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October 26, 2021

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
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Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599211

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Advanced Metering Infrastructure (AMI) Project (Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO) Information Request (IR) No. 1

On May 5, 2021, FEI filed the Application referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-302-21 for the review of the Application, FEI respectfully submits the attached response to BCOAPO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, PDF page 21

Preamble: In lines 3-16, FEI states:

Project Costs and Delivery Rate Impact

The AMI Project capital cost is estimated at $638.4 million and the incremental Project capital cost (over the Baseline scenario which is the continuation of manual meter reading) is estimated at $476.0 million.

During the Post-deployment phase, FEI estimates reduced capital spending of $355.0 million. FEI also estimates Post-deployment incremental O&M savings of $318.6 million. The Post-deployment phase is the time period from 2027 to 2046 over which the new AMI meters are expected to be in service, based on the estimated useful life of the new AMI meters of 20 years. The majority of the financial benefits of the Project, consisting primarily of reduced meter reading costs, will be realized over this Post- deployment phase.

Overall, the AMI Project is expected to be effectively rate neutral over the 26-year analysis period, with the incremental levelized delivery rate impact estimated to be 0.125 percent using conservative assumptions. There would be an overall rate savings for customers if the future cost of manual meter reading is higher than the Baseline low case cost scenario that has been assumed.

1.1 Please confirm that the AMI solution has a 26 year payback. If not confirmed, please fully explain.

<u>**Response:**</u>

Not confirmed. The cost of service analysis projects future cash flows and calculates what the increase or decrease would be to future revenue requirements. Based on the forecast capital, O&M, and deferred non-AMI meter write off costs included in the Application over the 26 year analysis period the levelized delivery rate impact is 0.125 percent. The 26 year analysis period should not be misinterpreted as a payback period.

Payback period usually determines the amount of time it takes to recover the initial investment. The forecast cost of the Project through deployment is $476 million. FEI has forecast incremental savings in capital and O&M as part of the cost of service analysis. Based on the incremental savings in capital and O&M included in the cost of service analysis the simple payback period would be 12 years post deployment.

1.2 Please provide all announcements, press releases, directives or other documentation that relates to the phasing out of the use of Natural Gas in British Columbia that FEI is considering when making its long- term plans, if any. If there is no such documentation, what is FEI using to inform its future plans as it relates to the phasing out of natural gas?

Response:

Currently, there are a number of announcements, plans or proposals across federal, provincial and local governments which aim to reduce GHG emissions, including those from the use of natural gas. However, many of these initiatives also recognize the role of the gas system to reduce GHG emissions through the use of renewable gas. FEI is responding to the need to take climate action through its climate strategy called the Clean Growth Pathway to 2050[1], which includes, among other actions, a transition to renewable energy and further investment in energy efficiency. FEI's climate strategy will contribute to BC's emissions reductions, and the gas delivery infrastructure plays a vital role in reaching climate targets. Some policies and plans that FEI is using to inform its future plans include:

Federal:

- *Pan Canadian Framework*[2] - a comprehensive set of policies aimed at reducing emissions, growing the economy and building resilience to climate change. Within the framework, there are a number of policies which reduce the use of natural gas, including carbon pricing and measures to promote fuel switching and increased energy efficiency. For example, the framework includes a requirement that all space heating technologies for sale in Canada exceed energy performance of more than 100 percent by 2035. However, this will promote the transition from conventional natural gas furnaces[3] to gas fired heat pumps and hybrid heating systems.

Provincial:

- *CleanBC Plan*[4] - CleanBC plan includes an important role for the gas system. There is a requirement to increase renewable gas content to 15 per cent of supply as well as incentives to promote switching from natural gas to electric heat pumps for space heating. The combination of the 15 per cent target and DSM measures will contribute to nearly 2.9 megatonnes of emissions reductions. Nearly 100 per cent of emissions reductions from the buildings sector will be enabled by FortisBC's delivery system.

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1 https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/clean-growth-pathway-brochure.pdf.
2 https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework.html.
3 https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Market-Transformation-Strategies_en.pdf.
4 https://blog.gov.bc.ca/app/uploads/sites/436/2019/02/CleanBC_Full_Report_Updated_Mar2019.pdf.

- *BC Carbon Tax*[5] - carbon tax increases the cost of natural gas and promotes the use of lower carbon energy sources, such as electricity or renewable gas. As the cost of natural gas increases from the carbon tax, the spread between renewable gases narrows, potentially improving the business case and acceptance of renewable gases among customers.
- *BC Energy Step Code*[6] - the BC Energy Step Code sets performance requirements for buildings in BC based on increasing efficiency in building envelope and mechanical systems, which decreases energy use, including natural gas in buildings.
- *Phase 2 of the Comprehensive Review of BC Hydro*[7] - among other recommendations, the review calls for discounted rates for industrial customers to encourage fuel switching to electricity from fuels such as natural gas. The recommendations also include incentives for residential customers to switch from natural gas furnaces to electric heat pumps for space heating.

Local:

- *City of Vancouver*[8] - the City has a number of plans and bylaws which promote the use of renewable energy and/or limit greenhouse gas emissions in buildings which reduces the use of natural gas in favour of renewable gas or electricity.
- *Climate emergencies*[9] – Other municipalities have followed suit in declaring climate emergencies, including the City of Burnaby, Metro Vancouver, Richmond, New Westminster and Port Moody, among others.
- *Metro Vancouver*[10] - Metro Vancouver's climate strategy includes reducing emissions by 45 per cent by 2030 and becoming carbon neutral by 2050 through a number of actions, including switching from natural gas to renewable sources of energy such as electricity and renewable natural gas.

Other:

- *Buildings Electrification Roadmap*[11] - the roadmap was created with participation from provincial and local governments as well as other industry participants. The roadmap is aimed at decreasing the use of natural gas in buildings in favour of electricity. The document indicates that renewable gas is an important mitigation option; however, its focus is on electrification.

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5 https://www2.gov.bc.ca/gov/content/environment/climate-change/clean-economy/carbon-tax.
6 https://energystepcode.ca/.
7 https://news.gov.bc.ca/releases/2021EMLI0049-001343.
8 https://vancouver.ca/green-vancouver/zero-emissions-buildings.aspx.
9 https://climateemergencydeclaration.org/climate-emergency-declarations-cover-15-million-citizens/.
10 http://www.metrovancouver.org/services/air-quality/AirQualityPublications/AQ_C2050-StrategicFramework.pdf.
11 https://www.zebx.org/wp-content/uploads/2021/04/BC-Building-Electrification-Road-Map-Final-Apr2021-1.pdf.

2.0 Reference: Exhibit B-1, PDF page 36

Preamble: On PDF page 36, at lines 21-26, FEI discusses estimates.

2.1 Please provide an analysis that demonstrates the FEI estimation accuracy.

Response:

FEI interprets this question to be seeking an analysis of the percentage variance between estimated consumption and actual consumption. Due to the significant volume of customer data (over one million records per month to analyze), challenges isolating the relatively small portion of data and variables for consideration to account for (such as multiple estimates), FEI has not completed this analysis and does not believe that this type of analysis would provide significant value. This is because the billing estimation process is based on system generated estimates, using recent available data that is tested on an ongoing basis as described further below, in addition to human intervention to confirm the estimate appears reasonable for billing purposes.

While FEI does not have a specific accuracy percentage available, the SAP system used for consumption estimates has built-in functionality to continually test estimates in relation to actual reads. This is intended to ensure that the extrapolation/estimation procedure produces accurate results. This embedded system test works as follows:

1. The actual consumption is compared to the extrapolated/estimated value that the system would have made for the same period;
2. If the ratio of actual to estimate is within a pre-determined range, it is deemed to be sufficiently accurate and the estimation factors remain unaffected;
3. If the ratio of actual to estimate lies outside of the algorithm, a correction process is initiated; and
4. If the ratio of actual to estimate repeatedly falls outside of tolerance limits, the estimation factors (such as the linear consumption per day) are recalculated to allow for more accurate estimations to be made.

3.0 Reference: Exhibit B-1, Table 3-5

3.1 Please provide an updated Table 3-5 that removes the COVID-19 Exposure Risk.

Response:

FEI has reproduced Table 3-5 below, having removed the estimated meter reads attributed to COVID-19 Exposure Risk noted in 2020 to the extent possible. It is FEI's understanding that some of the supervisory estimates may also be impacted by COVID-19 to the extent that meter readers are in isolation or experiencing symptoms and not available; however, FEI does not have a detailed split of this because a new reason code was not created.

Table 3-5: Olameter Estimated Meter Reads by Reason (Excluding COVID-19) 2016-2020

Summary by Reason	2016	2017	2018	2019	2020	Total
Dog	14,187	16,775	18,021	34,370	29,732	**127,937**
	4.11%	3.63%	3.15%	5.67%	3.06%	**3.96%**
Customer Prevented Access	51,781	61,003	58,623	56,003	58,804	**334,757**
	15.01%	13.20%	10.23%	9.24%	6.06%	**10.35%**
Supervisory Estimates (Lack of Available Readers)	172,669	252,269	342,275	367,190	692,140	**1,952,945**
	50.06%	54.59%	59.75%	60.57%	71.32%	**60.39%**
Seasonal Conditions / Obscured by Vegetation	39,553	65,789	78,090	68,193	101,429	**383,893**
	11.47%	14.24%	13.63%	11.25%	10.45%	**11.87%**
Other	66,732	66,244	75,839	80,449	88,328	**434,560**
	19.35%	14.34%	13.24%	13.27%	9.10%	**13.44%**
Total Estimated Meter Reads	**344,922**	**462,080**	**572,848**	**606,205**	**970,433**	**3,234,092**

4.0 Reference: Exhibit B-1, Table 3-6

4.1 Please provide an additional 5 years of history in Table 3-6

Response:

FEI has added an additional five years (2009-2013) of history to Table 3-6. The revised table is shown below.

It should be noted that 2016 represents the first full year of automated reads for FBC. In addition, the number (and percentage) of estimated reads in 2013 is high relative to previous and subsequent years. This is due to labour action impacting FBC's unionized meter readers that took place in the last six months of 2013. Many of FBC's customers' meters were estimated during this time frame, thereby increasing the number of estimates for that year.

Revised Table 3-6: Total FBC Estimated Meter Reads 2009-2020

Year	# of Estimates	# of Meter Read Requests	Estimates as a % of Total
2009	10,936	691,534	1.6%
2010	12,130	712,101	1.7%
2011	15,987	711,081	2.2%
2012	15,711	721,695	2.2%
2013	365,397	744,607	49.1%
2014	18,597	836,509	2.2%
2015	35,446	892,135	4.0%
2016	12,035	966,834	1.2%
2017	8,873	998,179	0.9%
2018	9,929	1,063,904	0.9%
2019	8,710	1,071,860	0.8%
2020	13,674	1,150,397	1.2%

5.0 Reference: Exhibit B-1, Section 3.2.2, PDF page 47

Preamble: On lines 12-28, FEI states:

Diaphragm meters for residential and small commercial applications in the North American gas utility industry are supplied by only three major vendors and there are indications that manufacturers are preparing for a technological shift. In September 2020, FEI received notice from one of the three vendors, Itron Inc. (Itron), that it was ending the manufacture of all diaphragm meters, effective 2021. Going forward, Itron will focus its efforts towards developing and marketing gas ultrasonic meters to provide AMI capability for residential and small commercial customer segments.

Similarly, of the remaining two vendors serving the residential/small commercial gas distribution market within North America, one vendor (Sensus) has already developed an ultrasonic meter and the other vendor (Honeywell-Elster) is in the process of developing an ultrasonic meter.

It is expected that new market participants for diaphragm meters are unlikely to materialize and as such, the absence of Itron as a supplier in the diaphragm meter market place is expected to result in an increase in the unit price and an overall decrease in the supply available. This is because supply will not meet demand in the short term; in the long term, utilities will see reduced competition and higher costs among diaphragm meter manufacturers. The first year that Itron will not be a supplier of diaphragm meters is 2021; the expected increase in unit price will be seen later in 2021 and into the following years.

5.1 Please provide all communication with the other suppliers of diaphragm meters that clearly demonstrate that they too will cease manufacturing diaphragm meters.

<u>Response:</u>

As stated in the preamble, FEI is only aware that Itron has ceased manufacturing 200 series diaphragm meters to focus their efforts on ultrasonic meter development. The removal of Itron from the diaphragm meter market, and the low likelihood of a new market entrant to replace them, will likely mean a decrease in supply and increase in price in the future.

The other two suppliers of residential meters in North America either have, or are developing, ultrasonic meters that FEI expects may replace diaphragm meters in the future, further decreasing market supply. However, FEI has not received communication from either of them on any plans to cease manufacturing of diaphragm meters at this time.

6.0 Reference: Exhibit B-1, Section 3.4, PDF page 54 and Table 3-11

Preamble: In Section 3.4, FEI discusses transformational changes.

6.1 Please provide an analysis that clearly demonstrates the cost of each additional benefit or change, along with an analysis that demonstrates customers willingness to pay for each benefit.

<u>Response:</u>

FEI is unable to break out the specific cost of each of the benefits or changes listed in Table 3-11 from the overall Project cost. Each of the benefits and changes will be provided by the proposed AMI technology as a whole, and removing a benefit or change does not result in a commensurate decrease in Project costs.

FEI has not conducted a specific analysis or surveyed customers for their willingness to pay for each benefit. However, FEI notes that the Project is expected to be effectively rate neutral over the 26-year analysis period, with the incremental levelized delivery rate impact estimated to be 0.125 percent. Therefore, FEI concludes that the additional benefits and changes provided by the AMI Project will come at a minimal cost for customers.

7.0 Reference: Exhibit B-1, Section 3.5

Preamble: On lines 7-14 of PDF page 56, FEI discusses four key drivers.

7.1 Please confirm that AMR and AMI will achieve the first three benefits listed. If not confirmed, please fully explain.

<u>Response:</u>

FEI clarifies that the benefits referred to in the question are described in the Application as drivers for the Project need.

Not confirmed. AMI will support the first three drivers listed; however, AMR only partially supports two of the drivers. Please refer to Table 4-1 in the Application, as well as Section 4.2.2, for further detail and discussion of these conclusions.

8.0 Reference: Exhibit B-1, Section 4.2.2. PDF page 61, lines 21-32

8.1 Please provide an analysis of kilometers driven under the current manual approach and what would be driven under the AMR solution.

Response:

As described in Section 3.1.1.5 of the Application, FEI currently has approximately 150 meter readers collecting meter readings. Meter readers drive 35,000 kilometres per year on average. Consequently, FEI estimates there are 5,250,000 kilometres driven annually under the current manual meter reading approach.

In Section 4.2.2.1 of the AMI Application, FEI states there would be a 50 percent reduction in the number of kilometres driven to read AMR equipped meters. Consequently, FEI projects the number of kilometres driven per year would reduce to 2,625,000 under an AMR scenario.

8.2 Please fully explain what impact natural disasters such as floods or wildfires would have on the AMI solution. Would the AMI solution operate continually during a natural disaster?

Response:

The impact of a natural disaster on the proposed AMI solution would depend on the nature of the event and any resulting damage to other AMI system infrastructure. The critical path for continued AMI network operations is whether a meter can communicate to a base station and the base station can communicate with the data centres.

For the meter to base station communication link, redundancy is inherent in the system (depending on location) in that an end point can communicate with multiple base stations. Failure of a single or even multiple base stations in an area due to a natural disaster would have negligible impact; however, widespread base station failures would begin to affect system performance. Failures could be caused by extended power outages or physical failure of the tower or building to which the base station is attached.

For the base station to data centre communication, FEI will be reliant on third-party communications networks for backhaul of the data. A widespread failure of these third-party systems would interrupt communication. Both the Sensus and FEI data centres are redundant and located in different geographical areas, so natural disasters are not expected to have an impact on them.

Meters also have capabilities such as automatic excess flow and temperature shutoff, which are not dependent on the network. These capabilities are not expected to be affected by natural disasters unless the meter itself is damaged. Additionally, while an outage caused by a natural disaster may interrupt communication for a short duration, the meter will continue to collect consumption data and alarms and send these back to FEI when communication is restored.

8.3 Please provide a detailed analysis of the number of "on demand" reads conducted in the last 5 years.

Response:

On demand reads are also referred to as off-cycle reads. Off-cycle meter reads are meter reads required outside of the normal billing cycle. As described in Section 3.1.1.3 of the Application, off-cycle reads are typically needed for final reads for customers who are moving in or moving out, or for special checks to assist with investigating matters such as bill disputes or switched meters.

Please refer to Table 3-2 in the Application, which displays the number of manual meter reads completed for the years 2016 to 2020, including both regular and off-cycle reads.

9.0 Reference: Exhibit B-1, Section 4.2.2. PDF page 62, lines 31-35

9.1 Please provide all analysis and communication that clearly demonstrates that manufacturers of natural gas meters are "investing most of their product development efforts into AMI since AMR has limited ability to accept technical enhancements."

Response:

The following response was provided by Util-Assist:

Direct statements or research and development investment figures from meter manufacturers attesting to the above are not available. However, the development and proliferation of AMI versus AMR is evident in vendor product releases and marketing and is re-enforced by the fact that there is almost no further development possible in AMR, because of the limitations of the hardware and communications protocol. The following is a high-level analysis of offerings from two of the leading meter manufacturers showing the inherent limitations of AMR and the prevalence of AMI focus, development, and market offerings.

AMR is limited by its one-way communications protocol and by its communication frequency, which is typically monthly or bi-monthly on walk or drive by reading. There is very little that can be developed for AMR in terms of new functionality because functions beyond basic meter read collection require the ability to send and receive data or commands to or from the meter on demand (i.e., requires two-way communication over a fixed network like AMI). Recent advances in gas module functionality are only available if the module is communicating on an AMI network as an AMI module, and these advances only offer some of the basic functions that would be available as standard in full AMI meters.

For example, the latest features in Itron's gas module, the Riva 500G, are only possible if it is functioning as an AMI module communicating on an AMI network, and not if the module is in AMR walk-by or drive-by reading mode. These features include firmware download, high flow alarms, sub hourly interval data, the ability to hop to a neighboring module for hard to read applications, and extended data storage. All of these features are only available if the module is deployed as an AMI module using the OpenWay Riva AMI Network mode, as described in the data sheet available at the following link: https://www.itron.com/-/media/feature/products/documents/spec-sheet/500g-ert-module.pdf.

In terms of what is offered by the meter manufacturer Sensus, the "Solutions" section of its homepage (sensus.com) lists the sixteen solution offerings/categories listed below:

- Advanced Metering Infrastructure (AMI)
- Automatic Meter Reading (AMR)
- Cathodic Protection

- Conservation Voltage Reduction (CVR)
- Customer Portal
- Data Analytics
- Demand Response (DR)
- Distributed Energy Resources (DER)
- Distribution Automation (DA)
- ERT Meter Reading
- Leak Management
- Lighting Control
- Non-Revenue Water
- Outage Management
- Power Line Carrier (PLC) Migration
- Pressure Regulation

Of these sixteen solutions, fourteen rely on AMI data and/or two-way communications on an AMI or cellular network (two of these, ERT Meter Reading and PLC Migration, are specifically focused on migrating to AMI from older reading methods). Of the remaining two, Customer Portal is dependent on AMI data if the portal is to display any information beyond past monthly usage, and the remainder is the Automatic Meter Reading (AMR) solution, the description for which ends with the following selling feature describing the upgrade to AMI: "And when you're ready to upgrade to Advanced Metering Infrastructure (AMI), our solutions allow you to easily migrate your Automatic Meter Reading infrastructure to our fixed-base FlexNet® communication network."

This is just a high-level examination of offerings from two of the leading meter manufacturers showing the prevalence of AMI focus and offerings. Other key development areas for these manufacturers, like meter data management systems, edge computing, meter apps, and smart cities initiatives, also rely on AMI data and networks and having smart meters or endpoints deployed in the field.

10.0 Reference: Exhibit B-1, Section 4.2.2.4. PDF page 63, lines 16-31

Preamble: On lines 19-31, FEI lists 8 areas where AMR is deficient.

10.1 Please provide a complete analysis of the cost of implementing AMI related to each of the issues, and an analysis of customers' willingness to pay for each of the enhancements.

Response:

Please refer to the response to BCOAPO IR1 6.1.

11.0 Reference: Exhibit B-1, Section 4.2.3.1. PDF page 66, lines 9-12

Preamble: On lines 9-12, FEI states:

Under the AMR alternative, FEI's existing meter exchange, bypass valve, and regulator replacement programs would continue to be completed as part of FEI's existing sustainment capital program and have been included in capital spending to provide the full costs over the analysis period.

11.1 Please provide an updated AMR analysis that excludes FEI's existing meter exchange, bypass valve, and regulator replacement programs

Response:

FEI notes FEI's existing meter exchange, bypass valve, and regulator replacement program is essentially the Baseline scenario. Therefore, by excluding these costs from the AMR alternative, this is essentially the incremental cost of the AMR alternative (i.e. the difference between AMR and Baseline) as shown in Table 4-5 of the Application (i.e. rows 14 and 15).

The table below provides the breakdown of the *incremental* capital costs and O&M savings for AMR (i.e. AMR less Baseline). The total incremental capital costs and O&M savings are $123.8 million and $158.8 million, respectively as shown in Table 4-5 of the Application. FEI also notes the incremental levelized delivery rate impact for the AMR alternative, also shown in Table 4-5, is a credit of 0.286 percent.

Financial Summary	AMR less Baseline
Capital Costs:	
Meter Capital	97.6
Project Management	26.2
Software Capital	2.2
Network Capital	0.3
Non-Meter Capital	0.8
Savings In House Meter Reading Capital	(7.0)
AFUDC	3.6
Total Capital	**123.8**
O&M Costs:	
Meter Reading Costs	(196.4)
Operations, Contact Centre and Meter Shop O&M	30.2
New O&M	7.3
Total O&M (incl. Capitalized Overhead)	**(158.8)**

12.0 Reference: Exhibit B-1, Section 6.4, and Table 4-5

Preamble: On line 11 of PDF page 132, FEI identifies capital cost of $638.4 million. In Table 4-5, FEI indicates total capital for the AMI alternative of $558.9 million.

12.1 Please provide a detailed analysis that reconciled the $638.4 million on PDF page 32 to the $558.9 million in Table 4-5

Response:

The $638.4 million is the estimated total AMI Project costs, in as-spent dollars, for the pre-deployment and deployment period from 2021 to 2026. This amount includes the AMI Development and Application deferral costs as well as the associated financing costs. Please refer to Table 6-1 of the Application (i.e. Line 1, Colum 3) which shows the $638.4 million.

The $558.9 million from Table 4-5 of the Application is the net present value (NPV) of all AMI capital costs over the 26-year analysis period from 2021 to 2046. This would include all capital costs for AMI during the pre-deployment and deployment period from 2021 to 2026, as well as the post-deployment capital costs related to AMI from 2027 to 2046. It does not include the AMI Development and Application deferral costs and the associated financing costs. The calculation of this 558.9 million is shown under Confidential Appendix G-1 of the Application, Line 19 of the "AMI Summary" tab.

The table below provides a breakdown of the $638.4 million with references to Confidential Appendix G-1 "AMI Summary" tab which is where the NPV of $558.9 million was calculated. To be clear, the capital costs from 2021 to 2026 that make up the $638.4 million are included in the NPV calculation of $558.9 million, which is for the 26-year period from 2021 to 2046.

Line	Items As-Spent ($000s)	2021	2022	2023	2024	2025	2026	Total	Reference
1	Total Capital	23,251	15,078	115,786	193,032	182,646	97,526	627,319	Appendix G-1, AMI Summary Line 19
2	AMI Development & Application Deferral Costs	8,067	1,606	308	247	248	-	10,475	Appendix G-1, AMI Summary Line 22
3	AFUDC on Deferral Costs	260	368					628	Appendix G-3, AMI Model, Schedule 9, Line 43
4	**Total Costs trough Deployment**	**31,577**	**17,053**	**116,094**	**193,279**	**182,893**	**97,526**	**638,422**	**Sum of Above**

13.0 Reference: Exhibit B-1, PDF page 154, lines 28-32

Preamble: On lines 28-32, FEI cites a portion of the CEA.

13.1 Please fully discuss how the referenced section of the CEA applies to natural gas meters.

Response:

Please refer to the response to BCSEA IR1 31.1.

14.0 Reference: Exhibit B-1, PDF page 156, lines 24-25

Preamble: On lines 24-25, FEI discusses the use of hydrogen.

14.1 Please fully explain the difficulties in using the FEI system to transport hydrogen. In the response, please fully explain all changes that would be required to the FEI system to transport hydrogen. In the response, please fully discuss whether the hydrogen molecule is smaller than natural gas, and what impact that may have on leaks, seals and other components of the FEI system.

Response:

Given the technical research and testing completed to date, FEI expects that the gas system in its current form is capable of distributing hydrogen as a blend in the natural gas stream. For example, a significant portion of FEI's gas distribution system is constructed of polyethylene components, which research indicates is compatible with up to 100 percent hydrogen transport. As such, FEI expects that minimal changes would be required to transport hydrogen at low blend limits initially. FEI also anticipates that any gas system modifications required to increase the blend limit over time will be identified through continuing research and testing. Further, FEI expects that achieving this goal will be managed effectively through the development of codes and standards, regulatory amendments, and ongoing sustainment upgrades as the gas network continually evolves.

FEI recognizes that because hydrogen is not currently present in the gas supply there are a number of factors that require consideration to ensure the ongoing safety and reliability of the energy delivery system. Compared to methane, hydrogen has different production costs, and different physical, chemical, and combustion characteristics. The smaller molecular size of hydrogen (compared to methane) could negatively affect leakage rates. However, FEI will work with governing bodies and authorities having jurisdiction to develop a deployment strategy to manage change and address safety, training, and education for supply chain stakeholders and wider societal perceptions and considerations.

FEI plans to execute a broad program of focused activities including technical feasibility studies and pilot projects to examine every aspect of the gas system and test how hydrogen interacts with all gas network equipment and customer equipment including seals and other components. This work will verify that hydrogen is safe to transport in the existing gas system and confirm any changes that would be required to FEI's system to transport hydrogen at higher blend levels, including up to 100 percent hydrogen. This work will also address gaps in codes, standards, and regulations and inform the regulatory pathway in BC for the implementation of hydrogen throughout the BC gas system with residential, commercial, and industrial customers.

Please also refer to the response to BCUC IR1 34.1 for a discussion of how the proposed AMI meters are compatible with hydrogen and methane mixtures.

15.0 Reference: Exhibit B-1, Appendix A, Util-Assist Report, PDF page 168

Preamble: On PDF page 168, Util-Assist provides a table of AMR and AMI

15.1 Please provide an updated table that only includes Natural Gas. In the table, please provide separate tables for Canada and the US, that provides totals for:

(i) AMR modules,

(ii) AMR meters,

(iii) AMI Modules, and

(iv) AMI meters

<u>Response:</u>

The following response was provided by Util-Assist:

The table has been updated, below, with total counts at the bottom. Note:

- The table is not meant to be exhaustive and does not include all AMI and AMR projects in North America
- "AMR meters" and "AMR modules" refer to the same kind of endpoint (a diaphragm meter with an AMR module installed on it) and so only one total is shown for these. A total for "AMI meters" is not shown as solid-state AMI meters have not been deployed on a large scale in North America and so actual deployment numbers are not available.

Utility	Project Type	Quantities	Timeframe and Notes
AltaGas (Alberta)	Aerial Gas AMR	80,000 gas AMR modules	2015 to 2016
ATCO Gas (Alberta)	Aerial Gas AMR	1.1 million gas AMR modules	Deployment from 2010 through 2014. Switched to aerial meter reading in July 2018.
City of Medicine Hat Utilities (Alberta)	Electric, water, and gas AMI	23,378 gas AMI modules	Deployment from 2012 through 2015. The first project in Canada to include electric, water and gas measurement, monitoring, and control over a single AMI network.
Energir (Quebec)	Gas AMR	225,000 gas AMR modules	
SaskEnergy and SaskPower (Saskatchewan)	Electric and gas AMI	370,000 gas AMI modules	Deployment 2014 through 2018. Electric meter deployment halted in 2014. Mass gas module installations completed in 2017.

Utility	Project Type	Quantities	Timeframe and Notes
Alliant Energy (Wisconsin, Iowa, Minnesota)	Multi-state electric and gas AMI	400,000 gas AMI modules	2007 start; deployment ongoing
Ameren Illinois	Electric and gas AMR, now transitioning to AMI	476,000 gas AMR modules	Aiming for 62% electric AMI coverage by 2022
Atmos Energy (Louisiana, Texas, Mississippi, Tennessee, Kentucky, Kansas, Colorado)	Multi-state, gas-only AMI module deployment	Serves approximately 3 million customers; all being transitioned to gas AMI modules over time	Deployment began in 2007 with 75,000 meter pilot, and is ongoing through service territory. One of the largest all-natural-gas distributors in the United States.
Baltimore Gas and Electric (BG&E – Maryland)	Electric and gas AMI	730,000 gas AMI modules	Deployment 2009 through 2011
Con Edison (New York)	Electric and gas AMI	1.3 million gas AMI modules	Planning and network 2015-2016 Implementation 2017-2022
Dominion Energy (Utah, Wyoming, Idaho)	Gas AMR	650,000 gas AMR modules	2016 project start
TECO Peoples Gas (Florida)	Gas AMR	400,000 gas AMR modules	
San Diego Gas and Electric Company (California)	Electric and gas AMI	900,000 gas AMI modules	Deployment from 2008 through 2010
SoCalGas (Southern California)	Gas AMI	6 million gas AMI modules (2.4 million new meters with AMI modules, and 3.6 AMI module retrofits)	Deployment 2013 through 2017. The largest gas-only AMI project in North America.
City of Long Beach (California)	Gas AMI	156,000 gas AMI modules	Deployment 2014-2017. Added 90,000 water endpoints to the network after gas deployment.
New Mexico Gas Company	Gas AMR	345,000 gas AMR modules	
Niagara Mohawk Power Corporation/ National Grid – Not Yet Approved (New York)	Electric and gas AMI	640,000 gas AMI modules	(Proposed) 2020 project start with 4 year deployment starting in 2022. Under consideration with the New York State Public Service Commission as of December 2019.

Utility	Project Type	Quantities	Timeframe and Notes
Nicor Gas (Illinois)	Gas AMI	Approximately 2.2 million gas AMI modules	2019-2020 deployment
NorthWestern Energy (Montana, South Dakota, Nebraska)	Multi-state electric and gas AMI	48,000 gas AMI modules in South Dakota 44,000 gas AMI modules in Nebraska	2018-2019 deployment
NV Energy (Nevada)	Electric and gas AMI	170,000 gas AMI modules	2009-2013 deployment
Pacific Gas and Electric Company (PG&E – California)	Electric and gas AMI	4.4 million gas AMI modules	Deployment 2007 through 2011. The largest AMI deployment in North America
Puget Sound Energy (Washington State)	Electric and gas AMI	800,000 gas AMI modules	Deployment 2018-2023
Totals			
	AMR Modules	**AMI Modules**	**Total AMR + AMI Modules**
Canada	1,405,000	393,378	1,798,378
U.S.	1,871,000	20,788,000	22,659,000
Note: This table and totals shown are not meant to be exhaustive and do not include all gas utilities with AMR or AMI in North America. The table includes only those utilities researched for the purposes of the report.			

16.0 Reference: Exhibit B-1, Appendix A, Util-Assist Report, PDF page 173

Preamble:

16.1 Please update the table on PDF page 173 to include each of the FEI AMI and AMR alternatives.

Response:

The following response was provided by Util-Assist:

Please refer to the below for an updated version of the table found in Section 2.2.2 of the Util-Assist *Overview of North American Natural Gas AMI and AMR Projects*.

Utility and Project Type	Total Cost (CAD Non-NPV)	Total Project Cost per Meter (CAD)	Comments
ATCO Gas Canadian Gas AMR 1.04 million AMR meters	$121 million (with 20% contingency: $9.7 million for first two years of deployment[12])	$116	Large operational savings realized, with low endpoint cost due to AMR. Route optimization added operational savings beyond just switch to automated reading. Large service territory now served by aerial AMR.
SoCalGas U.S. Gas AMI 2.4 million meters with AMI modules 3.6 million AMI module retrofits	$1,135 million ($963 million capital and $199 million O&M, with 6.5% contingency of $73.3 million)	$192	Business case was based on an extended term, and benefited from broad government support for environmental and conservation initiatives. The cost-effectiveness of the project relies upon the materialization of forecasted conservation benefits.
Nicor Gas U.S. Gas AMI 2.2 million AMI modules	$337 million	$153	A large AMI module project with a slim benefits margin – a positive business case was only reached by comparing against a base case that included switching from bi-monthly to monthly reads. Any cost overages will jeopardize the project's cost effectiveness. [13]
San Diego Gas and Electric U.S. Gas+Electric AMI 1.4 million electric AMI meters 900,000 million gas AMI module retrofits	$700 million	$326	The business case was allowed to include "newly quantifiable benefits," which were benefits not previously quantified or quantifiable in past projects reviewed by the CPUC. These benefits were given a value range of $34 million to $46 million CAD, which made up a significant portion of the net benefits.

[12] Alberta Utilities Commission. (July 20, 2012) *AUC Decision 2012-191 – ATCO Gas 2011-2012 General Rate Application Phase I Compliance Filing.* Page 16. http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2012/2012-191.pdf

[13] State of Illinois Commerce Commission. Northern Illinois Gas Company d/b/a Nicor Gas Company – Proposed General Rate Increase in Gas Rates and Revisions to Other Terms and Conditions of Service 17-0124 – ORDER. (January 31, 2018). Page 12. https://icc.illinois.gov/docket/P2017-0124/documents/264760/files/464441.pdf

Utility and Project Type	Total Cost (CAD Non-NPV)	Total Project Cost per Meter (CAD)	Comments
Con Edison U.S. Gas+Electric AMI 3.6 million electric AMI meters 1.3 million gas AMI module retrofits	$3,086 million ($1,642 million capital and $1,444 O&M)	$633	Extremely high total cost per meter, due to above average installation costs and ongoing IT operations costs. However, the business case included commensurate benefits (largely electric), which yielded a very high total project value.
City of Medicine Hat Canadian Gas+ Water+Electric AMI 81,800 AMI endpoints (23,000 gas modules)	$19.2 million (projected, with gas portion of $5.2 million) $21.9 million (actual)	$242 (projected) $267 (actual)	Lower than expected benefits, higher than expected costs, and small meter population yielded low financial benefits.
FEI AMI AMR	$770 Million $254 Million	$555 $206	See section 3 project need

16.2 Please update the cost per meter for San Diego Gas and Electric and for Con Edison to only include natural gas.

Response:

The following response was provided by Util-Assist:

Because these are joint electric and gas projects with shared costs including network infrastructure, IT and system costs, vendor professional services costs, internal project management costs, etc., it is not possible to derive a gas-only cost per meter for these projects.

17.0 Reference: Exhibit B-1, Appendix A, Util-Assist Report, PDF page 176

Preamble: In section 2.2.3.4, Util-Assist discusses ATCO Gas

17.1 Please provide a copy of all data related to ATCO Gas that Util-Assist relied on or examined in the preparation of its report. In the response, please include the ATCO Gas business case for AMR.

<u>Response:</u>

The following response was provided by Util-Assist:

Please refer to Attachments 17.1A through 17.1E for copies of the five documents that were used in preparation of the report. In addition to these PDF files, the websites below were also referenced:

ATCO Gas Linkedin Profile: https://ca.linkedin.com/company/atco-gas.

Itron Inc. News Release (August 1, 2013) *Itron Completes Installation of Canada's Largest Meter Automation Project at ATCO Gas*. https://www.itron.com/lam/company/newsroom/2013/08/01/itron-completes-installation-of-canada-s-largest-meter-automation-project-at-atco-gas.

18.0 Reference: Exhibit B-1, Appendix A, Util-Assist Report, PDF page 177

Preamble: Util-Assist discusses remote shut off.

18.1 Please fully explain how many natural gas utilities in Canada have implemented remote shut off.

Response:

The following response was provided by Util-Assist:

We are not aware of any Canadian gas utilities that have implemented remote shut off.

18.2 Please fully explain all issues with remote shut off that may exist.

Response:

As noted in the report prepared by Util-Assist, remote shutoff is a new capability in the North American gas market, and processes for remote disconnection or reconnection of service need to consider issues such as relighting appliances and safety checks.

FEI believes there are limited differences in the process and policy considerations around remote disconnections compared to those that are present today with manual disconnections. More specifically, FEI's current processes contemplate impacts to customers, implications on system operations, and overall premises/site safety. For example, FEI expects that the checks and balances around the safety considerations for the system and customers will remain largely the same as they are today, including considering the impact of potential weather circumstances on customers. The key difference will likely be the confirmation of the site safety on a remote basis as opposed to a site visit prior to the completion of a disconnection; however, with AMI, more information specific to that meter and location on the system will now be available which will provide a more comprehensive understanding of the circumstances at that site.

19.0 Reference: Exhibit B-1, Appendix A, Util-Assist Report, PDF page 177

Preamble: Util-Assist discusses Pipeline Corrosion.

19.1 Please provide a detailed analysis of the FEI distribution system that indicates the KM of (i) services, and (ii) mains that are each of steel pipe and poly pipe.

Response:

The requested information is provided below, and is current to Q2 2021.

