
The Brooklyn Union Gas Company
d/b/a National Grid NY
Case 16-G-0058 and 16-G-0059
Attachment 2 to DPS-482 JS-10 BULI-627

		KEDNY	Rate Year	Data Year 1	Data Year 2
1TXFER00099	GAS SCADA Upgrade/Modernize	38.38%	$ 112,432	$ -	$ -
1TXFER00099	GTIS	68.37%	$ 420,727	$ 398,256	$ 162,039
90000124369	GTIS	38.38%	$ 120,888	$ 115,078	$ 109,268
90000124368	Meter Route Consolidation	38.38%	$ 27,410	$ 26,071	$ 24,732
90000124375	GTIS	58.10%	$ 169,421	$ 161,146	$ 152,870
90000104112	IN1656-CUST.Systems Agent desktop	68.37%	$ 1,145,726	$ 1,085,073	$ 612,320
90000106246	IN2330 ETRM Repl Nucleus-Gas Benef	30.66%	$ 298,244	$ 282,593	$ 203,142
90000124371	IN2366 LI CNI Direct HW Upgrade	68.37%	$ 8,126	$ 7,737	$ 7,348
90000144051	INVP2960C GridForce SaaS Phase 2	30.66%	$ 173,745	$ 162,683	$ 154,736
			$ 2,476,719	**$ 2,238,636**	**$ 1,426,455**

		KEDLI	Rate Year	Data Year 1	Data Year 2
1TXFER00099	GAS SCADA Upgrade/Modernize	28.55%	$ 83,635	$ -	$ -
1TXFER00099	GTIS	31.63%	$ 194,641	$ 184,245	$ 74,964
90000124369	GTIS	28.55%	$ 89,926	$ 85,604	$ 81,282
90000124368	Meter Route Consolidation	28.55%	$ 20,389	$ 19,394	$ 18,398
90000124375	GTIS	30.27%	$ 88,268	$ 83,957	$ 79,645
90000104112	IN1656-CUST.Systems Agent desktop	31.63%	$ 530,047	$ 501,987	$ 283,278
90000106246	IN2330 ETRM Repl Nucleus-Gas Benef	22.81%	$ 221,883	$ 210,240	$ 151,130
90000124371	IN2366 LI CNI Direct HW Upgrade	31.63%	$ 3,759	$ 3,579	$ 3,399
90000144051	INVP2960C GridForce SaaS Phase 2	22.81%	$ 129,261	$ 121,030	$ 115,119
			$ 1,361,810	**$ 1,210,036**	**$ 807,215**
	Total Impact		**$ 3,838,529**	**$ 3,448,672**	**$ 2,233,670**

Service Company Capital Software allocated to Operating Companies as Rent Expense

$	8,553,899	**Existing IS Projects**
$	16,099,834	**Total RY 17 IS Projects**
$	9,147,151	**Test Year IS Projects**
$	6,952,683	**Adjustment**

Service Company Capital Software allocated to Operating Companies as Rent Expense

#	Investment Name	INVP #	Inception to Date	Bill Pool	Adjustments	Total US Spend	In Service Date	Amortization Period	12/31/2017 Balance	12/31/2018 Balance
36	EHR1 - Supply Chain		$14,769,439	G012		$14,769,439	12/1/2015	84	$ 10,373,772	$ 8,263,853
37	EHR1 - Finance		$16,145,346	G012		$16,145,346	12/1/2015	84	$ 11,340,183	$ 9,033,705
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84	$ 1,695,769	$ 1,350,867
39	EHR1 - Payroll		$12,187,165	G012		$12,187,165	12/1/2015	84	$ 8,560,033	$ 6,819,009
40	EHR1 - BPS		$9,915,257	5020		$9,915,257	12/1/2015	84	$ 6,964,288	$ 5,547,823
41	Customer Storm Outage Credit Program	3859	$0	5210		$0	3/1/2015	84	$ 0	$ 0
42	US CNI GMS SCADA Upgrade	3737	$5,739,504	C210		$11,369,504	1/1/2019	84	$ -	$ -
43	US Desktop Refresh	2927	$7,430,690	G020		$7,430,690	3/1/2016	48	$ 4,024,957	$ 2,167,285
44	Internet Explorer Upgrade	3644	$300,090	G020		$300,090	3/1/2016	84	$ 221,495	$ 178,625
45	Mobile Device for PTO	3883	$2,442,471	G173		$2,442,471	9/1/2016	48	$ 1,628,314	$ 1,017,696
46	SMI Conversion Mobilization	3896	$2,187,292	G020		$2,187,292	7/1/2016	84	$ 1,718,586	$ 1,406,116
47	S005242 M112 Systemic Improvement		$3,500,000	G012		$3,500,000	3/1/2016	12	$ -	$ -
48	Cadency Account Reconciliation Tool		$146,894	G012		$146,894	3/1/2016	12	$ -	$ -
49	Soft Off Program	4024	$1,278,485	C207		$1,278,485	2/1/2016	84	$ 928,423	$ 745,783
50	LI CSS Stabilization	4133	$847,000	5230		$847,000	3/1/2016	84	$ 625,167	$ 504,167
51	Mobile Capture of Data Fusion	4102	$1,580,000	C207		$1,580,000	10/1/2016	84	$ 1,297,857	$ 1,072,143
52	Gas GIS Upgrade	2577C	$1,200,000	G210		$1,200,000	10/1/2016	84	$ 985,714	$ 814,286
53	NY Pipeline Safety CMS Regulatory Compliance	3882	$3,374,000	G207		$3,374,000	10/1/2016	84	$ 2,771,500	$ 2,289,500
54	Massachusetts Gas 4 Hour Appointment Window	4074	$166,254	C310		$166,254	3/1/2016	84	$ 122,711	$ 98,961
55	Voice Record Elec Control Rooms	3851	$2,300,000	G186		$2,300,000	12/1/2016	84	$ 1,944,048	$ 1,615,476
56	Team Center Replacement or Upgrade	3958	$600,000	G236		$600,000	10/1/2016	84	$ 492,857	$ 407,143
57	US CNI NY EMS-Conversion to MPLS	3970	$160,000	G181		$160,000	5/1/2016	84	$ 121,905	$ 99,048
58	Legacy VSTIG Migration and Decommission	3538	$1,501,788	G020		$1,551,788	9/1/2017	84	$ 1,477,893	$ 1,256,209
59	Remote Net Metering	4124	$910,000	G194		$910,000	9/1/2016	84	$ 736,667	$ 606,667
60	RI Renewable Energy Growth	4055	$673,000	5360E		$673,000	4/1/2016	84	$ 504,750	$ 408,607
61	US Mobile Device Refresh	2935	$4,000,000	G173		$4,000,000	4/1/2017	48	$ 3,250,000	$ 2,250,000
62	US Mobile Device Refresh	2935	$0	G173		$2,000,000	4/1/2018	48	$ -	$ 1,625,000
63	US Mobile Device Refresh	2935	$0	G173		$0	4/1/2019	48	$ -	$ -
64	KEDNY AMR Project - FDM Interface to CRIS	4183	$356,000	5220		$356,000	9/1/2016	84	$ 288,190	$ 237,333
65	Cross Company Customer System Enhancements	4172	$9,143,000	C246		$9,143,000	9/1/2016	84	$ 7,401,476	$ 6,095,333
66	New Redundant SCC	3840	$900,000	G020		$900,000	3/1/2017	84	$ 792,857	$ 664,286
67	Capitalized Asset Replacement - Physical Security	3617C	$736,000	G084		$736,000	4/1/2017	84	$ 657,143	$ 552,000
68	Capitalized Asset Replacement - Physical Security	3617C	$0	G084		$797,000	4/1/2018	84	$ -	$ 711,607
69	Capitalized Asset Replacement - Physical Security	3617C	$0	G084		$0	4/1/2019	84	$ -	$ -
70	Capitalized Asset Replacement - Physical Security	3617C	$0	G084		$0	4/1/2020	84	$ -	$ -
71	UNY Capitalized Asset Replacement - Physical Security	3617D	$482,000	G003		$482,000	4/1/2017	84	$ 430,357	$ 361,500
72	UNY Capitalized Asset Replacement - Physical Security	3617D	$0	G003		$621,000	4/1/2018	84	$ -	$ 554,464
73	UNY Capitalized Asset Replacement - Physical Security	3617D	$0	G003		$0	4/1/2019	84	$ -	$ -
74	UNY Capitalized Asset Replacement - Physical Security	3617D	$0	G003		$0	4/1/2020	84	$ -	$ -
75	DSNY Capitalized Equipment Installs - Physical Security	3617B	$649,000	G235		$649,000	4/1/2017	84	$ 579,464	$ 486,750
76	DSNY Capitalized Equipment Installs - Physical Security	3617B	$0	G235		$701,000	4/1/2018	84	$ -	$ 625,893
77	DSNY Capitalized Equipment Installs - Physical Security	3617B	$0	G235		$0	4/1/2019	84	$ -	$ -
78	DSNY Capitalized Equipment Installs - Physical Security	3617B	$0	G235		$0	4/1/2020	84	$ -	$ -
80	Field PC Refresh	2935	$963,188	5230		$963,188	2/1/2016	48	$ 501,660	$ 260,863
81	Field PC Refresh	2935	$1,417,990	5220		$1,417,990	7/1/2016	72	$ 945,327	$ 708,995
82	Access Violation (& Regulation) Management	3922	$290,000	G020		$290,000	4/1/2017	84	$ 258,929	$ 217,500
83	Active Directory Upgrade	4287	$350,000	G020		$350,000	4/1/2017	84	$ 312,500	$ 262,500
84	Advanced Analytics	3902	$0	G020		$0	4/1/2019	84	$ -	$ -
85	US CNI Intrusion Detection and Prevention - Phase 1 (Cyber Security)	3863	$350,000	G020		$550,000	4/1/2018	84	$ -	$ 491,071
86	US CNI Intrusion Detection and Prevention - Phase 2 (Cyber Security)	3863	$0	G020		$0	4/1/2020	84	$ -	$ -
87	Risk Based Authentication (Cyber Security)	3863	$235,080	G020		$235,080	6/1/2017	84	$ 215,490	$ 181,907
88	Enhanced Phishing Protection (Cyber Security)	3863	$120,000	G020		$120,000	8/1/2017	84	$ 112,857	$ 95,714
89	Security Incident Management (SIEM) 4 (Cyber Security)	3863	$0	G020		$633,150	5/1/2019	84	$ -	$ -
90	Security Incident Management (SIEM) 5 (Cyber Security)	3863	$0	G020		$0	5/1/2020	84	$ -	$ -
91	Identity & Access Management - Role Based Access Management (Cyber Security)	3863	$1,650,000	G020		$1,650,000	10/1/2017	84	$ 1,591,071	$ 1,355,357
92	Identity & Access Management - Fine Grain Access Management (Cyber Security)	3863	$0	G020		$1,650,000	4/1/2018	84	$ -	$ 1,473,214
93	Identity & Access Management - Privileged Access Management (Cyber Security)	3863	$0	G020		$0	4/1/2019	84	$ -	$ -
94	Identity & Access Management - Shared Area Access Management (Cyber Security)	3863	$0	G020		$0	4/1/2020	84	$ -	$ -
95	US CNI Security Enhancements - CSP 2 - Phase 1 (Cyber Security)	3863	$990,000	G020		$2,640,000	11/1/2018	84	$ -	$ 2,577,143
96	US CNI Security Enhancements - CSP 2 - Phase 2 (Cyber Security)	3863	$0	G020		$0	11/1/2021	84	$ -	$ -
97	Big Data Security Analytics - Phase 1 (Cyber Security)	3863	$1,155,388	G020		$3,466,164	5/1/2019	84	$ -	$ -
98	Big Data Security Analytics - Phase 2 (Cyber Security)	3863	$0	G020		$0	5/1/2021	84	$ -	$ -
99	Enhanced DLP Gateway and Endpoint (Cyber Security)	3863	$1,305,780	G020		$2,238,480	12/1/2017	84	$ 2,211,831	$ 1,892,049
100	Cloud Security (Cyber Security)	3863	$1,460,000	G020		$1,460,000	5/1/2017	84	$ 1,320,952	$ 1,112,381
101	Situational Intelligence & Cyber Intelligence - Phase 1 (Cyber Security)	3863	$100,000	G020		$100,000	11/1/2017	84	$ 97,619	$ 83,333
102	Situational Intelligence & Cyber Intelligence - Phase 2 (Cyber Security)	3863	$0	G020		$0	11/1/2019	84	$ -	$ -
103	IT/OT Discovery & Implementation - Phase 1 (Cyber Security)	3863	$0	G020		$3,300,000	10/1/2019	84	$ -	$ -
104	IT/OT Discovery & Implementation - Phase 2 (Cyber Security)	3863	$0	G020		$0	10/1/2021	84	$ -	$ -
105	vStig Scaling - Upgrades (Cyber Security)	3863	$0	G020		$1,000,000	8/1/2018	84	$ -	$ 940,476
106	Domain Based Security - Phase 1 (Cyber Security)	3863	$0	G020		$0	4/1/2019	84	$ -	$ -
107	Domain Based Security - Phase 2 (Cyber Security)	3863	$0	G020		$0	4/1/2020	84	$ -	$ -
108	Security Research Lab (Cyber Security)	3863	$0	G020		$325,000	4/1/2020	84	$ -	$ -
109	Threat Behavior Modeling (Cyber Security)	3863	$800,000	G020		$800,000	3/1/2017	84	$ 704,762	$ 590,476
110	Enterprise Content Management (ECM) - Archiving	1134	$0	G020		$0	4/1/2020	84	$ -	$ -
111	Enterprise Content Management (ECM) Foundation Services (US only) - Upgrade	3995	$0	G020		$0	4/1/2020	84	$ -	$ -
112	Global Audit System Replacement	3673	$0	G020		$0	3/1/2020	84	$ -	$ -
113	Global Governance, Risk & Compliance	2940	$0	G020		$0	6/1/2019	84	$ -	$ -
114	HRIS Strategy Transformation Program	4144	$0	G020		$0	4/1/2021	84	$ -	$ -
115	IS Legacy Systems Archiving & Decommission	3631	$0	G020		$0	7/1/2020	84	$ -	$ -
116	Mobility - Mobile Application Development Platform (MADP) (US only)	3996	$0	G020		$0	3/1/2019	84	$ -	$ -
117	Mobility - Mobile Device Management (MDM) System	3430	$100,000	G020		$100,000	3/1/2017	84	$ 88,095	$ 73,810
118	Office 365	3999	$0	G020		$4,300,000	10/1/2019	84	$ -	$ -
119	RAS Re-Platform/Mobile	4269	$400,000	G020		$400,000	4/1/2017	84	$ 357,143	$ 300,000
120	Desktop XP to Win7	4308	$5,960,000	G020		$11,040,000	4/1/2018	84	$ -	$ 9,857,143
121	Talent Management	3674	$0	G020		$0	10/1/2020	84	$ -	$ -
122	UPS Replacement for Data Communication Closets	4003	$0	G020		$0	4/1/2019	84	$ -	$ -
123	US Global Security TWIC Compliance	4023	$270,000	G020		$1,080,000	4/1/2018	84	$ -	$ 964,286
124	US Network Improvements	4289	$350,000	G020		$350,000	4/1/2017	84	$ 312,500	$ 262,500
125	VC Room/Mobile Refresh	3424	$0	G020		$0	4/1/2019	84	$ -	$ -
126	VSTIG Hardware Refresh	4274	$300,000	G020		$300,000	4/1/2017	84	$ 267,857	$ 225,000
127	VSTIG upgrade Phase 2	4280	$2,600,000	G020		$2,600,000	4/1/2017	84	$ 2,321,429	$ 1,950,000
128	VSTIG upgrade Phase 3	4266	$1,300,000	G020		$1,300,000	4/1/2017	84	$ 1,160,714	$ 975,000
129	Wireless Network Expansion	3425	$1,600,000	G020		$1,600,000	6/1/2017	84	$ 1,466,667	$ 1,238,095
130	Mandated Customer Systems Projects - FY16	4094	$828,000	C173		$828,000	4/1/2016	84	$ 621,000	$ 502,714
131	Mandated Customer Systems Projects - FY17	4207	$4,000,000	C173		$4,000,000	4/1/2017	84	$ 3,571,429	$ 3,000,000
132	Mandated Customer Systems Projects - FY18	4207	$0	C173		$4,000,000	4/1/2018	84	$ -	$ 3,571,429
133	Mandated Customer Systems Projects - FY19	4207	$0	C173		$0	4/1/2019	84	$ -	$ -
134	Mandated Customer Systems Projects - FY20	4207	$0	C173		$0	4/1/2020	84	$ -	$ -
135	Customer Contact Center / SDC Technology Upgrade Implement Solution	3932	$1,403,000	C173		$8,417,000	4/1/2019	84	$ -	$ -
136	Meter To Cash Value Added Enhancements	3869	$0	C173		$0	4/1/2019	84	$ -	$ -
137	Meter To Cash Value Added Enhancements	3869	$0	C173		$0	4/1/2020	84	$ -	$ -
138	Credit & Collections Gap Analysis and Protections	4211	$0	C173		$0	4/1/2019	84	$ -	$ -
139	Eliminate SSN from Customer Systems	4216	$0	C173		$0	4/1/2019	84	$ -	$ -
140	Credit and Collections - Bad Debt Mitigation Initiatives	2959	$0	C173		$400,000	4/1/2018	84	$ -	$ 357,143
141	Distributed Generation Application Tracking	3941	$600,000	C173		$600,000	12/1/2016	84	$ 507,143	$ 421,429
142	Customer Interaction Channels	4139	$0	C173		$0	4/1/2020	84	$ -	$ -
143	Mandated Customer Choice Systems Projects	4186	$3,100,000	C173		$3,100,000	4/1/2017	84	$ 2,767,857	$ 2,325,000
144	Operational Requirements and Upgrades for Procurment & Supply Chain (US SAP)	4169	$0	G020		$0	4/1/2020	84	$ -	$ -
145	Enhancement Release - EHR-H2R	4170	$0	G020		$0	4/1/2020	84	$ -	$ -
146	Enhancement Release - EHR-Non-Utility Billing	4171	$0	G020		$0	4/1/2020	84	$ -	$ -
147	Enhancement Release - EHR-Xfunc	4165	$0	G020		$0	4/1/2020	84	$ -	$ -
148	PII Project - Security & Controls	4168	$0	G020		$0	4/1/2019	84	$ -	$ -
149	US SAP: Business Planning Consolidation - HANA	4217	$3,500,000	G020		$3,500,000	4/1/2017	84	$ 3,125,000	$ 2,625,000
150	Blanket Work Order Pilot	4218	$0	G020		$0	4/1/2019	84	$ -	$ -
151	PowerPlan Module Enhancements	4220	$0	G020		$0	4/1/2019	84	$ -	$ -
152	US SAP: Improve Performance Reporting	4221	$0	G020		$0	12/1/2018	84	$ -	$ -
153	US Gas Enablement IS Component (US Front Office)	2575	$0	G210		$0	3/31/2023	84	$ -	$ -
154	US Operations Infrastructure Minor Works Improvement	3716	$0	G173		$1,000,000	3/31/2018	84	$ -	$ 892,857
155	New Medical System	3718	$800,000	G020		$1,100,000	10/31/2017	84	$ 1,073,810	$ 916,667
156	Electric and Gas Service Fulfillment Web Portal	3946	$0	G173		$0	1/31/2021	84	$ -	$ -
157	NY Gas Audit Work Mgmt and Time Reporting	3953	$0	G207		$0	11/30/2021	84	$ -	$ -
158	Migrate NYS DMV Inspection Stations to LAN	3954	$0	G207		$0	3/31/2020	84	$ -	$ -
159	Wi-Fi for Fleet Service Diagnostic Laptops	3956	$0	G173		$0	2/1/2020	84	$ -	$ -
160	ISI Follow Up Work Creation in WMS and Customer System	3961	$0	G210		$0	9/30/2021	84	$ -	$ -
161	Contract Management Modernization	4151	$0	G198		$0	1/31/2020	84	$ -	$ -
162	Ageing System Stabization/Upgrades/Replacements	4188	$1,500,000	G020		$1,500,000	3/31/2017	84	$ 1,339,286	$ 1,125,000
163	Gas Outage Management System (GOMS)	4237	$0	G210		$0	3/31/2021	84	$ -	$ -
164	Operations Performance Management, Data Management, and Reporting	4247	$0	G210		$0	3/31/2020	84	$ -	$ -
165	Gas Services Database	3948/3949	$0	G207		$940,000	3/31/2018	84	$ -	$ 839,286
166	Document Management System Replacement	3985	$4,040,000	G020		$4,040,000	5/31/2017	84	$ 3,703,333	$ 3,126,190
167	Cascade Electric Application Upgrade Project	3986	$0	G198		$460,000	3/31/2018	84	$ -	$ 410,714
168	EJ Ward Upgrade	3955	$350,000	G107		$600,000	4/1/2018	84	$ -	$ 535,714
169	Double Pole Management Database upgrade	4045	$432,000	G198		$432,000	3/31/2017	84	$ 385,714	$ 324,000
170	NY REV Clifton Park Demo Information Systems Readiness	4298	$650,000	G181		$650,000	4/1/2017	84	$ 580,357	$ 487,500
171	US CNI GMS-SCADA Upgrade and Consolidation	3737	$4,540,000	G210		$10,166,000	10/1/2020	84	$ -	$ -
172	US CNI GMS-Downstate NY and LI Upgrade End-Of-Life Verizon Back-up Communication	3730	$0	G225		$1,200,000	4/1/2018	84	$ -	$ 1,071,429
173	US CNI-Infrastructure Reliability and Security Enhancements	2881	$0	G020		$600,000	3/31/2022	84	$ -	$ -
174	US CNI Tech Services-Data Center Capacity Expansion	2909	$0	G020		$0	3/18/2020	84	$ -	$ -
175	US CNI GMS-Operator Workstation Operating System	3965	$0	G210		$820,000	3/18/2018	84	$ -	$ 732,143
176	US Control-Wires Down for Massachusetts and NY	4044	$0	G186		$5,560,000	11/19/2019	84	$ -	$ -