Distribution Services

Material Type	Total Length (km)	# of Services
Polyethylene (PE)	13,589	600,494
Steel (ST)	6,281	296,674
Steel/Polyethylene (ST/PE)	628	22,395
Unknown	286	17,002
Total	**20,784**	**936,565**

Regarding Distribution Services, please note the following:

1) Material Type ST/PE represents cases where a PE service was installed off of a steel stub. This means that the tee and a short length of the main are steel, like the adjacent main, but the majority of the service line is PE.
2) Material Type Unknown represents cases where FEI is not confident whether the service is Steel, PE, or Steel/PE. This could be because FEI did not have this information when the data was migrated to the GIS from other historical systems, or because of data entry errors.

Distribution Mains:

Material Type	Total Length (km)
Polyethylene (PE)	15,100
Steel (ST)	10,953
Total	**26,053**

19.2 Please fully explain whether the referenced ability to collect cathodic protection monitoring has been implemented in Canada.

<u>Response:</u>

The following response was provided by Util-Assist:

Sensus has confirmed that three Canadian utilities have piloted the Sensus SentryPoint cathodic protection monitoring solution, and several customers in the US have implemented the solution in a production environment. Specific utility names were not provided because the program details between Sensus and its customers are kept confidential.

Attachment 17.1

Alberta Utilities Commission

AUC-Initiated Review Under the Reopener Provision of the 2013-2017 Performance-Based Regulation Plan for the ATCO Utilities

February 27, 2019

Alberta Utilities Commission
Decision 23604-D01-2019
AUC-Initiated Review Under the Reopener Provision of the
2013-2017 Performance-Based Regulation Plan for the ATCO Utilities
Proceeding 23604

February 27, 2019

Published by the:
Alberta Utilities Commission
Eau Claire Tower, 1400, 600 Third Avenue S.W.
Calgary, Alberta
T2P 0G5

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Contents

List of tables

AUC-Initiated Review Under the Reopener Provision of the 2013-2017 Performance-Based Regulation Plan for the ATCO Utilities

Decision 23604-D01-2019
Proceeding 23604

1 Decision summary

1. In this decision, the Alberta Utilities Commission must make a decision on whether to reopen and review either or both of the 2013-2017 performance-based regulation (PBR) plan of ATCO Electric Ltd. (distribution) (ATCO Electric) or the 2013-2017 PBR plan of ATCO Gas and Pipelines Ltd. (ATCO Gas). Collectively, ATCO Electric and ATCO Gas are referred to as the ATCO Utilities.

2. In Decision 2012-237,[1] the Commission determined that a PBR plan will not be reopened unless there is "sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan."[2] Based on the record of this proceeding, the Commission does not find that a problem exists with the ATCO Utilities' 2013-2017 PBR plans.

2 Introduction and procedural summary

3. In Decision 2012-237, the Commission established a PBR plan for Alberta electric and natural gas distribution companies for 2013-2017. The plan provided for a reopener provision allowing for a potential review of the PBR plan of a utility if the utility reported an earned return on equity (ROE) in its annual filings made with the Commission pursuant to Rule 005,[3] 300 basis points above or below the Commission-approved ROE for two consecutive years or 500 basis points above or below the approved ROE in a single year.[4]

4. At paragraphs 757 and 758 of Decision 2012-237, the Commission stated the following with respect to the implementation of the reopener provision:

> 757. The Commission does not consider that a re-opening of the PBR plans should be automatic. As with any other matter before the Commission, any re-opening of a PBR plan must be on application to the Commission and the onus is on the applicant to demonstrate that a re-opening is warranted.
>
> 758. As noted above, the Commission finds that any party, including the Commission on its own motion, should be permitted to bring an application to re-open and review a PBR plan if there is sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan. The Commission will consider applications to re-open and review a PBR plan and make a determination on the merits of the application as to whether a re-opening of the plan is warranted. In order to ensure fairness to all parties, parties are directed to notify the Commission of all events that they consider

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1 Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.
2 Decision 2012-237, paragraph 758.
3 Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.
4 Decision 2012-237, paragraphs 737-739.

> signal the need for a re-opener as soon as possible after they have been identified. The Commission also directs that the financial impact of any such event be captured in a separate account pending a ruling from the Commission. Any proposed financial impact is to be measured from the time the event occurred. The disposition of the balance in that account (positive or negative) would follow the Commission's ruling. [footnote omitted]

5. On May 30, 2018, the Office of the Utilities Consumer Advocate (UCA) filed a letter with the Commission stating that the 2016 and 2017 Rule 005 financial results of both ATCO Electric and ATCO Gas indicate that each company's actual ROE exceeded the reopener thresholds. ATCO Electric exceeded the +/-300 basis point threshold for 2016 and 2017, and ATCO Gas exceeded the +/-300 basis point threshold for 2016 and 2017 and the +/-500 basis point threshold for 2017. In its letter, the UCA inquired whether the Commission intended to review the ATCO Utilities' 2013-2017 PBR plans and suggested that the Commission initiate a proceeding to investigate the reasons for the actual ROEs exceeding the approved ROEs and whether this is the result of a flaw in the PBR plans approved in Decision 2012-237.

6. On June 1, 2018, the Commission issued a notice of application and a letter[5] initiating a proceeding to consider whether "there is sufficient evidence that there is a problem that cannot be resolved without reopening and reviewing the plan."[6]

7. The Commission established a two-phase process. In the first phase, the subject of this proceeding, the Commission considered whether "there is sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan." The second-phase proceeding would only be initiated if the Commission determined that a reopener is warranted. Given that the Commission has determined that a reopener is not warranted, consideration of a possible reopening of the ATCO Utilities' 2013-2017 PBR plans concludes with this decision.

8. The Commission registered the ATCO Utilities in the proceeding and invited interested parties to submit a statement of intent to participate (SIP) by June 15, 2018. The Commission received SIPs from EPCOR Distribution & Transmission Inc., FortisAlberta Inc., ENMAX Power Corporation and AltaGas Utilities Inc. These companies did not participate further in this proceeding. The Consumers' Coalition of Alberta (CCA), The City of Calgary (Calgary) and the UCA (collectively, the interveners) registered SIPs and actively participated in the proceeding.

9. The Commission established a process for this proceeding that included submissions from the ATCO Utilities, information requests (IRs) to and responses from the ATCO Utilities and submissions on the need for further process.

10. In response to the need for further process, the interveners submitted motions to compel further and better responses to certain information requests from the ATCO Utilities. On September 20, 2018, the Commission issued its ruling[7] on the motions from the interveners. In the ruling, the Commission partially granted the requested relief and set the dates for supplemental responses and for argument and reply argument.[8]

[5] Exhibit 23604-X0007.
[6] Decision 2012-237, paragraph 758.
[7] Exhibit 23604-X0070.
[8] Exhibits 23604-X0071 to 23604-X0073.

11. The main process steps, as amended throughout the course of the proceeding, are set out in the table below:

Process step	**Due date**
Submissions from the ATCO Utilities	June 22, 2018
IRs to the ATCO Utilities	July 6, 2018
IRs responses from the ATCO Utilities	July 27, 2018
Further IR responses from the ATCO Utilities (in accordance with the Commission's ruling on the interveners' motions for further and better IR responses)	October 5, 2018
Submissions on the need for further process	October 11, 2018
Commission supplemental IRs to the ATCO Utilities	November 1, 2018
Supplemental IR responses from the ATCO Utilities	November 8, 2018
Argument	November 15, 2018
Reply argument	November 29, 2018

12. The Commission considers the record for this proceeding closed on November 29, 2018, when parties filed reply argument.

13. In reaching the determinations set out within this decision, the Commission considered all relevant materials comprising the record of this proceeding. Accordingly, reference in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to a particular matter.

3 Overview of the Commission's approach to determining whether a reopener is warranted

14. In Decision 2012-237, the Commission determined that a PBR plan should include a provision for a reopener; however, a reopening of the plan should not be automatic. The Commission described the purpose of a reopener provision and the considerations in its decision in the following manner:

> 727. A re-opener is commonly included in a PBR plan in order to address specific problems with the design or operation of a PBR plan that may arise or come to light as the term of the PBR plan unfolds, and which may have a material impact on either the company or its customers which cannot be addressed through other features of the plan. No party recommended proceeding with a PBR plan without including the facility for a re-opening and review of the plan if it is determined that there may be a problem with the plan. The Commission agrees that a facility to re-open and review the plan is a necessary element of any PBR plan.
>
> …
>
> 757. The Commission does not consider that a re-opening of the PBR plans should be automatic. As with any other matter before the Commission, any re-opening of a PBR

plan must be on application to the Commission and the onus is on the applicant to demonstrate that a re-opening is warranted.

15. As evidenced by ATCO Electric's and ATCO Gas's 2017 Rule 005 filings submitted on May 1, 2018 and May 15, 2018, respectively, both companies' actual ROEs exceeded one or more of the reopener threshold criteria set out in Decision 2012-237. Tables showing the ATCO Utilities' actual ROEs compared to their approved ROEs for each of 2016 and 2017 are set out below.

Table 1. ATCO Electric 2016 and 2017 ROEs

	2016	2017
Actual ROE	13.03%	13.21%
Approved ROE	8.30%	8.50%
Difference (basis points)	473	471

Table 2. ATCO Gas North 2016 and 2017 ROEs

	2016	2017
Actual ROE	13.89%	16.61%
Approved ROE	8.30%	8.50%
Difference (basis points)	559	811

Table 3. ATCO Gas South 2016 and 2017 ROEs

	2016	2017
Actual ROE	11.75%	15.33%
Approved ROE	8.30%	8.50%
Difference (basis points)	345	683

Table 4. ATCO Gas combined 2016 and 2017 ROEs

	2016	2017
Actual ROE	12.93%	16.03%
Approved ROE	8.30%	8.50%
Difference (basis points)	463	753

16. As directed by the Commission, the ATCO Utilities were required to include the following information in their initial submission:

> With reference to the Rule 005 data, an analysis of items that contributed to the achieved ROEs exceeding the approved ROE in each of 2016 and 2017, for capital and operating and maintenance costs (e.g., productivity improvements implemented by the utility, externally driven factors affecting costs). In addition, identification of any attributes of the PBR features that affect revenues that may have contributed to the achieved ROEs exceeding the allowed ROE in each of 2016 and 2017 (e.g., going-in rates, I-X adjustments, customer growth, Y factors, Z factors, K factors).[9]

[9] Exhibit 23604-X0007, paragraph 9.

17. The Commission's analysis in determining whether a reopener of the ATCO Utilities' 2013-2017 PBR plans is warranted is discussed below.

18. First, in Section 4, the Commission addresses the issue of who bears the responsibility to demonstrate that a reopener is warranted in the circumstances of this proceeding.

19. Section 5 presents the ATCO Utilities' analysis of items that contributed to the achieved ROEs exceeding the approved ROE in each of 2016 and 2017.

20. In Section 6, the Commission evaluates the issues raised by the interveners as grounds for reopening the ATCO Utilities' 2013-2017 PBR plans.

21. The Commission's conclusions regarding its determination that a reopener is not warranted are set out in Section 7.

4 Evidentiary burden

22. Calgary submitted that the Commission must carefully consider the evidentiary burden that must be satisfied to initiate a reopening of a PBR plan. Cost information available to interveners and to the Commission in respect of utilities under PBR is extremely limited. The utilities are only required to file PBR-related filings, and financial information is reported through Rule 005 filings. Rule 005 filings are compiled and reported at an aggregated level and subject to adjustment by the utilities at their discretion.[10] In these circumstances, interveners are unlikely to be able to demonstrate, amongst other things, that the ATCO Utilities' earnings (or any portion thereof) were attributable to one or more components of their 2013-2017 PBR plans.

23. Given the informational disadvantages, Calgary submitted that the Commission should not adopt a component-based analysis at this stage of its consideration of a possible reopening of the ATCO Utilities' 2013-2017 PBR plans. Rather, the Commission should adopt a burden of proof in the nature of a "reasonable apprehension," such that if a reasonable apprehension is raised that the earnings of the ATCO Utilities are not exclusively due to the operation of the incentive properties of PBR, the plan should be reopened and reviewed. In Calgary's view, such a reasonable apprehension is raised in respect of the 2013-2017 PBR plan of ATCO Gas.[11]

24. The ATCO Utilities responded that the Commission's test to reopen a plan requires the demonstration of an actual flaw in a PBR plan design. Calgary, however, is attempting to make a reopener automatic without satisfying the onus to demonstrate a flaw in a PBR plan that led to the ROEs exceeding the review threshold triggers. The ATCO Utilities referred to paragraph 755 of Decision 2012-237 where the Commission rejected Calgary's position to have automatic reopeners when ROEs exceed the thresholds, and submitted that the Commission should again reject this Calgary position.[12]

[10] Exhibit 23604-X0092, Calgary argument, paragraphs 14-16.
[11] Exhibit 23604-X0092, Calgary argument, paragraphs 23-24.
[12] Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 72-74.

Commission findings

25. As indicated above, in its May 30, 2018 letter, the UCA inquired whether the Commission intended to review the ATCO Utilities' 2013-2017 PBR plans and suggested that the Commission initiate a proceeding. Concurrent with the receipt of the UCA's letter, the Commission had determined that a proceeding was required to determine whether a reopening of the ATCO Utilities' 2013-2017 PBR plans was required. While the Commission contemplated in Decision 2012-237 that "the onus is on the applicant to demonstrate that a re-opening is warranted,"[13] there is no applicant in this Commission-initiated proceeding. Accordingly, the Commission does not consider that any particular party bears the onus to provide sufficient evidence that there is a problem that cannot be resolved without reopening and reviewing the plan, failing which, the reopener must fail. Rather, the Commission considers the present proceeding to be more in the nature of an inquiry wherein the Commission sought factual information and submissions on the factors that led to the earnings exceeding the reopener thresholds. The Commission's decision, therefore, will not turn on whether a party met the required onus or not, but on the Commission's conclusions regarding whether a reopener is warranted based on the accumulated evidence and argument.

26. The Commission is not persuaded by Calgary's position that if there is a "reasonable apprehension" that the earnings of the ATCO Utilities are not exclusively due to the operation of the incentive properties of PBR, the plans should be reopened and reviewed. As required by paragraph 758 of Decision 2012-237, the evidence gathered and the arguments submitted must be sufficient to substantiate that there is a problem in the PBR plans that cannot be resolved without re-opening and reviewing the plan. This is consistent with the Commission's direction in Decision 2012-237 that exceeding the earnings thresholds will not automatically trigger a reopening of the plans.

5 ATCO Utilities' submission on factors that contributed to the achieved returns

27. The ATCO Utilities submitted that a reopener is not warranted, as the ROE achievements were not due to any flaw in the ATCO Utilities 2013-2017 PBR plans, but achieved as a result of management decisions responding to the incentives of PBR that led to productivity improvements greater than the X factor included in the PBR formula.[14] By restructuring their workforce during the PBR term, the companies realized labour savings of approximately $45 million and $38 million for ATCO Electric and ATCO Gas, respectively. In response to the reduced labour force, ATCO Gas and ATCO Electric stated that they had implemented hundreds of small improvements to minimize costs across the organization, with the majority of savings realized in the areas of customer accounting and distribution operating and maintenance.[15]

28. Specifically with respect to operating and maintenance (O&M) savings, ATCO Electric and ATCO Gas identified the following productivity improvement initiatives during the 2013-2017 PBR plan period, each of which contributed to earnings:

- ATCO Gas implemented automated meter reading (AMR) for residential customers beginning with the installation of 6,246 meters in 2010 and ending in 2013 with a total of

[13] Decision 2012-237, paragraph 757.
[14] Exhibit 23604-X0014, ATCO Utilities submission, paragraph 4.
[15] Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 9-12.

1,114,506 AMR meters in its system. The replacement of manual meter reading with AMR resulted in reducing labour, vehicle fuel and administration costs over the PBR period, with cost reductions of $0.8 million from 2015 to 2016 and $0.1 million from 2016 to 2017.[16]

- In 2015, ATCO Gas and ATCO Electric transitioned their customer care and billing (CC&B) services in-house from ATCO I-Tek Business Services, which allowed them to automate and optimize certain business processes.[17]
- Both ATCO Gas and ATCO Electric undertook a risk-based review of the timing of inspections, which resulted in safely extending the time interval for inspections and reducing volumes and costs.[18]
- ATCO Gas made changes to its gas meter recall program and the way in which it manages overtime and work schedules.[19]
- Both ATCO Gas and ATCO Electric made changes to the way in which they manage and pay for line locate activities.[20]
- ATCO Electric made changes to the way in which it plans work, responds to outages and manages vegetation.[21]

29. The ATCO Utilities noted that the approved approach in the PBR plan, whereby the billing determinant forecast used in the setting of the PBR annual rates is not trued up to actuals, is a feature that affects revenues. For example, an increase in ATCO Gas's customer usage resulted in higher revenues in 2017 than were forecast in the setting of the 2017 PBR annual rates. The inverse could also have resulted, however, had customer usage declined. Further, the ATCO Utilities explained that if the actual customer growth is different from the forecast, the difference affects both the revenue and the expenses at the same time.[22]

30. Regarding other attributes of the PBR plans that affect revenues, for example going-in rates, customer growth, Y, Z and K factors, the ATCO Utilities expressed the following views:[23]

- Any adjustments to the going-in rates would significantly undermine the incentive properties in all future PBR terms.
- Customer growth affects both revenues and expenses concurrently, and therefore growth would not have contributed to the achieved ROEs.
- Y, Z and K factors would also not have contributed to the achieved ROEs, because Y and Z factors are designed to recover or refund the actual costs incurred, and K factor capital earns a rate of return that is equal to the approved ROE.

16 Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 14-15; Exhibit 23604-X0033, ATCO-AUC-2018JUL06-002; Exhibit 23604-X0033, ATCO-AUC-2018JUL06-001, tables 7-8.
17 Exhibit 23604-X0014, ATCO Utilities submission, paragraph 16.
18 Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 19-21; Exhibit 23604-X0033, AG-AUC-2018JUL06-003(b)-(d).
19 Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 22-24.
20 Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 25-27.
21 Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 28-29.
22 Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 32-33 and 39.
23 Exhibit 23604-X0014, ATCO Utilities submission, paragraphs 38-43.

6 Issues raised by the interveners

31. The CCA, the UCA and Calgary submitted that there were circumstances unique to the ATCO Utilities during the 2013-2017 PBR term that were not experienced by other distribution utilities, leading to higher returns in 2016 and 2017 and warranting that the PBR plans for the ATCO Utilities be reopened.[24] The interveners recommended that a second-phase proceeding be initiated by the Commission.[25]

32. By way of IRs to ATCO Electric and ATCO Gas, the interveners examined the possible reasons for the companies' actual ROEs. In their respective arguments and reply arguments, the interveners raised certain issues and highlighted potential flaws in the ATCO Utilities' 2013-2017 PBR plans that they proposed resulted in ATCO Electric's and ATCO Gas's actual ROEs exceeding one or more of the reopener threshold criteria set out in Decision 2012-237. A summary of the interveners' submissions and the associated Commission findings are provided in sections 6.1 to 6.7 below.

6.1 Effects on the 2018-2022 PBR plans

33. In their argument submissions, the interveners noted issues affecting the ATCO Utilities' 2018-2022 PBR plans suggesting that these issues need to be addressed and form a basis for moving to a second-phase proceeding. The UCA suggested that if the Commission "does not deal with this issue now," ATCO Electric's and ATCO Gas's actual ROEs have the potential to exceed one or more of the reopener threshold criteria in 2018 and 2019, given that the 2017 actual O&M expenditures are significantly lower than the 2017 notional O&M expenditures.[26] Calgary surmised that ATCO Gas's 2018-2022 PBR plan going-in rates will be "excessive."[27] The CCA expressed a concern that "overly large amounts" of capital tracker capital have been carried over to the 2018-2022 PBR plans.[28]

Commission findings

34. The Commission considers that any potential implications for the ATCO Utilities' 2018-2022 PBR plans are outside the scope of this proceeding, which deals with ROE thresholds being exceeded during the 2013-2017 PBR term and whether "there is sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan." Therefore, the Commission did not consider the interveners' submissions with respect to the 2018-2022 PBR plans in its determinations regarding whether a reopener is warranted.

6.2 Magnitude and timing of increased returns

35. The UCA noted that the ROEs that triggered the reopener occurred in the final years of the PBR term, and submitted that this is counter-intuitive. The UCA stated that it expected the largest increase would be in 2014 or 2015, with declines in the latter years, and is concerned that the ATCO Utilities' implementation of cost reductions may have been coordinated in such a way as to delay cost improvements until the latter years of the 2013-2017 PBR term and thereby

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24 For examples see Exhibit 23604-X0096, CCA argument, paragraph 50; Exhibit 23604-X0094, UCA argument, paragraph 7; Exhibit 23604-X0104, Calgary reply argument, paragraph 13.

25 Exhibit 23604-X0096, CCA argument, paragraph 109; Exhibit 23604-X0094, UCA argument, paragraph 23; Exhibit 23604-X0092, Calgary argument, paragraph 95 and 101.

26 Exhibit 23604-X0094, UCA argument, paragraph 22.

27 Exhibit 23604-X0092, Calgary argument, paragraph 38.

28 Exhibit 23604-X0096, CCA argument, paragraph 126.

avoid passing on all efficiencies gained to the next PBR term. The UCA submitted this is reflected in the pattern of O&M spending, with costs increasing from 2012 to 2015 and then declining in 2016 and 2017.[29]

36. The ATCO Utilities responded that where and when they achieved cost savings cannot be described as a flaw in the PBR plan design, and offered five reasons that greater returns would be achieved in the latter years of the PBR plan:

(i) Cost-cutting initiatives are layered one upon the other in each successive year of the plan.

(ii) A utility would prefer to retain efficiencies for the longest period possible.

(iii) It takes time for the company to identify and implement the changes.

(iv) Ensuring service levels are not compromised during the cost savings efforts requires a careful and deliberate approach over time.

(v) The utilities did not know what the rules for rebasing would be until after the Commission announced them at the end of 2016.[30]

37. The ATCO Utilities also submitted that the UCA was wrong to suggest all O&M reductions were confined to the latter years, noting that ATCO Gas's O&M levels were still higher in 2016 and 2017 relative to 2012.[31]

Commission findings

38. The UCA suggested that the pattern of cost savings, with significant savings occurring in the latter years of the PBR term, is counter-intuitive and suggests that this indicates a problem with the ATCO Utilities' 2013-2017 PBR plans. The Commission disagrees. The Commission observes that on a total basis, the ATCO Utilities' O&M spending levels in 2016 and 2017, while lower than 2015, were still significantly higher than in 2012, suggesting that overall costs continued to increase. Further, although easily achieved O&M savings would be expected in the early years of a PBR term, significant O&M savings in the latter years does not necessarily indicate that there is a problem with the PBR plans. The Commission finds the five reasons provided by the ATCO Utilities in their explanation for higher returns occurring in the latter years of the plans to be persuasive. Companies under PBR are provided with incentives to achieve costs savings as rapidly as possible in order to maximize the period during which they can garner the economic benefits associated with these savings. In addition, the pattern of cost savings with significant savings in the latter years of the PBR term cannot be ruled out since the Commission approved an efficiency carry-over mechanism as part of the 2013-2017 PBR plan. This carry-over mechanism was included in the PBR plans in order to ensure that companies would continue to pursue productivity improvements and cost-saving measures near the end of the PBR term.[32] The Commission agrees with the ATCO Utilities that savings can increase over the term as productivity enhancements compound and productivity improvements that require a longer implementation period may require investment and may not generate costs savings until later in the term. Further, the ATCO Utilities did not have an incentive to delay cost-saving

29 Exhibit 23604-X0094, UCA argument, paragraphs 7-8.
30 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 25-30.
31 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 25.
32 Decision 2012-237, paragraph 775.

measures until the final years of the 2013-2017 period in order to avoid passing on savings to customers because of the uncertainty of the rebasing process, which was not established by the Commission until later in the plan period.

6.3 Going-in rates

39. The interveners raised several points in arguing that the ATCO Utilities' 2013-2017 PBR plans were flawed because the going-in rates had been improperly established.

40. Calgary considered that the methodology used in setting the going-in rates for the ATCO Gas 2013-2017 PBR plan raises a concern that excess costs were included in the 2012 revenue requirement used to establish the going-in rates. Calgary noted that ATCO Gas's actual O&M costs for 2012 were significantly (over $20 million) lower than the related revenue requirement included in the going-in rates.[33]

41. The CCA submitted that the going-in rates were flawed because they did not adjust for the known and increasing savings that were expected during the PBR term as a result of ATCO Gas's AMR project. The going-in rates only included related savings for 2012, which were less than half of the forecast savings.[34] The CCA submitted that ATCO Gas had initiated the AMR project prior to the start of PBR and the implementation of PBR commenced just as the large expenditure was winding up and benefits were being realized.[35]

42. The CCA explained:

> …the bulk of the expenditure was incurred at ratepayer expense while ATCO Gas was under cost of service. In other words, customers paid all the costs from 2010 to 2012 under cost-of-service with some residual costs in 2013 when the final meters were installed.[36]

43. Calgary stated that ATCO Gas confirmed that over 84 per cent of its AMR meter conversions had occurred by the end of 2012, suggesting that ATCO Gas was in a position to recover revenues from customers for costs that were one-time events in 2012 and would not be repeated during the 2013-2017 PBR term.[37]

44. Calgary submitted that the 2012 revenue requirement that formed the basis of the going-in rates appears to have over-compensated ATCO Gas, at least to the extent there was no correction after 2015 for the fact that AMR conversion costs fell off substantially through 2015.[38] In Calgary's view, each element of the 2012 going-in rates was not only overstated, but the excess costs would have attracted compounding (I-X) indexation effects into 2016 and 2017 and, therefore, would have been accretive to ATCO Gas's earnings in the latter years. Calgary provided a table to show the I-X compounding effect, reproduced below as Table 5.[39]

[33] Exhibit 23604-X0092, Calgary argument, paragraphs 46 and 48.
[34] Exhibit 23604-X0096, CCA argument, paragraph 106.
[35] Exhibit 23604-X0096, CCA argument, paragraphs 29-30.
[36] Exhibit 23604-X0096, CCA argument, paragraph 31.
[37] Exhibit 23604-X0092, Calgary argument, paragraph 49.
[38] Exhibit 23604-X0092, Calgary argument, paragraph 56.
[39] Exhibit 23604-X0092, Calgary argument, paragraph 50, Table 4; Exhibit 23604-X0104, Calgary reply argument, paragraph 13.

Table 5. ATCO Gas annual I-X factor compounding effect 2013-2017

	2013	2014	2015	2016	2017
(I-X) Index on revenue per customer	1.71%	1.59%	1.49%	0.9%	- 1.92%
Effective increase to 2012 = 100	101.71	103.33	104.87	105.81	103.78

45. Calgary submitted that the Commission's ruling in Decision 2014-169 (Errata)[40] (Evergreen 2 decision), which ordered that "glide path" reductions for information technology (IT) and CC&B costs would not continue past 2012 for the ATCO Utilities, also affected ATCO Gas's going-in rates.[41] Calgary stated that indexed escalation on costs for IT and CC&B, which would have been otherwise adjusted for the Evergreen 2 decision, created earnings leverage beginning in 2012 that carried on throughout the PBR term on an accretive basis. Calgary provided a table to show the effect of the divergence in rates.[42]

Table 6. Compounding glide path effect 2013-2017 IT and CC&B costs

	2013	2014	2015	2016	2017
Effective (I-X) Increase to 2012 = 100	101.71	103.33	104.87	105.81	103.78
Glide Path Effect to 2012 = 100 for IT	97.0	94.09	91.27	88.53	85.87
Glide Path Effect to 2012 = 100 for CC&B	100.00	100.00	100.00	100.00	100.00

46. In connection with the transition of CC&B services to in-house from ATCO I-Tek Business Services (I-Tek) commencing in January 2015, Calgary stated that the ATCO Utilities declined to provide any financial analysis to demonstrate the economic basis for this decision. Therefore, there is no basis for the Commission or customers to accept that the CC&B repatriation resulted in savings without clear financial data to confirm the result. Moreover, since the CC&B costs built into the 2012 going-in rates for the ATCO Utilities were based on the for-profit affiliate prices (from I-Tek), the effect of the CC&B repatriation in 2015 was to convert annual affiliate margins into excess earnings for the ATCO Utilities. Also, the ATCO Utilities confirmed that their repatriation decision was not motivated or based on financial (efficiency/productivity) considerations. As such, the excess earnings were not derived in any way by incentive behaviour.[43] Similarly, the CCA submitted that although the ATCO Utilities characterized the transition of CC&B as a PBR initiative, it is better characterized as a response to the Commission's Evergreen 2 proceeding, which was commenced long before PBR. The ATCO Utilities were required to reduce their costs whether or not PBR was in place, as the Commission was not prepared to allow the historical level of funding. In other words, the catalyst for the changes was not PBR but the Commission's Evergreen 2 proceeding.[44]

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40 Decision 2014-169 (Errata): ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009 (2010 Evergreen Application), Proceeding 240, Application 1605338-1, February 6, 2015.
41 Exhibit 23604-X0092, Calgary argument, paragraph 51.
42 Exhibit 23604-X0092, Calgary argument, paragraphs 52-53, 94, Table 5.
43 Exhibit 23604-X0092, Calgary argument, paragraphs 79-82, 84-85.
44 Exhibit 23604-X0103, CCA reply argument, paragraph 12.

47. Calgary concluded that these two issues combined are indicative that a portion of the ATCO Utilities' excess earnings in 2016 and 2017 can be attributed to revenue based on the calculation of the going-in rates, which is not due to the operation of the incentive properties of PBR, but rather as a result of a fundamental flaw in the ATCO Utilities' 2013-2017 PBR plans.[45]

48. The UCA agreed with Calgary and the CCA.[46] The Commission understands the position of the interveners is that the concern with respect to going-in rates as it relates to the impact of IT and CC&B costs applies equally to ATCO Gas and ATCO Electric.

49. The ATCO Utilities submitted that the same going-in rate methodology was applied to all PBR utilities. One central feature of these common plans was that going-in rates for the 2013-2017 PBR term were based on a full cost-of-service review involving the standard presentation of detailed evidence and business cases, tested by means of the normal regulatory process, which also applied to the AMR project. Similarly, the IT and CC&B costs and prices were separately tested and determined in the proceeding that led to Decision 2014-169 (Errata).[47]

50. The ATCO Utilities submitted that they also undertook route optimization activities after the AMR project was complete, which also drove O&M savings related to meter reading.[48]

51. The ATCO Utilities submitted that there is no evidence of a flaw in this aspect of the ATCO Utilities' 2013-2017 PBR plan design. The related costs were included in rates the Commission determined to be just and reasonable, which the Commission used to establish final going-in rates.[49]

52. Further, the ATCO Utilities submitted that with respect to the "one-time events" that Calgary suggested do not represent incentive-based earnings, the Commission did not consider them to be unexpected in terms of the normal and acceptable operation of the plan. AMR and IT and CC&B "glide path" reductions were not identified as eligible cost-of-service line item anomaly adjustments at the outset of the 2013-2017 PBR term, nor should they be now.[50]

53. The ATCO Utilities explained that although the AMR project was initially approved under cost of service, within the PBR plan term, there is no evidence to suggest that incentive properties ceased to operate or that the efficiency gains were only short term. ATCO Gas elected to invest as a matter of its own discretion and did not receive supplemental capital funding for the considerable capital investment it made during the 2013-2017 plan term. In accordance with the 2013-2017 PBR plan design, savings derived from programs like AMR, where capital expenditures replaced O&M expenses, were clearly intended to remain with the utility.[51]

54. The ATCO Utilities indicated that their shareholders invested $74.7 million of capital in order to drive O&M savings, while only $39.6 million of capital was funded through customer

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[45] Exhibit 23604-X0092, Calgary argument, paragraphs 54 and 57; Exhibit 23604-X0104, Calgary reply argument, paragraph 18.
[46] Exhibit 23604-X0101, UCA reply argument, paragraph 10.
[47] Exhibit 23604-X0095, ATCO Utilities argument, paragraphs 20-21; Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 99-101.
[48] Exhibit 23604-X0014, ATCO Utilities submission, paragraph 15.
[49] Exhibit 23604-X0095, ATCO Utilities argument, paragraph 21; Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 102.
[50] Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 105.
[51] Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 108-109.

rates, which allowed ATCO Gas to optimize the AMR project over the entire PBR period. In the ATCO Utilities' view, that showed the plan was working as intended; that showed the plan was not flawed.[52]

55. The ATCO Utilities submitted that ATCO Gas's rates related to AMR were not set on an interim or placeholder basis, and the CCA's suggestion for a readjustment to going-in rates to refund efficiency amounts now related to those costs is "nothing short of retroactive ratemaking which is inappropriate and impermissible."[53]

56. The ATCO Utilities submitted that to repatriate CC&B was an operational decision, made to retain core business process knowledge within the ATCO Utilities when the outsourcing of IT services shifted from ATCO I-Tek to Wipro. After repatriation, ATCO Gas was incented to find ways to reduce costs. The effect of that on earnings was derived by incentive behaviour, contrary to Calgary's claims.[54]

Commission findings

57. In correspondence issued on December 16, 2010, the Commission determined that the forthcoming rate decisions for the 2012 test year would be used to establish the going-in rates for the 2013-2017 PBR term.[55]

58. In Decision 2012-237, with respect to proposed adjustments to going-in rates, the Commission dismissed proposals to make adjustments to include certain costs that were either not forecast or otherwise approved for inclusion in the 2012 revenue requirement, other than amounts in the nature of corrections. The Commission also rejected adjustments to going-in rates to reflect possible efficiency gains that may have occurred in 2012 or in a prior period that were not captured in 2012 approved rates.[56]

59. The Commission explained its rationale indicating that the 2012 rates had been tested and approved by the Commission as just and reasonable for 2012 and were considered the correct starting point on which to base going-in rates.[57] In taking this approach, the Commission was aware that there would be examples of actual costs exceeding approved forecast costs and examples of actual costs below approved forecast costs in the 2012 test year. The Commission explained that adjustments to going-in rates should not be made selectively to reflect actual results incurred, as it could not be shown outside of a full rate case that the overall resulting rates were just and reasonable. Adjustments may be made in exceptional situations where they are in the nature of a correction to the going-in rates, and not rate adjustments made after-the-fact to reflect actual results.[58]

60. In this proceeding, interveners identified two potential issues with going-in rates that may have contributed to a portion of the ATCO Utilities' earnings in 2016 and 2017, which were not due to the operation of the incentive properties of PBR, but rather as a result of a fundamental

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52 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 163-165 and 170-172.
53 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 173.
54 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 131.
55 Decision 2012-237, paragraphs 77 and 85; Proceeding 556, Exhibit 0079.01.AUC-566 , AUC Letter - Request for Deadline Extensions, December 16, 2010, paragraph 4.
56 Decision 2012-237, paragraphs 86-88, 96.
57 Decision 2012-237, paragraph 88.
58 Decision 2012-237, paragraphs 88-89.

flaw in the ATCO Utilities' 2013-2017 PBR plans. The interveners proposed two adjustments, one for the known and increasing savings that were expected during the PBR term as a result of ATCO Gas's AMR project, and one for the Commission's ruling in the Evergreen 2 decision, which ordered that "glide path" reductions for IT and CC&B costs would not continue past 2012 for ATCO Electric and ATCO Gas. The Commission must consider whether the evidence demonstrates that the going-in rates for either of the ATCO Utilities were flawed because they did not include adjustments for anticipated AMR cost savings and the IT and CC&B "glide path" savings leading in a material way and distinct from the operation of PBR incentives to ROE results in 2016 and 2017 exceeding the reopener thresholds. Such a result would call into question whether rates were just and reasonable and support a reopening of the ATCO Utilities' 2013-2017 PBR plans.

61. The ATCO Utilities submitted that they were operating under PBR incentives from 2011.[59] The Commission announced its initiative to reform utility rate regulation in Alberta in February 2010 when it issued a letter inviting interested parties to participate in a round table discussion on the matter.[60]

62. The evidence confirms that O&M savings increased for ATCO Gas during the PBR term as the result of ATCO Gas's AMR project. O&M savings from the AMR project were anticipated at the time the going-in rates were approved. The Commission does not accept the argument that these savings can be attributed to AMR expenditures approved prior to the commencement of PBR and not, at least in part, attributable to ATCO Gas responding to PBR incentives. From the information provided by ATCO Gas in response to IRs, as shown in Table 7, the Commission observes that on a forecast basis AMR meters were to be deployed in a uniform manner from 2012-2014. On an actual basis, however, the implementation of AMR meters was accelerated, capturing more savings in 2013 than anticipated. This acceleration of the implementation of the AMR project is indicative of a response to PBR incentives, because savings achieved during the beginning of the PBR period result in O&M savings for a longer period over the PBR term.

63. The record indicates that a portion ($39.6 million) of the capital investment for the AMR project was captured in going-in rates; however ATCO Gas further invested $74.7 million of shareholder capital without applying for capital tracker treatment, in order to drive O&M savings during the PBR period. The Commission agrees with the ATCO Utilities that this behaviour is indicative of PBR incentives driving costs savings and overall earnings.

59 Exhibit 23604-X0014, ATCO Utilities submission, paragraph 5.
60 Proceeding 566, Exhibit 0001.01.AUC-566, AUC letter, February 26, 2010.

Table 7. AMR project 2010-2017

	Forecast in 2011-2012 GTA		Actual		
Year	AMR Meters Implemented[1]	O&M Savings ($000)	AMR Meters Implemented[1]	O&M Savings ($000)	Unit Meter Reading Cost
2010	10,000		6,246		$1.59
2011	134,000	520	225,175	1,835	$1.53
2012	348,000	4,490	690,388	7,349	$0.97
2013	333,000	7,810	192,697	12,782	$0.40
2014	219,000	13,700	26,937	13,886	$0.29
2015		19,670	25,296	13,884	$0.28
2016			15,315		$0.22
2017			17,211		$0.21

[1] Includes growth and retrofits
Source: Exhibit 23604-X0033, ATCO-AUC-2018JUL06-002(b); Exhibit 23604-X0039, ATCO-UCA-2018JUL06-002(b).

64. In their submission, the ATCO Utilities noted that they also undertook route optimization activities after the AMR project was complete, which also drove O&M savings related to meter reading. The decrease in unit meter reading costs over 2010-2017 indicates that additional savings were realized independent of the AMR meter implementation. The Commission finds this is indicative of a response to the incentive properties of PBR and underscores the complexity of PBR whereby it would be difficult, if not impossible, to isolate the impact of earnings resulting from changes directly related to the AMR project from other contributing factors.

65. The difficulty in isolating earnings impacts also applies to the Evergreen 2 issue identified by Calgary. The Commission is not convinced by the intervener arguments that the repatriation of the CC&B services are related to a flaw in the going-in rates. The ATCO Utilities submitted that ATCO Gas faced incentives to find ways to reduce these costs after the repatriation. The Commission considers that the ATCO group of utilities, including ATCO Pipelines and ATCO Electric (transmission), were motivated to consider cost reductions for these services as a result of the Evergreen 2 decision; however, it is difficult if not impossible to identify and separate costs reductions that the ATCO Utilities would have undertaken only as a result of the Evergreen 2 decision and additional measures taken as a result of PBR incentives.

66. In setting going-in rates, the Commission was aware that during a PBR term, some costs will increase while others will decrease or disappear when compared to the forecast costs approved in the last rate proceeding due to factors known at the time going-in rates are set. With respect to some utilities, there may be a greater amount of cost increases and for others there may be a greater amount of cost decreases. Although some cost increases and decreases could have been anticipated during the 2013-2017 period as a result of projects or expenditures approved in the last rate case, the actual cost changes could not be definitively determined in advance given the ability of the utility to respond to the incentives within the PBR plans. It would be difficult, if not impossible, to isolate the cost differential resulting from these anticipated changes arising in the context of the previous rate case from actual cost changes in respect of these utility functions, as well as impacts to other cost centres, arising as a result of measures taken by the utilities in response to PBR incentives. Under PBR, utilities are able to make trade-offs between capital and operating costs and to make longer-term investment decisions, using the collective revenue

received and managed by the utilities under the PBR plans in order to generate costs savings and higher earnings.

67. Further, selectively making adjustments for anticipated cost changes prior to the PBR term that were not included in the rates established in the last rate case would be contrary to the objective of setting going-in rates based on a tested rate application resulting in a Commission decision that confirmed overall rates to be just and reasonable. Such an approach could lead to potential unfairness through the inclusion of some adjustments and the exclusion of others. The approach would also not be in keeping with the regulatory efficiency objectives of PBR and would offend the basic premise of PBR, which is to separate costs from revenues during the PBR term in order to generate the desired incentives.

68. For these reasons, the Commission finds that there is insufficient evidence to find that setting going-in rates without an adjustment for the known or anticipated cost changes relating to the implementation of AMR for ATCO Gas or in respect of the IT or CC&B "glide path" for the ATCO Utilities is a flaw in the ATCO Utilities' 2013-2017 PBR plans resulting in potentially unfair or unjust rates during the 2013-2017 PBR term.

6.4 O&M savings during the 2013-2017 PBR term

6.4.1 Productivity improvements

69. The CCA and the UCA identified issues related to O&M savings associated with workforce restructuring. The CCA was concerned about the sustainability of the workforce reductions and stated that it did not support reductions that could benefit the shareholder at the expense of the customer if as a result of these reductions additional funds could be requested in subsequent applications.[61] The CCA also made reference to ATCO Gas's stated O&M savings of $1.6 million through reduced inspection frequency and $1.3 million in savings through improved overtime management and work scheduling.[62]

70. In response to a CCA IR, in which the CCA asked the ATCO Utilities whether the cuts were sustainable and would not affect service quality, the ATCO Utilities responded that, should the demands on the distribution system change and additional resources are required, the incentive properties of PBR will ensure that they respond in a cost-effective manner. They stated that they will continue to meet the service quality requirements under Rule 002,[63] but require the flexibility to do it using whatever mix of capital and O&M they deem best to meet those demands.[64] The CCA expressed a concern with this response because, in its view, this response lays the groundwork for future increases.[65]

71. The UCA was not satisfied with the ATCO Utilities' response that there will be no detrimental effects to future costs, service quality and reliability of service as a result of the workforce restructuring. The UCA disagreed with the ATCO Utilities' assertion that there were cultural changes by which all employees were empowered to suggest and implement efficiency improvements. The UCA expected that such culture changes are not easily achieved and take

61 Exhibit 23604-X0096, CCA argument, paragraph 101.
62 Exhibit 23604-X0096, CCA argument, paragraphs 76-77.
63 Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors.*
64 Exhibit 23604-X0030, AG-AUC-2018JUL06-003(a); Exhibit 23604-X0096, CCA argument, paragraph 101.
65 Exhibit 23604-X0096, CCA argument, paragraph 102.

more time to implement than the two years (2016 and 2017). Further, the ATCO Utilities did not provide an analysis of the effects on employees, service quality and safety.[66]

72. The UCA was not convinced that meeting the service standards set by Rule 002, as confirmed by the ATCO Utilities in response to IRs[67] to support their claim that cost reductions have not affected service quality, was enough to indicate that the companies have not sacrificed service quality to achieve lower costs. Given the lag between cost reductions and the potential consequences to service quality, the UCA submitted that customers might experience service quality degradations without having received the benefit of all cost reductions.[68] The CCA expressed a similar concern.[69]

73. The ATCO Utilities explained that the savings identified by the CCA for inspection frequency ($1.6 million) and overtime management and work scheduling ($1.3 million) are year-over-year savings from 2016 to 2017 and not a 2012 to 2017 savings.[70]

74. The ATCO Utilities also disputed the UCA's assertion that there could be detrimental effects to future costs, service quality and reliability. They reiterated that the Rule 002 standards would ensure that utilities would maintain acceptable service quality standards.[71] The ATCO Utilities submitted that the UCA's "hypothetical" service quality impact cannot be considered a flaw in the plan. They explained that service metrics such as customer appointments, emergency response time, complaint response and call-answering levels would most likely see an immediate deterioration if they were adversely affected by operational changes, which the ATCO Utilities noted has not occurred.[72]

6.4.2 Evergreen 2 decision

75. Another issue identified by Calgary was the adjustment that came as a result of the Evergreen 2 decision. Calgary explained that in ATCO Gas's 2014 Rule 005 filing, it expensed over $18.1 million through a one-time charge to account for adjustments related to this decision, covering costs for 2010 through 2014.[73]

76. Calgary argued that if ATCO Gas had prorated the adjustments over all of the test years in question, rather than a one-time adjustment in 2014, Evergreen 2 adjustments would have been enough to cause ATCO Gas to exceed the two-year reopener threshold in 2013 and 2014.[74] As a result, Calgary argued that the earnings in 2013 and 2014 were not solely related to incentives. Further, when looking at the excess returns for 2016 and 2017, and if one were to accept the ATCO Utilities' claims as to the source of their efficiencies causing excess returns in 2016 and 2017, it is not reasonable to attribute all of the excess returns to the operation of PBR incentives.[75]

66 Exhibit 23604-X0094, UCA argument, paragraphs 9-11.
67 Exhibit 23604-X0033, AG-AUC-2018JUL06-003.
68 Exhibit 23604-X0094, UCA argument, paragraphs 14-15.
69 Exhibit 23604-X0096, CCA argument, paragraph 101.
70 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 206-209.
71 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 35-36.
72 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 38.
73 Exhibit 23604-X0092, Calgary argument, paragraph 40.
74 Exhibit 23604-X0092, Calgary argument, paragraph 41.
75 Exhibit 23604-X0092, Calgary argument, paragraphs 42-44.

77. The ATCO Utilities argued that Calgary relies on the impact of a regulatory decision received in 2014 to speculate that, absent that impact, different ROE outcomes would have occurred. With respect to the Evergreen 2 decision, ATCO Gas refunded those amounts to customers after the decision, regardless of the time period to which the decision was attributed.[76]

78. The ATCO Utilities do not view it as appropriate to suggest that a retroactive consideration should occur now on the basis that a decision did not happen at a certain time. They noted that it was Calgary who sought disallowances in the proceeding that led to Decision 2014-169 (Errata), and the fact that some of Calgary's recommendations were adopted by the Commission in that decision cannot be used as a reason to claim that the reopener considerations for those years should be reviewed four years after the decision.[77]

79. The ATCO Utilities also submitted that Calgary's argument would essentially be a new test in which all cost-of-service or non-incentive-based earnings (such as capital trackers) would be viewed by Calgary as excessive and presumably returned to customers.[78]

Commission findings

80. After reviewing the evidence and argument filed by the ATCO Utilities and the interveners, the Commission finds no basis for the supposition that the workforce restructuring or other productivity improvements undertaken by the ATCO Utilities may negatively affect customer service or necessarily result in incremental costs to customers above costs that would otherwise arise in connection with future distribution system changes. The ATCO Utilities have indicated that these productivity improvements were undertaken without reducing their commitment and obligations to meet the service quality requirements under Rule 002. The PBR plan is designed to incent utilities to seek out productivity improvements where costs savings can ultimately be shared with customers without negatively affecting service quality. There is no basis on this ground to indicate a flaw with the ATCO Utilities' 2013-2017 PBR plans.

81. Regarding the Evergreen 2 adjustment, the Commission is not persuaded that ATCO Gas should have expensed the adjustment over the test years instead of expensing the entire amount in 2014. In Bulletin 2016-03,[79] the Commission indicated that restatements to Rule 005 are not required to reflect adjustments to placeholder values for distribution companies under first generation PBR. This includes updates from a placeholder to either a confirmed placeholder or final approved values issued after the reporting year reflected in the Rule 005 filing.[80] The Commission is satisfied that ATCO Gas made the adjustment correctly when it reflected the Evergreen 2 adjustment in its 2014 Rule 005 filing, after the Evergreen 2 decision was released. To the extent ATCO Electric proceeded in a manner similar to ATCO Gas, the Commission's reasoning would be the same.

[76] Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 95.
[77] Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 95.
[78] Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 96.
[79] Bulletin 2016-03, Clarification of Rule 005 financial reporting requirements, February 2, 2016.
[80] Bulletin 2016-03, Section 3.2.

6.5 Capital tracker funding

82. Calgary identified the following concerns with the capital tracker mechanism, which Calgary submitted contributed to ATCO Gas's favourable earnings in 2016 and 2017:[81]

- No adjustments were made to the return and taxes components of the revenue requirement in the accounting test to account for the lower rate base for capital trackers in the years subsequent to their initial approval.
- The grouping of positive replacement cycle assets separately from negative replacement cycle assets (negative capital trackers) provided substantial capital funding increases throughout the 2013-2017 PBR term.

83. The CCA submitted that "it is clear that while the premise for capital tracker funding may not have been flawed, the actual mechanism was overly generous since there was no reference to return."[82] It proposed that the ATCO Utilities submit an accounting test showing negative capital trackers and their effect on earnings.[83]

84. The UCA did not address capital tracker funding in its argument; however, in its reply argument, it noted the issues identified by the CCA and Calgary in their respective arguments.

85. In reply, the ATCO Utilities refuted the Calgary and CCA arguments, stating that the capital tracker accounting test was approved by the Commission in capital tracker decisions and the negative capital tracker issue brought forth by Calgary was rejected by the Commission in previous proceedings.[84] Further, the ATCO Utilities pointed out that capital trackers earn the approved rate of return and, therefore, do not contribute to earnings above the approved ROE. Accordingly, they concluded that capital trackers cannot be viewed as a flaw in the PBR plan design.[85]

Commission findings

86. In response to IRs, the ATCO Utilities provided the following information, as set out in the table below.

Table 8. Estimated earnings (per cent) related to capital

	ATCO Gas		ATCO Electric	
	2016	2017	2016	2017
ROE related to the total capital (based on capital tracker capital earning at 8.3% in 2016 and 8.5% in 2017)	8.49	8.93	8.70	7.79
Residual earnings attributable to non-capital trackers	8.66	9.47	10.40	5.13

Source: Exhibit 23604-X0078, ATCO-CCA-2018JUL06-003 Motion Response, PDF pages 3-4.

87. The Commission has reviewed the detailed calculations and explanations provided by the ATCO Utilities in their schedules[86] showing the estimated earnings related to capital, and is satisfied that, for the purposes of making its determinations in this proceeding, a detailed

81 Exhibit 23604-X0092, Calgary argument, paragraphs 62-67.
82 Exhibit 23604-X0096, CCA argument, paragraph 114.
83 Exhibit 23604-X0096, CCA argument, paragraphs 99-100, 114-115 and 126-127.
84 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 117-120.
85 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 213.
86 Exhibits 23604-X0090 and 23604-X0091.

accounting test showing negative capital trackers is not required in order to determine if the capital tracker mechanism created a flaw in the ATCO Utilities' 2013-2017 PBR plans.

88. The above table provides for the relative contributions to ROE from capital tracker capital and non-capital tracker capital. The impact of what interveners referred to as negative capital trackers would be reflected in the ROE attributed to the non-capital tracker capital. The Commission does not accept the arguments of the interveners that negative capital trackers contributed significantly to actual ROEs in excess of approved ROEs for the ATCO Utilities. The Commission observes that for ATCO Electric in 2017, the results were quite the opposite. A line-by-line breakdown of non-capital tracker capital ROE would not be sufficient to demonstrate that there is a flaw in the PBR plan as a result of negative capital trackers given the need for the utilities to manage their activities in real time, operating under the PBR incentives applicable to all non-capital tracker capital. In general, Table 8 reflects the higher incentives applicable to non-capital tracker capital.

89. In light of the above considerations, the Commission is not persuaded by the evidence on the record of this proceeding that there was a problem with the capital tracker mechanism in the ATCO Utilities' 2013-2017 PBR plans.

6.6 Forecast billing determinants

90. The revenue-per-customer cap plan, increased use per customer and the lack of a true-up of forecast to actual amounts were subjects of concern expressed by Calgary.

91. Under the revenue-per-customer cap plan put into place in Decision 2012-237, the approved revenue per customer from the previous year is adjusted by the I-X index on a class-by-class basis to arrive at the upcoming year's revenue-per-customer cap. To calculate actual customer rates, the indexed revenue is divided by the forecast consumption per customer on a class-by-class basis.

92. Consequently, unlike in a price cap plan, forecast billing determinants represent an integral part of the revenue cap mechanism and provide an incentive to connect new customers because customer growth drives revenue growth and in turn drives ROE growth, provided the increased revenue is not fully offset by the incremental costs of connecting the new customers not otherwise funded through a capital tracker.

93. At the time of the proceeding leading to Decision 2012-237, natural gas distribution companies were experiencing declining use per customer, and overall increases in the number of customers was not offsetting the declines in use per customer. This 1.5 per cent per year rate of decline in average customer use was forecast to continue into the future. The gas companies noted that overall customer growth and increased consumption by some existing customers were not completely offset by overall declines in the average use per customer.

94. In Decision 2012-237, the Commission also reviewed the need to true up billing determinants on an annual basis and determined that, in the interest of regulatory efficiency, no true-up for the actual weather normalized use per customer was required for both number of customers and usage per customer. The gas companies were directed to use the actual average change in weather normalized use per customer (per class) for the preceding three years as their forecast percentage change in weather normalized use per customer for the upcoming year.

95. Calgary submitted that the Commission's use of a three-year average of weather-normalized customer usage, rather than a true-up to actual customer usage, represents a fundamental flaw in the PBR formula because in any year where the actual throughput is greater than the three-year average forecast methodology, the prior three-year average methodology would generate customer rates that are too high.[87]

96. Calgary also submitted that if ATCO Gas had a billing determinant forecast embedded in its rates that is smaller than the actual billing determinants, it would achieve windfall profits not related to the operation of any PBR incentive. Calgary stated that ATCO Gas uses the Canada Mortgage and Housing Corporation's forecast for number of customers, and their forecasts have proven to be accurate, but the three-year average customer usage methodology is completely different because it will not properly account for a year in which throughput is higher than normal.[88]

97. To emphasize its point, Calgary referred to paragraph 128 from Decision 2012-237:

> 128. This effect is further amplified by the economies of density in the gas distribution industry, with the result that the price charged for an additional unit of gas delivered to customers is typically above the marginal cost of delivery. In such circumstances, increases in use per customer will increase revenue more rapidly than costs and, conversely, decreases in use per customer will decrease revenue more rapidly than costs. Consequently, unexpected changes in use per customer may lead to "windfall profits or extraordinary losses"… [footnote removed]

98. Using 2017 forecast and actual throughput amounts, and customer numbers for ATCO Gas, Calgary calculated the revenues actually achieved versus the revenues that would have been achieved if there had been a true-up. Calgary submitted that the result was a significant amount of windfall earnings to the ATCO Gas shareholder.[89]

99. The CCA agreed with Calgary's premise and stated that ATCO Gas's assertion of a continued decline in average customer use during the 2013-2017 PBR plan and the inability of increased revenue from customer growth to offset revenue decreases did not hold.[90]

100. The ATCO Utilities disagreed with Calgary's assertion that there is a fundamental flaw in the PBR formula and submitted that the use-per-customer forecasting methodology results in a reasonable forecast and is effective at capturing trends in use per customer. The ATCO Utilities submitted that the use-per-customer forecasting methodology cannot be properly evaluated by analyzing only one year in isolation. Rather, a period of years needs to be assessed to capture both the under- and over-forecasting symmetry. The ATCO Utilities also stated that they have no ability to influence use per customer, and the likelihood of a variance is therefore equal in either direction.[91]

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[87] Exhibit 23604-X0092, Calgary argument, paragraph 72.
[88] Exhibit 23604-X0092, Calgary argument, paragraphs 72-73.
[89] Exhibit 23604-X0092, Calgary argument, paragraphs 74-78.
[90] Exhibit 23604-X0103, CCA reply argument, paragraphs 36-39.
[91] Exhibit 23604-X0102, ATCO Utilities reply argument, paragraphs 122-129.

Commission findings

101. The three-year rolling average forecast was the methodology used by ATCO Gas prior to PBR and again approved by the Commission at paragraph 995 of Decision 2012-237 on the premise that, over time, the up-and-down economic cycles and associated increases and decreases in customer revenues should average out.

102. Calgary presented ATCO Gas South's 2017 forecast and actual number of customers and throughput values to show that the actual values were above forecast for 2017.[92] The Commission agrees with the ATCO Utilities that the use-per-customer forecasting methodology cannot be properly evaluated by analyzing only one year in isolation. For example, ATCO Gas South's 2016 actual values were below forecast for 2016.[93]

103. Based on the record of this proceeding, the Commission finds no evidence to conclude that the premise that, over time, variances between actual and forecast billing determinants should average out does not continue to be true over the long term. The lack of a true-up mechanism is consistent with this approach and is consistent with the objective of achieving regulatory efficiency in the PBR plan. The Commission does not consider this to be a fundamental flaw in ATCO Gas's 2013-2017 PBR plan. Rather, the approach is symmetrical and furthers the objectives of transparency and reduced regulatory burden.

6.7 Interest earnings and post-tax return

104. The CCA argued that ATCO Gas's ROE is understated because the revenues did not include interest income and the equity thickness is overstated.

105. The CCA pointed out that ATCO Gas reported $1.76 million of interest income in Schedule 10 of their 2017 Rule 005 filings and also disclosed the same in response to an IR from the CCA in this proceeding. The CCA argued that ATCO Gas reported the interest income as non-utility income and did not credit the amount to utility income but rather to the credit of shareholders. This suggests that the cash required to fund these earnings came from excess regulated borrowing or that ATCO Gas was charging customers for additional debt which was recovered in part through capital trackers, resulting in ATCO Gas keeping the interest earnings for the benefit of their shareholders.[94]

106. In argument, the CCA made four recommendations with respect to how interest revenue should be treated in order to address this issue.[95]

107. The CCA also argued that any interest earnings should be credited to customers because ATCO Gas should not be compensated by increasing debt above what is required at customers' expense to finance assets to increase its "off-the-books return." The CCA believes the net effect of carrying such a large amount of extra debt and cash and the reasonableness of ATCO Gas deeming away a substantial difference between its actual and deemed debt levels results in ATCO Gas overstating its equity thickness and understating its debt.[96]

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92 Exhibit 23604-X0092, Calgary argument, paragraph 75, Table 6.
93 Proceeding 23355, Exhibit 23355-X0018, Appendix I - 2016 PBR Forecast vs Actual Billing Determinants.
94 Exhibit 23604-X0096, CCA argument, paragraph 42.
95 Exhibit 23604-X0096, CCA argument, paragraph 53.
96 Exhibit 23604-X0096, CCA argument, paragraph 54.

108. The ATCO Utilities argued that the CCA offered no demonstration of how these issues represent a flaw in the design of the ATCO Utilities' 2013-2017 PBR plans and further that it includes arguments that have been previously rejected by the Commission.

109. The ATCO Utilities argued that the CCA has been misinterpreting the calculations in the Rule 005 schedules with respect to interest income and also the actual cost of debt that is used in the calculation of capital trackers. The ATCO Utilities referred to Decision 21843-D01-2017[97] where the Commission accepted ATCO Gas's explanation that a higher amount of borrowing does not result in a higher amount of interest expense, which is then passed onto customers. Further, issuing higher amounts of debt at a lower average interest rate than available historically would actually decrease the amounts recovered from customers as the average embedded debt cost rate would decrease.[98]

110. The ATCO Utilities explained that under the PBR plan, the actual cost of debt affects customer rates only through the K factor adjustment. Regardless of the amount of debt issued, ATCO Gas would flow through to customers the interest associated with the 62 per cent of the debt in the deemed capital structure of the utility, based on the mid-year invested capital tracker capital. With respect to the CCA's assertion that the equity ratio is overstated due to excess debt, the ATCO Utilities argued that the value used in the calculation is deemed at the approved equity thickness as determined in the Generic Cost of Capital decision. All other costs under PBR that include the remaining debt costs are managed through rates indexed by the I-X mechanism and therefore there is no effect on customer rates if the actual costs vary.[99]

111. The CCA provided calculations which examined the tax rate that ATCO Gas used in its calculation of its earnings on capital. The CCA's calculations demonstrated that ATCO Gas used a 37 per cent tax rate in 2016, which it stated is substantially higher than the rates that have been used in capital tracker accounting tests, which have been less than 10 per cent of the K factor revenue. The CCA submitted that the net impact of a higher tax rate is to suppress the return on capital.[100]

112. The ATCO Utilities explained that the calculations provided by the CCA are incorrect and that ATCO Gas used the same methodology as that used in the capital tracker accounting test. They explained that the income tax expense requires a gross-up in order to be equivalent to a revenue requirement for taxable utilities. The ATCO Utilities stated that the tax rate is 27 per cent, not 37 per cent, and is unware of an income tax rate less than 10 per cent of K factor revenue.[101]

Commission findings

113. The Commission agrees with the ATCO Utilities that the CCA has not demonstrated a flaw in the ATCO Utilities 2013-2017 PBR plans. The Commission has previously addressed the issue of interest income and interest expense charged to customers in Decision 21843-D01-2017[102] as discussed by the ATCO Utilities in their reply argument. The Commission accepts the

97 Decision 21843-D01-2017: ATCO Gas 2015 Capital Tracker True-up Application and 2017 Steel Mains Replacement Forecast Update, Proceeding 21843, June 12, 2017.
98 Exhibit 23604-X0096, ATCO Utilities reply argument, paragraphs 176-177.
99 Exhibit 23604-X0102, ATCO Utilities reply argument, paragraph 178.
100 Exhibit 23604-X0096, CCA argument, paragraphs 61-63.
101 Exhibit 23604-X0096, ATCO Utilities reply argument, paragraphs 188-196.
102 Decision 21843-D01-2017, paragraphs 151-161.

ATCO Utilities argument that ATCO Gas applied the correct equity thickness determined in the Generic Cost of Capital decision with respect to how the actual cost of debt affects customer rates through the K factor adjustment.

114. With respect to the tax rate that ATCO Gas used in their calculation of their earnings on capital, the Commission finds no merit in the CCA's claim that ATCO Gas is using an incorrect tax rate. The Commission finds that ATCO Gas used the correct tax rate and as a result rejects the CCA's arguments on this issue.

7 Conclusion

115. The Commission commenced this inquiry into the ATCO Utilities' 2013-2017 PBR plans because the ROE thresholds in the reopener provisions of the plans were exceeded in 2016 and 2017. In this decision, in accordance with the reopener provisions of the plans, the Commission sought to determine if there is sufficient evidence that there is a problem with the plans that cannot be resolved without reopening and reviewing the plans. The Commission has considered the record of this proceeding in carrying out this inquiry and finds that there is no evidentiary basis to conclude that the earnings achieved by the ATCO Utilities above the Commission's generically approved ROE were the result of a problem with the design or operation of the ATCO Utilities' 2013-2017 PBR plans.

Dated on February 27, 2019.

Alberta Utilities Commission

(original signed by)

Henry van Egteren
Panel Chair

(original signed by)

Mark Kolesar
Chair

(original signed by)

Neil Jamieson
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Electric Ltd. Bennett Jones LLP
ATCO Gas North Bennett Jones LLP
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP
Consumers' Coalition of Alberta (CCA)
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors

Alberta Utilities Commission Commission panel H. van Egteren, Panel Chair M. Kolesar, Chair N. Jamieson, Commission Member Commission staff B. McNulty (Commission counsel) A. Corsi P. Howard E. Deryabina A. Spurrell

Decision **2011-450**

AUC
Alberta Utilities Commission

ATCO Gas
(A Division of ATCO Gas and Pipelines Ltd.)

2011-2012 General Rate Application Phase I

December 5, 2011

The Alberta Utilities Commission
Decision 2011-450: ATCO Gas (a Division of ATCO Gas and Pipelines Ltd.)
2011-2012 General Rate Application Phase I
Application No. 1606822
Proceeding ID No. 969

December 5, 2011

Published by
The Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

Telephone: 403-592-8845
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Web site: www.auc.ab.ca

Contents

List of tables

ATCO Gas **Decision 2011-450**
2010-2012 General Rate Application **Application No. 1606822**
Phase I **Proceeding ID No. 969**

1 Introduction

1. ATCO Gas (AG or the company), a division of ATCO Gas and Pipelines Ltd, (AGPL), filed a 2011-2012 General Rate Application (GRA) Phase I (the application) with the Alberta Utilities Commission (the AUC or the Commission) on December 3, 2010. AG requested approval of its forecast revenue requirements for the 2011 and 2012 test years (the test years) that would form the basis for rates to be paid by customers receiving gas distribution services. AG's most recent GRA was for the 2008 and 2009 test years and was approved in Decision 2008-113.[1]

2. AG indicated its expectation that the approved 2012 revenue requirement would form the basis for the "going in" rates for performance-based regulation (PBR) effective January 1, 2013.

3. AG provides regulated natural gas distribution services through AG North (AGN) and AG South (AGS) in two service areas in Alberta. AGN serves customers living in, and north of, the City of Red Deer; AGS serves customers living south of the City of Red Deer. Separate rates, based on a combined revenue requirement are approved by the Commission for each of AGN and AGS. Issues with respect to rate design and revenue requirement allocation between AGN and AGS will be determined in a GRA Phase II proceeding.

4. In the application, AG summarized its forecast revenue requirements for the test years as follows:

Table 1. Base rate revenue requirement[2]

	2011	2012
	$000s	
Base rate revenue requirement	621,904	658,061
Less revenue on existing rates	560,436	571,285
Revenue shortfall	61,468	86,776
Less 2010 approved pension recovery	27,500	27,500
Less 2011 shortfall		33,968
Remaining shortfall	33,968	25,308

[1] Decision 2008-113: ATCO Gas, 2008-2009 General Rate Application Phase I, Application No. 1553052, Proceeding ID. 11, November 13, 2008.

[2] Exhibit 3, Table 1, page 1.0-9.

5. During the course of the proceeding AG submitted updates and corrections to its initial forecasts. The following is a summary of AG's revisions to its forecast revenue requirements for the test years.[3]

Table 2. Revised forecast revenue requirement

	2011	2012
	$000s	
Base rate revenue requirement	603,244	641,745
Less revenue on existing rates	561,426	571,952
Revenue Shortfall	41,818	69,793
Revenue shortfall as initially filed (Table 1 above)	61,468	86,776
Financing rates update	(398)	(1,002)
Lower rent revenue	110	433
Pension contribution adjustment	(11)	(20)
Customer information system (CIS) royalties - Income Taxes	37	33
Rate base and depreciation adjustments	(192)	(199)
Corrections to meter costs capitalized	0	163
Operating and maintenance (O&M) and capital update	(2,132)	(619)
Revenue update	(1,100)	(1,100)
Depreciation update	(793)	(884)
Variable pay plan (VPP) update	(531)	(531)
Capitalized pension - removal of immediate collection[4]	(14,640)	(13,257)
Updated revenue shortfall	41,818	69,793

6. On December 7, 2010, the Commission issued a notice of application, which was distributed electronically to parties on the Commission's gas and pipelines mailing list and posted on the Commission's website. An alert of notice of application was published in four major Alberta newspapers on December 13, 2010. Any party who wanted to intervene in the proceeding was required to submit a statement of intent to participate (SIP) to the Commission by December 29, 2010. Parties that filed SIPs are listed in Appendix 1.

7. On January 11, 2011, the Commission established a schedule for the proceeding. Subsequent to receipt of submissions from parties participating in the proceeding and in keeping with AUC Bulletin 2010-16,[5] on January 21, 2011 the Commission revised the process schedule.[6] On March 25, 2011, the Commission suspended the process schedule pending a ruling on a motion by The City of Calgary (Calgary)[7] to provide full and adequate responses to a number of information requests. The Commission issued its initial ruling[8] and re-started the process on April 1, 2011, with the schedule revised for submissions of intervener evidence and information requests.

8. An oral public hearing was convened on May 24, 2011, in Edmonton before Commission Member Moin A. Yahya (Panel Chair), Bill Lyttle and Kay Holgate. The hearing adjourned on June 2, 2011. Written argument was filed by parties on June 27, 2011.

[3] Exhibit 174.02.
[4] Transcript, Volume 4, page 614.
[5] Bulletin 2010-16, Performance Standards for Processing Rate-Related Applications, April 26, 2010.
[6] Exhibit 63.01.
[7] Exhibit 99.01.
[8] Exhibit 102.01.

9. On July 14, 2011, the Commission received a request from the Office of the Utilities Consumer Advocate (UCA) (UCA request) to suspend reply argument which was due on July 18, 2011. The UCA referenced a conditional agreement announced by the ATCO Group on July 7, 2011, for Canadian Utilities Limited to acquire Western Australia Gas Networks (WAGN). Canadian Utilities Limited is the holding company for ATCO Gas, ATCO Pipelines and ATCO Electric Ltd. By letter dated July 15, 2011, the Commission suspended the date for filing reply argument in order to seek comment from parties on the UCA request.

10. On August 12, 2011, the Commission ruled on this issue and reply argument was rescheduled for August 18, 2011. The Commission considers that the record closed for this proceeding on August 18, 2011.

1.1 Legislative authority

11. The application is governed by the *Gas Utilities Act*, RSA 2000 c. G-5, the *Public Utilities Act*, RSA 2000 c. P-45, and the *Alberta Utilities Commission Act*, SA 2007 c. A-37.2 and the respective regulations promulgated thereunder. The Commission has the authority to set just and reasonable rates, under subsection 36(a) of the *Gas Utilities Act* and fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of an owner of a gas utility, under subsection 36(b) of the *Gas Utilities Act*. In fixing just and reasonable rates, the Commission shall determine a rate base for the property of the owner of a gas utility used or required to be used to provide service to the public within Alberta and, on determining a rate base, fix a fair return on the rate base, in accordance with Section 37 of the *Gas Utilities Act*. Also, Section 40 of the *Gas Utilities Act* provides that, in fixing just and reasonable rates, the Commission may consider certain revenues and costs of an owner of a gas utility.

12. Section 44(3) of the *Gas Utilities Act* states that the burden of proof lies with the owner of a gas utility to show that increases, changes or alterations to rates are just and reasonable.

13. The *Public Utilities Act* has similar provisions to the aforementioned provisions contained in the *Gas Utilities Act*.[9]

14. The *Alberta Utilities Commission Act* grants the Commission general powers to deal with applications, and related proceedings, brought before it.

15. In Decision 2008-113[10] the Commission described the legislative framework regarding rate setting for utilities as follows:

> The legislative intent is straightforward. The utility company must apply to the Commission for any changes in rates and demonstrate to the Commission that the rates it proposes are just and reasonable and not unjustly discriminatory. This type of regulatory scheme is not the norm in Canada's market economy. It is adopted by legislators where essential or important services, such as the natural gas distribution services in this case, are provided to customers by monopoly suppliers. In normal competitive markets, it is the operation of competitive market forces that establishes and maintains a balance between competing companies and the customers they seek to serve. Where, as here,

[9] See sections 89, 90, 91 and 103(3) of the *Public Utilities Act.*

[10] Decision 2008-113: ATCO Gas, 2008-2009 General Rate Application Phase I, Application No. 1553052, Proceeding ID. 11, November 13, 2008, page 2.

> there is no competitive market, the legislature has stepped in to provide a regulatory scheme designed to establish and maintain a balance between monopoly companies and their customers. It has done so by establishing the Commission as an expert independent quasi-judicial tribunal whose duty it is to establish a balance between customers and monopoly companies that it is assumed by legislators would not be possible but for regulation. In order to achieve the balance envisioned by the legislators, the Commission must consider both the interests of the regulated companies and their customers and make its decisions in accordance with its governing legislation while conducting itself in accordance with the principles of natural justice and procedural fairness.

16. In reaching the determinations contained within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 Background

17. AG last filed a GRA Phase I for its 2008 and 2009 test years, which led to Decision 2008-113.[11] The first compliance filing led to Decision 2009-109.[12] A second compliance filing led to Decision 2010-025, where the revenue requirements for 2008 and 2009 were approved subject to certain placeholders and deferral accounts.[13]

18. AG did not submit a general rate application to determine a revenue requirement for 2010. AG's rates for 2008-2009 were the subject of a negotiated settlement agreement, which the Commission approved in Decision 2010-291.[14] In that decision the Commission noted that the 2009 final revenue requirement would serve as the basis for 2010 rates which were to be adjusted as the result of filing an updated cost of service study. Rates for January 1, 2008 to September 30, 2010 were approved as final in Decision 2010-466[15] with the exception of Carbon Riders G, H and I, Transmission Rider T and Rider P which remained in effect on an interim basis. The 2008 to 2010 rates were also subject to deferral accounts that would finalize all outstanding placeholders and the removal of the Carbon assets from utility service. The 2011 interim rates effective January 1, 2011 were approved for AG in Decision 2010-573.[16]

19. The application deals with the test years 2011 and 2012. The application identifies certain revenue requirement placeholders that are the subject of other proceedings. AG has requested approval of the volumes for customer care and billing (CC&B) services provided by

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11 Decision 2008-113: ATCO Gas, 2008-2009 General Rate Application Phase I, Application No. 1553052, Proceeding ID. 11, November 13, 2008.

12 Decision 2009-109: ATCO Gas, 2008-2009 General Rate Application Phase I Compliance Filing, Application No. 1603068, Proceeding ID. 154, July 28, 2009.

13 Decision 2010-025: ATCO Gas, 2008-2009 General Rate Application Phase I Second Compliance Filing, Application No. 1605412, Proceeding ID. 294, January 13, 2010.

14 Decision 2010-291: ATCO Gas, 2008-2009 General Rate Application – Phase II, Negotiated Settlement, Application No. 1604944, Proceeding ID. 184, June 25, 2010.

15 Decision 2010-466: ATCO Gas, 2008, 2009 and 2010 Final Rates, Application No. 1606375, Proceeding ID. 731, September 29, 2010.

16 Decision 2010-573: ATCO Gas, 2011 Interim Rates, Application No. 1606548, Proceeding ID. 832, December 14, 2010.

ATCO I-Tek Business Services Ltd. (ITBS) and for information technology (IT) services, and specified expenses, provided by ATCO I-Tek Inc[17] (I-Tek). The pricing of these services for 2010 and for the 2011 and 2012 test years will be determined in the ATCO Utilities' 2010 Evergreen proceeding.[18] Accordingly, placeholders were used in the application for the portion of revenue requirement related to these services.

20. In the pension common matters decision, Commission Direction 6 directed the ATCO Utilities to prepare a 2011 Pension Common Matters application by December 15, 2010 (Proceeding ID No. 999). Therefore, the pension funding in the 2011-2012 GRA is considered to be a placeholder.[19]

21. In Decision 2009-216,[20] the 2009 generic cost of capital proceeding, the Commission established a generic return on equity (ROE) for 2009 and 2010 of 9.0 per cent. The Commission also determined the ROE for 2011 would be 9.0 per cent on an interim basis.[21]

22. The Commission determined in its ruling dated August 12, 2011 that the impact associated with conditional agreement announced by the ATCO Group on July 7, 2011 for Canadian Utilities Limited to acquire Western Australia Gas Networks (WAGN) could potentially impact the allocation of corporate costs to AG, and established a placeholder in respect of the 2012 allocation of corporate costs to AG.

2.1 Procedural motions

23. During the course of this proceeding a number of motions were filed. The motions are briefly described below. The details of the motions are outlined in the Commission's rulings which are attached as Appendix 4.