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service Date	(f) Amortization Period	(g) 12/31/2018 Balance	(h) 12/31/2019 Balance
1	DMS/OMS Replacement	1185	$66,772,709	G198		$66,772,709	1/1/2016	84	$ 38,155,834	$ 28,616,875
2	Gas GIS Consolidation	2577	$10,283,069	G210		$11,633,069	4/1/2019	84	$ -	$ 10,386,668
3	AMAG Upgrades	1172	$5,991,812	G020		$5,991,812	10/1/2016	84	$ 4,065,872	$ 3,209,899
4	US CNI DKMS	3019A	$0	G098		$0	3/1/2017	84	$ 0	$ 0
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84	$ 258,135	$ 161,335
6	NE GAS LEAKS RECHECKS	3136	$1,788,826	G310		$1,788,826	8/1/2016	84	$ 1,171,255	$ 915,708
7	CI Services Foundation	3492	$2,644,306	G020		$2,644,306	2/1/2016	84	$ 1,542,512	$ 1,164,754
8	US CNI Frame Relay Replacement	2495H	$6,398,268	G210		$6,398,268	12/1/2015	84	$ 3,579,983	$ 2,665,945
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84	$ 1,250,117	$ 924,000
10	Customer Choice ESCO Gas	3564	$9,629,193	C225		$9,629,193	4/1/2016	84	$ 5,846,296	$ 4,470,697
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84	$ -	$ -
12	Challenge the Limits XML	3375B	$603,192	G179		$603,192	10/1/2015	84	$ 323,139	$ 236,968
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84	$ 205,726	$ 150,866
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84	$ 894,514	$ 666,127
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$1,240,600	G020		$1,240,600	9/1/2016	84	$ 827,067	$ 649,838
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84	$ -	$ -
17	CNI Network Security - (Cyber Security)	3614B7	$3,801,588	G020		$3,801,588	9/1/2016	84	$ 2,534,392	$ 1,991,308
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$1,362,769	G020		$1,362,769	6/1/2016	84	$ 859,842	$ 665,161
19	CNI Patch Management - (Cyber Security)	3614B11	$0	G020		$0	1/1/2099	84	$ -	$ -
20	CNI Network Security Controls - (Cyber Security)	3614B13	$0	G020		$0	1/1/2099	84	$ -	$ -
21	CNI SIEM - (Cyber Security)	3614B14	$1,106,000	G020		$1,106,000	9/1/2016	84	$ 737,333	$ 579,333
22	Enterprise Network Security - (Cyber Security)	3614D1	$5,946,273	G020		$5,946,273	9/1/2016	84	$ 3,964,182	$ 3,114,715
23	Network Risk & Compliance - (Cyber Security)	3614D2	$0	G020		$0	1/1/2099	84	$ -	$ -
24	Security Operations Center - (Cyber Security)	3614E2	$1,461,890	G020		$1,461,890	4/1/2016	84	$ 887,576	$ 678,735
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$121,600	G020		$121,600	4/1/2016	84	$ 73,829	$ 56,457
26	Security Reference Architecture - (Cyber Security)	3614G1	$60,800	G020		$60,800	9/1/2016	84	$ 40,533	$ 31,848
27	Cyber Security prioritised investments - (Cyber Security)	3614	$725,146	G020		$725,146	9/1/2016	84	$ 483,431	$ 379,838
28	NY Retail Access	3839	$2,872,399	G170		$2,872,399	12/1/2016	84	$ 2,017,519	$ 1,607,176
29	US Web Initiatives 2	3600B	$3,831,522	C175		$3,831,522	2/1/2016	84	$ 2,235,055	$ 1,687,694
30	Capitalized Asset Replacement	3617C	$935,395	G084		$935,395	4/1/2016	84	$ 567,919	$ 434,291
31	UNY Capitalized Asset Replacement	3617D	$265,077	G003		$265,077	4/1/2016	84	$ 160,940	$ 123,072
32	DSNY Capitalized Equipment Installs - Physical Security	3617B	$475,000	G235		$475,000	4/1/2016	84	$ 288,393	$ 220,536
33	Pelco Video System Conversion - Physical Security	3841	$480,000	G077		$480,000	4/1/2016	84	$ 291,429	$ 222,857
34	NMPC C-Cure Conversion to AMAG	3853	$1,182,427	G003		$1,182,427	3/1/2017	84	$ 872,744	$ 703,826
35	EHR1 - PMO		$8,928,548	G012		$8,928,548	12/1/2015	84	$ 4,995,735	$ 3,720,228
36	EHR1 - Supply Chain		$14,769,439	G012		$14,769,439	12/1/2015	84	$ 8,263,853	$ 6,153,933
37	EHR1 - Finance		$16,145,346	G012		$16,145,346	12/1/2015	84	$ 9,033,705	$ 6,727,227
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84	$ 1,350,867	$ 1,005,965
39	EHR1 - Payroll		$12,187,165	G012		$12,187,165	12/1/2015	84	$ 6,819,009	$ 5,077,986
40	EHR1 - BPS		$9,915,257	5020		$9,915,257	12/1/2015	84	$ 5,547,823	$ 4,131,357
41	Customer Storm Outage Credit Program	3859	$0	5210		$0	3/1/2015	84	$ 0	$ 0
42	US CNI GMS SCADA Upgrade	3737	$11,369,504	C210		$17,079,504	1/1/2019	84	$ -	$ 14,639,575
43	US Desktop Refresh	2927	$7,430,690	G020		$7,430,690	3/1/2016	48	$ 2,167,285	$ 309,612
44	Internet Explorer Upgrade	3644	$300,090	G020		$300,090	3/1/2016	84	$ 178,625	$ 135,755
45	Mobile Device for PTO	3883	$2,442,471	G173		$2,442,471	9/1/2016	48	$ 1,017,696	$ 407,079
46	SMI Conversion Mobilization	3896	$2,187,292	G020		$2,187,292	7/1/2016	84	$ 1,406,116	$ 1,093,646
47	S005242 M112 Systemic Improvement		$3,500,000	G012		$3,500,000	3/1/2016	12	$ -	$ -
48	Cadency Account Reconciliation Tool		$146,894	G012		$146,894	3/1/2016	12	$ -	$ -
49	Soft Off Program	4024	$1,278,485	C207		$1,278,485	2/1/2016	84	$ 745,783	$ 563,142
50	LI CSS Stabilization	4133	$847,000	5230		$847,000	3/1/2016	84	$ 504,167	$ 383,167