2.1.1 Calgary motion on AG information request responses

24. On March 25, 2011, Calgary filed a motion requesting the Commission to compel AG to provide full and adequate responses to a number of information requests.[22]

25. On March 29, 2011 AG provided additional information on the impugned information requests.[23]

26. On April 1, 2011 the Commission issued its initial ruling on this motion.[24] Having reviewed the information responses provided by AG on March 29, 2011 the Commission found that AG had provided full and adequate responses to certain information requests but that AG had not provided a sufficient response to CAL-AG-7(c). ATCO Gas was directed to provide the

17 Exhibit 3, pages 4.2-32 and 4.2-36. ATCO I-Tek Business Services Ltd. and ATCO I-Tek Inc. are non-regulated affiliates of AG, which provide CC&B and IT services, respectively, to AG.
18 ATCO Utilities 2010 Evergreen Proceeding, Application No. 1605338, Proceeding ID No. 240, (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd. (the ATCO Utilities), Application with Respect to CC&B and IT Services Beyond 2009).
19 Exhibit 3, AG application, 4.2-45, paragraph 124.
20 Decision 2009-216: 2009 Generic Cost of Capital, Application No. 1578571, Proceeding ID. 85, November 12, 2009.
21 Decision 2009-216, paragraph 75.
22 Exhibit 98.02.
23 Exhibit 100.01, page 1.
24 Exhibit 102.01.

following information for all assets listed in Exhibit 97.02 with an assessed value in excess of $250,000:

- the year of acquisition
- the original cost
- the operational purpose of the facility

27. AG responded on April 4, 2011,[25] that it could not fulfill the Commission's direction within the timeframe of the schedule. AG further stated that providing the requested information on the 500 pieces of property would take an average of two hours per property and could not be provided in five days time. AG proposed changing the dollar threshold to $1 million dollars for the requested information and stated that this would result in a more achievable figure of seven buildings and eight land items.

28. Calgary responded on April 6, 2011, stating that the Commission had struck a proper balance in its direction to AG and that the information should be provided without delay.[26]

29. By letter dated April 6, 2011, the Commission indicated that it was prepared to consider these latter submissions before issuing its final ruling on this matter. AG was directed to provide the requested information on the seven buildings and eight land items no later than April 11, 2011. Further, in the interest of fully understanding the parties' positions, the Commission permitted an expedited response from AG and a final reply by Calgary before the Commission issued its final ruling.

30. AG responded by letter dated April 7, 2011, and Calgary replied by letter dated April 8, 2010.

31. On April 8, 2011 the Commission provided its final ruling on the Calgary motion.[27] AG was directed to respond by April 15, 2011 with the year of acquisition, the original cost, and the operational purpose of the facility for each of the properties with an assessed value greater than $250,000, as listed in the "ATCO Gas Site Summary" Tab 3, Exhibit 97.02.[28]

32. AG provided the additional information on April 15, 2011.

2.1.2 Calgary motion on AG's application update

33. On April 21, 2011 AG filed with the Commission an application update (application update) rectifying omissions, providing corrections and incorporating new information. This information included a business case for the implementation of a talent management system (TMS business case).[29]

34. By letter dated April 27, 2011, Calgary requested that the Commission reject the application update filing, or delay the start of the hearing to a later date in 2011 to permit full, fair and complete testing of the application update.[30] Calgary submitted that Section 27 of

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25 Exhibit 104.01.
26 Exhibit 105.01.
27 Exhibit 113. 01.
28 Ibid. A detailed table of each property subject to the Commission's final ruling was provided in this exhibit.
29 Exhibit 118.01.
30 Exhibit 130.01.

AUC Rule 001: *Rules of Practice* (Rule 001) requires a party to seek leave from the Commission prior to filing a document after the time set out for the filing of that document. AG did not seek leave for its late filing nor did it receive the Commission's leave. Calgary also stated that its ability to retain an expert to test the materials and the applied for amounts with respect to the TMS business case was compromised as the oral hearing was scheduled to begin on May 24, 2011. Calgary submitted that there was no reason why AG could not have filed the TMS business case with its GRA application in December 2010.

35. The Commission ruled on Calgary's letter on April 29, 2011,[31] finding Section 27 of Rule 001 is not intended to apply to an omission and corrections update filing of the nature under review unless the Commission has previously established a timeline for such a filing. The Commission continued:

> …that updates are necessary to ensure that the Commission and interested parties have the most up to date and best information available to assess the application and complete the record of a proceeding. Although updated information would usually take the form of omissions and corrections, there is no reason why the applicant can not also elect to amend its application to seek approval of new cost items provided it could not have reasonably included that information with its original application. The ability to file updated information must be balanced with a requirement to provide parties with sufficient opportunity to review and test the new evidence.[32]

36. The Commission accepted the application update including the TMS business case but indicated that "it is incumbent on ATCO in future filings of this nature to clearly explain why evidence relating to new expenditures could not have been filed with the original application."[33] The Commission also permitted information requests on the application update and the filing of supplemental evidence by interveners.

2.1.3 AG motion to strike portions of Calgary evidence

37. During the course of the oral hearing, on May 29, 2011, ATCO filed a motion[34] requesting that the Commission strike portions of Calgary's addendum to its evidence filed on May 27, 2011.[35] Specifically, the motion requested that portions of the Calgary addendum to its evidence relating to the Oracle Human Resource Management System (HRX) be struck because they were outside of the permitted scope of the Commission's ruling dated April 29, 2011.[36] AG stated that the April 21, 2011 update was limited to the TMS business case and that the Calgary evidence specifically addressed the HRX system, which had been included in the original application and had been previously addressed in Calgary's evidence.

38. In its May 31, 2011 ruling,[37] the Commission found that an objective reading of the April 29, 2011 ruling confined the scope of Calgary's supplemental evidence to the TMS system. The Commission granted AG's motion to strike portions of Calgary's addendum to its evidence.

31 Exhibit 135.01.
32 Commission ruling dated April 29, 2011, Exhibit 135.01, paragraph 15.
33 Commission ruling dated April 29, 2011, Exhibit 135.01, paragraph 17.
34 Exhibit 176.02.
35 Calgary's addendum to its evidence related to AG's application update filed on April 21, 2011.
36 Ibid., paragraph 29.
37 Exhibit 187.01.

39. On June 1, 2011 Calgary brought a motion requesting that the Commission review and vary its ruling of May 31, 2011, and allow the dis-allowed evidence back onto the record of this proceeding. Calgary considered that the Commission, in the course of providing its ruling, had failed to consider the entirety of the record of the proceeding.[38] Calgary argued that by the Commission failing to consider the totality of the record, there was an error in fact or law.

40. The Commission requested oral comments from other parties present at the hearing and heard from AG, which opposed the motion, and the Consumers' Coalition of Alberta (CCA), which supported the motion. Calgary was provided an opportunity to respond. In an oral ruling the Commission denied the motion.[39] The Commission noted that "interlocutory R&Vs are generally only to be done in extreme circumstances."[40] Nevertheless the Commission reviewed the Calgary submissions and the submissions of the parties and concluded that an objective reading of its May 31, 2011 ruling would confine the evidence to that which had not been dis-allowed.

2.1.4 UCA motion to suspend proceeding in light of the Australia acquisition

41. On July 14, 2011, the Commission received a request from the UCA to suspend reply argument which was due on July 18, 2011. The UCA referenced a conditional agreement announced by the ATCO Group on July 7, 2011 for Canadian Utilities Limited to acquire Western Australia Gas Networks (WAGN).

42. The UCA suggested that should the acquisition close as anticipated in the third quarter of 2011, that there could be a material impact on the allocation of Head Office costs to AG at least in 2012. The UCA stated:

> Accordingly, the new acquisition appears to be similar to ATCO Gas. If this is true, and the Head Office costs are allocated to the new entity in the same manner, the estimated result would be a reduction in the allocation of Head Office costs to ATCO Gas by $1.4 million per year.[41]

43. The UCA expressed concern about customers paying for business development costs included within the head office function and any costs of AG staff seconded to business development activities. The UCA also suggested that there was the potential for increased vacancies or reduced full-time employees (FTEs) from the current AG forecast. The UCA argued that given the magnitude of the transaction, an expectation that such impacts are real and material is reasonable.

44. The UCA requested that the Commission create a process schedule including information requests, responses and, potentially, intervener evidence and an oral hearing, to explore the impact to the allocation of head office and business development costs as a result of the conditional agreement to acquire WAGN. In the alternative, the UCA requested the Commission to commence separate processes that could lead to the creation of placeholders for costs related to the acquisition and to examine the impact of the acquisition.

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38 Transcript, Volume 7, page 1388, lines 1-9.
39 Transcript, Volume 7, page 1416, lines 2-23.
40 Ibid., lines 8-9.
41 UCA request dated July 14, 2011, page 2.

45. In its August 12, 2011 ruling on the UCA motion the Commission recognized that AG could not have disclosed the conditional agreement to acquire WAGN prior to the public announcement on July 7, 2011. The Commission considered that material events relevant to the proceeding which occur prior to the closing of the record, and in some cases prior to the release of a decision, which were not known to all parties during the course of the evidentiary portion of the proceeding may provide a sufficient basis to re-open the evidentiary portion of the proceeding. In Decision 2008-113 the Commission stated the following with respect to receiving the most up-to-date information during a proceeding:

> Given the reality that the Commission expects to receive the most up-to-date information during a proceeding and that AG and other utilities bring evidence of increasing costs during a proceeding as it becomes available, the Commission agrees with CG's submission that prospectivity effectively starts from the close of the proceeding, rather than at the time of the application.[42]

46. The Commission agreed with the UCA that the impact of the WAGN acquisition is a material event that could significantly impact the allocation of head-office costs to AG as well as the other ATCO utilities.

47. The Commission considered that the next corporate cost allocation methodology proceeding is the proceeding best suited to consider the impacts of the WAGN acquisition. In the circumstances, however, the Commission considered that the September 30, 2012 date for the filing of the next ATCO Utilities application should be advanced to April 2, 2012. At that time the impacts of the WAGN transaction on corporate costs and the allocation of those costs would be better understood and 2011 audited financial information would be available.

48. The ATCO Utilities should include within the application a request to set the corporate allocation methodology for 2012 for all ATCO utilities that have not otherwise had their revenue requirement with respect to 2012 corporate allocations previously finalized. Following the Commission's decision on the ATCO Utilities application, AG would apply to the Commission to finalize the 2012 corporate allocation placeholder to be included in the final 2012 revenue requirement.

49. With respect to the UCA's concerns about business development costs included within the head office function, costs of AG staff seconded to business development activities and the potential for increased vacancies or reduced FTEs from the current AG forecast, the Commission stated that it was not prepared to enter into further process.

3 Role of Commission counsel

50. In addition to the various procedural motions filed during the proceeding referred to in the previous section of this decision, counsel for Calgary made oral submissions to the Commission during the hearing on May 31, 2011 with respect to the role of Commission counsel in questioning witnesses. Upon review of the prior day's transcript, Calgary expressed concerns

[42] Decision 2008-113, page 16.

with the nature and content of certain questions put to AG witnesses. Calgary expressed further concerns with the role of Commission counsel in questioning witnesses in general.[43]

51. In argument dated June 27, 2011, Calgary expanded on its concerns with respect to:

- the tone and content of certain statements made by Commission counsel in its cross examination of the ATCO witness panel;
- the role that counsel played in the Commission's decision to grant the ATCO motion to strike portions of the Calgary Evidence on Human Capital Management Systems; and
- the appropriateness of Commission counsel in developing the evidentiary record of the Proceeding in light of the *Dunsmuir*[44] decision and the fact the proceedings are highly contested.[45]

52. Calgary submitted that it was inappropriate for Commission counsel to provide the Commission with advice on an AG motion to strike a portion of the Calgary evidence when Commission counsel was at the same time conducting oral examination of AG witnesses. Calgary submitted that these activities may be in conflict with each other. Calgary submitted that academic commentary[46] had suggested that tribunal counsel should not provide "advice to a tribunal with differing functions and powers (for example functions containing investigation/regulatory powers and adjudicative powers), and in such circumstances the dual role of counsel raises a reasonable apprehension of bias."[47] Calgary submitted that oral examination by tribunal counsel is akin to an investigative role, in contrast to a role of giving legal advice on adjudicative matters such as ruling on a motion.

53. Calgary submitted that after the *Dunsmuir* decision:

> …one of the few limitations on the Commission's powers, apart from jurisdictional limitations, is the completeness of the evidentiary record on which the tribunal makes its decisions. In this light, it is Calgary's respectful submission that the Commission must be careful not to fashion the record of proceedings before it through inappropriate questions posed by Commission counsel. To do otherwise will raise questions as to whether counsel is engaging in roles which are "in fact and in appearance, consistent with principles of fairness and natural justice."[48] (footnote omitted)

54. Calgary stated that it was not raising a claim of tribunal bias.[49] However Calgary submitted that certain testimony given in response to Commission counsel's questioning should be given little or no weight. Calgary indicated that Commission counsel should limit their questions when examining parties in utility proceedings, to the following general matters:

- clarification of the party's or the witnesses' evidence

43 Transcript, Volume 6, pages 1072- 1076, pages 1082-1085.
44 *Dunsmuir* v. *New Brunswick,* [2008] S.C.J. No.9, 2008 SCC.
45 Calgary argument, page 6.
46 *Tribunal Counsel*, Graham Steele, 11 Can. J. Admin. L. & Prac. 57.
47 Ibid., page 74.
48 Ibid., page 14.
49 Calgary argument, page 8.

- acknowledgement by the witness of relevant factual matters, provided that the questions are not for the purposes of assessing the credibility of the witness or the party
- Counsel should also refrain from asking or posing questions that could be used by a party or the Commission to assess the credibility or weight to be given to the evidence; in contested proceedings, this role should be left to opposing parties to do so. Calgary cites the case of *Omineca Enterprises Ltd. v. British Columbia (Minister of Forests)* (1992), 72 B.C.L.R. (2d) 247 (B.C.S.C.) (the Omineca Decision) in support of this position.
- Lastly, counsel should refrain from posing leading or open ended questions to witnesses on their evidence.[50]

55. Calgary recommended the Commission undertake a consultative and comprehensive process, involving all stakeholders, to review the role that Commission counsel should play in proceedings before the Commission.[51]

56. In reply argument, the CCA stated that it "cannot oppose the conclusions and recommendations of Calgary."[52] The CCA noted that the detailed role of Commission counsel is not specified in any document but Section 45 of Rule 001 of the AUC *Rules of Practice* offers further guidance on the role of Commission counsel. Section 45 extends participation of Commission counsel to cross-examination but it is dependant on the circumstances as to when it is necessary or appropriate. The CCA submitted:

> that Commission counsel should only cross examine a witness where in the "opinion" of the Commission it is "appropriate" or "necessary" as the circumstances warrant the same.[53]

57. Neither the UCA nor C3 took a position on the matters raised by Calgary.

58. AG commented in its August 8, 2011 reply argument:

> First, ATCO Gas notes that Commission counsel's questioning is designed to explore the positions being advanced by parties, their knowledge base and the reasons supporting such positions. Stated differently, Commission counsel's role is to complete the record in order to assist the Commission Panel Members in the disposition of the application.[54]

59. AG submitted "that there is no factual basis to suggest that there was a lack of "neutrality" in relation to the Commission counsel's statements and lines of examination in the subject proceeding."[55] Counsel for AG noted at the hearing:

> But with respect, Commission counsel has, in my experience, come at this job of completing the record in a conscientious and thorough way. I haven't always liked it. I have objected when I thought it went too far.[56]

50 Ibid., page 16.
51 Ibid., pages 16 and 17.
52 CCA reply argument, page 21.
53 Ibid., page 20.
54 AG reply argument, page 134 and 135.
55 Ibid., page 137.
56 Transcript, Volume 6, page 1101, lines 1-11.

60. With respect to Calgary's submissions that Commission counsel should not be asking questions that might allow a witness to bolster earlier testimony to opposing counsel, AG submitted:

> Indeed, Commissioners themselves would be vulnerable to the same criticisms about lack of neutrality or bias if they asked questions after all cross-examination was complete which allow witnesses to shore-up their earlier testimony. The objective is to understand clearly the positions of all parties. The key factor is that the same approach is taken in a fair and balanced manner with all parties. That was done in this case.[57]

61. AG stated that it did not perceive any basis for an allegation of unfairness. AG submitted that in this proceeding Commission counsel struck a balance with respect to its questions of the AG panels and of the intervener panels.[58] Furthermore, AG submitted that it "cannot be said that the Commission counsel's examination created an unfair advantage to any one particular panel through lines of questions that allowed for an 'opportunity to rehabilitate'."[59]

62. AG stated that there is no legal basis to expunge or discount the weight of the subject evidence from the record at the reply argument stage of the proceeding. Further, Calgary's request to expunge or discount the weight of evidence on the basis of lack of neutrality is in effect a claim of bias and should have been raised in a timely manner.[60] Counsel for Calgary did not object at the time the cross-examination took place.[61]

63. AG did not agree with Calgary's recommendation for a generic proceeding to review Commission counsel's role in AUC proceedings.[62]

Commission findings

64. The Commission recently commented on its role and the nature of proceedings before it in Decision 2011-436.[63] In that decision the Commission also commented on its duty to use its' expertise to test an application, including testing through questioning by Commission members and Commission counsel to ensure that it has the information necessary to determine the public interest. In Decision 2011-436 the Commission stated:

> **2.1 The Commission's role**
>
> 73. The Commission is an independent, quasi-judicial agency of the province of Alberta. As a quasi-judicial body, the Commission is similar in many ways to a court when it holds hearings and makes decisions on applications. Like a court, the Commission bases its decision on the evidence before it and allows interested parties to cross-examine the applicants' witnesses to test that evidence. Other similarities with judicial process include the power to compel witnesses to attend its hearings, and the obligation to provide a written decision with reasons. However, the Commission is not a

57 Ibid., page 135.
58 Ibid., page 137.
59 Ibid., page 137.
60 AG reply argument, pages 137 and 138.
61 Ibid., page 139.
62 Ibid., page 140.
63 Decision 2011-436: AltaLink Management Ltd. and EPCOR Distribution & Transmission Inc., Heartland Transmission Project, Application No.1606609, Proceeding ID No. 457, November 1, 2011.

> court. It has no inherent powers. Its powers are set out in legislation. It is sometimes referred to as an expert tribunal because it deals frequently with specialized subject matter required to balance the public interest considerations it must address. Unlike a court proceeding, the Commission's proceedings are not matters between two or more competing parties to determine who wins and loses. In other words, the Commission's proceedings are not in the nature of a *lis inter partes* (a dispute between parties).
>
> 74. The Commission's proceedings are conducted to determine an outcome that meets the public interest mandate set out in the legislation. In the vast majority of its proceedings, the Commission is not limited to considering only the evidence presented to it by the applicant and by parties that may be directly and adversely affected. Indeed, it is the Commission's role to test the application to determine whether approval of that application would be in the public interest….
>
> 75. In performing its duty to test the application, the Commission not only actively tests the evidence by asking questions of the applicant and the parties but also by asking questions of any expert witnesses called by the applicant or the parties. In some cases, the Commission calls independent witnesses to address issues that the Commission considers important and wants to make sure are addressed in the record of the proceeding.…
>
> 76. The Commission's objective is to determine whether the application as filed is in the public interest and, if not, what changes could be ordered by the Commission to most effectively balance the various public interest factors it must consider using its own expertise to consider the evidence it has before it….
>
> 95. In summary, it is the Commission's duty to use its expertise to test the application placed before it to ensure that it has the information necessary to make a public interest determination and that all parties to the proceeding have the same information as the Commission before them so that they can explain how their private interests can best be balanced in the public interest determination. The Commission asks questions of the applicant and parties to the proceeding, including oral examination by its counsel and the Commission members and may call witnesses that it considers necessary for the proceeding so that it has the information necessary to determine the public interest.[64]

65. The Commission directly considered the role of counsel in questioning at an oral hearing in response to submissions made by Calgary in Decision 2011-076.[65] In that decision the Commission stated:

> 63. The Commission disagrees with the Calgary suggestion that the fact that parties were represented by counsel somehow changes the nature of the questions that may be appropriate to be asked by Commission counsel. Taken to an extreme, the Calgary position would prohibit Commission information requests, Commission counsel questions and Commission panel questions other than on procedural matters where parties adverse in interest are represented by counsel. The Commission has a public interest mandate and the statutory obligation to fix just and reasonable rates[22] for the utilities under its jurisdiction. In fulfilling this obligation, the Commission, acting through its staff and the assigned panel, must be able to probe into the evidence filed before it in

64 Decision 2011-436, page 14, paragraphs 73-76 and page 18, paragraph 95.

65 Decision 2011-076: The City of Calgary, Decision on Preliminary Question, Review and Variance of Decision 2010-511 ATCO Utilities 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up Cost Awards, Application No. 1606905, Proceeding ID No. 1029, March 2, 2011.

> order for the Commission panel to determine the merits and the weight to accord such evidence, subject always to the rules of procedural fairness. The Commission can not simply rely on counsel for the parties to act in the public interest or to test the evidence sufficiently to satisfy the Commission's statutory obligations when they do not bear the same statutory obligations, have completely different objectives in participating in the proceeding and where each has a stake in the outcome. One commentator has remarked on this issue as follows:
>
>> The work of most tribunals cannot be adequately accomplished by means of an adversarial system of evidence-gathering.
>>
>> Most tribunals have a "public interest" element that is not adequately covered off by the material put forward by the participants. Our civil justice system is based on an assumption that issue identification, evidence-gathering and argument can be left in the safekeeping of the parties. Our criminal justice system is based on a similar assumption, with the parties being the Crown and the defense. Administrative justice is different. There is the "public interest."
>>
>> To cover off the "public interest" angle, tribunals have to become inquisitorial (some more than others). And inquisitorial tribunals need more legal advice tha[n] more passive decision-makers.
>>
>> Another aspect of this same point is that an adversarial system relies for its fact-finding on having two more or less equal and competent counsel. The tribunal system can rely even less than the civil or criminal systems on the participants having counsel.[23] [66]
>
> [22] Section 36 *Gas Utilities Act* and Section 121(2) *Electric Utilities Act*.
> [23] G. Steele, "Tribunal Counsel" (1998) 11 Can. J. Admin. L. Prac. 57 at page 62.

66. The Commission finds that Calgary's submissions in this proceeding regarding the role of Commission counsel in oral hearings are similar to those raised by Calgary and addressed in Decision 2011-076, including Calgary's reliance on the Omineca Decision. The Commission considers that Calgary's submissions with respect to the role of Commission counsel at oral hearings were satisfactorily addressed in Decision 2011-076 and need not be further referenced here.

67. As noted in Decision 2011-436 and Decision 2011-076, the Commission is required by statute to ensure that the public interest is served. In a general rate application, the public interest is served by determining a revenue requirement for the utility that is both fair to the utility and to its customers, resulting in just and reasonable rates for the test period. The determination of just and reasonable rates is not a question of siding with one party or another on each cost or revenue item and then tallying up the pluses and minuses. As noted in Decision 2011-436, a proceeding before the Commission is not a *lis inter partes.* In order to carry out its public interest obligation to determine just and reasonable rates, the Commission must be able to fully test, clarify and probe the evidence submitted by the parties. This includes confirming the Commission's understanding of a party's position and its implications, testing the credibility of witnesses and clarifying earlier testimony where necessary in the public interest. The Commission carries out these functions through various mechanisms including issuing information requests, giving

[66] Ibid., pages 13 and 14.

directions to the parties on materials to be filed, and through questioning by Commission counsel and Commission members at an oral hearing. It is the obligation of the Commission to test an application before it to ascertain the public interest, regardless of whether or not other parties have intervened in the application. On occasion, the Commission will also engage an independent expert to provide additional evidence on a particular matter. It is only after a thorough vetting of the evidence that the Commission will be in a position to assess the merits and the weight to accord the evidence and to make a determination in the public interest.

68. Section 68 of the *Alberta Utilities Commission Act* authorizes the Commission to employ persons necessary for the transaction of its business and to engage experts and persons having "special technical or other knowledge" to assist the Commission in carrying out its powers, duties and functions. The Commission therefore, in addition to reliance upon the specialized expertise of its members, may retain the professional skills necessary to assist it in carrying out its public interest responsibilities. If the proceedings before the Commission were intended by the legislature to be conducted on a *lis inter partes* basis, like those before a court, it would not be necessary for the Commission to have a specialized expertise in utility matters nor would it be necessary for the Legislature to provide the Commission with the express power to retain specialized personnel. The Commission would rely solely on the parties to complete the record upon which it would make a decision.

69. Calgary also raised the issue of a potential conflict between Commission counsel's responsibilities to conduct questioning of witness panels as part of the Commission's investigation/regulatory function and the responsibility to provide advice to the Commission on adjudicative matters such as ruling on a motion.

70. The Commission considers that a separation of these functions may be required where a tribunal is charged with both the responsibility to investigate a party who has allegedly committed a regulatory offense and a prosecutorial responsibility which could result in an adjudication which imposes financial penalties or which may impact the personal rights, privileges or liberties of the party under investigation. The article by Graham Steele referred to by the Commission in Decision 2011-076 and also referenced by Calgary,[67] refers to examples of tribunals such as those which oversee gaming, licensing and professional organizations, where an overlap of investigative/regulatory and adjudicative functions may give rise to a reasonable apprehension of bias.[68] The Commission has recognized that special procedural fairness and natural justice requirements may be required in such situations. For example, in Bulletin 2010-17[69] dated April 23, 2010, the Commission outlined the process for the adjudication by the Commission of proceedings brought before it for alleged contraventions of various laws by the Market Surveillance Administrator (MSA). The bulletin recognizes the separation of the investigation function carried out by the MSA and adjudication function carried out by the Commission. As noted in paragraph 65 of the bulletin:

> However, the nature of a rate proceeding or a facility proceeding is quite different from that of an administrative penalty proceeding.

[67] Calgary argument, page 7.
[68] G. Steele, "Tribunal Counsel" (1998) 11 Can. J. Admin. L. Prac. 57 at page 74.
[69] Bulletin 2010-17, Consultation on Market Surveillance Administrator (MSA) Proceedings Before the Alberta Utilities Commission (AUC or Commission), April 23, 2010.

71. In a rate regulation proceeding, such as the current proceeding, no such separation of the investigatory and adjudicative function is required. While the Commission must investigate the evidence in performing its statutory obligations to fix just and reasonable rates the Commission is not acting in a prosecutorial capacity. The Commission must be able to rely on the various tools available to it, including questioning by Commission counsel, in order to complete the record from a public interest perspective, prior to making a determination of just and reasonable rates. The Commission is also entitled to rely on the expertise of Commission counsel with respect to legal and procedural matters that may arise during the course of a rate proceeding.

72. With respect to the nature, fairness, and neutrality of the questions asked by Commission counsel in the present proceeding, the Commission has reviewed the transcript and the submissions of the parties. The Commission finds the questioning conducted by each of the Commission counsel at the oral hearing to have been professional, impartial, directed at testing, clarifying or completing the evidentiary record and procedurally fair. The Commission finds no evidence of procedural unfairness or a breach of natural justice.

73. The Commission does not consider that a stakeholder consultative process on the role of Commission counsel as suggested by Calgary is required. The services of Commission counsel are determined by the Commission and are directed in a manner best suited to assist the Commission in carrying out its public interest responsibilities as the circumstances of each proceeding may warrant.

74. The Commission further observes that there is no reason for the Commission to engage in its fact findings through counsel. One of the Commission's expert staff could as easily engage in asking the witness panels questions. It is out of extreme respect for procedural fairness to all parties that the Commission has a member of the law society of Alberta engage in such questioning. A member of the law society is bound by certain rules of conduct, and the Commission is satisfied that its counsel conducted themselves appropriately in this proceeding.

75. It would be an expectation that counsel for all parties do the same. Using terms such as "softballs and lipstick,"[70] perhaps uttered in the heat of the moment, cannot become the norm in Commission proceedings. More importantly, however, it is standard practice that if a party objects to a line of questioning, that they make their objection known immediately. This would require the objecting party to be present in the room at the time. The reason for this requirement is that the transcript is tone deaf. The content and tone of the questions is what determines the appropriateness of the questions. None of the other parties, who were present in the room, objected to Commission counsel's questions, because there was nothing wrong with the questions.

4 Rate base

76. This section will discuss the additions to rate base from 2008-2010 and the forecast capital costs for a number of projects and programs that are planned by AG for the test years.

[70] Transcript, Volume 6, page 1074.

4.1 2011 opening rate base

77. In its April 21, 2011 submissions[71] AG updated its 2010 closing property, plant and equipment (PP&E) balances to $1,410.4 million. Table 3 below is a comparison of AG's actual rate base from 2008 to2010.[72] The change in net rate base was related to capital additions and retirements, changes in depreciation and other factors. In this section the Commission will examine capital additions to the opening rate base.

Table 3. Opening rate base

	2008 actual	2009 actual	2010 actual
Rate base ($ million)	1,261.2	1,327.9	1,410.4
Per cent Increase over prior year		5.3%	6.2%

78. A comparison of forecast and actual capital expenditures for 2008 to 2010 is shown in the table below.

Table 4. Comparison of forecast and actual capital expenditures

	2008	2009	2010
	($ millions)		
Forecast capital expenditures	256.7	273.4	214.0[73]
Actual capital expenditures	252.4	192.4	197.0

79. In Tab 8.1.1 of the application AG provided a comparison of its 2008 actual capital expenditures to the approved forecast in the 2008-2009 GRA. The total actual expenditures of $252.4 million were $4.3 million or 1.7 per cent less than forecast. AG spent $13.6 million below forecast in the distribution service category (30.4 per cent less than forecast), which AG explained was the result of the start of the economic downturn, and over-spent $8.6 million in the computer software and equipment category (94.5 per cent greater than forecast). AG explained that the latter was mainly due to proceeding with the new human resources system, Oracle HRX, which had not been included in the GRA forecast due to significant uncertainty regarding the timing, scope and cost to develop the system. AG underspent its land and structures 2008 approved forecast by $797,000.

80. In Tab 8.2.1 of the application AG provided a comparison of its 2009 actual capital expenditures to the approved forecast in the 2008-2009 GRA. The total actual expenditures of $192.4 million were $81.0 million or 29.5 per cent less than forecast. AG under-spent in all major categories, which it explained was a result of the continuing economic downturn and decisions to delay the construction of new operating centres, and the delay of the meter relocation and replacement project (MRRP). The exception was in the computer software and equipment category, where AG over-spent by $12.3 million (293 per cent greater than forecast). AG explained that the latter was mainly due to proceeding with the new human resources system, Oracle HRX, which had not been included in the GRA forecast and higher than expected

71 Exhibit 84.01, page 1, paragraph 1.
72 2008-2009 from Exhibit 84.01.
73 Response to CCA-AG-02.

development costs for the work management system. AG underspent its land and structures 2009 approved forecast by $4,832,000.

81. As there was not an approved forecast for 2010, AG did not provide an analysis of the differences between the 2010 forecast and 2010 actual expenditures. However, AG provided a capital assets continuity schedule for 2010 as part of its May 16, 2011 application update.[74] Schedule 4.2 provided a summary and reasons for the variance between 2010 and 2009 actual capital additions:

- Services were higher in 2010 due to increased customer growth.
- Meters, Regulators and Installations were higher in 2010 due to increased customer growth as well as an increase in larger commercial projects.
- Software Development was lower in 2010 due mainly to costs related to 2009 projects including Work Management, Oracle HRXellence, the Non-Gas Sales Information System (NGSIS), and the Service Initiation and Billing System (SIBS) replacement.
- Improvements and MRRP were higher in 2010 due to increased improvement work.
- Land and Structures were lower in 2010 as the majority of the work related to the North Edmonton Operating Centre took place in 2009.
- General Moveable Equipment was higher in 2010 due to the timing of the equipment purchases for 2009.
- Communication and Lab Equipment was higher in 2010 due to the commencement of the Mobile Radio Replacement project.

82. In its application AG identified only one major capital project which was initiated in 2010, the low use automatic meter reading (AMR) project.[75]

83. The Commission will review the prudence of some of the 2008 to 2010 capital expenditures in the other sections of this report. The Commission directs AG in its compliance filing to update its 2011 opening rate base in accordance with the findings in other sections of this decision. The 2011 opening property, plant, and equipment accounts are approved subject to the Commission's directions relating to specific assets addressed in subsequent sections of this decision.

4.2 Capital additions expenditure forecast

84. AG capital expenditures are classified into nine functional categories. AG submitted the following table in its application and in UCA-AG-62(a) summarizing the capital expenditures for the north and south service territories. In its January 21, 2011 submissions, AG provided information regarding high pressure relocations as a result of work undertaken by ATCO Pipelines. Business cases for the high pressure related work in downtown Edmonton, North East Edmonton, and southeast Calgary were provided in support of additional forecast costs.[76] The forecast additional cost of the three projects was $0.8 million in 2011 and $2.7 million in 2012.[77]

[74] Exhibit 160.01, UCA-AG-62(b), Attachment 2, Schedule 4.1 and 4.2.
[75] Ibid., Section 2.1-3, paragraph 6.
[76] Exhibit 70.01, Business cases: Downtown Edmonton, North East Edmonton and South East Calgary.
[77] Ibid.

In the April 21, 2011 update[78] AG filed a new business case for it's a proposed human resource program, Talent Mangement System (TMS). The forecast cost of TMS is $2 million in 2011.

Table 5. Capital expenditures

Table 2.1.1 ATCO Gas (Total) - Historic and Forecast Expenditures						
	($ millions)					
	Actual 2008	Actual 2009	Actual 2010	Forecast 2010	Forecast 2011	Forecast 2011
Distribution						
Distribution extensions	53.3	35.5	36.3	44.8	47.6	47.0
Distribution improvements	80.7	66.0	72.8	73.6	146.4	164.0
Distribution services	31.2	27.4	32.2	33.1	36.4	37.0
Meters, regulators and installations	23.3	16.2	23.0	25.8	44.8	63.2
Subtotal distribution	188.5	145.1	164.3	177.3	275.2	311.2
Land and structures	23.5	22.8	10.4	10.6	15.3	13.2
Moveable equipment	22.6	6.2	12.1	14.7	19.3	21.6
Communication equipment	-0.1	1.1	1.6	2.0	7.4	1.7
Information technology	17.7	16.5	8.2	10.0	9.0	6.9
Demand side management total expenditures	0.2	0.7	0.0	0.0	1.5	3.0
Total expenditures	**252.4**	**192.4**	**196.6**	**214.6**	**327.7**	**357.6**
High pressure relocations – Jan. 21, 2011 update					0.8	2.7
TMS – April 21, 2011 update					2.0	
Updated total					**330.5**	**360.3**

85. AG provided a further breakdown of each functional category in Table 1 above in UCA-AG-62(a) Attachment 1.

CCA broad brush reduction submission

86. This section will consider the proposal by the CCA to apply a broad brush reduction to AG's capital expenditure forecasts in the test years of 8.6 per cent.[79]

87. The CCA expressed concern with the magnitude of the increase from 2010 actual capital expenditures to forecast 2011 and 2012 expenditures. The CCA noted that AG over-forecast 2010 capital expenditures in every category for a total of $17.0 million or 8.6 per cent.[80]

88. AG disagreed with any reduction to its capital additions forecasts and indicated that there was no basis to apply a broad brush reduction to the test year forecasts as advocated by the CCA, stating:

[78] Exhibit 118.01, Attachment 1.
[79] CCA argument, paragraph 10, page 6.
[80] CCA argument, paragraph 9, page 5, (214-197)/197.

> The decisions of the regulator must be based on the evidence before it, they cannot be arbitrary. ...Although ATCO Gas views that no adjustments should be made to it revenue requirement forecast, in the event that the Commission disagrees, the adjustments made must be based on a reasoned, factual determination that is not inconsistent with decisions the regulator has made for other utilities, where relevant.[81]

89. In its reply argument AG also pointed out that it did not agree with the CCA's calculation of an 8.6 per cent differential between the 2010 forecast and actual capital expenditures. AG recalculated the differential as 7.9 per cent using 2010 data as the denominator. AG believed all CCA's calculations required the same correction.

90. AG noted that the CCA recommended reductions to individual capital forecasts which AG argued was double counting when combined with the broad brush reductions recommended. AG argued that the CCA had ignored all of the places where AG had spent more than it forecast in 2010 in its recommendations which made the effect of double counting even more significant.

Commission findings

91. The CCA has proposed a reduction in forecast capital expenditures of 8.6 per cent based on 2010 forecast versus actual expenditures. The Commission acknowledges that a broad brush reduction approach may be appropriate in situations where capital expenditures are primarily driven by inflation and system growth, and there has been a demonstrated trend of over-forecasting. The Commission does not accept the CCA proposal in the circumstances of this proceeding for the following reasons. The 2010 forecast was not approved by the Commission therefore it was not fully tested. A broad brush approach reduction requires greater support than a single non-test year analysis can provide, and typically should be supported by a trend. Further, major capital projects are fact specific and require justification through individual business cases. Accordingly, the Commission will consider the capital additions projects individually to determine whether the forecast costs are reasonable.

4.3 Business cases

92. The Commission notes that AG provided a total of 20 business cases in the application for various capital projects. This section will examine individually fifteen of these business cases. Business Cases 8 and 9 related to land and structures are examined in the Section 4.5.1; Business Case 11 – Energy Education program expansion is examined with related operating costs in Section 6.3.14, Business Case 12 – Single Source Communities Emergency Gas Supply is examined in moveable equipment and and Business Cases 14 to 20 related to computer equipment will be examined in the sections on those topics.

93. Business Case 3 – TransCanada Turbines HP [high pressure] Lateral Relocation, Business Case 6 – Viking Mainlines to Red Deer 1 HP Pipeline Replacement, Business Case 10 – Grande Prairie Operating Center and Business Case 13 – Mobile Radio Replacement were not opposed by interveners. The Commission has reviewed these business cases and has determined that the cost/benefit analysis and discussion therein is sufficient. The Commission therefore approves the forecast costs associated with these programs for inclusion in revenue requirement. The remaining business cases outlined below are discussed in subsequent sections of this decision:

[81] AG reply argument, paragraph 17, page 10.