Service Company Capital Software allocated to Operating Companies as Rent Expense

13,670,747	#########		$ 1,145,031	$ 3,337,075		$ -	$136,428,012

$ 4,482,106 Rate Year IS Projects

15,325,494	#########		$ 1,272,993	$ 4,660,199		#########	$225,478,898

$ 5,933,193 Existing IS Projects

$ 10,415,299 Total RY 17 IS Projects
$ 6,317,433 Test Year IS Projects
$ 4,097,866 Adjustment

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service	(f) Amortization Period	(g) 12/31/2017 Balance	(h) 12/31/2018 Balance	(i) = (g+h)/2 Average Balance	(j) 9.9500% Service Co Return
1	DMS/OMS Replacement	1185	$66,772,709	G198		$66,772,709	1/1/2016	84	$ 47,694,792	$ 38,155,834	$ 42,925,313	9.9500%
2	Gas GIS Consolidation	2577	$5,573,069	G210		$10,283,069	4/1/2019	84	$ -	$ -	$ -	9.9500%
3	AMAG Upgrades	1172	$5,991,812	G020		$5,991,812	10/1/2016	84	$ 4,921,845	$ 4,065,872	$ 4,493,859	9.9500%
4	US CNI DKMS	3019A	$0	G098		$0	3/1/2017	84	$ 0	$ 0	$ 0	9.9500%
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84	$ 354,936	$ 258,135	$ 306,536	9.9500%
6	NE GAS LEAKS RECHECKS	3136	$1,788,826	G310		$1,788,826	8/1/2016	84	$ 1,426,802	$ 1,171,255	$ 1,299,028	9.9500%
7	CI Services Foundation	3492	$2,644,306	G020		$2,644,306	2/1/2016	84	$ 1,920,270	$ 1,542,512	$ 1,731,391	9.9500%
8	US CNI Frame Relay Replacement	2495H	$6,398,268	G210		$6,398,268	12/1/2015	84	$ 4,494,022	$ 3,579,983	$ 4,037,002	9.9500%
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84	$ 1,576,235	$ 1,250,117	$ 1,413,176	9.9500%
10	Customer Choice ESCO Gas	3564	$9,629,193	C225		$9,629,193	4/1/2016	84	$ 7,221,895	$ 5,846,296	$ 6,534,095	9.9500%
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84	$ -	$ -	$ -	9.9500%
12	Challenge the Limits XML	3375B	$603,192	G179		$603,192	10/1/2015	84	$ 409,309	$ 323,139	$ 366,224	9.9500%
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84	$ 260,587	$ 205,726	$ 233,157	9.9500%
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84	$ 1,122,900	$ 894,514	$ 1,008,707	9.9500%
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$1,240,600	G020		$1,240,600	9/1/2016	84	$ 1,004,296	$ 827,067	$ 915,681	9.9500%
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84	$ -	$ -	$ -	9.9500%
17	CNI Network Security - (Cyber Security)	3614B7	$3,801,588	G020		$3,801,588	9/1/2016	84	$ 3,077,476	$ 2,534,392	$ 2,805,934	9.9500%
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$1,362,769	G020		$1,362,769	6/1/2016	84	$ 1,054,524	$ 859,842	$ 957,183	9.9500%
19	CNI Patch Management - (Cyber Security)	3614B11	$0	G020		$0	1/1/2099	84	$ -	$ -	$ -	9.9500%
20	CNI Network Security Controls - (Cyber Security)	3614B13	$0	G020		$0	1/1/2099	84	$ -	$ -	$ -	9.9500%
21	CNI SIEM - (Cyber Security)	3614B14	$1,106,000	G020		$1,106,000	9/1/2016	84	$ 895,333	$ 737,333	$ 816,333	9.9500%
22	Enterprise Network Security - (Cyber Security)	3614D1	$5,946,273	G020		$5,946,273	9/1/2016	84	$ 4,813,650	$ 3,964,182	$ 4,388,916	9.9500%
23	Network Risk & Compliance - (Cyber Security)	3614D2	$0	G020		$0	1/1/2099	84	$ -	$ -	$ -	9.9500%
24	Security Operations Center - (Cyber Security)	3614E2	$1,461,890	G020		$1,461,890	4/1/2016	84	$ 1,096,417	$ 887,576	$ 991,997	9.9500%
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$121,600	G020		$121,600	4/1/2016	84	$ 91,200	$ 73,829	$ 82,514	9.9500%
26	Security Reference Architecture - (Cyber Security)	3614G1	$60,800	G020		$60,800	9/1/2016	84	$ 49,219	$ 40,533	$ 44,876	9.9500%
27	Cyber Security prioritised investments - (Cyber Security)	3614	$725,146	G020		$725,146	9/1/2016	84	$ 587,023	$ 483,431	$ 535,227	9.9500%
28	NY Retail Access	3839	$2,872,399	G170		$2,872,399	12/1/2016	84	$ 2,427,861	$ 2,017,519	$ 2,222,690	9.9500%
29	US Web Initiatives 2	3600B	$3,831,522	C175		$3,831,522	2/1/2016	84	$ 2,782,415	$ 2,235,055	$ 2,508,735	9.9500%
30	Capitalized Asset Replacement	3617C	$935,395	G084		$935,395	4/1/2016	84	$ 701,547	$ 567,919	$ 634,733	9.9500%
31	UNY Capitalized Asset Replacement	3617D	$265,077	G003		$265,077	4/1/2016	84	$ 198,808	$ 160,940	$ 179,874	9.9500%
32	DSNY Capitalized Equipment Installs - Physical Security	3617B	$475,000	G235		$475,000	4/1/2016	84	$ 356,250	$ 288,393	$ 322,321	9.9500%
33	Pelco Video System Conversion - Physical Security	3841	$480,000	G077		$480,000	4/1/2016	84	$ 360,000	$ 291,429	$ 325,714	9.9500%
34	NMPC C-Cure Conversion to AMAG	3853	$1,182,427	G003		$1,182,427	3/1/2017	84	$ 1,041,662	$ 872,744	$ 957,203	9.9500%
35	EHR1 - PMO		$8,928,548	G012		$8,928,548	12/1/2015	84	$ 6,271,242	$ 4,995,735	$ 5,633,489	9.9500%
36	EHR1 - Supply Chain		$14,769,439	G012		$14,769,439	12/1/2015	84	$ 10,373,772	$ 8,263,853	$ 9,318,813	9.9500%
37	EHR1 - Finance		$16,145,346	G012		$16,145,346	12/1/2015	84	$ 11,340,183	$ 9,033,705	$ 10,186,944	9.9500%
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84	$ 1,695,769	$ 1,350,867	$ 1,523,318	9.9500%
39	EHR1 - Payroll		$12,187,165	G012		$12,187,165	12/1/2015	84	$ 8,560,033	$ 6,819,009	$ 7,689,521	9.9500%
40	EHR1 - BPS		$9,915,257	5020		$9,915,257	12/1/2015	84	$ 6,964,288	$ 5,547,823	$ 6,256,055	9.9500%
41	Customer Storm Outage Credit Program	3859	$0	5210		$0	3/1/2015	84	$ 0	$ 0	$ 0	9.9500%
42	US CNI GMS SCADA Upgrade	3737	$5,739,504	C210		$11,369,504	1/1/2019	84	$ -	$ -	$ -	9.9500%
43	US Desktop Refresh	2927	$7,430,690	G020		$7,430,690	3/1/2016	48	$ 4,024,957	$ 2,167,285	$ 3,096,121	9.9500%
44	Internet Explorer Upgrade	3644	$300,090	G020		$300,090	3/1/2016	84	$ 221,495	$ 178,625	$ 200,060	9.9500%
45	Mobile Device for PTO	3883	$2,442,471	G173		$2,442,471	9/1/2016	48	$ 1,628,314	$ 1,017,696	$ 1,323,005	9.9500%
46	SMI Conversion Mobilization	3896	$2,187,292	G020		$2,187,292	7/1/2016	84	$ 1,718,586	$ 1,406,116	$ 1,562,351	9.9500%
47	S005242 M112 Systemic Improvement		$3,500,000	G012		$3,500,000	3/1/2016	12	$ -	$ -	$ -	9.9500%
48	Cadency Account Reconciliation Tool		$146,894	G012		$146,894	3/1/2016	12	$ -	$ -	$ -	9.9500%
49	Soft Off Program	4024	$1,278,485	C207		$1,278,485	2/1/2016	84	$ 928,423	$ 745,783	$ 837,103	9.9500%
50	LI CSS Stabilization	4133	$847,000	5230		$847,000	3/1/2016	84	$ 625,167	$ 504,167	$ 564,667	9.9500%
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

Service Company Capital Software allocated to Operating Companies as Rent Expense

	Investment Name	INVP #	(a) Inception to Date $	(b) Bill Pool	(c) Adjustments	(d) = (a)+(c) Total US Spend	(e) In Service	(f) Amortization Period
1	DMS/OMS Replacement	1185	$66,772,709	G198		$66,772,709	1/1/2016	84
2	Gas GIS Consolidation	2577	$10,283,069	G210		$11,633,069	4/1/2019	84
3	AMAG Upgrades	1172	$5,991,812	G020		$5,991,812	10/1/2016	84
4	US CNI DKMS	3019A	$0	G098		$0	3/1/2017	84
5	Street Light Outage Improvement	3237	$677,605	G198		$677,605	9/1/2014	84
6	NE GAS LEAKS RECHECKS	3136	$1,788,826	G310		$1,788,826	8/1/2016	84
7	CI Services Foundation	3492	$2,644,306	G020		$2,644,306	2/1/2016	84
8	US CNI Frame Relay Replacement	2495H	$6,398,268	G210		$6,398,268	12/1/2015	84
9	Cascade System for Gas	3629	$2,282,823	G210		$2,282,823	11/1/2015	84
10	Customer Choice ESCO Gas	3564	$9,629,193	C225		$9,629,193	4/1/2016	84
11	CRIS Migration	2583	$28,617,090	C343		$28,617,090	1/1/2099	84
12	Challenge the Limits XML	3375B	$603,192	G179		$603,192	10/1/2015	84
13	Challenge Limits Letters	3375D	$384,023	C434		$384,023	10/1/2015	84
14	IAM Ph2: Federated Identity (Cyber Security)	3614A1	$1,598,706	G020		$1,598,706	12/1/2015	84
15	IAM Ph3 Identity Administration - (Cyber Security)	3614A2	$1,240,600	G020		$1,240,600	9/1/2016	84
16	CNI Separation of Test & Prod - (Cyber Security)	3614B2	$152	G020		$152	1/1/2099	84
17	CNI Network Security - (Cyber Security)	3614B7	$3,801,588	G020		$3,801,588	9/1/2016	84
18	Security Incident & Event Monitoring (SIEM) 2 - (Cyber Security)	3614E3	$1,362,769	G020		$1,362,769	6/1/2016	84
19	CNI Patch Management - (Cyber Security)	3614B11	$0	G020		$0	1/1/2099	84
20	CNI Network Security Controls - (Cyber Security)	3614B13	$0	G020		$0	1/1/2099	84
21	CNI SIEM - (Cyber Security)	3614B14	$1,106,000	G020		$1,106,000	9/1/2016	84
22	Enterprise Network Security - (Cyber Security)	3614D1	$5,946,273	G020		$5,946,273	9/1/2016	84
23	Network Risk & Compliance - (Cyber Security)	3614D2	$0	G020		$0	1/1/2099	84
24	Security Operations Center - (Cyber Security)	3614E2	$1,461,890	G020		$1,461,890	4/1/2016	84
25	End user initiated secure file & email transfer - (Cyber Security)	3614C1	$121,600	G020		$121,600	4/1/2016	84
26	Security Reference Architecture - (Cyber Security)	3614G1	$60,800	G020		$60,800	9/1/2016	84
27	Cyber Security prioritised investments - (Cyber Security)	3614	$725,146	G020		$725,146	9/1/2016	84
28	NY Retail Access	3839	$2,872,399	G170		$2,872,399	12/1/2016	84
29	US Web Initiatives 2	3600B	$3,831,522	C175		$3,831,522	2/1/2016	84
30	Capitalized Asset Replacement	3617C	$935,395	G084		$935,395	4/1/2016	84
31	UNY Capitalized Asset Replacement	3617D	$265,077	G003		$265,077	4/1/2016	84
32	DSNY Capitalized Equipment Installs - Physical Security	3617B	$475,000	G235		$475,000	4/1/2016	84
33	Pelco Video System Conversion - Physical Security	3841	$480,000	G077		$480,000	4/1/2016	84
34	NMPC C-Cure Conversion to AMAG	3853	$1,182,427	G003		$1,182,427	3/1/2017	84
35	EHR1 - PMO		$8,928,548	G012		$8,928,548	12/1/2015	84
36	EHR1 - Supply Chain		$14,769,439	G012		$14,769,439	12/1/2015	84
37	EHR1 - Finance		$16,145,346	G012		$16,145,346	12/1/2015	84
38	EHR1 - IT Delivery		$2,414,316	G012		$2,414,316	12/1/2015	84
39	EHR1 - Payroll		$12,187,165	G012		$12,187,165	12/1/2015	84
40	EHR1 - BPS		$9,915,257	5020		$9,915,257	12/1/2015	84
41	Customer Storm Outage Credit Program	3859	$0	5210		$0	3/1/2015	84
42	US CNI GMS SCADA Upgrade	3737	$11,369,504	C210		$17,079,504	1/1/2019	84
43	US Desktop Refresh	2927	$7,430,690	G020		$7,430,690	3/1/2016	48
44	Internet Explorer Upgrade	3644	$300,090	G020		$300,090	3/1/2016	84
45	Mobile Device for PTO	3883	$2,442,471	G173		$2,442,471	9/1/2016	48