- Business Case 1 – Urban Mains Replacement (UMR) is discussed in Section 4.3.1
- Business Case 2 – Above Ground Entry – Meter Relocation and Replacement is discussed in Section 4.3.2
- Business Case 4 – Plastic Pipe Replacement is discussed in Section .4.3.3
- Business Case 5 – Line Heater Reliability is discussed in Section 4.3.4
- Business Case 7 – Low Use AMR Project is discussed in Section 4.3.5
- Business Case 8 – Okotoks Operating Center is discussed in Section 4.5.5
- Business Case 9 – Drayton Valley Operating Center is discussed in Section 4.5.6
- Business Case 11 – Energy Education Program Expansion is discussed in Section 6.3.14
- Business Case 12 - Single Source Communities is discussed in Section 4.6.1
- Business Case 14 – Oracle HRX is discussed in Section 4.7.1
- Business Case 15 – Instrument Record System Upgrade, is discussed in Section 4.7.3
- Business Case 16 – Oracle E-Business Suite R12 and 10g Upgrade, is discussed in Section 4.7.3
- Business Case 17 – Oracle Version 10G to 11 Upgrade Mid Sized Applications, is discussed in Section 4.7.3
- Business Case 18 – Workstation Operating System Upgrade, is discussed in Section 4.7.3
- Business Case 19 – Work Management System Enhancements is discussed in Section 4.7.3 and
- Business Case 20 – PDA Replacement Project is discussed in Section 4.7.3

4.3.1 Urban mains replacements (Business Case 1)

94. AG has applied for approval of a capital program of $50.2 million in 2011 and $62.3 million in 2012 for the replacement of urban steel mains. The company has traditionally based its urban main replacement activities on the company's demerit point system which applies points to potentially negative attributes to existing mains including pipe material, operating pressure, installation date, soil, type of coating, coating condition, cathodic protection performance, below ground leak history and service entry location. Those areas with higher risk points are further examined for two and 10-year leak histories. Finally, areas of greatest concern are subjected to an engineering evaluation to consider the condition and risk of these assets in greater detail.

95. AG indicated that it would be stepping up its UMR program by adopting a new proactive[82] approach to target complete replacement of all existing steel mains and services within the next 100 years. In attempting to meet this objective AG indicated that it intended to replace approximately 90 kilometres (km) of urban mains in each of the test years.[83] AG noted in its business case that "increasingly vintage of pipe is used to identify areas of higher risk."[84]

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[82] UMR Business Case, page 2, paragraph 2; Transcript, Volume 5, page 992, line 15.
[83] AG rebuttal evidence, paragraph 51, page 13.
[84] UMR Business Case, page 3, paragraph 6.

96. The application and business case indicated the purpose of the program:

> Should even a small percentage of this pipe vintage [at least 50 years old] develop an unacceptable level of leaks, the safety risk would be unacceptable and ATCO Gas could easily become overwhelmed with work to address the situation.[85]

97. AG submitted that it would continue to use the same methodology it had used in the past to identify and prioritize urban mains to be replaced. However, it will take into account the aging nature of the urban mains infrastructure. Mr. Dixon, Senior Vice-President and Chief Engineer for AG explained the difference between what AG had historically done to determine UMR projects from what it was proposing to do in the test years and thereafter in the following terms:

A. MR. DIXON: I'll give it a try here,
Mr. McNulty. So the demerit point system and the engineering
assessments have not changed one iota. In the past, that's
what we applied, and our leak frequency, as I mentioned
before, has been pretty stable and our rate of replacement
has been pretty stable. And we could continue in that mode
going forward, and we fully expect that the demerit point
system and engineering assessments would identify more and
more pipe to do, as we're getting this wall of aging pipe
coming towards us.
The trouble with the demerit point system is
it relies on last year's leak survey information. So it's
kind of one year behind. And that's fine if everything is
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stable. You're on top of the right areas. But when you've
got a huge amount of vintage pipe coming at us, what's going
to happen is we're going to be trying to catch up all the
time. It's going to be identifying leaks. We'll up our
mains replacement program, but it's never going to be quite
enough.
So what we're doing in this application is
we've got a good eye on that vintage pipe, and we know it's
coming. We're stepping up, as Mr. Hahn said, stepping up our
mains replacement. Going to apply the same demerit and
engineering assessment. Now, it may be where we were
replacing -- or doing engineering assessments when the
demerit point was, you know, 65, we may be doing it at 60
now. But it's -- it's more proactive, and it's in the now,
rather than waiting for a delayed reaction of a year for
actual leak information.
I point again to the rebuttal evidence where
we showed what happened to us in the '80s, well, at least for
Canadian Western Natural Gas in the Calgary region, where we
weren't keeping up. And the leak frequency -- the number of
leaks can escalate very quickly, and it can take a decade to
correct that. And that was one thing back then when we were
only talking of bare mains -- the remaining bare mains, 370
kilometres in total. But we're talking about adding hundreds
of kilometres each year in the vintage category.

[85] Exhibit 3, application, paragraph 21, page 2.1-9 and Exhibit 1, Business Case 1, paragraph 10, page 5.

00992

And if we get behind the eight ball, as they call it, if we get behind on the leaks and they get away from us, I am really worried we won't be able to catch -- get on top of it again, because it's such bigger numbers than we have ever seen before.

Q. Thank you, sir. That helps to clarify. So what ATCO is doing, then, is changing the rationale for why it wants to go ahead going forward with a larger pipe replacement program than it has before. If I heard you correctly, you're using the demerit point system and engineering assessments, but you also factored into the account you're trying to get ahead of the game, look at the vintaging that's happening, and start acting proactively to address what you believe to be a problem coming; is that right?

A. MR. DIXON: "Proactive" is the keyword, Mr. McNulty. Correct.

Q. But you are doing something differently than what you used to do before, right?

A. MR. DIXON: I guess the eye to the amount of vintage that's coming at us, because we know it's a sea change coming. And that is new because the situation is new.[86]

98. AG stated that based on its current replacement rates the amount of pipe over 50 years of age would almost double in 10 years with the expectation that the current leak frequency of 5.2 leaks per 100 km per year would double in 10 years without an aggressive replacement program.[87]

99. AG submitted that the pipe installed in 1950 had been in service for 60 years and that the average retirement age of pipe experienced historically by AG was approximately 60 years. AG argued that history had shown that if it did not start to replace pipe when it reached that age, its leak frequencies would increase.[88] The amount of 60-year old pipe was growing by an average of 128 km per year over the next five years. AG referred to Figure 1 in the business case included with the application[89] and included again in the rebuttal[90] which graphically represented the amount of pipe in service by vintage. AG submitted that the graph clearly supported the required steel mains replacement program. The graph demonstrated that the amount of vintage steel pipe in service was increasing at a rate almost 10 times anything experienced by AG in prior years.[91]

100. AG argued that the proposed 100-year replacement program assumed that the average service life for all remaining steel pipe currently in service would rise to approximately 80 years from the current average of 60 years.[92] AG claimed it was clear that this pipe did not have a 500-year life, which was what would be required based on the prior level of pipe replacement.[93]

86 Transcript, Volume 5, pages 990 to 992.
87 AG rebuttal evidence, paragraph 56, page 16.
88 AG rebuttal evidence, pages 13-14.
89 Application, Tab 2.1, Business Case 1, page 4.
90 AG rebuttal evidence, page 14, paragraph 51.
91 AG rebuttal evidence, page 15, paragraph 53.
92 Transcript, Volume 5, page 1053, lines 11-12.
93 AG argument, page 14, paragraph 34.

101. AG provided a graph in Figure 2.1 of its rebuttal evidence[94] which provided a leak history for bare steel mains which were not cathodically protected. The graph demonstrated that the bare steel mains experienced a greater frequency of leaks as the pipe aged, requiring the utility to dramatically increase its pipe replacement program in order to maintain leak frequency within acceptable levels. AG submitted that it was reasonable to consider that the need to replace existing pipe would also increase dramatically over time despite improvements in coatings and cathodic protection, particularly given the fact that large quantities of pipe were installed during an approximately thirty year period starting in about 1950. AG suggested that the lessons learned from the need to replace the bare steel mains on an accelerated basis as it aged should be used in planning for an orderly replacement of pipe installed subsequently. AG noted in the application:

> ATCO Gas currently has 2,300 km of steel main in operation that is at <u>least</u> 50 years old. By 2020, at the historical rate of replacement, this would grow to 3,800 km of steel main in operation that is at <u>least</u> 50 years old. Should even a small percentage of this pipe vintage develop an unacceptable level of leaks, the safety risk would be unacceptable and ATCO Gas could easily become overwhelmed with work to address the situation.[95]

102. The AG witnesses emphasized during the oral hearing the significant consideration pipe vintage had in its proposed UMR program as evidenced as the following exchange with Commission counsel:

> Q. Okay. Now, over time as pipe gets older, would you
> agree that that evaluation process that you've been doing
> would naturally result in increasing levels of steel mains
> 00934
> replacement?
> A. MR. DIXON: Not in and of itself. What's
> driving the increase in pipeline replacement is what we refer
> to as Figure 1 that was shown in the business case. It's
> also repeated in the rebuttal, and it's really the key to our
> steel maybe mains replacement program. I'll just call that
> up. Page 14, it's paragraph 51.
> Q. So are you in the rebuttal now?
> A. MR. DIXON: I'm in the rebuttal, page 14,
> paragraph 51, and this figure is really the key figure. It's
> the amount of vintage really drives the pace of our
> replacement program.

103. Despite the above characterization of the urban mains replacement program as a proactive program in which 90 km per year would be replaced with increased reliance on vintage, AG also indicted at the oral hearing that the specific urban mains replacement projects forecast for the test years were the same that would have been identified using the demerit point/leak history/engineering assessment procedures it had applied in prior years. Mr. Dixon had the following exchange with Commission Counsel:

> Q. …But just to be sure, then, so the projects you've identified in the business case, they would have been -- they would have been on tap, so to speak, to be replaced in 2011

94 Rebuttal evidence, paragraph 55, page 16.
95 Application, paragraph 21, page 2.1-9.

and 2012 under the existing demerit point and engineering assessment methodology? Is that right?
A. MR. DIXON: That's right. And I think we saw signs of that in 2010. Things are starting to ramp up. And that's solely due to the more vintage pipe adding to our system.
Q. Okay. So there are no additional projects for 2011 and '12 that have been added that would not have been there under -- using the methodology you applied last year.
A. MR. DIXON: That's correct.[96]

Views of the parties

104. Calgary noted that AG proposed to increase the replacement of steel mains from previous years by five fold.[97] In 2010 the leak frequency was lower than in the previous nine years,[98] so that Calgary considered it was clear that the age of pipe was not the only factor driving leaks. Calgary suggested it might be argued that the worst of the pipe has been replaced so that the leak frequency would be expected to be down. Calgary argued that there was no justification for the significant increase in the capital expenditures forecast for the test periods.

105. The UCA's position was that the Commission should not approve the steel mains replacement program at this time, either as an on-going program or in relation to the test years. The UCA stated it was not opposed to an urban mains replacement program of some kind but that, in this proceeding, AG had not demonstrated that the applied for program was needed. Further, even if some such program was needed, AG had not demonstrated that the program suggested by AG was the most reasonable and economically efficient available alternative.

106. It was the UCA's submission that AG had failed to do or to consider at least three things that should be prerequisites to any kind of Commission approval of the program as follows:

a. AG has failed to show, as even an initial step, that there is a need for the program or that the existing or status quo approach to dealing with the aging of its urban mains system is not adequate,

b. AG has completely failed to acknowledge or assess the question of how its program and the available alternatives, including the status quo, would affect customers economically in the long run, and

c. AG has failed to examine or consider any alternatives to its own proposal.[99]

107. The UCA argued that AG already had in place a sophisticated system for monitoring the condition of its system, identifying and prioritizing risks, and taking appropriate remedial action when necessary. That mechanism resulted in on-going replacement and retirement activity at a modest level. Over time one would expect that natural retirement activity to increase, although when and at what rate that would happen appeared to be unknown.

108. The UCA considered that what was at issue was how that natural retirement process would play out in the long run as the components of the system age, and whether that natural retirement process was likely to create difficulties in the future. In the UCA's view AG had not

96 Transcript, Volume 5, page 1029, line 14 to page 1029, line 1.
97 Exhibit 3, page 2.1-2, paragraph 5.
98 Exhibit 83-01, response to UCA-AG-8(c).
99 UCA argument, pages 2 and 3, paragraph 7.

provided any actual evidence suggesting that a peak for replacement would occur, or indicating when it would occur, or how significant it would be.

109. The UCA argued that what was needed in order to establish a natural retirement peak, and what would go directly to the issue AG raised, was a forecast of natural urban mains replacements or retirements over the next several decades under the status quo approach.[100]

110. The UCA did not dispute that the implications of aging infrastructure were an important issue for utilities and their customers, but argued that the AG evidence in support of its urban mains replacement program did not come close to meeting the required onus. AG's forecast that leak frequencies would double in ten years was not supported by any study, but was a "rule of thumb" that had apparently been derived entirely from AG's experience with bare steel mains rather than its actual experience with modern coated steel mains that have enjoyed cathodic protection for all or most of their lives.[101] The UCA argued that the consideration that steel mains installed in the late 1970s and early 1980s reach 60 years of age, by and in itself did not mean that the pipe should be retired.

111. The UCA considered that AG was proposing to spend significant amounts of money on an annual basis over a period of several decades in response to a problem that it was not able to demonstrate existed. The UCA submitted that AG had apparently taken the position that the cost implications of this large ongoing program, and the relative cost implications of the various alternatives, were irrelevant to the issue of whether to allow it to proceed with its preferred program.[102]

112. The UCA argued that the fact was that the status quo and the proposal by AG would have significantly different cost implications for different generations of customers, and for existing customers in present value terms.

113. The UCA pointed out in its reply argument that AG appeared to have altered its main focus for support of the replacement program. In the business case submitted with the Application, AG had maintained the business program was necessary in order to avoid potential difficulties in the long run associated with a peak or spike in replacement activity. In its rebuttal evidence[103] AG had developed a different theory that characterized the issue as one of safety and reliability in the near term, based on a claim that without programmed replacements leak frequencies would increase dramatically over the next 10 years.

114. The UCA observed that AG did not indicate that it had conducted any testing or sampling of its coated pipes; conducted any scientific research into the corrosion resistance or overall life characteristics of either bare steel mains or modern coated mains; or surveyed the scientific or trade literature in relation to these issues. It was the UCA's opinion that AG had failed to make any serious effort to demonstrate, with any kind of logical or scientific rigor, that its massive proposed expenditures were required or reasonable.[104] The UCA submitted that:

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[100] Exhibit 110.07, UCA general evidence, page 9, Q.16 and Q.17 for the UCA's analysis of the analytical approach that ATCO should have taken in examining the steel mains replacement issue. See also in this connection the discussion between Mr. McNulty and Mr. Stauft at Transcript, Volume 8 at pages 1700 to 1712.

[101] See discussion with Mr. Dixon at Transcript, Volume 5, page 937.

[102] Exhibit 83.01, response to UCA-AG-12(a).

[103] Exhibit 163.01, paragraphs 46-67.

[104] UCA reply argument, page 6, paragraph 14.

> There is no urgent need to institute the proposed program now, before it has been established that there is a problem or that an optimal and prudent solution has been identified. AG's program would take 100 years to complete. A delay of a year or two, or even five or ten years, to ensure that the approach that is ultimately taken is appropriate and necessary will make no material difference to the ultimate outcome.[105]

115. The UCA noted the testimony of AG's witness, Mr. Dixon, who stated "That feedback loop for us on the leak inspections is really the critical piece in determining how well our mains replacement is operating."[106] The UCA argued that the difficulty with that argument was that the feedback loop was telling AG that leak frequencies were low and stable at 5.2 leaks per 100 km[107] and that natural retirements of modern steel mains were also modest and stable at about $10 million per year. The onus was on AG to demonstrate that the feedback loop was not painting an accurate picture of the future. The UCA stated that this was the basis for the UCA's position that the steel mains replacement proposal should be rejected for the purposes of this case.

116. The UCA argued that it had assumed that AG had operated its long-standing and comprehensive program for monitoring and, when necessary, replacing facilities based on the demerit point system and associated engineering assessments on a good-faith basis so as to only replace facilities that genuinely need to be replaced and that this approach should continue, in the absence of evidence to the contrary that it was not sufficient. In response to a question from the UCA, AG provided its historical forecast and actual expenditures for the UMR replacements as well as leak frequency data.

Table 6. UMR 2003-2010 actual and forecast expenditures, pipe installed and leaks[108]

$000			
	Forecast	Actual	$ Overspent/(Underspent)
2003	7,092	8,498	1,406
2004	7,092	13,610	6,518
2005	14,959	18,921	3,962
2006	11,886	10,376	(1,510)
2007	11,940	5,981	(5,959)
2008	8,378	8,428	50
2009	13,562	8,049	(5,513)
2010	11,600	11,200	(400)

105 UCA evidence, page 11, Question 20.
106 AG argument, paragraph 39.
107 Exhibit 163.01, AG rebuttal evidence, paragraph 56.
108 2003-2009 from UCA-AG-03(d), 2010 from CCA-AG-03(d).

ATCO Gas UMR Actual vs. Forecast Pipe Installed[109]			
Kilometre			
	Forecast	Actual	Overbuilt/(Underbuilt)
2005	51.29	35.35	(15.94)
2006	31.50	17.32	(14.18)
2007	15.43	8.90	(6.53)
2008	11.00	13.90	2.90
2009	11.30	9.80	(1.50)
2010	14.30	14.30	0.00

	Total Steel Mains (km)	Total Steel Leaks	Leaks/100km[110]
2001	9958	607	6.1
2002	9342	661	7.1
2003	9161	563	6.1
2004	9150	721	7.9
2005	9126	667	7.3
2006	9100	576	6.3
2007	9059	503	5.6
2008	9056	725	8
2009	9053	706	7.8
2010	9043	474	5.2

117. The UCA believed the question of what the level of natural retirements was likely to be, based on the existing procedures and the retirement criteria that had been applied in past years, should be addressed to determine what forecast to adopt for the 2011 and 2012 test years.

118. The UCA observed that in order to identify the specific facilities to be retired on a programmed basis under the 90 km per year approach, AG had simply moved down its list until it reached roughly the 90 km level.[111] The UCA argued that identifying the facilities to be replaced that way did not mean that 90 km of pipe would have been naturally retired in those years if AG had continued to apply the criteria that it applied prior to 2011.

119. In response to the interveners' submissions, AG maintained that the steel mains replacement program was required to provide safe and reliable distribution service and pointed out that it had already begun the accelerated program in 2011.[112]

120. AG submitted that the delay proposed by the UCA in order to study the urban mains replacement issue was unacceptable. AG argued that the UCA's proposal would not allow AG to carryout its mandate to provide safe, reliable gas distribution service. AG argued that Calgary was looking backwards when it argued that the leak frequency in 2010 was lower than the previous nine years. Both the UCA and Calgary were ignoring the large increase in the amount of vintage pipe that was accumulating.

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109 Ibid.
110 UCA-AG-8(c).
111 UCA reply argument, page 8, paragraph 22.
112 AG argument, page 15, paragraph 35.

121. AG also argued that the UCA seemed to miss the point that the steel mains replacement program proposed by AG assumed that the average service life for all remaining steel pipe in service would rise to approximately 80 years from the current average of 60 years.[113] This recognized that steel pipe coatings and cathodic protection continued to improve from 1950 to the present time.

Commission findings

122. The Commission notes that the amount of actual spending by AG on urban steel main replacements was $8.4 million, $8.0 million and $11.6 million in 2008, 2009 and 2010, respectively. AG has applied for approval of an urban mains replacement capital program forecast of $50.2 million in 2011 and $62.3 million in 2012. The forecast amounts would result in a significant increase over 2010 actual spending of $11.6 million, and the actual of 2008 and 2009.

123. While the Commission appreciates AG's concerns with respect to its aging urban mains infrastructure, the Commission agrees with the interveners that AG has failed to demonstrate a need to implement an urban mains replacement program of the nature and timing proposed. The Commission does not accept the AG proposal to step up its urban main replacement program to target replacement of all existing urban steel mains and services within the next 100 years.

124. AG appears to have based the need for its proactive program on three concepts:

- on the large increase in pipe installed in the 1950-1990 period depicted in Figure 1 of Business Case 1
- the potential for an unmanageable need for replacements if the present level of urban main replacements continued and
- past history, and in particular the experience with bare steel mains as demonstrated in Figure 2.1 of the Rebuttal Evidence[114]

125. The Commission is not persuaded by AG's evidence that there is either an immediate need to address the fact that infrastructure is aging or that resources may be constrained in the future in a manner that would prevent addressing the issue as it arises.

126. AG notes the large increase in pipe installation from approximately 1950 to 1990 depicted in Figure 1 of the business case and indicates that a correlation between aging pipe and leak frequency has been demonstrated. In support of this conclusion, AG refers, among other things, to Figure 2.1 of the rebuttal evidence which depicts the leak frequency of bare steel mains relative to year with increasing leak frequencies prior to the introduction of a bare steel mains replacement program. AG argued that this supported the need to stay ahead of the curve with respect to the need to replace aging pipe. AG has failed, however, to demonstrate that pipe presently in service, which has the benefits of coating and cathodic protection, will exhibit leakage or failure patterns similar to pipe previously installed without such features.

127. The Commission would expect that a capital program of the nature requested would have significantly greater probative support than what was provided. The rationale for the business case included references to system safety and reliability. The Commission, however, does not

113 Transcript, Volume 5, page 1053, line 11-12.
114 AG rebuttal evidence, pages 15 and 16, paragraph 55.

find that evidence on the record with respect to leak history for coated, cathodically protected steel mains and the nature of steel pipe failures[115] supports either the timing or extent or the proposed program. Mr. Dixon made the following statement in response to a question by Commission counsel:

> A. MR. DIXON: Well, it was finding us with
> leaks. And I have to point out, too, with plastic pipe, the
> cracking and the -- we've got lots of photographs in the
> business case. It's much more dramatic failures than you get
> with steel pipe. Steel pipe, you'll get pinhole corrosion
> leaks that grow over time. You don't get dramatic failure of
> steel pipe. You get lots of early warning, I would call it, 12:00
> where plastic pipe will sit there and operate without a leak
> at all, and then all of a sudden, it's a sudden and dramatic
> failure.[116]

128. The Commission agrees with the three deficiencies in the AG evidence cited by the UCA:[117]

- AG failed to demonstrate that there is a need for the program or that the existing or status quo approach to dealing with the aging of its urban mains system is not adequate
- AG has failed to address how the proposed program would affect customers economically in the long run, and
- AG has failed to fully examine or consider any alternatives to its own proposal

129. The Commission agrees with the UCA, that it does not appear that AG had conducted any testing or sampling of its coated mains pipes nor had it undertaken research into the corrosion resistance or overall life characteristics of either bare steel mains or coated and cathodically protected mains. AG also did not indicate that it had canvassed the relevant scientific or trade literature.

130. AG referred to Figure 2.1 in its rebuttal evidence as evidence in partial support for the steel mains replacement program. The Commission notes that the figure details the experience for bare steel mains and there is no reason to expect a similar failure pattern for the existing coated steel mains. The evidence indicates that coating and cathodic protection techniques became available or were improved starting in the 1950s[118] and that cathodically protecting steel pipe and maintaining a corrosion control program will reduce the occurrence of corrosion leaks. As noted by Mr. Dixon in the following exchange with Commission counsel:

> Q. Okay. And what I'm trying to understand, sir, is there
> was some suggestion, and we'll get into depreciation
> tomorrow, Mr. Kennedy, but some suggestion that around 60
> years is the present foreseeable average useful life of this
> class of steel mains, but your program is aimed at replacing
> the mains over a hundred years. So perhaps you can explain
> why 100 as opposed to 60 or something else?

115 Transcript, Volume 6, page 1155, lines 14-23.
116 Transcript, Volume 6, page 1155, lines 18-20.
117 See paragraph 106 above.
118 Transcript, Volume 5, page 1026, lines 10-18.

> A. MR. DIXON: Well, as I mentioned a little
> bit earlier, that, you know, we anticipate that the coatings
> on steel pipe and cathodic protection have got better and
> better over time, so I fully expect that 60 year life that we
> have now is going to get longer as we move out through the
> program. I'm depending on that actually.[119]

131. Because there is no evidence on the record to indicate the point at which the steel mains will develop an unacceptable level of risk, nor was there evidence of an anticipated distribution pattern of the experience around the mean, AG has been unable to persuasively demonstrate the required start date or duration of an urban steel mains replacement program. Consequently, the Commission sees no reason for AG to move to a proactive replacement program at this time.

132. The Commission has in past decisions accepted the rationale used by AG in forecasting urban steel main replacement projects during a test period. The demerit point system and associated leak and engineering studies have been in use for some years in identifying and prioritizing urban steel main replacements and this methodology continues to perform as intended. As noted by Mr. Dixon:

> … real -- the real proof of how well our replacement program is
> going is our leak frequencies, and we talked about that in
> another IR response. And if we see that staying fairly
> stable -- and I would look at those past ten years as being
> fairly stable even though it bounced from 5.2 to 8.something.
> That's a fairly stable level of leaks.
> And that means your mains replacement and all
> your other safety systems and inspections you have in place
> are working. If that leak frequency starts to rise, then
> your mains replacement is not effective. So that's the real
> key. The demerit point system is a prioritization trying to
> get us focused on the right areas, and the proof in the
> pudding is the leak frequency after the fact.[120]

133. While AG has not been able to demonstrate to the satisfaction of the Commission a need to commence a proactive urban steel mains replacement program at this time, the Commission is aware that ageing infrastructure is an industry wide issue and recommends that AG monitor industry research and experience with coated, cathodically protected pipe. Should industry experience and AG specific leak frequency begin to rise despite the use of the existing demerit point and related systems and inspections, then the Commission would be prepared to reexamine the need for a modified approach to urban steel main replacements.

134. As noted above, despite the majority of the AG evidence indicating a stepping up of the urban mains replacement program, as a proactive approach to replacing 90 km per year with an increasing reliance on pipe vintage, AG indicted at the oral hearing that the specific urban mains replacement projects forecast for the test years were the same as those which would have been identified using the demerit point/leak history/engineering assessment. The Commission finds this latter statement to be inconsistent with the characterization of the evidence as a new proactive approach to urban mains replacement over a 100-year period. Indeed the Commission

[119] Transcript, Volume 5, page 1010, lines 5-17.
[120] Transcript, Volume 5, page 1039, lines 6-18.

considers that evidence with respect to a proactive program would have been unnecessary had the projects proposed for the test years fully satisfied the criteria applied in previous years.

135. Given all the above the Commission approves a capital expenditure based on a status quo urban mains replacement program during the test years based on the actual expenditures in 2010 increased each year by an inflation factor of three per cent. The amounts approved for inclusion in revenue requirement are $12.0 million and $12.4 million in 2011 and 2012, respectively.

4.3.2 Meter relocation and replacement program (MRRP) (Business Case 2)

136. AG requested approval for expenditures of $33.2 million and $32 million in 2011 and 2012 for the MRRP.

137. MRRP includes three classifications of meter moves and a proposed premise survey as detailed in the following table:

Table 7. MRRP actual and forecast costs

	Table 2.1.1.2(c) ATCO Gas (Total) - Meter Relocation and Replacement Project				
	($ millions)				
	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast	2012 Forecast
Planned below ground	36.0	27.0	16.1	3.3	0.0
Planned above ground	0.2	0.7	8.8	29.3	29.7
Safety/accessibility	0.9	0.4	0.6	0.6	0.6
Premise surveys	1.7	0.4	0.0	0.0	1.7
Total expenditures	8.8	28.5	25.5	33.2	32.0

138. The forecast for 2010 was $25.5 million but AG provided the following actual costs in response to CCA-AG-7(b):

- planned below ground $18,111,000
- planned above ground $ 9,799,000
- safety/accessibility $ 440,000

Total $28,350,000

139. AG stated that the AUC and its predecessor the Alberta Energy and Utilities Board (EUB or board) had supported the meter relocation and replacement project since its inception in 2003, through Decisions 2003-072,[121] 2006-004[122] and 2008-113.[123] The MRRP program for 2011 and 2012 was focused on completing the below ground meters and continuing the above ground component begun in 2010. AG will continue to replace meters for safety and accessibility reasons and seeks approval for a premise survey in 2012. AG stated that the currently proposed

[121] Decision 2003-072: ATCO Gas, 2003/2004 General Rate Application – Phase I, Application No. 1275466, October 1, 2033.

[122] Decision 2006-004: ATCO Gas, 2005-2007 General Rate Application Phase I, Application No. 1400690, January 27, 2006.

[123] Exhibit 3, paragraph 30, page 2.1-12.

MRRP project with respect to inside meters with above ground entries is focused on reducing risk and improving the safety for employees and the public.[124]

140. AG submitted that when the MRRP project was initiated in 2003, AG had planned to move all inside meters to the outside, on a subdivision by subdivision basis, regardless of whether there was a below ground entry or above ground entry service. AG was directed by the EUB in Decision 2003-072 to focus on below ground entry sites first. AG was also directed to address inside meters with above ground entries through the meter recall program, estimated to be between 15 to 20 years.[125]

141. AG stated that it had indicated in its 2005-2007 GRA its intention to proceed with replacement of above ground entry meters immediately after the below ground entries were complete but that a survey of these sites was required in order to prioritize the work based on safety concerns.[126] AG expected to substantially complete relocating outside all inside meters with below ground entries in 2010.

142. AG indicated that all below ground entry meters would be completed in 2011 and that the above ground meters had been prioritized for replacement by way of a risk ranking into four tiers. The basis for the four tier ranking was a number of conditions identified as high medium and low risk in Table 1 of Business Case 2.[127] Table 2.1.1.2(e) reproduced below from the application categorizes the above ground entry meter sites based on a grouping of the risk conditions.

Table 8. MRRP above ground entry risk analysis

	Table 2.1.1.2(e) ATCO Gas (Total) - Meter Relocation and Replacement Project - Above Ground Entry Tiers Program Sequence Condition Quantity	
Tier 1	Multiple occurrences of high risk ranking factors at a single residence	569
Tier 2	A high risk factor, multiple medium risk factors, or both at a single residence	14,950
Tier 3	A medium risk factor, multiple low risk factors, or both at a single residence	51,649
Tier 4	A low risk factor at a single residence or no risk factors	38,406

143. AG stated that replacement of Tier 1 meters was completed in 2010 and replacement of Tiers 2 and 3 were anticipated to be completed over a five-year period ending in 2014. Tier 4 meters would be addressed in conjunction with other work such as meter recalls.

Views of the parties

144. The UCA did not provide evidence related to MRRP but submitted argument as summarized below.[128]

145. The UCA noted AG's justification for all of this work was safety-related, but argued that it was not clear that the locations classified as Tier 2 and Tier 3 presented significant risks.

124 Ibid., paragraph 4, page 2.1-2.
125 Transcript, Volume 6, page 1187, lines 15 to 24.
126 Exhibit 3, paragraph 31, pages 2.1-12 and 13.
127 Exhibit 1, application, Volume 2-2, Business Case 2.
128 Exhibit 200.20, paragraphs 43 to 49.

146. The UCA argued that safety concerns associated with meter reading personnel entering customers' residences on a monthly basis would be addressed if theAMR program were approved because it would eliminate the need for a meter reader to enter the residence.

147. The UCA also noted its concern that AG was not capturing all efficiencies by coordinating with other programs such as AMR.

148. The UCA questioned the pace of relocations given the Commission's historical view that inside meters with above-ground entries present less of a safety risk than those with below-ground entries.

149. The UCA recommended either allowing the Tier 2 and Tier 3 meters to be relocated in the normal course of meter testing, as AG had proposed for Tier 4 meters, or implementing the program over a longer period of eight years. In its reply argument AG stated that the UCA suggestion that the reasons for the MRRP program were access issues and meter reader safety were incorrect. It stated that homeowner safety and code compliance were the main reasons for MRRP. AG noted that until the low use AMR project was completed operational issues related to reading inside meters would continue. Completion of the AMR project was not expected before 2014.

150. AG observed that the UCA had provided no evidence to support its recommendation that the Tier 2 and Tier 3 meters be moved in the normal course of meter testing or over a longer period of eight years.

Commission findings

151. In Decision 2003-072 in which the EUB approved the original MRRP program the board directed AG to "incorporate in its Refiling, a revised proposal for replacement of meters with underground entries over a 10-year timeframe, and replacement/relocation of meters with aboveground entries on a schedule coincident with the recall program. The proposal should identify criteria for replacement and relocation in terms of safety or other considerations."[129]

152. In Decision 2006-004 the EUB approved a revised MRRP plan reducing the 10-year replacement period to eight years.

153. In Decision 2008-113 the Commission in its findings stated:

> Given that the MRRP proposed by AG for 2008 and 2009 mirrors the previous plan the Commission accepts the implementation of the MRRP in the manner proposed by AG.[130]

[129] Decision 2003-072, page 81.
[130] Decision 2008-113, page 41.

154. Table 2.1.1(d) of the application, reproduced below, indicates the number of units replaced and forecast to be replaced in the respective years.

Table 9. MRRP actual and forecast relocations and replacements

	ATCO Gas (Total) - Meter Relocation and Replacement Project				
	2008 Actual	**2009 Actual**	**2010 Forecast**	**2011 Forecast**	**2012 Forecast**
Planned below ground units	14,295	9,258	3,988	618	0
Planned above ground units	81	438	4,034	15,714	15,714
Safety/accessibility units	840	334	435	435	435
Total units	**15,216**	**10,030**	**8,457**	**16,767**	**16,149**

155. The Commission's approval in Decision 2008-113 was limited to capital expenditures in the test years for the below ground entry meter replacement program and safety and accessibility replacements. In addition the Commission approved the cost of the premise survey.

156. Table 2.1.1(e) reproduced in Table 8 categorizes above ground meter entries by risk into four tiers.

157. The Commission understands that the replacement of all Tier 1 above ground entry meters has been completed.

158. Tier 2 meters exhibit a high risk factor, multiple medium risk factors or both at a single residence. Given the identified level of safety concerns and risk the Commission accepts AG's proposal to replace Tier 2 above ground entry meters.

159. In response to UCA-AG-33(a), the number of Tier 3 meters identified as having medium risk factors is 32,511. The Commission considers that the Tier 3 meters with a medium risk factor should be removed by 2014 as contemplated in the application. The timing of the Tier 3 meter replacements should be coordinated with Tier 2 replacements to achieve efficiencies.

160. The Commission approves the relocation of meters classified as Tier 3 with low risk factors in conjunction with other work such as meter recalls.

161. The Commission approves the forecast capital expenditures for the replacement of meters designated under the safety/accessibility heading in Table 2.1.1.2(c). The Commission assumes that any Tier 3 or Tier 4 meters which subsequently develop safety or accessibility issues will be replaced under this program.

162. The Commission has not been persuaded there is a need for an additional premise survey, given that a survey was recently completed.

163. The Commission directs AG in the compliance filing to this decision to provide the Commission with the actual number of Tier 2 meters replaced in 2010 and the actual capital costs incurred. AG is directed to indicate the number of Tier 2 meters and Tier 3 meters with a medium risk factor left to be replaced in 2011 and 2012 and to provide the forecast capital costs in each year using the forecast capital costs calculated from Tables 2.1.1.2(c) and (d) in the application.

164. The Commission further directs AG to plan the replacement of the Tier 2 and the portion of the Tier 3 meters with a medium risk factor in a manner that achieves efficiencies and distributes the costs evenly over the period 2011 to 2014.

4.3.3 Plastic mains replacements (Business Case 4)

165. In the application and in the Business Case 4, AG proposed to begin a program to replace all of its approximately 9,600 km of polyvinylchloride (PVC) pipe and early generation polyethylene (PE) pipe currently in operation before any of it exceeds 50 years in age. The pipe to be replaced includes 1,597 km of PVC[131] installed primarily in rural areas between 1966 and 1977. AG estimated it would spend $19.5 million in 2011, $23.4 million in 2012, and approximately $20 million plus inflation per year on a go forward basis to replace approximately 600 km of pipe annually taking 17 years to complete the project.

166. The business case considered three alternatives: the status quo, the recommended proposal to replace all pipe installed before 1978 within 17 years and a third alternative to replace 1966-1974 vintage plastic pipe over 20 years at an estimated cost of $11 million annually plus inflation.[132]

167. The summary table below shows the plastic pipe that would be replaced under the two main alternatives. Alternative 2, the recommended alternative, includes pipe installed from 1966 to 1977. Alternative 3 includes pipe installed from 1966-1974.

Table 10. PE/PVC installed from 1966 to 1977

Year	Total PE/PVC Main Installed (km)[133]
1966	106
1967	688
1968	1,119
1969	916
1970	634
1971	327
1972	189
1973	243
1974	531
	Alternative 3 Sum-total 4753
1975	2,012
1976	2,038
1977	637
Total	9,441

168. During the past several years AG has replaced some PVC and PE, but not as part of a proactive program. The following table[134] provides a history of the replacements since 2002 and indicates that in the past nine years AG has replaced 32 km of pipe at a total cost of $2.6 million:

131 Exhibit 84.01, AUC-AG-8(a).
132 Exhibit 1, Volume 2-2, Business Case 4, paragraph 7.
133 Exhibit 83.01, UCA-AG-107(a).

Table 11. Plastic pipe replaced from 2002 to 2010

Year	Pipe Replaced (m)	Cost ($000's)
2002	502	8
2003	3037	68
2004	1200	44
2005	8523	512
2006	2392	158
2007	420	43
2008	5914	343
2009	1500	54
2010	8517	1,408
Totals	32005	2,639

169. AG indicated that the PE pipe to be replaced was non-certified in Canada as it was manufactured before the Canadian quality assurance test, CSA B137.4 - Polyethylene Piping Systems Fittings for Gas Services was established or made mandatory. The CSA B137.4 standard was first available in 1973, and the manufacture of pipe to this standard was optional between 1973 and 1975 at which time the standard became mandatory in Canada.[135] Prior to the CSA B137.4 standard, plastic pipe was manufactured to a US quality assurance test, ASTM D2837 - Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products. Accordingly, AG was targeting the removal of PVC pipe and PE pipe manufactured prior to 1976. Given that some of this pre-1976 pipe may have been in inventory and installed for up to two years after its manufacture, AG's replacement program included PE pipe installed up to the end of 1977. AG indicated that replacement of plastic pipe installed in 1976 and 1977 would occur at the very end of the 17-year program at which point the pipe would be at least 50 years old.

170. AG noted that Alberta Transportation and Utilities published a report based upon extensive testing of plastic pipe in Alberta in 1985. This report found that plastic pipe from the 1960's and early 1970's contained questionable resin materials and was produced using questionable extrusion manufacturing operations.[136] The National Transportation and Safety Board (NTSB) in the US published a special investigative report on "Brittle-Like Cracking in Plastic Pipe for Gas Service" in 1998. AG indicated that the report demonstrated that early generation plastic pipe failures were not isolated incidents and more such incidents were expected.[137]

171. AG noted in the application and in the business case that Alberta Rural Utilities Branch had put pressure limitations on all PVC and early generation PE pipe manufactured prior to 1975 in Bulletin RUB 2004-02.

172. AG included in its plastic pipe replacement business case as Figure 1,[138] and again in its Rebuttal Evidence,[139] a graph from the NTSB report showing the transition "knee" where

[134] Exhibit 83.01, UCA-AG-17(a).
[135] AG rebuttal, page 8, paragraph 29.
[136] AG rebuttal, page 8, paragraph 31.
[137] AG rebuttal, page 9, paragraph 34.
[138] Application, Tab 2.1, Business Case 4, page 10.
[139] AG rebuttal, page 7, paragraph 24.

significant deterioration in pipe strength over time becomes evident for older generation plastic pipe. AG stated:

> Figure 1 shows the relationship that has been determined between hoop stress and time of failure. It has been proven that as plastic pipe ages, it will exhibit increasingly brittle properties where the stress required to cause failure dramatically decreases. It can be shown through material failures that the older generation (pre-1978) plastic in the Company system is within the brittle area of the curve.[140]

173. AG noted that the NTSB graph was generic for PE pipe and that there would be a unique plot for each resin, pipe manufacturer and pipe diameter. However, the consensus among researchers was that earlier generation plastic pipe reaches the transition knee at a younger age than does more modern plastic pipe. The business case included a review of the evidence demonstrating the need for the program. In its rebuttal evidence AG stated that it had "…done its own engineering assessment which concluded that the early generation plastic pipe it installed is limited to no more than a 50 year life."[141]

174. AG noted that its records of installed plastic pipe did not include resin or manufacturer, so laboratory testing to identify the most probabilistic pipe would not be of assistance. The pipe in service has 143 combinations of manufacturer and resins, each with its own characteristics. Each combination would have to be tested.

175. AG stated that the examples of plastic pipe failures provided in the business case also show that plastic pipe can fail dramatically at the end of its service life. AG noted that this makes timely replacement of this pipe before it reaches the end of its service life all the more critical. Steel pipe would provide some indication it is nearing the end of service life by developing more corrosion leaks. AG argued that plastic pipe did not generally provide any such warning as it neared the end of its service life[142] which necessitated erring on the side of caution with respect to replacement programs.

176. AG surveyed a number of other gas distribution companies with regard to PVC or brittle PE plastic pipe. The findings of the survey summarized in Table 3 of the business case were that these companies were monitoring their systems or undertaking a replacement program.

177. AG also noted that PVC pipe was considered to be inferior to PE pipe because it was more brittle than PE pipe to begin with.[143]

Views of the parties

178. Calgary argued that AG had ignored the fact that there was significant replacement of the early generation PE pipe in the 1970s and Calgary understood that virtually all of the PVC pipe was replaced in the 1970s.

179. Calgary argued that the evidence provided by AG did not provide the justification to increase the amount of pipe replaced by almost 100 fold.[144]

140 Application, Tab 2.1, Business Case 4, page 9.
141 AG rebuttal, pages 7-8, paragraph 26.
142 Transcript,Volume 6, page 1155, line 24.
143 AG rebuttal, page 7, paragraph 25.

180. In its evidence the UCA submitted[145] that AG's business case had not demonstrated the need for a program to replace this vintage of pipe either at all, or over the proposed 17-year period. The UCA examined the following components of the AG evidence:

- the NTSB report
- a survey that AG conducted of other Canadian utilities in relation to older vintage plastic pipe
- anecdotal evidence of examples of plastic pipe failures on the AG system
- a claim that the expected life of the older vintage plastic pipe is only 50 years

181. The UCA noted that the 1998 NTSB report, made no recommendations concerning replacement programs and observed that hardening of the pipe over time "appears to have little observable adverse impact on the serviceability of plastic piping except in those instances in which the piping is subjected to external stresses."[146]

182. The UCA noted that no other Canadian utility that responded to the survey had an approved and ongoing program to replace its older plastic pipe.

183. With respect to the anecdotal evidence, the UCA stated that it did not consider these examples justify the wholesale replacement of several thousand kilometres of plastic pipe.

184. The UCA submitted that the underlying premise on which AG's program was based was a non-conservative estimate of the life of PE pipe of 50 years.[147] The UCA noted that AG had not provided a copy of its engineering assessment or explained the basis for its conclusions. The UCA stated that the response to UCA-AG-18 did not indicate reliance on external research, scientific papers, industry publications or research, or any other external sources of information, and that AG had not conducted empirical testing or other research in the course of conducting its assessment.[148]

185. The UCA acknowledged that it was possible that a thorough and properly done analysis would show that what AG had proposed was necessary and that it would ultimately benefit customers, but that analysis had not been done,[149] and in fact stated in argument:

> At the same time, the UCA does acknowledge that it appears that there are physical problems with older vintage plastic pipe that do not exist with the steel piping … there does not seem to be any doubt that the older vintage plastic pipe is now of an age where it is subject to brittle-like failure under stress, and in that sense at least is an inferior technology.[150]

186. In light of the UCA's analysis of the four tenants of the AG proposal the UCA recommended that the Commission direct AG to undertake a testing and research program, potentially with other utilities, and report back to the Commission.

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144 Exhibit 3, pages 2.1-16 and 2.1-18 (from 7-8 km/year to 600 km/year).
145 Exhibit 110.07, UCA general evidence at pages 13-14, Q.23-Q.26.
146 As cited in UCA evidence from Exhibit 1, application Volume 2.2, Business Case 4, Plastic Pipe Replacement, Attachment 1, page 37.
147 Exhibit 110.07, UCA evidence, page 15, Q26.
148 Ibid., page 15, Q27.
149 Exhibit 110.07, UCA evidence, page 15, Q28.
150 UCA argument, paragraph 35, page 10.

187. Finally, in the event the Commission was amenable to some aspects of AG's plastic pipe replacement proposal the UCA recommended that:

- Any Commission approval should exclude pipe installed during 1976 and 1977 as AG was proposing to include in the replacement program plastic pipe installed during 1976 and 1977 "…even though the record makes it clear that very little, if any, pre-1976 plastic pipe was installed after 1975. As indicated by ATCO Gas in Argument, quoting Mr. Hahn, ATCO Gas's approach reflects an 'abundance of caution'." (footnotes omitted).[151]
- The UCA submitted that even if some portion of pre-1976 plastic pipe had been installed AG's normal maintenance resources would still be available to deal with any issues that arose.
- The Commission should distinguish between the older pre-1973 vintages and the 1973 to 1975 vintages because they have different maximum allowed operating pressures suggesting different physical properties.[152]

Commission findings

188. The Commission accepts AG's evidence that all PVC and early generation PE is at risk of brittle failure when under stress and should be replaced. The risk of brittle failure when under stress is a serious issue impacting safety and reliability and the Commission considers that some action must be taken. The Commission will consider two issues: the time period over which this pipe should be replaced and the need to include in the replacement program plastic pipe installed between 1975 and 1978.

189. With respect to the lack of records AG has explained that the combination of manufacturers and resin in the early years complicated record keeping. The Commission rejects the proposal by the UCA to undertake additional testing and research prior to implementing a replacement program. The Commission questions the practicality and cost/benefit of such an approach given the different characteristics and circumstances of the pipe.

190. The UCA recommended that if the Commission approves a plastic pipe replacement project, the program should be scaled back by excluding 1976 to77 pipe and drawing a distinction between the older pre-1973 vintages and the 1973 to 1975 vintages, which have different maximum allowed operating pressures.

191. With respect to the second UCA recommendation the Commission acknowledges that pre-1973 plastic pipe and 1973 to1975 plastic pipe were subject to different certification practices and approved for different operating pressures. However, the Commission notes that neither vintage group was required to meet the CSA standard which became mandatory in 1975. Accordingly, the Commission considers it in the public interest to remove all pipe manufactured prior to 1973. With respect to pipe manufactured from 1973 to 1975, the Commission notes AG's comment that it is acting with an "abundance of caution." With regard to the UCA's first recommendation, the issue for the Commission to address is the extent to which inventory practices may have resulted in the installation in 1976 or 1977 of interim certified pipe from the 1973 to1975 period. AG's records are inadequate. AG is neither able to identify whether pipe purchased during the interim 1973 to1975 period was certified nor has it the ability to determine how long pipe remained in inventory and therefore, what portion, if any of the pipe was installed

151 UCA reply argument, paragraph 29, page 11.
152 UCA argument, paragraph 40 and 41, pages 11-12.

in 1976 and 1977. These facts have made the consideration of this program difficult. Nonetheless, the Commission considers the risk of brittle failure associated with plastic pipe and PVC pipe when subjected to stress to be a serious safety and reliability issue, and therefore, the Commission approves the entire program. However, the Commission directs that the program be implemented over a 20-year period considered in alternative three in the business case rather than the 17-year proposed in alternative two. Given the fact that the pipe manufactured during the 1973 to1975 period was of a higher quality than the pre-1973 pipe and some of the 1973 to 1975 pipe may have met the then voluntary CSA standard and noting that this vintage of pipe was proposed to be removed last, the Commission considers the extended installation period to be warranted. Lengthening the time period over which replacement occurs will reduce the magnitude of the impact on rates to customers but does put in place a comprehensive plan to replace PVC and early generation PE.

192. As additional leak history data on pipe installed from the 1973 to1977 period becomes available it may be appropriate to reconsider the program scope and timelines. The Commission directs AG to continue to provide plastic pipe leak history in future capital program applications.

193. The Commission directs AG in the compliance filing required by this decision to indicate what the 2011 and 2012 plastic pipe replacement program revenue requirement would be based on a 20-year program, without considering the actual 2011 expenditures.

4.3.4 Line heater reliability (Business Case 5)

194. As part of the expenditures included in regulating metering station improvements AG submitted Business Case 5. AG proposed to make improvements to 500 line heaters over three years beginning in 2011 for a total estimated cost of $20.85 million or about $7 million each year for the purpose of improving reliability and resolving safety, CSA standard, *Safety Codes Act* and Occupational Health and Safety (OH&S) Code compliance issues. AG referred to three outages in 2006, 2007 and 2010 to support implementation of the project.

195. Mr. Dixon indicated that the project would achieve compliance with OH&S requirements and that improvements would be made at the same time to achieve greater reliability of the heaters. Approximately half of the forecast costs are related to OH&S compliance and half to reliability improvements.[153]

196. In response to questions by Commission counsel the witness for AG confirmed that half the work was to comply with safety standards and that the estimated cost per unit to do the work had not been changed as a result of the on-going, half completed survey of the 501 units. Mr. Dixon indicated that a survey of approximately half of the line heaters has been completed and that nothing had been noted that would lead it to change its estimates. He confirmed that line heaters with non-compliance issues with OH&S standards would be given the highest priority for replacement. When questioned regarding the three examples of line heater failures, Mr. Dixon stated that none were in locations known for having high liquid content or problems with the upstream pipelines. Despite the small number of failures, he stated that the three-year time period was necessary to comply with the OH&S standard.[154]

[153] Transcript, Volume 5, pages 973-974.
[154] Transcript, Volume 6, pages 1204-1205.

197. AG considered proper functioning of line heaters was critical to ensure that customer outages did not occur.[155]

198. AG noted that many of its line heaters had been in service for 30 years. The line heaters also did not have modern burner management systems and/or did not contain SCADA systems that permit real time monitoring of their operation.[156]

199. AG stated its three-year program was based upon an average cost per site of $41,700. The average cost per site was determined from eight sites where the necessary improvements have been completed. Each site was unique and included different sizes of line heaters but the eight were selected as being representative of the entire 500 sites requiring improvements. AG stated it had inspected approximately half of the 500 sites and had found nothing that would indicate the need for a different average cost forecast.[157]

Commission findings

200. The Commission relies on AG's statement that OH&S regulations require AG to update its line heaters. A three-year program has been proposed to complete the work to bring the non-compliant line heaters into compliance and to do reliability work at the same time. The plan by AG to complete the compliance work in three years seems reasonable and the Commission approves this portion of the program for inclusion in revenue requirement. The Commission finds that when reliability improvements are to be made on heaters for which compliance work is to be done, it is practical to do both at the same time over the three year period. However, the Commission does not consider that justification has been made for a three-year period to complete work on line heaters that do not have a compliance component. Therefore the Commission directs AG to exclude from its program, line heaters that are in compliance with OH&S regulations. The Commission directs AG in the compliance filing to this decision to reflect two years of the three-year replacement and upgrading of the non-compliant line-heaters.

4.3.5 Low use AMR (Business Case 7)

201. AG proposed to install AMR on all 1,044,000 residential and low use customer premises over a five-year period starting in 2010 with field installations starting in 2011. AG indicated that the project will allow meter reading remotely without having a meter reader manually record the reading for low use residential and commercial customers and the associated meter reading cost reduction benefits outweigh the capital costs to install the AMR system. AG provided the following forecast:

Table 12. AMR expenditures - Table 2.1.1.4(c)

	ATCO Gas (Total) - Low Use AMR Project - By Year					
	2010	2011	2012	2013	2014	Total
Units	10,000	134,000	348,000	333,000	219,000	1,044,000
Forecast ($ millions)	3.7	17.2	37.4	35.2	27.5	121.0

202. During the test years of 2011 and 2012 AG forecast expenditures of $17.2 million and $37.4 million, respectively.

155 Application, Tab 2.1, Business Case 5, Line Heater Reliability, page 5.
156 Application, Tab 2.1, Business Case 5, Line Heater Reliability, page 3, 6.
157 Transcript, Volume 5, page 972, line 19.

203. AG submitted that it had been evaluating and testing advances in AMR technology for some time. The AMR technology had reached the stage where it could reliably meet AG's requirements now and into the future, on a cost effective basis. AG proposed a stand-alone implementation independent of AMI [advanced metering infrastructure] deployments by electric utilities. AMR would be accomplished by the installation of AMR endpoints on each meter. Itron Inc. (Itron) was selected as the vendor following a request for proposals which evaluated, among other things, functionality, technology, cost and industry proven reliability. AG also implemented several pilot projects prior to electing to proceed with the AMR project. AG indicated that, at the completion of the project, approximately 200 FTE positions would be re-deployed into other positions, a portion of which would become available as the result of retirements and attrition. AG indicated that no severance costs would be incurred.

Views of the parties

204. Calgary stated it could not support the project as proposed due to the lack of reasonable assurance that former meter readers would actually assume open positions due to retirement and attrition. Calgary's opposition to the AMR project related to the operating and maintenance (O&M) expenses and will be discussed further under O&M.

205. The CCA recommended that AG should be directed to report to the AUC and interveners before the end of 2011 on the results and effects of the proof of concept stage for AMR before rate base additions are permitted.

206. The UCA did not object to AG's low use AMR,[158] however, it had the following concerns:[159]

a. Timing of harvesting of benefits. The UCA is concerned that the timing of the reduction in meter reading positions does not reflect the timing of the installation of AMR meters.
b. Contingency. AG has included a 20% contingency, and the UCA is concerned that this unnecessarily inflates the costs included in the 2011 and 2012 forecasted capital expenditures.
c. Opportunity for daily reads. The UCA wants to ensure that the capability for daily reads does not require additional costs or site visits at a later date.[160]
d. Introduction of a program to have the RF [radio frequency] signal turned off.

207. The contingency item of concern to the UCA was related to capital and is reviewed in this section. The other items are more related to O&M and will be discussed in the appropriate section of this decision.

208. The UCA noted that AG had included a 20 per cent contingency in the AMR business case, which was subsequently reduced to 15 per cent ($6.851 million for the capital portion of the work and $0.484 million for the work removal) as a result of the finalization of the contract for the installation and the majority of the materials.[161] The UCA noted this was still higher than other contingency provisions used by AG which ranged from 10 per cent to 12.3 per cent.[162]

158 Exhibit 110.07, UCA general evidence, A29.
159 UCA argument, page 14, paragraph 50.
160 Exhibit 110.07, UCA general evidence, A30.
161 Exhibit 83.01, UCA-AG-51(b).
162 Exhibit 200.02, UCA argument, page 19, paragraph 65.

209. The UCA also noted that the only project with a higher contingency at 18.3 per cent was the Oracle Human Resource Management System, an IT project. The IT component of the AMR project was complete and AG had converted its systems within budget,[163] and the additional system work to interface the contractor's work management system with the AG work management system was completed within 10 per cent of the budget.[164] The UCA was concerned that AG was not capturing possible cost savings and efficiencies that could result between projects. The UCA referred to the following statement from an AG witness at the hearing:

> 00754
> A. MR. DIXON: Okay. A couple of points there. The first one, let's talk about the MRRP program, MRRP, and AMR. Yes, the two groups are in constant communication so that we don't -- for efficiency reasons and that we're not bothering the customer more than once.
> So, basically, what we're doing is trying to hold off in the areas that are designated for MRRP work, hold the AMR work off from those areas until the MRRP work is done, and then it makes the AMR installation easier, because that meter is already outside, so that's how we're marrying up those two programs.[165]

210. From this statement, it appeared to the UCA that AG was completing the MRRP task and then going back and installing an AMR endpoint. The UCA submitted that it would be more efficient to install AMR fitted meters at the time of the MRRP activity.

211. Based on all of the factors discussed above, the UCA argued that a reduction in the contingency was required. A reduction to 10 per cent would result in a reduction in the forecast capital expenditures for 2011 and 2012 of $2,284,000 for the capital portion of the work and a reduction of $161,000 for the removal work for 2011 and 2012.[166]

212. AG argued that its response to UCA-AG-51 and its rebuttal evidence[167] had highlighted the factors which continued to remain unknown, and which the contingency was intended to cover, including uncertainties around the quantity and cost of ancillary materials, unforeseen costs related to information system related work, and unforeseen project costs that might be required to aid in project management and inspection. AG stated it was too early in the project to quantify or estimate in detail the costs associated with the unknown factors listed above, and therefore it was premature to reduce the contingency any further than had been done. AG further argued that it had already demonstrated that five per cent of the original contingency built into the project was required as a result of the finalization of the contract with Itron.[168]

213. In respect of the UCA's concern that AG was not capturing all efficiencies between the MRRP and the low use AMR projects,[169] AG argued that in the event that the MRRP necessitated a meter exchange at a particular site, the exchanged meter would be equipped with an AMR unit.

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163 Transcript, Volume 4, page 793, line 9.
164 Transcript, Volume 4, page 793, lines 22-23.
165 Transcript, Volume 4, page 754, lines 6-16.
166 Exhibit 110.07, UCA general evidence, A35.
167 AG rebuttal, page 25, 26, paragraph 85-87.
168 AG rebuttal, page 26, paragraph 87.
169 UCA argument, page 20, paragraphs 68-69.

However, that unit would not be used for meter reading until the site was ready to be included in a new AMR route, sometime in the future. AG submitted that a reduction to the project contingency should not occur as a result.

Commission findings

214. The Commission observes that there was no objection to the overall concept of the low use AMR project. The interveners expressed concern related to the potential O&M savings to be realized in meter reading and the assumptions regarding the deployment or attrition of the current meter readers. The UCA also had a concern regarding the forecast of capital costs.

215. The Commission supports the low use AMR project as set out in the business case, but finds it does not have sufficient information to address the capital cost component. The Commission's findings with respect to O&M, including cost savings, are discussed later in the decision.

216. The UCA's primary concern with the AMR program was the magnitude of the contingency included in the forecast estimates. The Commission agrees that the contingency may be too high, but notes that AG was expected to complete a "proof of concept" by the end of June 2011. The Commission directs AG to report in the compliance application to this decision on the results and effects of the "proof of concept" stage for installations made in the initial phase of the project and the results and the effect on the contingency, if any. AG is directed to submit an update to its business case economic analysis. The Commission will finalize the test year forecast amounts along with the contingency following the compliance application.

4.4 Distribution

217. The remaining costs in distribution will be reviewed. AG has forecast 21,700 new primary service installations in each of 2011 and 2012.[170] Primary service installations are a driver of costs for distribution services. Other drivers are system improvements and re-development. AG described how system growth is accompanied by general capital growth in its distribution system:

> The addition of new customers being served by ATCO Gas requires capital for more than just service line installations. New capital is required to construct mains, to purchase and install meters and regulators and to construct regulating stations. Many system improvements also have customer growth as a primary driver. Redevelopment of existing areas into higher density residential and commercial use often requires ATCO Gas to upgrade its system to meet the higher load. This redevelopment is particularly prevalent in the major urban centres. Typical upgrades include system looping and station upgrades to meet the increased customer requirements.[171]

[170] Application, page 2.1-1, paragraph 2.
[171] Ibid., paragraph 3.

Table 13. Distribution actual and forecast expenditures

Table 2.1.1 ATCO Gas (Total) - Historic and Forecast Expenditures						
	($ millions)					
	Actual 2008	Actual 2009	Actual 2010	Forecast 2010	Forecast 2011	Forecast 2012
Distribution						
Distribution extensions	53.3	35.5	36.3	44.8	47.6	47.0
Distribution improvements	80.7	66.0	72.8	73.6	146.4	164.0
Distribution services	31.2	27.4	32.2	33.1	36.4	37.0
Meters, regulators and installations	23.3	16.2	23.0	25.8	44.8	63.2
Subtotal distribution	188.5	145.1	164.3	177.3	275.2	311.2

4.4.1 Distribution extensions

218. Distribution extensions includes costs related to urban main extensions, rural main extensions and services, urban feeder mains and new regulating meter stations. The costs are related to system growth and are largely driven by demands made by municipalities, developers and rural customers. In 2008 the forecast was $27 million and in 2009 the forecast was $33 million. There were no intervener comments on general distribution extensions.

Commission findings

219. The Commission notes the difficulty in forecasting the expenditures in this area given the need to be responsive to customer growth and as evidenced in the discrepancy between actual and forecast expenditures since 2008. Directionally the change is consistent with the inflation and growth forecasts provided by AG in its application. The Commission considers it reasonable to approve the forecast for the test years.

4.4.2 Distribution improvements

220. Distribution improvements relate to the improvement and replacement of the distribution system and system upgrading. Business cases 1 (Urban Mains Replacement), 2 (Above Ground Entry Meter Relocation and Replacement Program), 3 (TransCanada Turbines HP Lateral Relocation), 4 (Plastic Pipe Replacement) and 5 (Line Heaters Reliability) fall within this classification and have been dealt with above. With respect to the remaining distribution improvements to be dealt with in this section, the Commission notes that the interveners did not provide comments.

Table 14. Distrbution improvements

	Actual			Forecast		
	2008	2009	2010	2010	2011	2012
	($ millions)					
Urban Mains Improvements	18.2	16.1	20.1	20.4	69	78.6
Meter Relocation & Replacement Project	38.8	28.5	25.3	25.5	33.2	32
Commercial Below Ground Entry Project	6.1	6.5	7	6.8	0.6	0
Urban Main Relocations	6.4	5.1	6.1	8	7.8	5.3
Rural Main Replacements and Relocations	5.2	4.6	7.9	6.4	4	4
PE/PVC Pipe Replacement	0	0	0	1.1	19.5	23.4
Regulating Metering Stations Improvements	3.7	2.7	3.4	3.4	10.6	19.2
Cathodic Protection	0.8	1	1.1	0.6	0.9	0.8
Southern Extension Project Total Expenditures	1.5	1.5	1.9	1.4	0.8	0.7
	80.7	66	72.8	73.6	146.4	164

221. Urban mains improvements includes business cases 1 and 3 approved above, the urban mains replacement program, AP HP Relocations as updated in the January 21, 2011 update,[172] and urban mains improvements.

4.4.2.1 High pressure relocations

222. AG submitted that the forecast costs included two projects in the City of Edmonton in 2011. The first was related to ATCO Pipelines abandoning a portion of line serving downtown Edmonton. The second was a result of ATCO Pipelines abandoning a line in northeast Edmonton. The third and final project was proposed for The City of Calgary in 2012 and was a result of ATCO Pipelines abandoning high pressure facilities in south east Calgary.

223. In all three cases, AG has recommended the option of installing new distribution facilities and transitioning a portion of the high pressure pipelines to distribution service, where those assets are assessed to be of acceptable integrity.

224. AG noted that the AUC had not approved the ATCO Pipelines’ business cases supporting their projects, but that ATCO Pipelines was proceeding with this work and AG argued it had no option but to proceed with its work in order to maintain distribution service to the affected areas, and thus its revenue requirement forecasts must reflect the cost of undertaking that work.

Commission finding

225. The Commission is satisfied with AG’s explanation and notes there were no opposing views provided by interveners. Accordingly, the Commission approves the incremental costs for high pressure relocation set out in its January 21, 2011 update.

4.4.3 Purchase of non-SCADA meters from ATCO Pipelines

226. In 2012, ATCO Gas included within its distribution improvements forecast a one-time $6.5 million expenditure related to the purchase of non-SCADA metering equipment from ATCO Pipelines at its net book value.

172 Exhibit 70.01.

227. AG submitted in its application and rebuttal[173] that the 986 non-SCADA meters that it was planning to purchase from ATCO Pipelines were no longer needed by ATCO Pipelines after the 2011 integration with NOVA Gas Transmission Ltd. (NGTL). AG however, continued to need that data supplied by these meters for the determination of unaccounted for gas (UFG), transmission billing contract demand, flow information for facility sizing and design and transmission account settlement

Views of the parties

228. Calgary expressed concerns with the cost of integration of ATCO Pipelines and NGTL and recommended that the cost of the non-SCADA meters not be included in rate base.

229. The CCA submitted that the purchase of the non-SCADA meters from ATCO Pipelines' capital assets, which were transmission related, should not be included in a distribution utility rate base. The CCA agreed with Calgary that these asset transfers should have been considered and raised by AG and ATCO Pipelines as part of the integration negotiations. The measurement of natural gas delivered off the transmission system was a transmission function no matter what the size of the meter. The CCA recommended that the purchase of the high pressure non-SCADA meters should not be added to rate base.

230. AG argued that its customers were paying for the cost of these meters in their rates at present through the transmission charge. This was appropriate, because it was AG's customers who received the benefits of these meters, not NGTL.[174] In AG's reply it argued that contrary to the suggestion by Calgary, there would not be a cost increase to customers as a result of AG buying the non-SCADA meters which AG required in order to ensure that accurate measurement was occurring on its distribution system.

231. In rebuttal[175] AG noted that these meters were being used at present and would continue to be required in the future for a number of purposes including the determination of UFG, calculation of the contract demand quantity, network modeling and transportation account settlement.

Commission finding

232. The Commission notes AG's statement that these meters will be required in the determination of UFG. For this reason, and as supported by the other reasons put forward by AG, the Commission accepts AG's position that the meters it proposes to purchase from ATCO Pipelines will benefit AG. The Commission approves the purchase of the non-SCADA meters from ATCO Pipelines at book value.

4.4.4 Other distribution improvements

233. The Commission has reviewed the forecast costs of urban mains upgrades and urban mains improvements relative to actual costs for the years 2008 to 2010 and finds that the costs are reasonable.

173 Exhibit 163, AG rebuttal evidence, paragraph 95.
174 Transcript, Volume 5, page 962, lines 17-24.
175 AG rebuttal evidence, paragraph 95.

Commission finding

234. The Commission approves the other costs in distribution improvements as filed.

4.4.5 Distribution services

235. AG is requesting approval of forecast costs for new urban service line installations of $31.4 million in 2011 and $32.0 million in 2012, and an additional $5 million in each year for "service line replacements and improvements. AG stated in its application that the utility rate base is net of customer contributions.[176] Therefore, approval is implicitly sought for the related customer contributions. In response to AUC-AG-21,[177] AG provided details of the customer contributions for new urban service lines. AG explained in the application that the forecast costs for new urban services were based on a three-year average:

> An average price per service line is forecast for each service area. The three year average is calculated based on historical information to arrive at an average price. The average price per service line is then inflated to obtain a unit price per service for each of the test years. This unit price is then multiplied by the forecast number of service lines to obtain the total forecast cost.

236. The costs of new service lines are to be offset by a contribution from customers that is expected to amount to 5/8ths of the total cost. However, in the application AG indicated that it will not again achieve this level until after the tests years are completed. The test years included a forecast total of $16.7 million and $19.2 million for 2011 and 2012, respectively,[178] which were only 53 per cent and 60 per cent of the total costs.

237. Mr. Zurek, explained in the oral hearing that actual contributions can lag the Schedule "C" rates.[179]

Views of the parties

238. CCA noted that the cost of a new urban service was set at 5/8ths or 62.5 per cent for the customer contribution level.[180] The CCA suggested that the AG forecast of contributions was incorrect and should be $16.8 million in 2011. However, AG was only forecasting $11.6 million which seemed to be consistent throughout the distribution service forecasts. Although CCA

176 Exhibit 3, Section 2.3, paragraph 1, page 2.3-1.
177 Exhibit 84.01, AUC-AG-21.
178 Exhibit 84.01, AUC-AG-21.
179 Decision 2010-291, page 33, paragraphs 136-137:
"The contributions are based on rates approved in Schedule "C", which was last approved in Decision 2010-291. In that decision the Commission made the follow statements in it findings:

> The Commission notes that the Schedule "C" changes will be phased in over a three-year period in order to minimize customer impact. As part of this plan the Settlement Parties proposed deferral account treatment for these costs. The Commission will deal with the issue of deferral accounts later in this Decision.
>
> The Commission realizes that, although Schedule "C" charges are included as part of the T&Cs, the charges result in revenues that are contributions-in-aid-of-construction and therefore directly impact the revenue requirement. It would be appropriate to discuss and approve the estimated revenues generated by such charges during the Phase I of a GRA. Accordingly, the Commission directs ATCO to submit and support the estimated revenues attributable to Schedule "C" charges and any proposed changes in its next GRA Phase I application."

180 AUC-AG-21.

noted that AG explained the lower amount was due to a lag in implementation of Schedule "C" charges which set customer contribution levels[181] CCA argued that AG should be directed to investigate whether the goal of 5/8ths customer contributions of new service connections should continue.

239. The CCA noted that in 2010 AG over-forecast residential urban service unit costs by 10 per cent[182] and under forecast commercial unit costs by 11.8 per cent.[183]

240. The CCA recommended that both the residential and commercial urban service unit costs be adjusted for 2011 and 2012. The CCA recommended that the 2011 and 2012 residential unit cost be decreased by 10 per cent while the commercial unit cost be increased by 11.8 per cent. Although these two recommendations have an offsetting effect, the CCA noted that there were rate design implications and accurate costing should be utilized.

241. The CCA also noted that in 2010 AG had over-forecast rural pool services unit costs by 11.4 per cent[184] and over-forecast extension unit costs by 3.3 per cent.[185] The CCA recommended that the 2011 and 2012 rural pool unit cost be decreased by 11.4 per cent. The CCA did not consider the extension cost variance to be material.

242. AG noted in its reply argument that the calculations performed by the CCA were incorrect.[186] The $11.6 million of contributions the CCA indicated that AG was forecasting was the 2008 actual level of contributions.[187]

243. AG submitted that a review of the correct 2011 and 2012 level of contributions to service line expenditures indicated that AG was recovering 53 per cent of the cost in 2011 and 60 per cent in 2012.[188] The reason for the lower level of recovery in 2011 was because AG was increasing its Schedule "C" charges for service line contributions over a three year period to reduce the rate shock to customers as approved in Decision 2010-291.

Commission findings

244. AG has used an average of historical actual costs adjusted for inflation to arrive at the regional unit costs which are multiplied by the forecast of new customer service lines to determine total distribution service line forecast costs. Given the use of actual costs, the process is self adjusting. If previous forecasts have been over stated then so too have the revenues, which again is self compensating. As a consequence, the Commission does not agree that the unit costs should be reduced as proposed by the CCA. Based on the preceding analysis, the Commission approves the forecast expenditures for distribution services.

245. In respect of the contribution by customers for their portion of the service line which has historically been determined to be equal to 5/8ths of the total service line cost, the Commission is satisfied that AG is increasing the contribution from lower amounts to the approved level of

181 Transcript, Volume 6, page 1210.
182 CCA argument, paragraph 13, page 6 (1578-1737)1578.
183 Ibid., (7007-6183)/824.
184 CCA argument, paragraph 15, page 7 (4808-5406)/4808.
185 Ibid., (8712-8998)/8712.
186 CCA argument, page 6, paragraph 11.
187 Ibid.
188 Ibid.

62.5 percent by 2013 in accordance with the negotiated settlement as approved in Decision 2010-291. The Commission expects AG to maintain the approved level with greater diligence so that it does not fall to the levels it has in recent past or require a graduated correction.

246. In Section 9.1 the Commission approved the growth forecast for the test years. As discussed above the Commission finds the three-year averaging methodology to be reasonable. The Commission approves the forecast costs of $36.4 million in 2011 and $37.0 million in 2012 for distribution services. The Commission also approves the customer contributions of $16.7 million in 2011 and $19.2 in 2012 as identified in response to AUC-AG-21 and implicitly reflected in the application.

4.4.6 Meters, regulators and installations

247. AG is requesting approval of forecast costs of $44.8 million of forecast costs in 2011 and $63.2 million of forecast costs in 2012 related to meters, regulators and installations. The cost classification has seven sub-accounts. The low use AMR project applied for in Business Case 7 accounts for $17.2 million of 2011 forecast costs and $37.3 million of forecast costs for 2012. The remaining $27.6 million for 2011 and $25.9 million for 2012 will be considered in this section. Two significant policy changes are introduced in relation to this cost classification: the request for an accounting change related to removal costs for the AMR project and a change in policy regarding meter replacements. AG will no longer be repairing or refurbishing meters. These changes in policy have implications for O&M Account 673 and will be examined in that section.

Commission findings

248. The Commission’s analysis of forecast costs related to Business Case 7, were addressed in discussion of that business case. The residual amounts are related to meters and instruments, other AMR, SCADA, relocations and replacements and capitalization due to the change in accounting policy. Interveners did not comment on these costs.

249. The Commission has compared the forecast costs relative to actual costs for 2008 and 2009 and finds the only account with a significant increase is the meters and instruments. AG has explained that the increase in this cost is due in part to the need to replace non-temperature compensated meters for the MRRP program and for 2011 completing the replacement of mechanical temperature correcting modules on rotary meters. The Commission finds the explanations reasonable and approves the costs as forecast, subject to the Commission’s determinations with respect to the MRRP program set out in Section 4.3.2 above.

250. The new classification for the capitalization of costs related to meter replacement has been addressed in the analysis of Account 673.

4.5 Land and structures

251. In the application AG estimated capital expenditures totaling $15.3 million in 2011 and $13.2 million in 2012 for land and structures.

Table 15. Distribution improvements

	Actual			Forecast		
	2008	2009	2010	2010	2011	2012
	($ millions)					
Leasehold Improvements	0.8	0.6	1.3	1.1	1	1
New Operating Centre-Viking	2.9	0.1	0	0	0	0
New Operating Centre-Edmonton North	7.1	13.5	0.4	0.4	0	0
New Operating Centre-Fort McMurray	3.8	2.3	0	0	0	0
New Operating Centre-Peace River	2.5	2.2	0	0	0	0
Blue Flame Kitchen	0.3	0.2	1.3	1.2	0	0
New Operating Centre-Okotoks	0	0	0	0	7.3	4
Whitehorn Parking Lot Expansion	0.2	0.7	0	0	0	0
New Operating Centre-Airdrie	2.8	0.8	4.6	4.8	0	0
New Operating Centre-Drayton Valley	0	0	0	0	0.8	4.5
Grande Prairie Shop Extension and Yard	0	0	0.9	0.5	2.3	0
Total	23.5	22.8	10.4	10.6	15.3	13.2

252. Calgary raised a general issue related to AG's record keeping for land and structures and whether all properties included in the calculation of rate base in the test years continued to be used or required to be used to provide service. The Commission will consider this issue first.

4.5.1 Land and structures – used or required to be used

253. In response to CAL-AG-07(c) and a subsequent ruling by the Commission,[189] AG provided information with respect to the acquisition date, original cost and operational purpose of certain of its land and structures. Calgary called into question whether the balance of AG's land and structures currently in rate base continued to be used or required to be used to provide utility service.