$ 6,379,255 Rate Year IS Projects

$ 4,790,558 Existing IS Projects

$ 11,169,813 Total RY 19 IS Projects
$ 10,435,048 RY 18 IS Projects
$ 734,765 Adjustment

Date of Request: May 9, 2016
Due Date: May 19, 2016

DPS Request No. DPS-487 JL-8
KEDNY/ KEDLI Req. No. BULI-661

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: NYPSC, James Lyons

TO: National Grid, Sean Mongan

SUBJECT: Research and Development Costs for KEDNY

Request:

Provide the following:

1. For KEDNY, KEDLI, and Niagara Mohawk Power Corporation, d/b/a National Grid (NMPC), reconcile the information provided in the National Grid Triennial R&D Report 2016 by program area, as follows, National Grid Internal Program, Millennium and NYSERDA, with the Companies' response to information requests DPS-420 and DPS-421, Attachment 1 for calendar years 2014 and 2015. Provide with the reconciliation a breakdown of the following for each company by program and by year:

    a. Budget;

    b. Annual Customer Surcharge per Dth;

    c. Total Revenue Collected;

    d. Total Expenditures;

    e. End of year balance; and

    f. Reconcile total balance by year (*e.g.,* previous year program balance plus current year program balance).

2. National Grid's Triennial R&D Report 2016 provides aggregated information for KEDNY, KEDLI, and NMPC by program area with limited detail regarding customer contributions and program expenditures broken-out for each company. Typically, these programs and related costs are reported by the individual company in relation to a given company's customer surcharges and their R&D program participation. Explain or provide the authority for aggregating this information as it is presented in the April 2016 Triennial R&D Report?

3. If the Utilization Technology Development (UTD) program and associated proposals are approved, describe the differentiation between the projects that are included in UTD program and any associated programmatic costs from projects associated with or funded through the current internal R&D program.

4. Will implementation of the UTD R&D programs change the funding currently required for the internal R&D program projects supported by the companies?

Response:

1. Attachment 1 is a reconciliation of the 2016 Triennial R&D Report ("R&D Report") by program area for NMPC, KEDNY, and KEDLI for Calendar Years ("CY") 2014 and 2015. In preparing the attachment, the Company identified two errors in the R&D Report. First, the R&D Report reflected a "NYSERDA Assessment" of $3.565 million for CY 2014 and $4.906 million for CY 2015. However, the amounts shown as CY 2015 were actually Fiscal Year amounts and not CY amounts. The amounts shown as CY 2014 were incorrect and did not represent the final ERDA assessments billed by NYS. Attachment 1 contains the actual "NYSERDA Assessment" amounts of $1.702 million and $4.514 million for CYs 2014 and 2015, respectively. Attachment 2 shows the reconciliation of these amounts by operating company. Second, the "National Grid Internal Program Operations" line item of $28,476 for CY 2015 was misstated in the R&D Report. The correct amount is $94,923, as shown in Attachment 1.

   Attachment 3 provides the Millennium surcharges per Dth for NMPC, KEDNY, and KEDLI for calendar years 2014 and 2015. Attachment 4 contains the reconciliation of the R&D Millennium program. The variance between the ending deferral balance and general ledger balance represents a difference between actual project expenditures and project expenditures recorded to the deferral. The Company is currently reviewing the variances shown.

2. From inception of the Millennium program, National Grid's Gas RD&D reports have been filed as a single combined report that shows a total research program and total financial investment rather than by individual operating company.

3. On the programmatic side, the projects approved by the UTD Board exclusively support the development of technologies that benefit customers after the meter. Projects include advanced energy using technologies such as distributed generation, advanced heat and cooling, transportation technologies, and industrial process improvements. KEDNY and KEDLI's current internal program supports the development of technologies on the

company's side of the meter that improve the safety, reliability or cost effectiveness of gas distribution operations.

On the cost side, UTD projects that proceed will include co-funding from other companies as well as GTI and any other sources GTI may obtain. By contrast, projects in the Companies' internal program may or may not have co-funders based on the level of interest from other companies and the perceived importance of the project to National Grid. With regard to programmatic or management costs, the Companies' internal program is managed by internal staff while UTD projects are managed by GTI's staff. GTI's costs are embedded in the project costs and listed in each proposal.

4. No, the request to fund the UTD program is supplementary to the current internal program and no changes to funding are anticipated.

<u>Name of Respondent</u>: <u>Date of Reply</u>:
Mary Holzmann, Chris Cavanagh, Keith Sperling May 18, 2016

National Grid Gas R&D Spending
KEDLI, KEDNY and NMPC

	Calendar Year Expenditures ($)							
Year	2014				2015			
	Total	KEDLI	KEDNY	NMPC	Total	KEDLI	KEDNY	NMPC
National Grid Internal Program*								
Utilization	$104,800	$43,243	$43,739	$17,819	$211,426	$211,426	$0	$0
Operations	$57,708	$9,455	$20,438	$27,814	$94,923	$12,010	$54,437	$28,476
Ngrid Labor and Expenses	$229,692	$55,126	$114,846	$59,720	$184,741	$29,947	$64,807	$31,184
TOTAL INTERNAL	$392,200	$107,824	$179,023	$105,352	$491,090	$253,383	$119,244	$59,660
National Grid Millennium Program								
NYSEARCH Projects	$2,265,234	$329,180	$637,868	$1,298,186	$1,311,235	$218,935	$690,217	$402,083
OTD Projects	$750,000	$175,000	$380,000	$195,000	$870,279	$295,279	$380,000	$195,000
National Grid Projects	$40,000	$20,568	$9,516	$9,916	$103,502	$18,675	$65,367	$19,460
TOTAL MILLENNIUM	$3,055,234	$524,748	$1,027,384	$1,503,102	$2,285,016	$532,889	$1,135,584	$616,543
TOTAL MILLENNIUM AND INTERNAL	$3,447,434	$632,572	$1,206,407	$1,608,455	$2,776,106	$786,272	$1,254,828	$676,203
NYSERDA Assessment	$1,701,900	$542,324	$814,840	$344,736	$4,514,020	$1,063,547	$1,995,469	$1,455,004
TOTAL R&D PROGRAM	$5,149,334	$1,174,896	$2,021,247	$1,953,190	$7,290,126	$1,849,819	$3,250,296	$2,131,207

* "Utilization" and "Internal" are not funded through the Millenium Fund.
* As discussed with Staff, the Company reflected the total payments of $211,426 made for residential methane detector research to show that these costs are being separately funded by KEDLI.

Keyspan Gas East Corporation d/b/a National Grid
The Brooklyn Union Gas Company d/b/a National Grid NY
Case Nos. 16-G-0058 and 16-G-0059
Attachment 2 to DPS-487

	CY 2014 ERDA				
	KEDLI	KEDNY	NMPC	Totals	
Description	CY 2014	CY 2014	CY 2014	CY 2014	
Revenues (Included in Base Rates)	$1,056,054	$1,835,525	$681,060	$3,572,639	
Expense	$542,324	$814,840	$344,736	$1,701,900	**C**
Variance (Expense vs Revenues)	($513,730)	($1,020,685)	($336,324)	($1,870,739)	**A,B**

	CY 2015 ERDA				
	KEDLI	KEDNY	NMPC	Totals	
Description	CY 2015	CY 2015	CY 2015	CY 2015	
Revenues (Included in Base Rates)	$1,056,054	$1,835,525	$681,060	$3,572,639	
Expense	$1,063,547	$1,995,469	$1,455,004	$4,514,020	**C**
Variance (Expense vs Revenues)	$7,493	$159,944	$773,944	$941,382	**B**

A The Companies received a refund from NYS for ERDA during calendar year 2014
B Please note that there is no reconciliation/true up for NYSERDA expenditures

C:	KEDLI	KEDNY	NMPC	Totals
Per Final NYS Assessment FY14	$1,093,832	$1,686,648	$848,133	$3,628,613
Per Final NYS Assessment FY15	$1,015,204	$1,570,166	$752,584	$3,337,954
Per Final NYS Assessment FY16	$1,079,661	$2,137,236	$1,689,145	$4,906,042
Monthly Amortization:				
Per Final NYS Assessment FY14	$91,153	$140,554	$70,678	$302,384
Per Final NYS Assessment FY15	$84,600	$130,847	$62,715	$278,163
Per Final NYS Assessment FY16	$89,972	$178,103	$140,762	$408,837
Calendar Year Expense:				
2014 (3 Months of FY14 and 9 months of FY15)	$1,034,861	$1,599,287	$776,471	$3,410,619
Refund from NYS posted to ERDA expenditures	$492,537	$784,446	$431,736	$1,708,719
Net CY 2014	$542,324	$814,840	$344,736	$1,701,900
2015 (3 Months of FY15 and 9 months of FY16)	$1,063,547	$1,995,469	$1,455,004	$4,514,020

	KEDNY (per Dth)		KEDLI (per Dth)		NIMO (per Dth)	
Jan-2014	$	0.01740	$	0.01240	$	0.01067
Feb-2014	$	0.01740	$	0.01240	$	0.01067
Mar-2014	$	0.01740	$	0.01240	$	0.01067
Apr-2014	$	0.01740	$	0.01240	$	0.01067
May-2014	$	0.01740	$	0.01240	$	0.01067
Jun-2014	$	0.01740	$	0.01240	$	0.01067
Jul-2014	$	0.01740	$	0.01240	$	0.01067
Aug-2014	$	0.01740	$	0.01240	$	0.01067
Sep-2014	$	0.01740	$	0.01240	$	0.01067
Oct-2014	$	0.01740	$	0.01240	$	0.01067
Nov-2014	$	0.01740	$	0.01240	$	0.01067
Dec-2014	$	0.01740	$	0.01240	$	0.01067
Jan-2015	$	0.00670	$	-	$	0.01214
Feb-2015	$	0.00670	$	-	$	0.01214
Mar-2015	$	0.00670	$	-	$	0.01214
Apr-2015	$	0.00670	$	-	$	0.01214
May-2015	$	0.00670	$	-	$	0.01214
Jun-2015	$	0.00670	$	-	$	0.01214
Jul-2015	$	0.00670	$	-	$	0.01214
Aug-2015	$	0.00670	$	-	$	0.01214
Sep-2015	$	0.00670	$	-	$	0.01214
Oct-2015	$	0.00670	$	-	$	0.01214
Nov-2015	$	-	$	-	$	0.01214
Dec-2015	$	-	$	-	$	0.01214

	2014 Millennium Fund Deferral Account		
	KEDLI	KEDNY	NMPC
Activity	CY 2014	CY 2014	CY 2014
Beginning Balance	($1,255,371)	($124,403)	($556,031)
Collections	($1,226,719)	($2,559,962)	($1,163,093)
Expenditures Charged	$524,748	$1,027,384	$1,503,102
Ending balance	($1,957,342)	($1,656,982)	($216,021)
Balance Per G/L	($2,059,672)	($1,917,378)	($272,401)
Variance [1]	$102,330	$260,396	$56,380

	2015 Millennium Fund Deferral Account		
	KEDLI	KEDNY	NMPC
Activity	CY 2015	CY 2015	CY 2015
Beginning Balance	($2,059,672)	($1,917,378)	($272,401)
Collections	($19,973)	($799,032)	($1,723,532)
Expenditures Charged	$532,889	$1,135,584	$616,543
Ending balance	($1,546,756)	($1,580,827)	($1,379,390)
Balance Per G/L	($1,755,136)	($1,705,513)	($1,041,975)
Variance [1]	$208,380	$124,686	($337,415)

	2016 Millennium Fund Deferral Account			
	KEDLI	KEDNY	NMPC	
Activity	CY 2016	CY 2016	CY 2016	As of March 2016
Beginning Balance	($1,755,136)	($1,705,513)	($1,041,975)	
Collections	($6)	-	($76,352)	
Expenditures Charged	$221,146	$820,785	$247,460	
Ending balance	($1,533,996)	($884,728)	($870,866)	
Balance Per G/L	($1,533,996)	($884,728)	($870,866)	
Variance	$0	$0	$0	

[1] The Company is currently reconciling project expenditures relating to the Millennium Fund Deferral

Date of Request: March 30, 2016
Due Date: April 11, 2016

LIPA Request No. LIPA-7 RS-7
KEDNY/ KEDLI Req. No. BULI-390

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID
THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Case 16-G-0058 KeySpan Gas East Corporation d/b/a National Grid
Case 16-G-0059 The Brooklyn Union Gas Company d/b/a National Grid NY

Request for Information

FROM: LIPA, Rick Shansky

TO: National Grid, Rate Design Panel

SUBJECT: **GENERATOR TRANSPORTATION RATES**

Request:

7. Please provide a comparison of the components of the transportation rates, and the precise rates in each element, between KEDNY's and KEDLI's SC-14 services and the equivalent services offered by Consolidated Edison.

Response:

Please see Attachment 1 for a comparison of the rate components of KEDLI's SC-14 and KEDNY's SC-20 service classifications. Please refer to Consolidated Edison's tariff for its rates and services.

Name of Respondent:
Pamela Dise

Date of Reply:
April 8, 2016

	KEDLI SC14, Rate Schedule 1	**KEDNY SC20, Rate Schedule 1**
On-System Transportation Charge		
1) Contribution to Fixed Costs	$.10 / dth	$.10 / dth
2) Unitized Long Run Marginal Costs	$.14 / dth	$.10 / dth
Value Added Charge	Variable - Determined in accordance with Leaf No. 194	Variable - Determined in accordance with Leaf 427.12
Daily Balancing Service Demand Charge	$.01 / dth	$.01 / dth

The sum of the per dekatherm charges listed in (a), (b) and (c) above shall not exceed the per dekatherm charge of the otherwise applicable interruptible transportation service. If this condition exists, the Company shall reduce the Value Added Charge such that the sum of these charges is capped at the applicable interruptible transportation service rate.

Annual Minimum Bill Obligation	50% of the facility's MAQ, multiplied by all charges payable under this Service Classification, whether such quantity is actually transported.	50% of the facility's MAQ, multiplied by all charges payable under this Service Classification, whether such quantity is actually transportated.
Daily Balancing Charge	Per Leaf 190 and 191	Per Leaf 427.8 and 427.9

Note: 1) On-System Transportation Charge is tariffed
Note: 2) Daily Balancing Service Demand Charge stated in Seller Statement

Skills Shortages in a Booming Market:
The Big Oil and Gas Challenge

The strains on labor capacity in oil and gas construction markets worldwide are becoming increasingly well known. These strains continue to affect projected project costs, and several large capital projects have already been delayed or cancelled (see Shell's Louisiana GTL plant as an example) as a result of rising costs and questionable long-term profitability projections. As demand continues to increase in the face of the LNG export gold rush, construction firms are faced with unprecedented pressures to retain and grow talent.

To keep up with this extremely dynamic and competitive – if not unprecedented – business environment, U.S. energy infrastructure construction firms need to develop a robust talent pipeline to tackle the industry's many business challenges in the coming years. In 2008 just 3.8 percent of the total construction workforce was engaged in direct oil and gas construction. By 2012, 6.4 percent – nearly double 2008's number – of that workforce was engaged in direct oil and gas construction. According to FMI's estimates, by 2017 nearly 10 percent of the total U.S. construction workforce will have moved over to this burgeoning segment of the industry.

Fierce competition for talent in this sector is already driving construction companies to think about their human capital needs and the strategies required to optimize their access to – and retention of – qualified and experienced workers. Questions that are starting to move up company executives' strategic agendas include, "How do we prevent knowledge loss with a large percentage of experienced workers preparing for retirement?" and "How do we anticipate and prepare for the workforce depletion and adapt to a shifting employee culture?"

Scott Duncan, vice president with FMI Capital Advisors, states, "The oil and gas construction market remains vibrant, and many firms are seeking new ways to expand and grow their market presence. As competition for limited resources intensifies, labor and talent management are quickly becoming a key differentiator in company performance and overall company value. Companies seeking to build a presence in this market need to ensure they have the systems and processes in place to maximize productivity and retain top talent."

This article provides oil and gas construction demand and labor supply forecasts, presents key labor dynamics in today's U.S. oil and gas construction industry, and summarizes recommendations on how to prepare for the imminent labor and knowledge void. Information was collected through 25 in-depth interviews with executives of energy infrastructure construction firms as well as with select FMI industry experts.

The article also presents three case studies, including ARB, Inc.; Kiewit; and Henkels & McCoy, and describes how these companies are dealing with long-term talent management and resource planning issues.

FMI Corporation Locations

Raleigh - Headquarters
5171 Glenwood Avenue
Suite 200
Raleigh, NC 27612
Tel: 919.787.8400
Fax: 919.785.9320

Denver
210 University Boulevard
Suite 800
Denver, CO 80206
Tel: 303.377.4740
Fax: 303.398.7291

Scottsdale
14500 N. Northsight Boulevard
Suite 313
Scottsdale, AZ 85260
Tel: 602.381.8108
Fax: 602.381.8228

Tampa
308 South Boulevard
Tampa, FL 33606
Tel: 813.636.1364
Fax: 813.636.9601

www.fminet.com

FMI™

The refinement of hydraulic fracturing technology has allowed the United States to go from an increasingly dependent buyer of foreign oil to the second-leading producer of oil in the world.

Overview of the U.S. Oil and Gas Construction Boom

In 2008 approximately 60 percent of the crude oil produced in the United States came from one of three places: the Gulf of Mexico, Texas or Alaska. Domestic production was on the decline, having decreased about 2 percent annually on average since 1970. Imports from foreign nations filled the gap, bringing with them significant political and economic implications for the country.

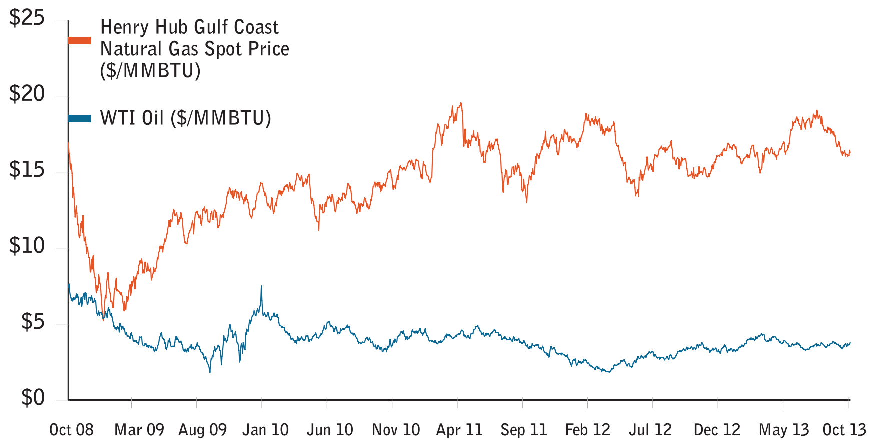
In the five years following, the refinement of hydraulic fracturing technology has allowed the United States to go from an increasingly dependent buyer of foreign oil to the second-leading producer of oil in the world. The technology has also given energy companies the ability to exploit huge natural gas reserves across the country. While traditionally much of the country's oil and gas infrastructure lies along the Gulf Coast, shale development is now taking place across the country in states like Pennsylvania, West Virginia, Ohio, Oklahoma, Colorado and North Dakota, increasing oil and gas production at previously unfathomable rates. Located deep beneath Pennsylvania and West Virginia, the Marcellus Shale has increased natural gas production by six times in just four years. If the Marcellus were its own country, it would be the 8th-largest gas producer in the world. Ten years ago this was unimaginable.

Figure 1. Lower 48 States Shale Plays

Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

This dramatic production increase has affected prices. The rush to produce natural gas from formations like the Marcellus began to have a significant effect in 2012, when the price of natural gas fell to an all-time low of $1.82 per MMBTU on April 20, effectively making it one of the cheapest energy resources in the world. Oil prices also began to exhibit some very peculiar behavior: In early 2011, oil produced in the United States began to trade at a substantial discount to oil produced overseas. With so much oil production in far-off places of the country, surpluses were developing at storage and transportation hubs unable to get to market. As a result, prices declined and refiners rejoiced.

Figure 2. The Cost of Energy — Oil versus Natural Gas



Source: Energy Information Administration

In just five years, the United States has witnessed an energy revolution. Production of oil and gas is increasing, prices are falling, and entrepreneurs nationwide are finding newer and better ways to take advantage of this dynamic. The biggest challenge for all of them comes down to one issue: infrastructure.

Due to infrastructure constraints, domestically produced oil has traded at a discount, and natural gas prices have declined precipitously. There is tremendous profit incentive for companies that can liquefy natural gas and transport it overseas, and for companies that can transport oil from overstocked hubs in the Bakken shale and other oil-rich areas.

FMI estimates that capital expenditures on oil and gas construction projects in the United States will exceed $55 billion in 2013, up 11 percent from 2012. We estimate this growth will continue at an average of 17 percent through 2017 as the construction of refineries, petrochemical facilities, pipelines, liquefied natural gas facilities and related infrastructure projects heats up. What is not included in these figures is the effect that cheaper energy prices will have on industrial spending nationwide. Already, utilities across the country are switching from coal-powered electricity generation to gas, and other energy-intensive industries are examining whether natural gas is a more affordable commodity. All of this will require new investment and new construction.

In all, FMI estimates more than $330 billion will be spent on oil- and gas-related construction during the next four years, nearly double the amount that has been spent in the past four years. As oil and gas producers increase drilling efficiencies and place greater pressure on prices (particularly in natural gas markets), we expect this figure to increase as the United States begins to return to its manufacturing and industrial roots.

The Looming Gap: Oil & Gas Construction Demand and Labor Supply

Full Throttle Ahead

The oil and gas sector has experienced an era of intense and accelerated growth over the last few years. Even as many other industries have fallen prey to the economic recession and other negative impacts, this particular industry has remained strong and steadfast; that is not expected to change anytime soon. Through 2017, in fact, the rate of growth in oil and gas is projected to be more than twice that of the construction industry as a whole (Table 1).

The fact that many construction employees have gravitated to the growing oil and gas sector should come as no surprise. In 2008 just 3.8 percent of the total construction workforce was engaged in direct oil and gas construction. By 2012, 6.4 percent – nearly double 2008's number – of that workforce was engaged in direct oil and gas construction. According to FMI's estimates, by 2017 nearly 10 percent of the total U.S. construction workforce will have moved over to this burgeoning segment of the industry (Table 2).

Table 1. U.S. Construction Volume Put in Place and Construction Spending in the U.S. Oil and Gas Industry

	2008	2009	2010	2011	2012	2013e	2014e	2015e	2016e	2017e	Total % Change
Residential Buildings	357,746	253,930	249,113	252,658	286,523	338,163	379,599	420,452	465,383	505,941	41%
Nonresidential Buildings	499,702	432,196	346,488	336,438	354,202	352,509	369,070	392,102	418,454	446,789	-11%
Non-Building Structures	210,118	217,078	208,959	198,918	216,228	218,971	228,435	238,879	252,080	267,411	27%
Total	1,067,566	903,204	804,560	788,014	856,953	909,643	977,104	1,051,433	1,135,917	1,220,141	14%
% Change from prior year	na	-15%	-11%	-2%	9%	6%	7%	8%	8%	7%	

Construction Spending in the Oil & Gas Industry
Estimated for the United States
Millions of Current Dollars
September 2013

	2008	2009	2010	2011	2012	2013e	2014e	2015e	2016e	2017e	Total % Change
	35,878	38,314	40,536	43,855	48,897	55,008	63,680	75,264	89,181	102,784	186%
% Change from prior year	na	7%	6%	8%	11%	12%	16%	18%	18%	15%	

Source: FMI Projections

According to FMI's definition, the oil and gas industry comprises the following projects:

- New buildings and structures related to extraction, processing/refining. Storage, transmission and distribution of oil and gas products.
- Similar buildings and structures within the chemical industry, which are wholly dedicated to petroleum-based chemicals.
- Additions, alterations, conversions, expansions, reconstruction, renovations, rehabilitations and major replacements.
- Site preparation and outside construction of fixed structures or facilities such as petroleum and gas pipelines, sidewalks, on-site streets, parking lots, utility connections and similar facilities that are built into or fixed to the land.
- Fixed, largely site-fabricated equipment not housed in a building, primarily for petroleum refineries and chemical plants, but also including storage tanks, refrigeration systems, etc.

The following are excluded from FMI's definition of the oil and gas industry:

- Maintenance and repairs to existing structures or service facilities.
- Cost and installation of production machinery and equipment items not specifically covered above, such as heavy industrial machinery.
- Drilling of gas and oil wells, including construction of offshore drilling platforms.
- Land acquisition.
- Ancillary construction that supports the oil and gas industry, including rail, ports, streets and highways, commercial buildings and housing.