Views of the parties

254. Calgary submitted that AG had accounted for approximately 56 per cent of the $123.3 million of structures and land, excluding land rights, in rate base at the end of 2010.[190] Calgary then stated:

> Therefore approximately 47% of the land and structures, at original cost, that AG claims it owns have not been shown to provide utility service. As such the owning and operating costs of these assets should be excluded from rate base and revenue requirement.[191]

[189] Exhibit 113.
[190] Exhibit 117.01, Q. 3, page 2.
[191] Exhibit 117.01, Q. 3, page 3.

255. AG submitted that Calgary's position that approximately 47 per cent of the land and structures AG uses to provide utility service should be removed from rate base because AG had not demonstrated that the assets are required for the provision of utility distribution service was "nonsensical".

256. When asked to confirm "that all assets represented in Rate Base are presently used, are reasonably used, and are likely be used in 2011 and 2012 to provide utility services.", in AUC-AG-3A(b),[192] AG answered "confirmed." AG also stated in AUC-AG-3A(a):

> Subsequent to placing an asset in utility service, ATCO Gas undertakes inspection, maintenance, and integrity programs on assets to ensure they continue to perform safely, reliably, and cost effectively… When an asset can no longer provide safe, reliable, and cost effective service, ATCO Gas undertakes a review of alternatives to replace that asset. …Any asset that is removed from service is also removed from rate base through the retirement process.

257. In reply argument AG submitted that its evidence indicated that:

> ATCO Gas has removed the cost of all assets no longer required for the provision of utility service from its rate base and revenue requirement forecasts.[193]

258. AG submitted that it is entitled to a presumption of prudence with regard to property previously approved as prudent for inclusion in rate base. AG further submitted that Calgary had not demonstrated that AG had behaved imprudently with regard to the inclusion of any property in its rate base. Calgary had not demonstrated that AG has any assets in rate base that are not used or required to be used for the provision of utility service.[194]

Commission findings

259. Section 37 of the *Gas Utilities Act* requires the Commission in fixing just and reasonable rates to "determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta."

260. The Commission does not consider that AG may rely upon a presumption of prudence that assets previously found to be used or required to be used to provide service and approved for inclusion in rate base should continue in forecast rate base and revenue requirement. In this regard the Commission notes the guidance of the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2008 ABCA 200[195] (Carbon decision) when it stated:

> 29. The *Act* does not contain any provision or presumption that once an asset is part of the rate base, it is forever a part of the rate base regardless of its function. The concept of assets becoming "dedicated to service" and so remaining in the rate base forever is inconsistent with the decision in ***Stores Block*** (at para. 69). Such an approach would fetter the discretion of the Board in dealing with changing circumstances. Previous inclusion in the rate base is not determinative or necessarily important; as the Court

192 Exhibit 84.01.
193 AG reply argument, paragraph 20, pages 11-12.
194 AG argument, paragraph 12, page 6; AG reply argument, paragraph 21, page 12.
195 Leave to Supreme Court of Canada dismissed [2008] S.C.C.A. No. 347 (S.C.C.).

> observed in ***Alberta Power Ltd. v. Alberta (Public Utilities Board)*** (1990), 72 Alta. L.R. (2d) 129, 102 A.R. 353 (C.A.) at pg. 151: "That was then, this is now."[196]

261. The court in the Carbon decision also made it clear that assets previously included in rate base that are not presently used or required to be used to provide utility service as required by Section 37 of the *Gas Utilities Act* should not remain in rate base.

262. The words "used or required to be used" are intended to identify assets that are presently used, are reasonably used, and are likely to be used in the future to provide services. Specifically, the past or historical use of assets will not permit their inclusion in the rate base unless they continue to be used in the system.[197]

263. A utility must be diligent in reviewing its assets on an ongoing basis to ensure that the assets included in rate base and revenue requirement continue to be used or required to be used for the provision of utility service. Any asset determined no longer to be used or required to be used for the provision of utility service must be removed from rate base and revenue requirement.

264. With respect to the assets presently forecast to be in rate base and revenue requirement, the record provides clear confirmation by AG that all assets represented in rate base are presently used, are reasonably used, and are likely to be used in 2011 and 2012 to provide utility services. AG outlined the measures it takes to ensure assets once included in service continue to perform "safely, reliably and cost effectively." Further, AG indicated that it has removed the cost of all assets no longer required for the provision of utility service from rate base. AG also provided confirmation of the continued utility use of certain specific assets that the Commission directed it to address. In the absence of any contrary evidence which indicates that any particular asset or group of assets included in rate base forecasts is not required to provide utility service in the test years, the Commission accepts AG's statement that its forecast rate base includes only those assets which continue to be used or required to be used to provide utility service in the test years.

4.5.2 Airdrie operating centre

265. AG indicated that the construction of a new Airdrie operating centre had been approved in Decision 2008-113 with the expectation of completion in 2010. The facility was completed in 2010 at a cost below forecast. The Commission has compared the actual costs of $5.6 million incurred in constructing the Airdrie operating center to the forecast costs previously approved by the Commission and notes that no intervener has objected to the inclusion of these costs in 2011opening property, plant and equipment balances. The Commission approves the inclusion of these costs in 2011 opening property, plant, and equipment balances.

266. AG confirmed that the previous agency office had been sold. Section 26(2)(d) of the *Gas Utilities Act* provides that a utility must obtain the consent of the Commission prior to the disposition of an asset outside of the ordinary course of business. AG treated the sale as a disposition within the ordinary course of business and accordingly had not sought prior Commission approval.

[196] Carbon decision, paragraph 29.
[197] Carbon decision, paragraph 23.

267. AG indicated[198] that the proceeds of sale had been accounted for in a manner consistent with the Uniform Classification of Accounts Regulation.[199] In AUC-AG-31(b) AG provided the following breakdown of how the proceeds, net of disposition costs of $795,000, were accounted for:

- $318,000 – credited to accumulated depreciation as salvage
- $477,000 – used to retire the land of which $308,000 represented the pre-tax gain on sale which was recognized as income

268. At the hearing AG explained why the sale of the Airdrie agency office was considered to be a sale within the ordinary course of business.[200] AG had suggested a materiality limit guideline of $1.5 million in determining whether transactions were within the ordinary course of business in its application with respect to the disposition of proceeds from the sale of the Red Deer agency office. This application was considered by the EUB in Decision 2006-127.[201] Transactions below this threshold AG suggested should be considered as occurring inside the ordinary course of business and those above the threshold should be considered as occurring outside of the ordinary course of business. Transactions outside the ordinary course of business would require prior Commission approval under Section 26(2)(d) of the *Gas Utilities Act*. The EUB had not commented on the $1.5 million threshold guideline in its decision. Ms. Wilson, witness for AG at the oral hearing, further explained the factors that AG considers when assessing whether a transaction should be considered either within or outside the ordinary course of business:

> Well, I think probably the proceeds value certainly is one of the first things we would likely look to. I think if we added disposition, that --where the frequency was low and the proceeds were in excess of 1.5 million, there the decision in essence would be made that it would not be viewed as a disposition in the ordinary course.
>
> If the proceeds are under 1.5 million, then we next look to what's the -- what's the rate base value. Are we talking about something significant here? If that's not significant either, then generally at that time we feel -- and as I said, we do look at other dispositions that we've had. I would note that in order U 2008 158, the Commission found that the disposition of the Brooks agency office, which had estimated proceeds of $400,000 and a net book value of $275,000 should be viewed in the ordinary course of business. So when we looked at that decision and the Airdrie situation, they seemed quite similar to us in materiality and situation.
>
> So those are the kinds of things we look at, sir.[202]

269. In testimony, AG confirmed that the proceeds of sale allocated to the building exceeded book value and that the entire proceeds, less an allocated share of disposition costs, had been credited to accumulated depreciation. The proceeds of sale allocated to the land also exceeded

[198] AUC-AG-31(b).
[199] *General Instructions to the Canadian Gas Association Uniform Classification of Accounts for Natural Gas under the Jurisdiction of the Public Utilities Board of the Province of Alberta,* Alberta Regulation 546/63 (Uniform Classification of Accounts Regulation).
[200] Transcript, Volume 6, pages 1241-1248.
[201] Decision 2006-127: AG North, Disposition of Red Deer Operating Centre Part B - Final Disposition, Application No. 1421444, December 13, 2006.
[202] Transcript, Volume 6, page 1242, line 22 to page 1243, line 16.

book value. The shareholder received a return of the original cost of the land and after paying an allocated share of disposition costs, retained the net gain on the sale of the land.[203]

Views of the parties

270. Calgary noted in reply argument that AG had not fully explained why the Airdrie agency office had been considered by AG as a disposition in the ordinary course of business or why the proceeds should not be applied to the benefit of ratepayers.

271. In reply argument AG noted that it had treated the disposition in the ordinary course of business because the proceeds of sale were less than $1.5 million. AG had further discussed other criteria that it considers when determining whether a disposition was in the ordinary course of business during questioning by Commission counsel.[204]

Commission findings

272. The Commission must first consider whether the disposition of the Airdrie agency office was a disposition within the ordinary course of business and therefore did not require the prior consent of the Commission.

273. The Commission recently reviewed the legislation, prior regulatory decisions and addressed the criteria to apply when considering whether an asset disposition by a utility is inside or outside the ordinary course of business. In Decision 2011-387[205] the Commission considered an application by AltaLink Management Ltd. to dispose of certain assets outside of the ordinary course of business requiring the consent of the Commission pursuant to Section 102(2)(d) of the *Public Utilities Act*. The provisions of Section 102(2)(d) of the *Public Utilities Act* are nearly identical to the wording of Section 26(2)(d) of the *Gas Utilities Act*. In finding that the proposed disposition was outside the ordinary course of business, the Commission identified the frequency and materiality of the proposed transaction as the key factors to consider in determining if a proposed asset disposition is within or outside of the ordinary course of business. The Commission referred to Order U2001-196,[206] a decision of the EUB which helped to develop this frequency and materiality test. In that decision the EUB stated:

> …The Board confirms that it must first determine whether the disposition of an asset is outside the ordinary course of business for a utility. The proceeds of disposition, NBV, frequency and type of sale would be among the factors considered by the Board in that determination. The quantum, and materiality (in relation to the total rate base) of the proceeds of disposition and the NBV would all be considered.[207]

274. The EUB also stated in U2001-196 that "both the quantum and materiality of the proceeds of the sale and net book value should be considered independently when the Board determines whether a transaction is in the ordinary course of business for a particular utility."[208]

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203 Transcript, Volume 6, pages 1243-1245.
204 Transcript, Volume 6, pages 1241-1243.
205 Decision 2011-387: AltaLink Management Ltd., Sale of AltaLink Assets at Riverside 388S Substation; Provident Energy Ltd. Amendment to Redwater Industrial System Designation, Applications Nos. 1606975 and 1606873, Proceeding ID. No. 1063, September 22, 2011.
206 Order U2001-196: NOVA Gas Transmission Ltd., In the matter of the Sale of the Athabasca Maintenance Facility, Application No. 2001112, File No. 6417-04, August 3, 2001.
207 Order U2001-196, page 3.
208 Order U2001-196, page 3.

In finding that the sale of a service center was outside the ordinary course of business for NOVA Gas Transmission Ltd. the EUB noted:

> For example in this case, the NBV of $2,163, 801 would be at the bottom end of the range of dispositions the Board would consider as outside the ordinary course of business. With respect to the frequency and type of sale the Board does not agree with NGTL that acquiring and divesting regional service centres, maintenance facilities, and field offices are necessarily in the ordinary course of NGTL's business. The Board considers that NGTL's ordinary business is the owning and operating of a pipeline, not the acquiring and divesting of real estate.[209]

275. In Order U2008-158[210] the Commission followed the criteria set out in Order U2001-196 and determined that the sale by AG of the Brooks agency office for approximately $400,000 with a book value of approximately $275,000 was within the ordinary course of business.

276. This panel of the Commission concurs with the earlier decisions of the Commission and its predecessor that materiality and frequency are relevant factors to consider when determining whether the disposition of an asset is within or outside of the ordinary course of business. The Commission considers that the approach outlined by Ms. Wilson at the oral hearing provides a satisfactory balance between bringing multiple minor applications to the Commission for review while ensuring that substantive transactions are brought forward for consideration. The Commission agrees that $1.5 million is a reasonable transaction value at this time to use as a threshold guideline. Should the transaction price be over $1.5 million, AG will be required to bring an application for Commission approval under Section 26(2)(d) of the *Gas Utilities Act*. If the transaction price is less than $1.5 million, AG should consider if there are other factors that would suggest that the transaction is outside of the ordinary course of business and therefore require the consent of the Commission to the disposition. Those other factors would include:

- the quantum and materiality of the proceeds of disposition in relation to the total rate base of the utility
- the quantum and materiality of the net book value of the asset in relation to the total rate base of the utility
- whether all or any portion of the functionality of the asset being disposed of has been relocated to an existing facility or relocated to a new facility
- the frequency and type of disposition of like assets
- the other party(ies) to the transaction and if the transaction involves an affiliate, whether the ATCO Group Inter-Affiliate Code of Conduct has been complied with
- the market value of the asset when compared to the consideration received on the disposition
- the allocation of sale proceeds between depreciable and non-depreciable property
- the net book value of the assets
- whether the asset was a utility or non-utility asset
- any other unique or distinguishing aspect of the asset or of the transaction

277. If a review of the circumstances and factors described above do not suggest that a transaction of less than $1.5 million should be considered to be outside of the ordinary course of

[209] Order U2001-196, page 4.
[210] Order U2008-158, ATCO Gas Disposition of Brooks Agency Office, Application No. 1571404, May 9, 2008.

business, AG may proceed to deal with the disposition of the asset on the basis that it is within the ordinary course of business.

278. The Commission notes that ATCO Gas has negotiated the sale of a number of smaller agency and service facilities over the last several years. The sale of the Airdrie agency office appears to have been done at market value, did not involve an affiliate and generated proceeds were less than $1.5 million. The record also does not indicate a concern with respect to the allocation of proceeds between depreciable and non-depreciable property. Having considered the above criteria, the Commission considers that the disposition of the Airdrie agency office qualified as a transaction within the ordinary course of business.

279. The second issue that the Commission must consider is whether the accounting treatment of the disposition proceeds received on the sale of the Airdrie agency office has been properly determined. At the time the asset was disposed of it was a utility asset with the sale proceeds being allocated between buildings and land in accordance with the Uniform Classification of Accounts Regulation. Proceeds allocated to the depreciable assets were credited to accumulated depreciation as salvage and proceeds allocated to land after retirement of the original cost of the land were recorded as utility income. The Commission will not disturb the accounting treatment for this asset given that it was retired and sold prior to the test period. However, had the asset not been sold prior to the test period the Commission would have conducted a different analysis, similar to the treatment directed for the Okotoks facility described below.

4.5.3 North Edmonton operating centre and North Yard service centre

280. The North Edmonton operating centre was approved in Decision 2008-113 and completed in 2010. AG indicated it had transferred certain services performed at the North Yard service centre to the North Edmonton operating centre. Services and groups of employees from other locations were also moved to the North Edmonton operating centre. No additional capital costs were forecast for the North Edmonton operating centre with respect to the test years.

281. Following the transfer of certain services from the North Yard service centre to the North Edmonton operating centre, AG continued to use the North Yard service centre for meter reading functions as well as a training facility for almost a year after the North Edmonton operating centre was in use. Those functions were then transferred to other facilities other than the North Edmonton operating centre[211] and the North Yard service centre was moved to non-utility accounts in 2010 as the asset was no longer required for the provision of utility service. AG has not disposed of the North Yard service centre. The accounting for the North Yard service centre became an issue in this proceeding.

282. In response to CAL-AG-03, AG indicated that the net book value at the end of 2010 for the North Yard service centre was $1,792,703, suggesting that a future disposition of the facility would be outside of the ordinary course of business. AG also indicated in the same IR response that a market evaluation of the North Yard service centre prepared in March 2010 showed an estimated market value of $8,560,000.

Views of the parties

283. AG noted that it had not disposed of the North Yard service centre, nor had it brought an application related to that disposition before the AUC. AG submitted that any discussion

[211] AUC-AG-3A(d) and AG rebuttal evidence, paragraph 15, page 4.

regarding the disposition of the North Yard service centre was beyond the scope of the present general rate application.[212]

284. Calgary suggested that any proceeds arising from the ultimate disposition of the North Yard service centre and other facilities that are no longer used or required to be used to provide utility service should be for the account of ratepayers. Calgary stated in evidence:

> ATCO is proposing to, and has replaced, a number of structures and improvements and in some cases transferred the previous facility to non-utility. ATCO should be required to credit the value of the old properties against the new as a contribution toward the construction costs of the new facility. This concept was accepted by the Supreme Court in the *Stores Block* case. In this proceeding, one of the obvious applications would be the North Yard Service Centre which is being replaced by the North Edmonton Operating Centre.[213]

285. In argument Calgary submitted: "[A]s a matter of fact, fact based upon ATCO's own evidence, NEOC replaces NYSC, as this was stated in ATCO's economic justification for including NEOC in rate base."[214]

286. AG rejected Calgary's position that AG should be required to credit the value of old properties (such as the North Yard service centre) no longer required for the provision of utility service against the cost of new facilities (such as the North Edmonton operating centre). AG submitted that the Calgary position was another means of trying to appropriate the value of the assets owned by the utility for the benefit of customers and contrary to Supreme Court of Canada in *ATCO Gas & Pipelines Ltd. V. Alberta (Energy & Utilities Board)* 2006 SCC 4, [2006] 1 SCR 140 (Stores Block decision) and related cases. AG stated:

> …ATCO Gas would note that an alternative to disposition of the property would be to lease out the non-utility property. Consistent with the *Carbon* appeal decision, the proceeds generated through the lease of the NYSC, which is no longer required for the provision of utility service, could not be used to reduce ATCO Gas' rates, as revenue generation is not a utility service. The regulator cannot do indirectly what it cannot do directly. ATCO Gas questions how a different outcome could occur depending on what is done with the property. The simple answer is that the outcome must be the same. To do otherwise would amount to an expression of contempt for the findings of the Alberta Court of Appeal in *Carbon, Harvest Hills, Salt Caverns* and for the Supreme Court in *Stores Block.*[215] (footnote omitted)

287. With respect to Calgary's argument that North Edmonton operating centre replaced North Yard service centre, AG noted in reply argument:

> The costs of NEOC are general system costs associated with the growth of ATCO Gas' overall operations, not simply a single function. It is clear from the evidentiary record, therefore, that the NEOC cannot be characterized as a one-for-one replacement of NYSC.[216]

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212 AG rebuttal evidence, paragraph 16, page 4.
213 Calgary evidence, Question 22, pages 23-24.
214 Calgary argument, page 20.
215 AG argument, page 7, paragraph 14.
216 AG reply argument, page 15, paragraph 27.

288. AG also submitted that: "[T]here is no legal basis to do anything but reflect the removal of the net book value of the NYSC assets from rates, which AG has done in its revenue requirement forecasts."[217] There is no actual sale of the North Yard service centre before the Commission to consider. AG stated:

> The determinative fact in *Harvest Hills* was the lack of **immediate** need to replace the surplus lands as a direct result of the sale. Even if the utility had sold an asset and then had to replace it across the street, however, ATCO Gas maintains that this issue would be one of prudence of costs incurred. There is no basis for invoking paragraph 77 of *Stores Block* or reversing the findings of the Commission in Decision 2008-113.[218] (emphasis in original)

289. AG also submitted that even if there was a sale of the property before the Commission for consideration, customers have benefited from and not been harmed by the construction of the new facilities previously approved by the Commission: "[H]arm is not generated through the disposition of utility assets no longer required for utility service because customers are not entitled to the future earning potential of properties removed from rate base."[219]

Commission findings

290. The forecast cost for the North Edmonton Operating Centre is $21.0 million and that amount is approved for inclusion in 2011 opening rate base.

291. The Commission notes that the residual value of the of the North Yard service centre and other AG properties that are no longer used or required to be used to provide utility service were also considered in Decision 2008-113 and deferred to the Utility Asset Disposition Proceeding, Proceeding ID No. 20. The Commission stated:

> Having regard for the Stores Block Decision and the Asset Disposition Rate Review Proceeding, the Commission is of the view that commenting on Calgary's recommendations concerning the use of net proceeds from a sale of assets by AG would not be appropriate at the present time. The Commission will consider such issues in the Asset Disposition Rate Review Proceeding.[220]

292. The Utility Asset Disposition Proceeding was suspended by the Commission in Decision 2008-123.[221] While that proceeding continues to be suspended, the Commission considers that certain of the matters raised for consideration by the parties can be advanced in the present decision.

293. A portion of the services provided from the North Yard service centre were transferred to the North Edmonton operating centre when it was constructed. The Commission must determine if a proportion of the value of the North Yard service centre, equal to the proportion of services transferred to the North Edmonton operating centre, can be attached in a manner advocated by Calgary so as to reduce the overall cost of the North Edmonton operating centre to ratepayers

217 AG reply argument, page 16, paragraph 30.
218 AG reply argument, page 17, paragraph 33.
219 AG argument, page 7, paragraph 16.
220 Decision 2008-113, page 48.
221 Decision 2008-123: Review of Rate Related Implications of Utility Asset Dispositions Following the Supreme Court's Calgary Stores Block Decision, Application No. 1566373, Proceeding ID No. 20, November 28, 2008.

despite the fact that a disposition of the North Yard service centre has not occurred and the asset has been removed from rate base and moved to non-utility accounts.

294. The Stores Block decision dealt with entitlement to the proceeds of disposition of a utility asset when sold outside of the ordinary course of business under Section 26(2)(d) of the *Gas Utilities Act*. The Supreme Court confirmed that ratepayers are entitled to the receipt of a service at fair rates; they do not gain an ownership interest in the property of the utility. The court stated:

> Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves…[222]

295. The Supreme Court further clarified: "…the ownership of the assets is clearly that of the utility; ownership of the assets and entitlement to profits or losses upon its realization are one and the same."[223]

296. The Alberta Court of Appeal in the Carbon decision confirmed that ratepayers have no property interest in the assets owned by the utility nor do they have an entitlement to the profits or unregulated revenue that they may generate. The court stated:

> Just as the end customers have no ownership interest in the assets of the utility, they have no interest in the profits, unregulated revenues, or unregulated businesses of the utility. The value of economic assets is often largely determined by the revenues they can generate, and if the end customers are not entitled to any ownership interest in the assets, they are likewise not entitled to any interest in the cash flow generated by those assets: ***Stores Block*** at para. 78.

297. The Stores Block decision also indicated however, that the regulator could attach conditions to the proceeds of sale for the benefit of ratepayers in certain circumstances, stating in paragraph 77 of its decision:

> This is not to say that the Board can never attach a condition to the approval of sale. For example, the Board could approve the sale of the assets on the condition that the utility company gives undertakings regarding the replacement of the assets and their profitability. It could also require as a condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system.[224]

298. The Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2009 ABCA (Harvest Hills decision) had occasion to consider the guidance of the Supreme Court in paragraph 77 of the Stores Block decision. In the Harvest Hills decision the court considered whether the EUB could attach a condition to an approval under

222 Stores Block decision, paragraph 68.
223 Stores Block decision, paragraph 67.
224 Stores Block decision, paragraph 77.

Section 26(2)(d) of the *Gas Utilities Act* such that the proceeds of sale of a utility asset could be set aside to defer the cost of replacement facilities of a similar nature. In attaching the condition the EUB had relied on the wording of paragraph 77 of the Stores Block decision.

299. The court in the Harvest Hills decision concluded the condition contemplated by the Supreme Court would allow an attachment of sale proceeds in the following circumstances:

> In our view, a more reasonable interpretation of the Supreme Court's words would permit the Board to impose a condition if there was a close connection between the sale of the asset and the immediate resulting need to replace it. For example, the utility might sell a pumping station and, in order to service the public, it might need to access a different pumping station or even replace the existing one. The sale and purchase would be closely connected. This is what the majority of the Supreme Court had in mind when it stated that in some circumstances the Board could impose a condition that required the utility to reinvest the proceeds of sale into the system.[225]

300. The Commission considers that the Harvest Hills decision established four criteria that must be met before the Commission can attach a condition to the proceeds of disposition of a utility asset which requires the utility to reinvest the proceeds into the regulated system. The four criteria are:

- there must be a disposition of property by a utility
- the sale must be outside of the ordinary course of business, giving rise to the jurisdiction of the Commission to review the transaction
- there must be a close connection between the sale of the asset and the need to replace it
- the need to replace the asset must be immediate, in other words the need to replace the asset must arise at the same time as the disposition

301. With respect to the third and fourth criteria, the record is clear that certain functions were relocated from the North Yard service centre to the North Edmonton operating centre and that within a year of relocating those services all remaining North Yard service centre service functions were transferred to other existing facilities. At that point the North Yard service centre ceased to be used or required to be used to provide utility service and the facility was removed from rate base. The Commission notes that Business Case 10 filed in the 2008-2009 GRA[226] specifically stated:

> This business case addresses how best to create a new North Edmonton Operating Centre to replace the NYSC.[227]
>
> ATCO Gas initiated an evaluation to determine a long term solution for Edmonton operations facilities in order to ensure customer needs will be met in a cost effective manner for the foreseeable future. The result of that evaluation is the recommendation to replace the NYSC with a new North Edmonton Operations Centre (NEOC) in 2008.[228]

225 Harvest Hills decision, paragraph 35.
226 2008-2009 GRA, Tab 2.1, North Edmonton operating centre.
227 2008-2009 GRA, Tab 2.1, North Edmonton operating centre, page 2.
228 2008-2009 GRA, Tab 2.1, North Edmonton operating centre, page 5.

302. The Commission finds that there is a clear and immediate connection between the decision to transfer certain functions from North Yard service centre and the decision to proceed with constructing the North Edmonton operating centre. Certain functions were immediately transferred from the North Yard service centre to the North Edmonton operating centre upon the latter's completion. Further, the North Yard service centre ceased to be used in the provision of utility services within a year after construction of the North Edmonton operating centre was finished.

303. With respect to the first and second criteria, there has been no actual sale and no application for approval of a disposition under Section 26(2)(d) of the *Gas Utilities Act*. It was argued by Calgary that the Stores Block decision line of cases should apply. Calgary stated above that "ATCO should be required to credit the value of the old properties against the new as a contribution toward the construction costs of the new facility." This line of argument would suggest that the findings of the court in the Harvest Hills decision with respect to the ability of the Commission to attach the proceeds of sale where there is "a close connection between the sale of the asset and the immediate resulting need to replace it" should not be allowed to be circumvented by the timing chosen by the utility for the actual disposition of the retired property. If a utility is able to avoid the establishment of a close connection between the sale of an existing asset and the resulting need to replace it by simply removing the existing asset from rate base and delaying the sale to a future period after the new asset is in service, unfairness and harm to ratepayers in the form of higher rates would result because the utility would avoid the potential attachment of the proceeds of disposition. This harm would occur despite the Commission having previously approved the construction of the new facility and its inclusion in rate base because rates could have been lower than otherwise would be the case. Such a result would provide a utility with the motivation to arrange its affairs in a manner that would not give rise to the possibility that the Commission might attach conditions to the proceeds of sale.

304. Given the wording specifically chosen by the court in the Harvest Hills decision, the Commission can not agree to apply the Harvest Hills decision in a manner that would credit the value of the North Yard service centre toward the construction costs of the North Edmonton operating centre as suggested by Calgary. In order to do what Calgary is suggesting, the Commission would, in effect, need to deem a disposition of the North Yard service centre effective at the time that the facility was no longer required for utility purposes in order to potentially attach the value of the North Yard service centre for reinvestment in the AG system.

305. The Commission's jurisdiction to potentially attach a condition to the value of a property only arises when Section 26(2)(d) is invoked which is upon a disposition of the property outside of the ordinary course of business. The Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2009 ABCA 246 (Salt Caverns decision) determined that a decision of a utility to withdraw an asset from rate base did not constitute a "disposition" under Section 26(2)(d) of the *Gas Utilities Act*. The Alberta Court of Appeal stated:

> Ceasing to use an asset for utilities purposes involves the traditional criteria for what is in the rate base (discussed in Part F above), and does not involve or require a s. 26 application at all.[229]

306. The Commission notes that the utility may have very practical reasons for delaying or deciding not to sell an asset when it is retired, including the absence of a market in a rural

[229] Salt Caverns decision, paragraph 56.

environment, poor market conditions, or because the utility has decided to retain the asset to conduct a separate unregulated business.

307. The Commission does not have the jurisdiction as the result of the Salt Caverns decision to deem a disposition of the North Yard service centre in order to potentially attach a condition to deemed proceeds under Section 26(2)(d) of the *Gas Utilities Act*. Accordingly, the Commission finds that it does not have jurisdiction over the value of a property withdrawn from rate base and/or moved to a non-utility account unless and until a disposition out of the ordinary course of business should occur. Further, the ability of the Commission to potentially attach proceeds of disposition arises only if there is a “close connection between the sale of the asset and the immediate resulting need to replace it.” It therefore would appear that the ability of the Commission to consider the possible attachment of proceeds of sale arises only in the very limited circumstances where the disposition and the replacement of the functionality of the disposed asset occur relatively contemporaneously.

4.5.4 Irma agency office

308. AG confirmed in response to AUC-AG-31(a) that the Irma agency office was no longer needed for utility service and had been retired in 2010. Decision 2008-113 referred to AG’s intention to move the services delivered through the Irma agency office to the new Viking operations centre[230] along with services relocated from other facilities. At the hearing Ms. Wilson, on behalf of AG, confirmed that the Irma facility had been retired in the ordinary course of business when it was no longer required for utility service and that it had “in essence had been fully consumed in the provision of utility service.”[231] Ms. Wilson also confirmed her belief that upon retirement “from a depreciation theoretical standpoint, there would not be any value in rate base related to the facility” but that the facility had not been moved to a non-utility account.[232] Ms. Wilson confirmed that although AG was seeking a purchaser of the facility, that it had not yet been sold. When sold, the proceeds were expected to be immaterial and the transaction would be considered a disposition in the ordinary course of business so that Commission consent would not be required. Ms. Wilson indicated that the proceeds associated with the depreciable assets would in accordance with the Uniform Classification of Accounts Regulation be recorded as salvage and credited to accumulated depreciation and the proceeds associated with the land would offset the original cost of the land and any excess proceeds would be recognized as utility income for the benefit of the shareholder. If the sale proceeds allocated to the land did not recover the original cost of the land, the AG shareholder would bear the loss.[233]

309. Ms. Wilson further clarified in the following excerpt from a discussion of the Okotoks facility with Commission counsel that the accounting treatment AG uses on the disposition of an asset depends on whether or not the asset is sold within or outside of the ordinary course of business:

> …The distinguishing factor to some extent is whether the disposition is inside or outside the ordinary course. If it's inside the ordinary course, we have the uniform classification of accounts, and that is our guide for how we account for the disposition.

230 Decision 2008-113, page 45.
231 Transcript, Volume 6, page 1237, lines12-13.
232 Transcript, Volume 6, page 1236, lines 13-22.
233 Transcript, Volume 6, pages 1236-1240.

> If it's outside of the ordinary course, then of course an application has to be made to the Commission, and our view -- our understanding of the current state of the law is that proceeds of non-utility assets are not to be used reduce distribution rates for customers, and that would be regardless of whether the assets are depreciable or non-depreciable.[234]

310. When questioned by Commission counsel about responsibility for any ongoing operating costs at the Irma facility, Ms. Wilson indicated that she did not think that there were any but that if there were, they would be included in customer rates even though the facility had been retired.[235] When asked why any ongoing costs would continue to be recovered from ratepayers, Ms. Wilson stated:

> Well, sir, the asset was fully consumed in the provision of utility service; and if there is any residual net book value, first of all, I doubt that it's material, and second of all, it's likely due to some extent to the fact that your depreciation estimates are never going to be 100 percent -- never going to match 100 percent what actually happens.
>
> So there is always going to be differences between the theoretical value of the asset, theoretical and the actual net book value, simply due to differences between what your depreciation rates assume and what actually occurs.[236]

Commission findings

311. The Commission considers that in the event that a utility is unable to, or chooses not to, prudently dispose of an asset approximately at the same time that it ceases to be used or required to be used to provide utility service; it is incumbent on the utility to retire that asset and to move the asset to a non-utility account. As discussed above in connection with AG’s land and structures generally, the Alberta Court of Appeal in the Carbon decision made it clear that assets previously included in rate base that are not presently used or required to be used to provide utility service as required by Section 37 of the *Gas Utilities Act* should not remain in rate base.

312. The words “used or required to be used” are intended to identify assets that are presently used, are reasonably used, and are likely to be used in the future to provide services. Specifically, the past or historical use of assets will not permit their inclusion in the rate base unless they continue to be used in the system.[237]

313. The court in the Carbon decision also stated:

> Thirdly, the only reasonable reading of s. 37 is that the assets that are “used or required to be used” to provide service are only those used in an operational sense.[238]

314. In the Salt Caverns decision the Alberta Court of Appeal stated:

> Can it be reasonably argued that this regulatory power is confined to ruling on adding new items to the rate base, but inapplicable to excluding old or unused items? No. Phillips, *op. cit supra*, at 302 quotes another established textbook and lists items which regulatory commissions may exclude from the rate base. They include obsolete property,

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234 Transcript, Volume 6, page 1252, line 15 to page 1253, line 1.
235 Transcript, Volume 6, page 1236, line 23 to page 1237, line 8.
236 Transcript, Volume 6, page 1238, line 23 to page 1239, line 8.
237 Carbon decision, paragraph 23.
238 Carbon decision, paragraph 25.

> property to be abandoned, overdeveloped property and facilities for future needs, and property used for non-utility purposes.[239]

315. The Commission considers that assets that are not properly in rate base because they are no longer used or required to be used to provide utility service should not be reflected in rates in any fashion. It is irrelevant whether the asset was fully consumed in providing utility service or whether it has residual value or not.

316. The Commission notes the apparent conflict between the testimony of Ms. Wilson that indicated that if there were operating costs for the Irma agency office that they would be in customer rates[240] with the statement quoted above in the reply argument of AG that:

> ATCO Gas has removed the cost of all assets no longer required for the provision of utility service from its rate base and revenue requirement forecasts.[241]

317. The Supreme Court of Canada in the Stores Block decision stated that upon disposition of an asset the profit or loss associated with the asset sold outside of the ordinary course of business is for the account of the utility shareholder. The Supreme Court noted:

> The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. In fact, the wording of the sections quoted above suggests that the ownership of the assets is clearly that of the utility; ownership of the asset and entitlement to profits or losses upon its realization are one and the same.[242]
>
> Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality.[243]

318. The Commission considers that the retirement of a utility asset should be followed by the removal of the net book value, if any, from rate base and the movement of the asset to a non-utility account if it is not disposed of at approximately the same time as it is retired. Ongoing operational and remediation costs (except to the extent that remediation costs are notionally offset by the net salvage component of depreciation expense previously included in rates and collected from ratepayers) associated with the asset after it is no longer used or required to be used to provide utility service should be for the account of the shareholder as the owner of the asset.

319. Neither the timing of the actual disposition of an asset nor the characterization of a disposition as either within, or outside, the ordinary course of business, can logically serve to distinguish the entitlements or obligations of ownership once the asset is no longer used or required to be used to provide utility service. It would be unreasonable to suggest that a utility

239 Salt Caverns decision, paragraph 28.
240 Transcript, Volume 6, page 1236, line 23 to page 1237, line 8.
241 AG reply argument, paragraph 20, pages 11-12.
242 Stores Block decision, paragraph 67.
243 Stores Block decision, paragraph 69.

could pass on the costs of ongoing obligations associated with the ownership of an asset to ratepayers after the asset is no longer used or required to be used to provide utility service simply by keeping the asset as a utility asset rather than moving it to a non-utility account. Similarly, it would be illogical to require ratepayers to pay for ongoing operational costs of an asset while the utility waits for an improvement in market conditions in order to maximize potential gains or simply because the utility is unable to dispose of the property because of associated liabilities or market conditions.

320. Accordingly, retired assets that are not anticipated to be disposed of at approximately the same time that they are retired should be moved to a non-utility account where any ongoing costs associated with the assets would be for the account of the utility shareholder. Given that the Irma agency office has been retired and not disposed of, the Commission directs AG to move the Irma agency office to the applicable non-utility accounts effective January 1, 2011. Operating costs and other costs associated with the facility, to the extent there are any, will be for the account of the AG shareholder from and after January 1, 2011.

321. The Commission also considers that the above analysis with respect to the North Yard service centre and the application of the Harvest Hills decision is equally applicable to the value associated with the Irma agency office. The Commission notes that the Irma agency office ceased to be used or required to be used for utility service when the services it provided were relocated to the Viking service centre in 2010. There was a close connection between the retirement of the Irma agency office and the immediate resulting need to replace it as demonstrated by the relocation of the services provided at the Irma agency office to the Viking operations centre. However, there was no disposition of the Irma agency office at the time that the functions of that office were moved to the Viking operations center. Further, a disposition of the Irma agency office, given its net book value, would likely not be a sale outside of the ordinary course of business. In these circumstances, the Commission does not have the jurisdiction to either deem a sale of the Irma agency office effective at the time that the Viking operations center opened nor would it have the jurisdiction to attach the proceeds of sale even if there had been a sale at that time.

322. As discussed above in relation to the North Yard service centre, the Commission’s ability to potentially attach a paragraph 77 Stores Block decision type of condition to sale proceeds of a utility asset arises only when all four criteria outlined in the Harvest Hills Decision are present. In the present situation, there has been no sale of a utility asset and any sale would not have been outside of the ordinary business of AG and accordingly, a Section 26(2)(d) *Gas Utilities Act* application would not have been required.