Table 2. Total Construction Employment Demand — All Segments

Estimated for the United States
Thousands of Full-Time Workers
September 2013

	2008	2009	2010	2011	2012	2013e	2014e	2015e	2016e	2017e
Carpet, Floor and Tile Installers and Finishers	79.4	68.0	62.1	538.7	61.3	60.6	63.6	66.9	70.2	74.6
Sheet Metal Workers	107.9	95.3	87.8	77.6	87.5	85.7	92.1	104.5	113.6	127.7
Brickmasons, Blockmasons and stonemasons	110.5	91.3	86.3	75.2	84.5	85.9	89.8	102.1	114.7	121.3
Roofers	113.5	105.6	93.1	82.2	94.1	99.5	107.2	119.3	130.3	142.4
General and Operations Managers	121.2	107.4	98.6	84.7	96.5	110.8	119.8	133.3	145.2	153.1
Cost Estimators	128.0	111.0	102.8	91.1	101.1	107.1	114.2	126.6	137.4	154.6
Drywall Installers, Tapers, Ceiling Tile Installers	151.3	124.9	109.3	96.8	109.4	114.4	122.6	134.4	147.3	162.1
Construction Managers	176.9	154.0	142.2	122.9	139.8	150.7	161.9	183.2	195.9	215.0
Cement Masons, Concrete Finishers and Terrazzo Workers	184.7	155.7	140.3	122.3	138.6	152.0	166.6	182.8	199.2	219.2
Painters and Paperhangers	197.6	168.3	155.5	135.6	153.4	157.5	172.3	187.0	204.4	217.3
Engineering & Design Occupations	265.7	235.6	216.7	189.0	209.8	219.3	232.8	252.5	272.2	292.5
Construction Equipment Operators	297.5	257.4	238.0	209.3	239.3	241.6	253.4	272.1	291.6	315.4
Helpers, Construction Trades	349.2	303.3	275.1	240.4	272.1	274.5	287.4	304.8	326.3	361.4
Pipelayers, Plumbers, Pipefitters and Steamfitters	398.0	358.3	324.2	286.5	331.1	330.8	353.3	374.2	399.9	425.9
First-Line Supervisors/Managers	442.1	392.8	359.8	309.0	349.5	349.5	370.1	398.6	423.4	445.7
Electricians	484.0	427.0	394.8	342.7	394.4	394.3	408.0	434.5	461.4	493.5
Carpenters	721.0	598.6	525.8	459.5	524.8	530.0	565.3	593.7	616.1	647.2
Construction Laborers	771.0	663.3	594.7	520.5	581.6	577.4	603.6	628.2	657.9	694.1
Total	5,099.5	4,418.0	4,007.0	3,983.7	3,968.9	4,041.6	4,283.8	4,598.7	4,907.0	5,263.0
% Change from Prior Year		-13%	-9%	-1%	0%	2%	6%	7%	7%	7%

Source: FMI Projections

Growth, of course, is good. However, this particular expansion could come at the expense of other construction sectors that are now experiencing their own recoveries and the growth associated with such revival. It could also affect the oil and gas industry itself. The growth in the sector's share of total workers, for instance, is taking place despite concurrent double-digit growth in the U.S. residential sector. This fact alone could put constraints on the rebirth of residential construction across the nation as contractors scramble to fill positions.

Across the 17 craft categories that FMI tracks, the total number of workers required across all categories within the oil and gas industry was 254,600 in 2012 (Table 3). By 2017 this demand will have approximately doubled, leaving more than 247,000 skilled positions unfilled. As any top construction firm understands, mitigating shortages through additional hours and workers often leads to limitations and can take a toll on safety, quality and productivity. And while required skill sets are readily transferable in some cases (i.e., roofers, masons, painters and operators), the oil and gas industry will find itself competing with other construction sectors for available talent while also trying to develop new talent.

The Value of Construction Put in Place. This is a measure of the value of construction as it is installed or erected at the site during a given period. For an individual project, this includes:

- Cost of materials installed or erected.
- Cost of labor (both by contractors and force account) and a proportionate share of the cost of construction equipment rental.
- Contractor's profit.
- Cost of architectural and engineering work.
- Miscellaneous overhead and office costs chargeable to the project on the owner's books.
- Interest and taxes paid during construction (except for state and locally owned projects).

Table 3. Total Construction Employment Demand — Oil and Gas Segment

Estimated for the United States

Thousands of Full-Time Workers

September 2013

	2008	2009	2010	2011	2012	2013e	2014e	2015e	2016e	2017e
Carpet, Floor and Tile Installers and Finishers	0.5	0.6	0.6	0.6	0.7	0.8	0.9	1.1	1.2	1.4
Sheet Metal Workers	4.4	4.6	4.8	5.2	5.7	6.4	7.3	8.5	9.9	11.3
Brickmasons, Blockmasons and stonemasons	1.2	1.3	1.4	1.5	1.6	1.8	2.1	2.4	2.8	3.2
Roofers	26.7	28.3	29.7	31.8	35.1	39.0	44.6	52.1	60.5	69.2
General and Operations Managers	4.9	5.2	5.5	5.9	6.5	7.2	8.2	9.6	11.2	12.8
Cost Estimators	4.9	5.2	5.5	5.9	6.5	7.2	8.3	9.6	11.2	12.8
Drywall Installers, Tapers, Ceiling Tile Installers	1.1	1.2	1.2	1.3	1.5	1.6	1.9	2.2	2.5	2.9
Construction Managers	6.8	7.2	7.5	8.1	8.9	9.9	11.3	13.2	15.3	17.5
Cement Masons, Concrete Finishers and Terrazzo Workers	6.2	6.6	6.9	7.4	8.2	9.1	10.4	12.1	14.1	16.1
Painters and Paperhangers	4.8	5.0	5.3	5.7	6.3	6.9	7.9	9.3	10.8	12.3
Engineering & Design Occupations	13.7	14.5	15.2	16.3	18.0	20.0	22.9	26.8	31.1	35.6
Construction Equipment Operators	10.6	11.2	11.7	12.6	13.9	15.4	17.7	20.6	23.9	27.4
Helpers, Construction Trades	11.7	12.4	13.0	14.0	15.4	17.1	19.6	22.9	26.5	30.4
Pipelayers, Plumbers, Pipefitters and Steamfitters	28.2	29.9	31.3	33.6	37.1	41.2	47.1	55.0	63.8	73.1
First-Line Supervisors/Managers	14.9	15.7	16.5	17.7	19.5	21.7	24.8	29.0	33.6	38.5
Electricians	15.4	16.3	17.1	18.3	20.2	22.5	25.7	30.0	34.8	39.8
Carpenters	15.0	15.8	16.6	17.8	19.7	21.8	25.0	29.2	33.9	38.8
Construction Laborers	22.7	24.0	25.2	27.0	29.8	33.1	37.9	44.2	51.3	58.8
Total	193.8	205.1	215.0	230.5	254.6	282.8	323.6	377.6	438.3	501.8
% Change from Prior Year		6%	5%	7%	10%	11%	14%	17%	16%	14%

Estimated Composition of Engineering and Design Demand

Petroleum Engineers	8.9	9.5	9.9	10.6	11.7	13.0	14.9	17.4	20.2	23.2
Other Engineering and Design	4.8	5.1	5.3	5.7	6.3	7.0	8.0	9.3	10.8	12.4
Total	13.7	14.5	15.2	16.3	18.0	20.0	22.9	26.8	31.1	35.6

Estimated Composition of Pipelayers, Plumbers, Pipefitters and Steamfitters

Pipefitters	16.4	17.4	18.2	19.6	21.6	24.0	27.5	32.1	37.2	42.6
Welders	10.7	11.3	11.8	12.7	14.0	15.6	17.8	20.8	24.1	27.6
Other	1.1	1.2	1.2	1.3	1.4	1.6	1.8	2.1	2.5	2.8
Total	28.2	29.9	31.3	33.6	37.1	41.2	47.1	55.0	63.8	73.1

Source: FMI Projections

In other instances, the severity of labor shortages is compounded by required skill sets that are more specific to the oil and gas industry. Petroleum engineers, pipefitters, welders, controls electricians, supervisors and managers, for example, will all be in high demand during the next four years, according to FMI's research. One executive of a large global EPC company confirms, "Just like electricity is sold on the spot market when there's an emergency or a hurricane, the price of labor is going to go sky-high. It's a basic supply-demand model. The open-shop-certified welders right now have pushed the rate to $35 per hour and $70 per diem. That's the going rate on the Gulf Coast, up from about $28 per hour a year or two ago." During the five-year period 2012 to 2017, key shortages will include:

Petroleum Engineers:	11,500
Pipefitters:	21,100
Welders:	13,600
Supervisors:	19,000

In each case, the demand for these workers will approach twice the current supply. This will require employers to sharpen their focus both in terms of recruiting, training and retaining new talent as well as developing a long-term comprehensive human resource strategy. Without these and other initiatives in place, firms will risk missing this period of impressive growth and expansion within the industry. The rewards are sure to be substantial for those companies that focus on growing and nurturing their talent pools, and challenging, at best, for those firms that take a more languid approach to their human capital.

The Changing Face of Today's Oil and Gas Industry

Preparing for the Next Big Labor Squeeze

Industry experts and company leaders alike have been talking about the looming construction labor shortages for years now. The Great Recession has exacerbated this concern due to the thousands of workers that have left the construction industry. Today, the depleted skills and knowledge pool has left contractors across the nation and abroad scrambling for skilled workers to build quality work on time and on budget.

Stephen E. Sandherr, CEO of the Associated General Contractors (AGC) of America, says, "With many former construction workers now employed in other industries, a number of firms are likely to have an increasingly hard time finding enough skilled workers if employment continues to expand."

The U.S. oil and gas construction industry, which did not track the typical slowdown of other construction sectors, is bracing itself for unprecedented labor shortages, particularly in the U.S. Gulf Coast region. An executive at a large international EPCM firm states, "If all the build-out projects driven by the natural gas supply become a reality, then there's going to be a major shortfall of qualified, skilled trades on the Gulf Coast, both for union and open-shop contractors."

These near-term skill shortages will likely peak in 2014 and 2015, when oil and gas construction projects around the Gulf Coast are expected to come online, specifically in the Lake Charles, La., area. Several industry experts pointed out that there were distinct similarities between the work and labor dynamics in today's Lake Charles area and the oil sands region of Fort McMurray, Alberta, Canada, in the mid-2000s. Dan Lumma of Kiewit's Energy Group says, "There is a natural ceiling to the amount of craft, resources, infrastructure, engineering, equipment, etc., that you can apply in one location at one time. It's a self-regulating phenomenon, and clients naturally adjust their schedules to react to those circumstances."

Although craft labor shortages are a regional phenomenon, they can still create a ripple effect across the globe in today's flat and shrinking world. As one labor relations manager for a large global industrial contractor says, "There is a huge skilled international workforce from India and the Philippines that has filled the industry's jobs in the Middle East and Africa for the past decade. Today, this workforce is being lured to countries like Australia, Chile and Canada where they can increase its salary tenfold. This is starting to have an impact on international companies' ability to staff their work in lower-paying regions of the world."

"I've never known a project that didn't get built because construction firms couldn't find enough labor. Now it may take longer and it may cost more, but we're a pretty innovative nation and we always find a way to get things done."

– Executive of a large international EPCM firm

Time to Rethink Old Business Paradigms

Based on these widespread global implications, the need for long-term resource planning and comprehensive risk assessment is becoming ever more important. Construction firms that operate in a direct-perform general contractor role as part of a larger EPC team, for example, have the opportunity to plan for future labor needs well in advance. Kiewit is a good example of a company that places qualified individuals in its clients' and engineering partners' offices. Lumma states, "This is a fairly new strategy that's working out well for the company, particularly with progressive clients who have a long-term vision and strategy."

Several participants in this study pointed out the need for better industrywide coordination in terms of long-term resource planning and project development. As one executive at a large international EPCM firm states, "Company A is doing one thing. Company B is doing something else. In addition, company C is working on five other things. Everyone is stuck in their own corner with their hands over their eyes so that nobody can see or read anything. What's really needed is more transparency and an open dialogue among both contractors and owners industrywide."

Eddie Clayton, contracting strategies manager for the Southern Company Generation, confirms this sentiment, "Companies need to work together to solve these long-term resource problems. If owners are going to leave it solely up to the contractors, then they're going to be sadly mistaken. Owners should develop a craft labor strategy that includes their engagement in workforce development activities. Not only will appropriate involvement help to mitigate project staffing risks but it will also benefit the communities and regions that they serve."

Changing Labor Dynamics

With the current oil and gas boom ramping up in the United States, many projects are underway, and many more will be kicking off over the coming months. "If all those projects happen, the peak workforce would have to multiply five to six times about what it is right now. The fact is, that's not going to happen," states Lumma. "We're heading into a very, very significant demographic issue."[1]

Under these unprecedented levels of labor pressure, industry participants must acknowledge that, in these transformational times, not all of the previous forms of labor models and business approaches will continue to be appropriate. The changing competitive landscape, combined with emerging technologies and ideas about how to ramp up and organize companies, has become a real force influencing the oil and gas industry. As such, we will likely see more union labor re-entering high-growth markets such as the Gulf Coast area, with owners scrambling to get projects off the ground. As one industry executive points out, "There's a reluctance on the part of the owners to bring back the unions into the market (in the Gulf Coast area), but that needs to be transcended with the pragmatic reality that you cannot get these facilities built all open-shop or all union. It's going to take a combination of the two."

In addition, numerous U.S. construction companies are looking to bring on foreign workers to fill some of the labor void. However, the topic of immigration in the U.S. remains highly

[1] Energy Industry Faced with Possible Workforce Shortage. The Energy Collective. Sarah Battaglia. March 23, 2013.

complicated and controversial, and is unlikely going to solve the immediate labor requirements for the oil and gas industry.

Success Stories: Preparing for the Next Big Boom

ARB, Inc.: Stepping Up to the Plate

For Greg Dahl of ARB, Inc., the current labor shortage is less about not being able to find individuals to fill specific job roles and more about not being able to locate ample skilled labor who are properly trained and qualified to do the work at hand. To ward off any challenges that could be coming down the labor pike, Dahl, vice president, says ARB consistently cross-trains its employees, thus creating a "fully diversified" workforce that can handle myriad tasks and responsibilities.

"As a company, we do all types of pipeline work, not only oil and gas, but also pipeline rehabilitation and water work. You name it, we do it," says Dahl. "In order to hold on to a competent workforce to handle all of that, we're always cross-training. That allows us to identify future needs and, ideally, have the employees working on other projects until the need arises." The fact that the U.S. workforce is aging – and that millions of baby boomers are heading into retirement – also challenges companies like ARB, which is bringing in younger workers to offset the exodus. That younger blood creates an entirely new set of challenges, according to Dahl. "Most of them would rather be in front of computers," says Dahl, "and doing less physical work."

Developing Stability and Continuity

A union shop, ARB is signatory to contracts with the building trades and the United Association, which includes welders, plumbers and pipefitters. As such, the company has partners when it comes to finding skilled labor. Ultimately though, ARB is responsible for the quality and competency of its workforce. The challenges are many: seeking out individuals who have the potential to succeed, contribute and grow; outlining the opportunities that will exist for those who are prepared; and providing ongoing training in all aspects of pipeline construction, jobsite management, behavior-based safety initiatives, awareness of environmental best practices, and importantly, offering feedback on performance, naming just a few of them.
Like most companies in the oil and gas sector, ARB wants to develop and maintain a stable workforce. To make that happen, ARB will in some cases pay higher than union scale, depending on skill and experience levels. "I've never had a case where a union objected to us paying its people more than the scale wage," says Dahl.

The company also provides incentives to employees who "show initiative and leadership qualities," says Dahl. "We feel like we offer the best environment, opportunities and compensation to retain the people and the workforce that we need. That commitment has served us well." As a result, ARB's workforce has been trained and shaped over years and understands how to be highly productive, safe and make money on jobs. "Some of our people, I've worked with for more than 20 years. They're more productive compared to workforces of other companies that tend to go through cycles of hiring and firing," explains Dahl.

New Regulations, New Training Requirements

Looking ahead, Dahl expects the cost of getting a new employee up, running and productive to increase due to new operator qualification requirements, certifications and safety standards. "The level of training, knowledge and awareness expected of an individual who worked on pipelines 10-20 years ago wouldn't be acceptable today," Dahl points out. "There's just so much more that you have to know and such extensive training to undergo."

Safety, for example, was not understood as a key component of productivity. Today it is an integral part of everything companies like ARB do. In fact, Dahl says there are direct correlations between productivity, safety and lower costs. "Everything these days is integrated as a comprehensive approach to performing the work," says Dahl, "so it costs a lot more to put a competent worker out in the field."

The industry's commitment to safety and increased regulation is not going away and neither is the anticipated labor shortage. These two trends will continue to put pressure on companies like ARB to build long-term, reliable workforces that stay in place as long as possible and that get the job done in a timely, productive and safe manner. "We're constantly trying to understand and work through issues regarding regulations, certification requirements, new safety standards, etc., and make sure that everyone is correctly trained," says Dahl. "We're working our way through all of that now."

Kiewit: Getting in on the Ground Floor

Labor constraints are taking their toll on the oil and gas industry, where executives like Dan Lumma of Kiewit's Energy Group work harder these days to get in on the "ground floor" with client projects. Operating in a direct-perform general contractor role as part of a larger EPC team – as opposed to working in a subcontractor role – Kiewit often gets involved with jobs several years before they even break ground.

"That gives us the opportunity to plan for future labor needs well in advance," says Lumma, senior vice president. During the months or years leading up to a new project, for example, Kiewit places qualified individuals in its clients' and engineering partners' offices. Lumma says this is a fairly new strategy that is working out well for the company, particularly with progressive clients who have a long-term vision and strategy.
For Kiewit, that level of labor planning takes on several forms. The company establishes relationships with the respective entities years before the project even starts, including working with local union halls, and talking to them about our manpower peaks over time," Lumma explains.

Keeping Workers Safe and Engaged

To help manage the war for skilled craft labor, Kiewit focuses on the long-term, safe, controlled work environment that it can provide. "On good project sites that extend over time," says Lumma, "we usually don't have much of a problem with high turnover."

With approximately 10,000 staff members, Kiewit hires anywhere from 1,200-1,400 new employees annually. Most are graduate engineers and business managers right out of college, says Lumma. Those individuals are trained and developed by the company's senior managers and supervisors, many of whom have been with the company for 15-20 years. "A portion of their job responsibility is to develop new employees, from senior managers all the way down to first-line supervisors," says Lumma, who expects that internal commitment to training will be an important strategy as the labor market heats up even further over the coming years. For craft labor, Kiewit aims to retain highly skilled workers whenever possible. "We try to take them to the next project," says Lumma, "instead of letting them sit on the bench for months at a time in between projects."

Changing the Business Paradigm

Pointing to the Lake Charles, La., region, Lumma says the area looks a lot like the Fort McMurray, Alberta, region did back in the mid-2000s. "Lake Charles is going to be one of the most overheated regions in the near future," says Lumma. When that happens, he says there will be a natural ceiling to the amount of labor, resources, infrastructure and staff that can be mobilized in a single location at any given time. "It's a self-regulating phenomenon that we saw happen at Fort McMurray," says Lumma, "and clients naturally adjusted their schedules to react to those shortages."

Lumma points out that the industry as a whole needs to change the way these types of projects are planned and carried out in the future. "I don't think the industry should approach these new projects in a business-as-usual sort of way, but instead everyone ought to take on a more progressive, long-term view of how to approach these projects in the planning stage, engaging people early on so that they can help overcome these resource challenges," says Lumma.

Henkels & McCoy, Inc.: Bracing for the Next Big Surge

With the national construction market solidly in recovery mode, the leadership team at Henkels & McCoy, Inc. knows it is only a matter of time before finding skilled workers to fill field positions becomes a challenge. Finding experienced construction management superintendents and project managers will not be any easier, predicts John Harrower, vice president and division manager of the pipeline construction division, namely because so many of these individuals exited the industry during the economic recession.

"Individuals who can implement and manage project controls, manage cost controls and forecasting, and handle scheduling are already in short, short supply," says Harrower, who is also seeing a dearth in the number of experienced "front-end" professionals who can deftly assess potential projects and submit bids when applicable. These "basic estimating skill sets" have been hard to come by for several years, according to Harrower, who sees that early, upfront work as an essential component for successful projects.

At this point, Henkels & McCoy is covering its projects across all areas where employees are getting harder to find and recruit. "We have good control over what we already have in-house right now," says Harrower, "but if we had more candidates in each of the three areas (superintendents, project managers and front-end types), we'd be able to undertake a lot more work as the market continues to heat up."

Shifting Positions

One way Henkels & McCoy is offsetting the labor shortage issue is transferring administrative professionals into its estimating group and building up the latter in a way that will allow the company to bid on more projects. On the project management side, the company relies on an in-house job rotation and management training program called Growth Opportunities for Leadership Development (GOLD), which focuses on candidates who already have some level of construction management expertise but want to fast-track their project management development. GOLD participants rotate through assignments in seven different operations platforms over a 21-month period, allowing them to take on larger responsibility upon graduation from GOLD more quickly than those who have not gone through the program.

"Where it used to take 15-20 years to build a senior project manager, we're now able to fast-track them within six to eight years," Harrower explains. The GOLD program incorporates a pipeline division sponsor who also heads up the project management group. Responsible for bringing in new talent, evaluating the candidates every three to four months and then rotating individuals through different assignments on a quarterly basis, the sponsor helps candidates get an "overall perspective of everything that they need to manage, and within a much shorter time frame," says Harrower. He adds, "That way they get an overall perspective of everything they need to manage a lot quicker than they normally would in their career."

As part of this development program, Henkels & McCoy is very strategic about promoting foremen into assistant superintendent roles – in an effort to build more superintendents organically. "That takes some time to cultivate," says Harrower, "but it's a solution that we're using on several of our larger projects right now."

Finally, Harrower says Henkels & McCoy has taken a closer look at the specific skill sets needed within the pipeline division and the role that those skill sets play within the various projects that the company undertakes. This exercise has helped the company build "pools" of employees who can cover specific aspects of a project while also giving individuals more job options. A new employee, for example, can get his/her feet wet doing less complicated work, while a senior project manager would take on a larger role within a bigger project. "That effort is part of an ever-changing commitment to continuous improvement that's underway here at any given moment," says Harrower.

Reputation Counts

Growing organically is one thing, but attracting new blood to the workforce requires a different level of effort. To keep its new employee pipeline growing, Henkels & McCoy leans on its reputation of 90 years as a privately held, large company in its field. "We have an incredible reputation for maintaining people and continuity," says Harrower. "Our average management tenure is very high and our attention to safety is very well-known."

Harrower says Henkels & McCoy's attention to safety and commitment to running a best-in-class organization will help tackle the looming labor crunch. "We're definitely on the right road, with a focus on project management and project controls on our jobs that wasn't seen in the pipeline sector for many generations," says Harrower. "As clients become more sophisticated and jobs more complicated and expensive, we'll be gearing up to handle the project backlogs that we're seeing and bracing ourselves for an interesting second half of the year."

Top Business Imperatives for Energy Infrastructure Construction Firms

Following is a summary of the top-five business fundamentals pulled from 25 in-depth interviews with executives of energy infrastructure construction firms and select FMI industry experts.

1) **Develop comprehensive in-house training programs and build long-term knowledge pipelines.** The recent expansion of the U.S. oil and gas industry coupled with the retirement of many experienced supervisors is causing overstretched construction firms to rethink their training and succession plans. Successful companies are developing comprehensive knowledge transfer programs, shifting knowledge from senior (and soon-to-be-retiring) employees to the next generation and leveraging organizational expertise and best practices across the business.

   Fast-track leadership programs are also becoming critical as experienced craft workers move into leadership and mentor roles, training less experienced employees in a very short time frame. As one industry executive explains, "With the limited amount of skilled labor available, we took many of our company's highly skilled craftsmen and turned them into supervisors to help manage less experienced workers. These skilled craftsmen went from being welders one month to foremen the next month, which doesn't necessarily mean they're good-quality supervisors. Leadership and mentoring skills are very different from technical expertise."

   In the fast-paced oil and gas industry, a purposeful approach to training and knowledge transfer will not only significantly increase the readiness and skill sets of the employees, but also will attract new talent to the industry with the compelling story of commitment to the individual employee. For energy infrastructure construction firms to succeed, they will have to effectively attract, develop and retain human resources. Developing a long-term strategy to address these human talent issues and following through with diligence and consistency on the execution of that strategy will become the key competitive differentiators among firms in the oil and gas sector.

"With the limited amount of skilled labor available, we took many of our company's highly skilled craftsmen and turned them into supervisors to help manage less experienced workers. These skilled craftsmen went from being welders one month to foremen the next month, which doesn't necessarily mean they're good-quality supervisors. Leadership and mentoring skills are very different from technical expertise."

— Industry Executive

"In construction there's a lot of emphasis on individual achievement. As a result, rather than rewarding soft skills around leadership or mentoring, we often tend to look at individual performance. It's definitely an area where the industry as a whole needs to transform in the coming years."

— CEO of a pipeline construction company

2) **Engage your people and provide a healthy, safe work environment.** In an industry that is constantly in flux and characterized by extreme working conditions, company executives must keep their employees engaged and devoted on a daily basis. Industry leaders who have established a good reputation over the years with corporate cultures focused around safety, education and employee well-being find themselves at an advantage in the war for talent. Rena Lo, human resources manager at AMEC Oil and Gas, Inc., states, "If we're talking about retention, then two things are very important: Employees have to like what they do and also like the people they work with/for."

   Motivation, reward management and performance appraisal largely drive employee retention and satisfaction. Even when offered higher salaries and/or compensation packages, for example, the most engaged and trained employees are less likely to jump ship.

   Cory Jodoin, president at Jen-Col Construction, confirms, "It really must be more than just the dollars. Every single person in my company can find a job elsewhere that will pay more than what they earn here at Jen-Col. So you need a culture where people value more than dollars. That's the challenge: coming up with a plan for retention, training, development and making every job meaningful. Just really creating opportunity, growth and development for people – that is key."

   Another industry executive adds, "A key focus for us is succession, and we try to keep our people engaged at all times. You have to treat people right, and these days many companies don't seem to invest enough in their people."

   In addition to the methods mentioned above, the oil and gas sector is using techniques like e-learning to retain current employees and recruit new ones. Also playing a key role in both retention and recruitment are fundamentals such as safety culture, working conditions, supervision, co-workers/interpersonal relationships, job security and organizational policies.

3) **Integrate HR with other core business functions.** Look at your organizational structure and re-evaluate how all the different departments and business units are performing – both together and separately. Over the last few years, CEOs in the construction industry have started to look for synergies among functional areas, finding ways to leverage support functions, such as HR, IT and finance, to be "fit for a purpose" and ensure that they are more closely aligned with the overall enterprise strategy. Jason Baumgarten, FMI's Western consulting group manager, explains, "I see a lot of stand-alone systems work counter to each other. It can be very inefficient. For example, if you have a strong HR department and are hiring great people but have no systems in place – such as a strong career path or effective incentive-based compensation program – then you'll end up being a prime target for your competitors to recruit from."

   In the oil and gas sector, specifically, this could not be more accurate. Human capital has become a hurdle, and overcoming that obstacle requires buy-in from technical, operating and HR leaders. From the board down to the individual operating company level, new attention is being paid to human resource functions whose operational objectives must be linked to the firm's overall operating targets. Aligning different business functions in more integrated ways will help increase communication across the organization and push employees to work collaboratively and more effectively toward common strategic goals.

4) **Understand your (human) risk**. According to the Bureau of Labor Statistics, the U.S. oil and gas industry lost a record number of workers on the job in 2012 – the same year that industry fatalities increased to 138 from 112 (in 2011). This represents a 23 percent increase and the largest number of oil and gas worker fatalities since the current data series for the BLS Census of Fatal Occupational Injuries (CFOI) began in 2003.

These numbers echo the rapid pace at which the oil and gas industry has been expanding in recent months. As energy infrastructure construction firms scramble for skilled workers to keep up with demand, companies are more apt to hire less experienced workers who lack the necessary safety training or technical skills. An executive of a large EPC firm states, "We've seen brokers recruit people who worked as fishermen in the past and say they can weld and now they're applying for offshore welding jobs. Most of these people don't have any experience working in safe environments, and it's a huge risk for a company like ours to hire them on our projects."

To circumvent this whole frenzy and scramble for last-minute "bodies," construction firms and end users/owners must rethink their collaboration efforts. Progressive energy infrastructure construction firms are already looking into innovative partnering approaches as witnessed in the case of Kiewit, where the company establishes relationships with the respective entities years before the project even starts, including working with local union halls and talking to them about their labor peaks over time.

In the oil and gas industry, where owners demand rigorous safety standards and thorough risk management practices, construction companies cannot afford to make any mistakes. A competent workforce – particularly skilled supervision – will become ever more crucial in managing risk and productivity on oil and gas construction projects. Mark Breslin, CEO of United Contractors and author, adds, "In five to seven years, I believe a contractor's ability to grow will hinge on their ability to procure competent field supervision. The boomer retirement curve is going to be painful. It won't be bonding, capital or the market – but contractors' ability to provide qualified foremen superintendents who can build work in a risk-averse environment."

5) **Work smarter and increase project management capacity.** Oil and gas projects worldwide are increasing in complexity and scope as more companies discover new frontiers and invest in non-traditional exploration methods. Environmental impact, employee safety and strict adherence to budgets and schedules top the list of stakeholder concerns. Successful energy infrastructure construction companies are investing heavily in building their project management capacity by innovating in areas such as prefabrication, technology, knowledge management, communication, among other things. In the coming years, clients will focus on construction companies that can limit rework orders; optimize labor, equipment and materials scheduling; and use a modular approach to project management. These tactics will help improve productivity and manage costs in a tight labor market – two key concerns for owners in this sector.

"In five to seven years, I believe a contractor's ability to grow will hinge on their ability to procure competent field supervision. The boomer retirement curve is going to be painful. It won't be bonding, capital or the market – but contractors' ability to provide qualified foremen superintendents who can build work in a risk-averse environment."

— Mark Breslin, CEO of United Contractors and Author

"If construction firms active in the oil and gas sector had invested in hiring and training talent back in 2010-11, they would be significantly more profitable today. Instead, most firms are today confronted with a chronic shortage of engineers, project managers and skilled tradesmen. And odds are that situation will worsen in the years ahead."

— Michael Mangum, Senior Consultant with FMI's Center for Strategic Leadership

Brian Johnson, executive vice president at Michels Corporation, states, "Due to the current shortage of skilled welders as a result of the increased volume of pipeline work throughout the country, we are taking a harder look at automated welding systems to offset the needs that our clients are requiring of us. Although this only helps in the larger diameter pipe sizes."

Don Thorn, president at Welded Construction, adds, "We're seeing some advancements of processes and equipment through the use of technology. The long, large-diameter pipes will probably be done with mechanized welding in the future, and that will certainly help with the craft shortages to some extent. As a result, we will need people with experience utilizing mechanized welding equipment and increased training activity from our labor forces."

Planning for Future Labor Needs

The U.S. oil and gas industry is on the brink of its largest human capital shortfall as it faces one of the most significant expansion periods in its history. If companies do not figure out how to transfer knowledge from soon-to-be-retiring employees to younger generations of workers, decades of industry wisdom and expertise will be lost forever over the next five to seven years. Fierce competition for talent in this sector is already driving energy infrastructure construction firms to rethink their human capital needs and optimize access to – and retention of – qualified and experienced workers. Some firms have circumvented the crisis by simply poaching talent from competing firms or leaning even more heavily on their veteran workers. Unfortunately, these are stopgap measures at best.

Successful companies are thinking long term and building new talent pipelines, developing targeted interventions, assessing the business impact of skills shortages and considering the options available to build competency. While there is no silver bullet to solve significant skills shortages (the ongoing nursing shortage is a good example of this), tactical combinations of programs and new paradigms will become the standard as the U.S. oil and gas industry labor shortages exacerbate. Potential implications for the industry might include higher wage-push inflation, potential decreases in international competitiveness and even the erosion of future domestic oil production capacity.

In Canada, for example, FMI consultants have observed a shifting HR strategy to finding/hiring talent regardless of current project demands or needs. Put simply, progressive companies are actively building their benches in anticipation of future projects and are willing to take a P&L hit to avoid labor crunches. As Michael Mangum, senior consultant with FMI's Center for Strategic Leadership, explains, "If construction firms active in the oil and gas sector had invested in hiring and training talent back in 2010-11, they would be significantly more profitable today. Instead, most firms are today confronted with a chronic shortage of engineers, project managers and skilled tradesmen. And odds are that situation will worsen in the years ahead."

It is time to tie HR objectives directly to business objectives and build continuous feedback loops that help improve management techniques and ultimately influence strategy. Through these and other efforts, oil and gas infrastructure construction firms will find themselves better positioned to tackle the labor shortages and move beyond to ongoing success. Without these proactive moves, the U.S. oil and gas construction industry will struggle to right itself during a period of unprecedented labor shortages.

For more information please contact: Sabine Huynen Hoover, Senior Research Consultant, at 303.398.7238 or via email at shoover@fminet.com

Scott Duncan, Vice President, at 303.398.7250 or via email at sduncan@fminet.com

W. Christopher Daum, Senior Managing Director, at 919.785.9264 or via email at cdaum@fminet.com

About FMI

FMI is a leading provider of management consulting, investment banking† and research to the engineering and construction industry. We work in all segments of the industry providing clients with value-added business solutions, including:

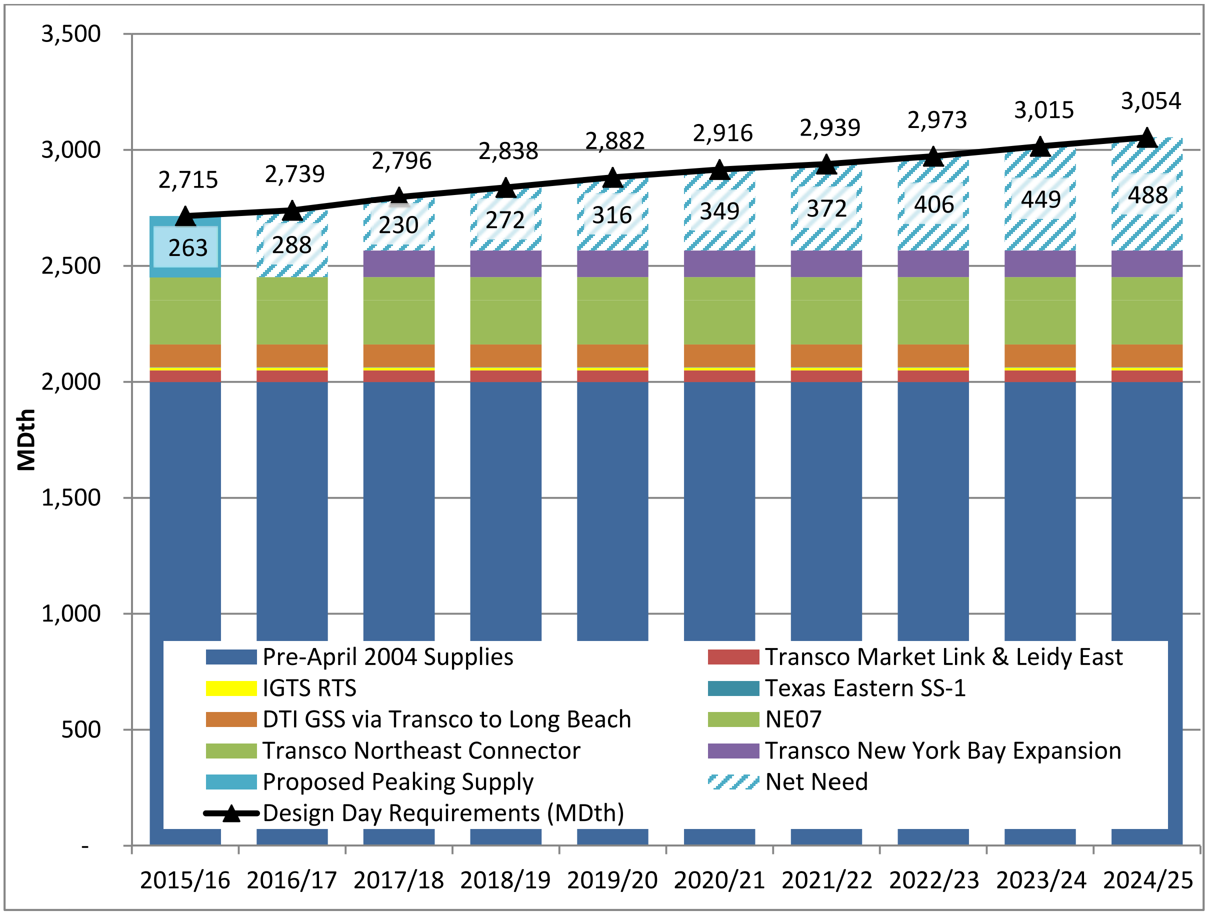
- Strategic Advisory
- Market Research and Business Development
- Leadership and Talent Development
- Project and Process Improvement
- Mergers, Acquisitions and Financial Consulting†
- Compensation Benchmarking and Consulting
- Risk Management Consulting

Founded by Dr. Emol A. Fails in 1953, FMI has professionals in offices across the U.S. We deliver innovative, customized solutions to contractors, construction materials producers, manufacturers and suppliers of building materials and equipment, owners and developers, engineers and architects, utilities, and construction industry trade associations. FMI is an advisor you can count on to build and maintain a successful business, from your leadership to your site managers.

FMI
Sixty Years

† Investment banking services provided by FMI Capital Advisors, Inc., a registered broker-dealer and wholly owned subsidiary of FMI.

Downstate NY Supply/Demand Balance



For the 2015/16 design day, the portfolio will require approximately 263 MDth of city gate delivered supplies to meet forecast customer requirements. This need for incremental supplies grows to 288 MDth in 2016/17. However, for the 2017/18 winter, the Company expects that the Transco New York Bay Extension project will be in service, providing an additional 115 MDth/day of capacity to the Company's Transco city gates (as discussed further in response to Question 29). Therefore, the need for city gate delivered supplies is reduced to 230 MDth in 2017/18.

Beyond 2017/18, forecast customer requirements continue to grow. Although the Company intends to rely on city gate delivered supplies to meet a portion of customer requirements, National Grid is also exploring options to build incremental capacity to the Downstate NY region. The parties and potential projects are identified in the response to Question 32.

Attachment 242.1.1

FortisBC Energy Inc.

Account #: 44900 - LNG PLANT - OTHER EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 33
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	5,536,937.17	4,471,984	5,507,450	0.9947	583,181	8.77	66,497	29.0
1991	554,462.83	413,410	509,133	0.9182	100,776	10.63	9,479	26.0
1992	562,926.89	407,182	501,463	0.8908	117,757	11.30	10,421	25.0
1993	2,336,891.81	1,636,601	2,015,548	0.8625	555,033	11.99	46,291	24.0
1994	195,647.09	132,385	163,039	0.8333	52,173	12.70	4,108	23.0
1995	2,871,517.51	1,873,177	2,306,902	0.8034	851,767	13.43	63,422	22.0
1996	801,912.30	503,114	619,608	0.7727	262,496	14.18	18,514	21.0
1997	81,130.05	48,830	60,136	0.7412	29,107	14.94	1,948	20.0
1998	18,560.60	10,687	13,161	0.7091	7,255	15.73	461	19.0
1999	644,297.54	353,822	435,748	0.6763	272,979	16.53	16,519	18.0
2000	964,847.19	503,660	620,281	0.6429	441,051	17.34	25,436	17.0
2001	21,505.53	10,631	13,093	0.6088	10,563	18.17	581	16.0
2002	357,001.87	166,438	204,976	0.5742	187,726	19.01	9,873	15.0
2003	1,799,856.75	787,607	969,973	0.5389	1,009,869	19.87	50,818	14.0
2004	32,356.13	13,218	16,279	0.5031	19,313	20.74	931	13.0
2005	198,987.18	75,420	92,883	0.4668	126,003	21.63	5,826	12.0
2006	305,886.62	106,786	131,511	0.4299	204,964	22.53	9,099	11.0
2007	359,087.89	114,476	140,982	0.3926	254,015	23.44	10,839	10.0
2008	4,157,417.12	1,197,852	1,475,209	0.3548	3,097,950	24.36	127,193	9.0
2009	1,849,724.98	475,588	585,708	0.3166	1,448,989	25.29	57,303	8.0
2010	627,350.21	141,649	174,447	0.2781	515,639	26.23	19,661	7.0
2011	64,069.35	12,441	15,322	0.2391	55,155	27.17	2,030	6.0
2012	668,179.44	108,452	133,563	0.1999	601,434	28.13	21,380	5.0
2013	26,659.00	3,471	4,275	0.1604	25,050	29.09	861	4.0
2014	88,599.02	8,674	10,682	0.1206	86,776	30.06	2,886	3.0
2015	152,230.67	9,958	12,264	0.0806	155,190	31.04	5,000	2.0
2016	442,339.16	14,496	17,853	0.0404	468,720	32.02	14,640	1.0
2017	19,526.33	0	0	0.0000	21,479	33.00	651	0.0

FortisBC Energy Inc.

Account #: 44900 - LNG PLANT - OTHER EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 33
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	25,739,908.23	13,602,010	16,751,489		11,562,410		602,667	

COMPOSITE ANNUAL ACCRUAL RATE	2.34%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.65
COMPOSITE AVERAGE AGE (YEARS)	17.94
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	17.15