323. The Commission directs AG in the compliance filing to this decision to reflect the movement of the Irma agency office to a non-utility account as of January 1, 2011 and to reflect the removal of any operating or related costs associated with the facility as of that date.

4.5.5 Okotoks operating centre

324. AG indicated its intention in the application to construct a new operating centre in Okotoks. The new building is planned to have 14,000 square feet and would be large enough to accommodate current operational concerns and to service construction projects in the Okotoks area. The new operating centre was forecast to be occupied in 2012 at a cost of $7.3 million in 2011 and $4.0 million in 2012.

325. AG indicated that the existing Okotoks agency office which was completed in 1982 is no longer adequate to meet the agency needs. AG expressed its intention to relocate a number of field operations and construction staff in addition to the employees presently located in the Okotoks agency office, to the new operating centre. The operating centre would be used to perform the services previously made available through the agency office but would also be used to perform additional functions previously performed from other locations. Mr. Dixon on behalf of AG described the activities that were going to be relocated to the new operating centre in the following manner:

> Just to describe what we're doing there, the existing office is an agency office that I described earlier where we've got approximately ten district service operators that are uniform guys that, you know, attend to gas odours inside your house and appliance checks. They don't have any heavy equipment of any kind.
>
> There's no personnel in that office that can install pipe in the ground, do the heavy work. The new operating centre we're building in Okotoks is an operating centre, so it's going to have the ability to contain heavy equipment and the personnel that do that kind of work that we're moving out of overcrowded facilities elsewhere in the company, the maintenance depot up by the airport in Calgary and Midnapore operations centre, which is in south Calgary, because we find that Okotoks and that whole area is becoming so busy on the growth side that those crews that are required to go down there to install pipes to new homes down there on a pretty regular basis.
>
> So it makes a lot more sense to get those installation crews located right in Okotoks, so that's what the new operation centre is. That's its purpose. Once it is built, it makes a lot of sense not to keep two buildings, to move the existing staff that were in the agency office, just move them into that operations centre.[244]

326. Mr. Dixon also confirmed that the Okotoks office would be closed when the personnel relocated to the new operations centre although the exact timing of the closure was not certain. He also confirmed that the Calgary depot and Midnapore operations centre would continue to be used after the relocation of certain personnel and equipment to Okotoks. In AUC-AG-31(a), AG indicated that the existing Okotoks agency office is forecasted to be retired with a net book value of $255,000 when the new operating centre would be ready for occupancy in July 2012.[245] The net book value of the agency office would be removed from rate base upon retirement. The assessed value for the Okotoks agency office for property tax purposes in 2009 was $940,000.[246]

327. None of the interveners commented about the need for the Okotoks operating centre, its forecasted costs or the proposed retirement of the existing agency office.

Commission findings

328. The Commission finds the rationale for the new Okotoks operations centre to be convincing and the forecast costs to be reasonable. The Commission approves the forecast costs for the test period.

329. With respect to the existing Okotoks agency office, the Commission considers that there is a close connection between the retirement of the agency office and the immediate resulting

[244] Transcript, Volume 6, page1250, line 6 to page 1251, line 4.
[245] CCA-AG-8 (c).
[246] CCA-AG-8 (g).

need to replace it as demonstrated by the planned relocation of the personnel and services provided at the agency office to the new Okotoks operations centre. Even though other functions will be performed at the new operations centre, all of the services presently performed at the agency office are being relocated to the new operations centre. In the Commission's view these facts might be sufficient under the criteria established in the Harvest Hills decision to attach the actual proceeds of disposition of the agency office if the eventual disposition is outside of the ordinary course of business and occurs relatively concurrently with the relocation of the functionality of the Okotoks agency office to the new Okotoks operations centre. This matter, however would have to be more fully reviewed should AG file a Section 26(1)(d) *Gas Utilities Act* application with the Commission. The application of such proceeds would be directed at reducing rates that customers would otherwise be required to pay.

330. Should the Okotoks agency office not be disposed of at approximately the same time as it is retired, AG is directed to move the asset to a non-utility account where further operating and capital costs would be for the account of the utility shareholder.

4.5.6 Drayton Valley operating centre

331. AG indicated its intention to replace the leased facility in Drayton Valley with a new operating centre that would be ready for occupancy just prior to the lease expiring on December 31, 2012. The new operating centre would have 5,900 square feet compared to the leased 3,100 square feet to accommodate growth and storage space requirements. The new operating centre was forecast to cost $0.8 million in 2011 and $4.5 million in 2012. The new facility is anticipated to be ready for occupancy in October 2012.

Views of the parties

332. The CCA considered that the new operating centre should not be considered to be used or required to be used until 2013 at the expiry of the current facility lease renewal. The CCA did not consider it appropriate that customers pay for the lease of the current facility and pay the ownership costs of the new proposed facility in the same test year. Accordingly, the CCA recommended that $ 5.3 million be removed from 2012 rate base and deferred until 2013.[247]

333. AG noted in reply argument[248] that it had indicated in the response to CCA-AG-12(a), that the Drayton Valley operating centre planned occupancy date was October 2012. However, that did not mean that AG could immediately evacuate the leased facility. The fact that the leased facility might not be totally vacated prior to the end of 2012 did not alter the need to start using the new operating centre prior to the end of 2012.

Commission findings

334. The Commission finds the rationale for the new Drayton Valley operating centre to be convincing and the forecasted costs to be reasonable. The Commission understands the CCA's concern with having the expenditures in revenue requirement related to two facilities that will, at least in part, be providing overlapping functions for a period of time. However, the Commission accepts AG's explanation that both facilities are likely to be accommodating activities at the same time as staff and equipment are moved from one location to the other toward the end of the lease term. The Commission also notes that with the possibility of unanticipated construction

[247] CCA argument, page 9, paragraphs 20 and 21.
[248] AG reply argument, page 18, paragraph 36.

delays it is reasonable to a have a short overlapping period when moving facilities. In these circumstances the Commission considers it reasonable to approve the forecasted costs for the test period.

4.6 Moveable equipment

4.6.1 Purchase of compressed natural gas (CNG) trailers

335. AG planned to purchase three used CNG trailers from ATCO Pipelines in 2011 at net book value and then purchase three additional new CNG trailers from an outside vendor (two in 2012) and to install refueling compression facilities in several communities for a total project capital cost of $5.3 million. Included within its forecast for moveable equipment the total $415,000 in 2011 would purchase the ATCO Pipelines trailers and in 2012 $761,000 would purchase two new trailers. Also, after completing the design and permitting the compression for Fort McMurray and Grande Prairie in 2010 at a cost of $126,000, AG proposed to spend $1,466,000 in 2011 and $1,414,000 in 2012 to complete the compressor installations in Fort McMurray, Grande Prairie, Lloydminster and Edson, and the engineering for Brooks.

336. AG has experienced several incidents in which large numbers of customers have lost gas service. The communities which were affected are referred to as single source communities. For most of these communities it is not economically feasible to provide a second source of supply to the community. As an alternative, an emergency gas supply source can be used to safely maintain service to the community. There are two main pieces to emergency gas supply infrastructure, CNG trailers and compressors used to fill the trailers.

337. An analysis of all outages in single source communities between 2001 and 2009 was completed and is included in Appendix 6 of Business Case 12. Ten incidents were found involving where 250 or more customers had lost service when the natural gas feed to the community was lost.

338. AG submitted that CNG trailers were required to provide emergency backup supply across the province to single source communities as an emergency gas supply.

Views of the parties

339. Calgary expressed concerns with the cost of integration of ATCO Pipelines and NGTL and recommended that the cost of the CNG trailers also be excluded.

340. The CCA considered that the CNG trailers purchased from ATCO Pipelines were related to transmission and should not be included in a distribution utility rate base. The CCA agreed with Calgary that these asset transfers should have been considered and raised by AG and ATCO Pipelines as part of the integration negotiations. The CCA viewed the CNG trailers as an alternative for when natural gas transmission was unavailable. Therefore the CNG trailers should continue to be considered an ATCO Pipelines asset.

341. The CCA recommended that the purchase of the CNG trailers should not be added to rate base. ACTO Pipelines should retain the asset to provide the alternative supply.

342. AG noted that no party filed evidence indicating that AG did not require CNG trailers to provide emergency backup supply across the province. AG also pointed out that it had identified the requirement in Business Case 12 to purchase six trailers to provide this emergency supply

capability. The business case also outlined that of the alternatives considered, the most cost effective solution was to purchase three existing trailers from ATCO Pipelines and purchase three additional new trailers. AG argued that regardless of whether AG purchased the three trailers from ATCO Pipelines, or it purchased them from a third party, AG still needed to make the purchase, and no party had filed evidence to demonstrate otherwise.

Commission findings

343. With respect to the CNG trailers, the Commission does not agree with the CCA that an isolated outage in a remote community would necessarily be the responsibility of the transmission company. There are no standards or regulations that make the transmission company responsible. Despite the small number of incidents experienced, the Commission accepts that there are risks of failure in communities with a single source supply and that the acquisition of portable trailers is a practical way to protect customers in the event of an extended outage or adverse weather conditions and approves the acquisition costs as forecast.

344. Specifically, the Commission approves the purchase of the CNG trailers from ATCO Pipelines at book value as filed, and the forecasted expenditures for the refuling compressor facilities and the purchase of trailers from an outside vendor, which are to be located in several communities around the province.

4.6.2 Other moveable equipment

345. The remaining accounts in the moveable equipment category not dealt with above include the following along with the actual and forecast expenditures indicated:[249]

Table 16. Moveable equipment expenditures (in part)

	Actual			Forecast		
	2008	2009	2010	2010	2011	2012
	($ million)					
Transportation equipment	12.0	3.4	7.0	8.3	10.0	11.9
Tools and work equipment	2.6	1.0	1.7	2.4	2.6	2.5
Heavy work equipment	5.5	0.7	1.6	2.4	3.2	3.4
Garage, stores and shop equipment	0.3	0.3	0.3	0.5	0.6	0.6
Office furniture and equipment	1.8	0.6	1.1	0.7	0.7	0.7
Technical support equipment	0.4	0.2	0.3	0.3	0.3	0.3
Total	22.6	6.2	12.0	14.6	17.4	19.4

Views of the parties

346. The CCA observed in 2010 that AG forecast $14.7 million[250] in the overall category of moveable equipment but actually spent $12.1 million.[251] The over-forecast amount was

249 Exhibit 83.01, UCA-AG-62(a), Attachment 1, page 8 of 11.
250 AG filing 2.1-36.
251 CCA-AG-14.

$2.6 million or 21 per cent.[252] AG was forecasting an increase from the 2010 actual level of expenditures of $12.1 million to $19.3 million for 2011 and $21.6 million for 2012.[253]

347. The CCA expressed concern about the ability of AG to make reasonable forecasts in this category and recommended that 2011 and 2012 moveable equipment forecasts be reduced by 21 per cent.

348. The CCA also noted that AG forecast $2.6 million[254] in tools and work equipment but actually spent $1.7 million in 2010.[255] The over forecast amount was $0.9 million or 53 per cent.[256] AG was forecasting an increase from 2010 actual level of expenditures of $1.7 million to $2.6 million for 2011 and $2.5 million for 2012.[257] The CCA again expressed concerned about the ability of AG to make reasonable forecasts and recommended that 2011 and 2012 moveable equipment forecasts be reduced by 53 per cent.

349. The CCA noted further that AG forecast $2.4 million[258] in heavy work equipment but actually spent $1.6 million in 2010.[259] The over forecast amount was $0.8 million or 50 per cent.[260] AG was forecasting an increase from the 2010 actual level of expenditures of $2.4 million to $3.2 million for 2011 and $3.4 million for 2012.[261]

350. Again the CCA expressed concern about the ability of AG to make reasonable forecasts in this category and recommended that 2011 and 2012 heavy work equipment forecasts be reduced by 50 per cent.

351. AG took exception to the CCA's recommendations that a reduction be made to AG's forecasts for tools and work equipment and heavy work equipment based on the differences between the 2010 forecasts and actual results.[262]

352. AG noted in the rate base section above that the CCA recommendations with regard to the 2010 actual results had the following flaws:

- By making a recommendation to reduce ATCO Gas' total capital expenditure forecast as well as individual recommendations for the same thing, the effect of the CCA's recommendation would be a double counting of that impact;
- The fact that the CCA's individual recommendations only focus on those areas where the actual results were lower than forecast for 2010, the CCA is cherry-picking the 2010 actual results, and this makes the effect of the double counting even more significant;
- ATCO Gas noted that the 2010 difference in total rate base was very insignificant (0.8%) and it would be inappropriate to focus on only one aspect of the rate base when considering the 2010 actual results.

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252 (12.1-14.7)/12.1.
253 CCA-AG-14.
254 AG filing 2.1-38.
255 CCA-AG-15.
256 (1.7-2.6)/1.7.
257 CCA-AG-15.
258 AG filing 2.1-39.
259 CCA-AG-16.
260 (1.6-2.4)/16.
261 CCA-AG-16.
262 CCA argument, pages 9-10.

353. AG argued that the recommendations of the CCA on these individual areas of expenditure must be ignored for all the reasons noted above.

Commission findings

354. The Commission agrees with the CCA that there is a concern with the estimates and comparative spending between actual and forecast expenditures. While the Commission has not subscribed to the suggestion of the CCA to implement an across-the-board reduction to rate base, for the other moveable equipment being discussed, it does consider that rather than looking at specific components an overall adjustment could be made.when dealing with small amounts. The Commission agrees with AG that the CCA's recommendation would be double counting. For example, the tools and work equipment expenditures are included in the moveable equipment expenditures.

355. Rather than an across the board reduction, the Commission prefers to use an escalation of past costs based on a three-year average of the actual expenditures in 2008, 2009 and 2010. AG has noted it has used a three-year average of past costs in other categories. In this case the three-year average applied across-the-board to all the accounts noted above in the table equals $13.6 million. Allowing for inflation of three per cent, the amount approved for all the above accounts in 2011 is $14.0 million and in 2012 is $14.4 million. AG is directed to indicate in its compliance filing how it proposes to allocate the approved total amounts between the different accounts.

4.7 Information technology

Opening rate base

356. AG applied for approval of the January 1, 2011 opening rate base related to IT capital projects undertaken in the 2008 to 2010 period. The actual expenditures for IT capital were $17.7 million in 2008, $16.5 million for 2009, and $8.2 million 2010. The forecast IT capital expenditures were $9.1[263] million for 2008, $4.2[264] million for 2009, and $10 million in 2010.[265]

357. The major variances in IT opening rate base costs are in relation to SIBS (NGSIS Replacements) and Oracle Human Resources Excellence (HRX). For the SIBS project actual expenditures in 2008 and 2009 were $1.8 million and $5.0 million compared to forecasts of $1.8 million and $2.5 million for an actual amount in excess of approved forecast costs of $2.7 million. AG explained that more hours were required to design and implement the system but no support was given for the extra hours and spending in Tabs 8.1 and 8.2 of the application.

358. The HRX project continued into the test period and is examined separately below.

Commission findings

359. The Commission acknowledges that expenditures in excess of the approved amounts in Decision 2008-113 could be due in part to the pricing determined in the Evergreen proceeding. The Commission finds that the over-expenditure on SIBS (NGSIS) replacements was not adequately explained in the application or supported in the analysis of variances provided in

263 Exhibit 3, AG application, Tab 8.1, Table 2.2.25.
264 Exhibit 3, AG application, Tab 8.2, Table 2.2.25.
265 Exhibit 3, AG application, Table 2.1.1 ATCO Gas (Total) – Historic and Forecast Expenditures, page 2.1-4.

Tabs 8.1 and 8.2. The Commission directs AG in its compliance filing to revise the SIBS amount to be included in opening rate base to the forecast approved in Decision 2008-113, adjusted for increases in price approved by this Commission.

360. The Commission approves the opening rate base for IT capital projects subject to changes for SIBS referred to in the preceding paragraph and the changes to opening rate base in respect of HRX discussed below.

Overview of IT capital projects

361. AG proposed forecast IT capital expenditures for new and existing programs for 2011 and 2012. The AG forecast capital expenditures for 2011 and 2012 are $8.959 million and $6.880 million respectively. The IT capital projects are described in the application[266] and at Tab 4.2 I-Tek Forecast. Table 17, below from Tab 4.2, summarizes the IT capital projects and the forecast 2011 and 2012 costs:

Table 17. IT capital summary

ATCO Gas capital summary		
Projects	**2011**	**2012**
ATCO CIS enhancements	$950,000	$625,000
ATCO CIS VB to C#.Net Upgrade	$225,000	$0
Capital budgeting	$200,000	$0
DFSS development & enhancements	$150,000	$100,000
DGIS enhancements	$69,000	$45,000
Fleet management enhancements	$0	$60,000
Graphics enhancements	$150,000	$155,000
HRX development & enhancements	$265,000	$275,000
IRIS development & enhancements	$100,000	$100,000
IRS upgrade	$500,000	$0
OFIN enhancements	$200,000	$200,000
Oracle budgeting enhancements	$120,000	$100,000
Oracle data warehouse (B.I.)	$0	$0
Oracle database upgrade mid apps	$505,000	$78,000
Oracle enterprise suite epgrade	$2,748,000	$0
Reg. station upgrade	$300,000	$0
SIBS enhancements	$255,000	$265,000
Tariff billing enhancements	$600,000	$625,000
Windows 7 & Office Upgrade	$0	$3,448,000
Work management PDA replacement	$841,000	$0
Work management PDA Enh.	$181,000	$179,000
Work management enhancements	$600,000	$625,000
Total	**$8,959,000**	**$6,880,000**

266 Application, Section 2.1.1.8, pages 2.1-45 to 2.1-61.

362. In its application, AG outlined the need for the above IT capital projects including program upgrades to meet changing business needs and to ensure AG IT programs are vendor supported.

363. The Commission will review the significant IT capital projects individually followed by a consideration of the smaller projects collectively.

Views of the parties

364. Calgary stated in evidence that AG's requested IT volumes for 2011 and 2012 should not be approved.[267] AG did not provide adequate information to justify why the forecast capital volumes vary from year to year. The IT capital business cases did not quantify the IT capital or ongoing O&M unit volumes and cost breakdowns.

365. Calgary further stated in evidence that the IT capital business cases did not quantify the benefits to be realized or how to determine whether the benefits will be realized.[268] An IT capital budgeting process would demonstrate offsetting productivity benefits associated with new hardware and software. Calgary submitted that without the detail on unit volume forecasts for an IT project, it is not possible to know if upgrade costs were considered in the original GRA business case, statements of work, or supporting evidence.

366. In reply argument AG responded to Calgary's recommendation that all IT capital volumes should not be approved, submitting that it had provided a full set of documentation on IT capital projects in its application and responses to IRs. AG also submitted that it had provided the historic actual volumes for 2008 to2009 as well as the forecast volumes for 2010 to2012 for both IT capital and O&M.

4.7.1 Oracle Human Resource Management System (HRX or HRMS)

367. AG requested approval to include in January 1, 2011 opening rate base the capital costs associated with the Oracle Human Resource Management System (HRMS) which was also referred to as Oracle Human Resources Excellence (HRX). HRX is a fully integrated human resources (HR) information system. AG provided a business case dated August 26, 2009[269] in support of its application. The business case indicated that this enterprise-wide application would replace the legacy systems in three functional areas: HR/benefits, payroll, and time and labour.

368. AG's business case detailed forecast costs to implement HRX of $16.1 million.[270] AG reported actual HRX project costs of $15.1 million for 2008 to 2010.

369. AG also applied for approval of forecast HRX capital enhancement costs of $0.3 million for each of 2011 and 2012.[271] AG was applying for the HRX project costs and the forecast HRX enhancement costs in this application.

370. In 2000, the ATCO Group chose Oracle Corporation to provide enterprise wide application solutions for the ATCO group of companies,[272] including AG.[273] AG stated in cross-

[267] Exhibit 109.02, Calgary evidence, page 31 and 43.
[268] Ibid., page 33.
[269] Exhibit 1, Tab Business Case 14, Oracle Human Resource Management System (HRX).
[270] Application, Business Case 14, page 21.
[271] Exhibit 28, I-Tek Schedules for 2011-2012.
[272] Exhibit 1, Tab Business Case 14, Oracle Human Resource Management System (HRX), page 4, paragraph 3.

examination that the decision to add HRX was an ATCO Group decision and subject to IT governance of all ATCO companies, including ATCO I-Tek.[274] AG commenced implementation of the HRX system in 2009 with completion in 2010.[275] AG did not file a GRA in 2009 for approval of a revenue requirement for 2010 and therefore this is the first time the costs for this project have been before the Commission for approval.

371. AG stated that a fully integrated HR information system was required to respond to changing business needs and support future growth, including sustaining a high performance workforce in a competitive environment. The current human resource system and the related information systems no longer meet the functionality required by AG. In support of HRX[276] AG stated that its existing HR related systems were in excess of 20 years old, built on aging technology and could not meet AG's business requirements without significant upgrades. The HRX system has the ability to integrate with the Oracle Financials suite of applications currently in use by the ATCO Group and will standardize the recording of employee data as well as automate and streamline HR processes. AG indicated that there would be significant business benefits in replacing multiple systems with one integrated system.

Views of the parties

372. Calgary stated in evidence that given this project was initiated in a non-test year, the Commission should assess the approval of the entire project and not only the capital additions in 2011 and 2012. Calgary also stated, "[t]he HRX Development and Enhancement business case does not contain operational volumes nor did it indicate any business or technology benefits"[277] and therefore there was no basis for the forecast capital expenditures. Calgary recommended that the HRX of $15.1 million and enhancement projects of $0.3 million for 2011 and 2012 should not be approved until AG has filed a business case for the project costs by IT project unit volume, including AG's indirect costs. Calgary referred to Decision 2001-96[278] which provided direction on the specific information to be included in business cases for capital projects.[279] In this decision, the Commission's predecessor, the EUB, requested further information from AG for all major capital projects including: a detailed justification including demand, energy and supply information, a breakdown of the project cost, the options considered and their economics, and a discussion of the need for the project.[280]

373. Calgary requested that the Commission direct a post-implementation review of the HRX project and its enhancements in the next GRA.

374. Calgary in review of the HRX business case and the business case from AE 2007-2008 General Tariff Application (AE 2007-2008 GTA)[281] compared the capital costs of the project to

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273 Transcript, Volume 3, pages 600 to 605, and Volume 4, pages 619 to 630.
274 Calgary argument, pages 55 to 56.
275 Application, Section 2.1.1.8, page 2.1-49, paragraph 140 states that final c ompletion of HRX was forecast for 2010. Exhibit 1, Tab Business Case 14, Oracle Human Resource Management System (HRX) details that HRX went live by January 1, 2010 with post-implementation support occurring in the first quarter of 2010.
276 Ibid., pages 2.1-49 to 2.1-50.
277 Exhibit 109.02, Calgary evidence of April 7, 2011, page 52.
278 Decision 2001-96: ATCO Gas South, 2001/2002 General Rate Application, Phase I, Application No. 2000350, File No. 1307-1, December 12, 2001.
279 Exhibit 109.02, page 34.
280 Decision 2001-96, pages 28-29.
281 Decision 2007-071: ATCO Electric Ltd. 2007-2008 General Tariff Application – Phase I, Application No, 1485740, September 22, 2007.

the proposed Sum Total Talent Management System (TMS) discussed later in this decision. Calgary submitted in argument that:

> …based upon the evidence provided with respect to TMS, it is clear that the cost of the ATCO HRMS is grossly over priced. Therefore, Calgary submits that the amount to be included in the opening rate base for HRMS should not exceed $3.8 million on the basis that if the cost of TMS is 4x too much, it is likely that the cost of HRMS is 4x too much.[282] (footnote omitted)

375. Calgary argued that its recommendation that costs should not exceed $3.8 million was consistent with the forecast cost of HRMS, approved in the ATCO Electric (AE) decision[283] adjusted for staff counts.[284] Calgary also stated that absent the I-Tek affiliate relationship, it was likely the cost to AG of implementing and setting up the HRMS would have been about 25 per cent of the $15 million claimed by AG.

376. AG submitted in argument that Calgary had confirmed in testimony that it was not disputing IT volumes related to capital projects, but that the HRX volumes should not be approved, until AG had demonstrated further benefits of HRX.[285] AG argued that this was inconsistent with the position that Calgary had outlined in its response to AUC-CAL-8 which had not identified that Calgary was requesting any adjustments to the IT capital volumes in AG's forecast.

377. Calgary reiterated that the decision to move to HRX was an ATCO Group decision and was subject to IT governance of all the ATCO companies.[286] In its business case, AG did not consider alternative deployment options such as software as a service (SaaS), as outlined for TMS in the HRchitect Report,[287] or any business or technology benefits. Calgary stated that if the only purpose of the software was to replace the existing legacy software, there would be no need for a business case.

378. Calgary stated that HRMS was not the complete solution to AG's human resources management needs as another $2 million would need to be spent on TMS.[288] Calgary argued AG has not met its onus with respect to the cost of the HRX project.[289]

379. In reply AG argued that there was nothing on the record to support Calgary's position that HRX was overpriced and that Calgary's position was based on speculation. Calgary, by relying on the HRX business case from the AE 2007-2008 GTA, had developed its position on a business case that was filed in a different proceeding some four years ago. AG stated, "Calgary has not provided any evidence that actual HRX costs were imprudently incurred."[290]

282 Calgary argument, page 22.
283 Decision 2011-134: ATCO Electric Ltd. 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Application No. 1606228, Proceeding ID. 650, April 13, 2011.
284 Exhibit 201.01, Calgary argument, page 22.
285 Transcript, Volume 7, page 1616, lines 7-10.
286 Exhibit 201.01, Calgary argument, pages 55 to57 and Exhibit 214.02, Calgary reply argument, page 11.
287 Exhibit 0192.04, Revised HRchitect Report (Implementing Human Capital Management Systems) dated May 31, 2011.
288 Exhibit 214.02, Calgary reply argument, page 21.
289 Exhibit 214.02, Calgary reply argument, page 12.
290 AG reply argument, page 44.

380. AG argued that the actual costs for this system were accepted into opening PP&E as part of the recent ATCO Electric General Tariff Application Decision 2011-134[291] and the Commission's decisions on HRX should be consistent.

Commission findings

381. AG's evidence indicated that its existing HR related systems were in excess of 20 years old and they were built on aging technology which would require significant upgrades to meet ongoing business needs. The Commission accepts that AG's HR legacy systems did not have the capability to accommodate its ongoing business requirements. The Commission also accepts that Oracle HRX is an appropriate replacement program as noted by AG in its business case. The increased functionality and business benefits have been sufficiently supported by the HRX business case. The Commission also accepts that the Oracle HRX system is an enterprise system that AG uses to interface with a number of other programs.

382. The Commission notes and accepts AG's statement in the HRX business case that:[292]

> Generally the application cost only represents approximately 15%-25% of the total cost of implementing enterprise applications.

383. The Commission understands that the one time licensing fee of $390,000 in the business case is the cost of the HRX application.[293] Applying the above guideline for enterprise projects, leads to a total capital cost range of $1.6 million to $2.6 million.

384. Calgary submitted based on the report of its IT consultant that as the TMS program was four times more expensive than the IT consultant recommended, that the HRX program cost was likely four times more expensive and should be reduced to $3.8 million.

385. The Commission has replicated Calgary's forecast of HRX based on the business case provided in the ATCO Electric proceeding adjusted for staff counts and estimates a forecast project cost of $9.6 million. The Commission notes AG's comment that the AE business case was four years old but finds that the business case was dated May 2008, the year in which the project commenced. The Commission considers the AE business case is the best information on the record regarding the forecast cost of HRX.

386. The Commission finds the actual cost of $15.1 million to be in excess of these three cost estimates. The Commission also recognizes that the estimates undertaken are imprecise and accordingly relies on them as directional guidance. The Commission has reviewed the business cases of ATCO Electric and AG and other evidence on the record and determines that a 10 per cent cost reduction in the actual costs of HRX is warranted. The Commission directs AG in its compliance filing to reduce the actual cost of HRX in its opening rate base by 10 per cent.

4.7.2 Sum total talent management system (TMS)

387. As part of its April 21, 2011 application update, AG filed a business case proposing the implementation of TMS to be integrated with AG's existing human resource talent management

[291] Decision 2011-134, page 19.
[292] Tab 4.2 Business Case 14, Oracle Human Resource Management System (HRX), page 18.
[293] Ibid., page 21.

system.[294] The project was scheduled to commence in March 2011.[295] TMS was proposed to address AG's performance management, succession planning, employment, workforce planning, and compensation management needs. AG stated that the system would enhance its ability to retain and develop staff, enable better management decisions through access to talent management data, improve existing talent management processes, measure key talent management performance indicators, reduce reliance on manual processes, and enhance human resources reporting requirements.[296] During the oral hearing Mr. Schmidt on behalf of AG confirmed that TMS is an enterprise application.[297]

388. AG requested that it be allowed to update its 2011 capital expenditure forecast to include the estimated $2 million forecast capital cost of TMS and to increase its O&M by $0.1 million in 2011 and $0.4 million in 2012.[298]

389. The business case provided a breakdown of the $2 million forecast capital expenditure including the acquisition of five modules;[299] and implementation of two of the modules, performance management and succession planning. A separate business case is to be prepared for the other modules after the implementation of the first two modules is completed and AG is satisfied with the functionality of the software.[300] AG stated that the forecast annual cost benefit arising from the performance management and succession planning modules was in the range of $561,000 to $775,000.[301]

390. In testimony, AG advised that it would revise the forecast capital expenditure to exclude the three modules for which a business case had not yet been prepared.[302]

391. AG's forecast 2011 capital costs, before adjustment for the three modules that may be implemented at a later date are provided in the in the following table:[303]

294 Exhibit 118.01, AG application update Attachment 1.
295 AG confirmed that ATCO I-Tek on behalf of all ATCO companies, has entered into an agreement with SumTotal for the TMS system in March 2011 in CAL-AG-63(i) at Exhibit 162.02, page 6.
296 Exhibit 118.01, application update, Attachment 1, page 7.
297 Transcript, Volume 4, page 630, line 19-23.
298 Exhibit 118.01, Attachment 2, page 26.
299 The five modules outlined in the business case include: performance management, success planning, employment, workforce planning and compensation management, Ibid. page 8.
300 ATCO has stated in response to our IR, AUC-AG-112(c) that the implementation of the two modules is October 2011.
301 Exhibit 118.01. Attachment 2, page 17.
302 Exhibit 203.01, AG argument, paragraph 84, page 34.
303 Ibid., page 25.

Table 18. TMS capital estimate

Phase I -business requirements, RFP process		**$54,000**
Phase II - implementation costs		
I-Tek PM & oversight	$130,000	
Modules: performance management and succession planning	$145,000	
Travel & expenses	$15,000	
Technical/Infrastructure personnel	$650,000	
I-Tek sub total	**$940,000**	**$940,000**
Change management (client team)	$50,000	
Client sub total	**$50,000**	**$50,000**
Vendor implementation	$225,000	
License costs	$390,000	
Travel expenses	$30,000	
Vendor sub total	**$645,000**	**$645,000**
ITEK contingency vendor contingency	$200,000	
Vendor contingency	$125,000	
Contingency sub total	**$325,000**	**$325,000**
Total forecast capital costs		**$2,014,000**

392. AG requested that the Commission approve the capital expenditures for this project and the related O&M billing unit costs for the test years.[304]

Views of the parties

393. Calgary provided a review of AG's TMS business case by HRchitect.[305] Calgary stated in its written evidence that the cost of TMS as proposed is approximately 75 per cent more expensive than necessary.[306] This was corrected at the oral hearing to 94 per cent higher.[307] Calgary proposed that only three-eighths of the cost of acquiring the license should be included in rate base and the remainder of approximately $243,750 should be put in plant held for future use since only two of the modules will be in service during the test period.

394. Calgary stated in argument that the ATCO Group was aware in 2010 that TMS would be implemented and that the software had been acquired before the business case was filed by AG. ATCO I-Tek proposed to use an application service provider (ASP) deployment model where a third party firm hosts, manages and upgrades the application software.[308] Mr. Hanscome on behalf of HRchitect expressed the opinion that a SaaS deployment model where the vendor manages customizes and configures capabilities tailored to customer needs would have been

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304 Exhibit 118.01, AG April 21, 2011 application update, business case talent management system.
305 Exhibit 192.04, revised HRchitect Inc. Report dated May 31, 2011.
306 Revised Addendum 2 to Calgary's evidence, page 2, dated May 31, 2011.
307 Transcript, Volume 7, page 1621, lines 10-18.
308 Exhibit 201.01, Calgary argument, page 24.

preferable. According to the HRchitect report, a SaaS model allows for greater data security and privacy.[309] Calgary stated that if the ATCO Group was truly seeking the lowest cost provider consistent with security, confidentiality and privacy, it would require ATCO I-Tek to match the price of a SaaS system.

395. Calgary submitted that the review and evidence on TMS provided by Mr. Hanscome on behalf of HRchitect should be given more weight than that of AG's IT consultant, as Mr. Hanscome is the only human resources information technology specialist on record. Calgary identified three major differences between the HRchitect report and AG's business case:[310]

- the evaluation and selection of TMS would require future enhancement work, apparently influenced by ATCO I-Tek
- the costs associated with TMS were excessive for certain components
- the productivity benefits of TMS were overstated

396. Calgary stated that the 2011 capital costs should be reduced to $500,000, with cost reductions in three areas: the purchase of software, use of a third party consultant and I-Tek labour hours.

397. Calgary also took issue with the projected annual operating costs for TMS of $0.1 million in 2011 and $0.4 million in 2012.[311] HRchitect suggested that the costs should be for a partial year in 2011, operating costs should be $77,000, and for a full year in 2012, operating cost should be $108,000.[312]

398. AG submitted in argument that it had included forecast capital and O&M costs related to the implementation of TMS in its update filing of April 21, 2011, and that the forecasts were supported by a business case included in that filing. AG submitted that Calgary had indicated in the course of the oral hearing that AG should proceed with the implementation of TMS. AG submitted that it was important to note that Mr. Hanscome agreed that the selection of SumTotal as the vendor software was a reasonable choice.[313]

399. AG argued that the HRchitect report was based on a generic and high level analysis rather than an analysis of the specific functional and security requirements of AG. Further, the HRchitect analysis for costing was based on an amalgam of vendors. AG submitted that the forecast capital and operating costs related to TMS should be approved as filed.

400. AG submitted in argument that Mr. Hanscombe had acknowledged that the HRchitect report was not a business case specific to the circumstances of AG.[314]

309 Calgary argument, pages 23 to 25.
310 Ibid., page 26 to 27.
311 Ibid., Attachment 2.
312 Transcript, Volume 7, page 1622, lines 17-25.
313 Transcript, Volume 7, page 1620, lines 12-17, page 1621, lines 4-9 and lines 19-24 and Exhibit 203.01, AG argument, page 34, paragraph 36.
314 AG argument, page 35, paragraph 88.

401. Calgary noted that Mr. Hanscome had explained in testimony[315] his views why the AG HR business requirements were not specific or unique. Mr. Hanscome stated:

> A. MR. HANSCOME: A certain percentage of a
> company's individual business requirements are key to
> implementing a TMS. Our rule of thumb in approaching these
> engagements is that human resources or talent management
> particular requirements are at a minimum 80 percent across
> industry, that these capabilities are common to HR. HR is HR
> is HR at about 80 percent level. There's about 10 to 15
> percent of a requirement that may be related to a particular
> industry segment, regulated industries or utilities, and an
> additional 5 to 10 percent that are unique to the culture and
> the individual aspects, the uniqueness of the organization.

402. Calgary raised concerns about the timing of the filing of the business case. Calgary argued that the TMS project, like HRX and other IT projects, did not meet all the project criteria in Decision 2001-96 and that AG had not met its statutory onus. In support of this statement, Calgary argued that AG did not consider; all the security options addressed in the HRchitect Report, that the HRchitect Report provided insight on why some IT project estimates from I-Tek were high, and that the HRchitect report contained more detailed benefit information.[316]

403. In reply AG argued that it would not have been able to reasonably estimate the cost of TMS until the project scope and statements of work were completed in March 2011.[317] HRchitect did not have access to AG's business requirements and it takes time to find vendors and review their proposals to assess which vendor and software to select. HRchitect's analysis is based on a SaaS model and AG excluded this model as it did not meet AG's functional and security requirements. AG argued that the evidence it filed supported the need for TMS and the selection of an ASP deployment model.

Commission findings

404. AG indicated that it took a modular approach to assessing and implementing the HRX and TMS systems and AG prepared stand alone business cases for these systems. Although the two software programs both address human resources business needs, the Commission will assess the TMS proposal independently of HRX.

405. The Commission notes that the TMS program itself is being implemented in a modular fashion. The business case addresses only two of the five purchased modules; performance management and succession planning.

406. Neither Mr. Hanscome nor Mr. Stephens for Calgary objected to the selection of either sum total as a vendor or to the TMS system. They did, however, object to the forecasted costs. This position is reflected in the following exchanges with Commission counsel:

> Q. However, you still seem to suggest that the choice of SumTotal TMS system was the correct one even with these problems; is that right?

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315 Transcript, Volume 7, page 1550, lines 5-15.
316 Calgary's reply argument, page 14.
317 Exhibit 218.01, AG reply argument, page 45, paragraph 103.

A. MR. HANSCOME: Yes. My issue is not with the choice of the vendor who is certainly a major player in the talent management systems marketplace.[318]

Q. So again Calgary is not objecting to the selection of TSM [sic]; is that correct sir?
A. MR. STEPHENS: No.
Q. It's the cost associated with it that you have an issue with?
A. MR. STEPHENS: It's the capital cost to implement it and the ongoing operations cost.[319]

407. The Commission accepts AG's evidence that the performance management and succession planning modules of TMS will be of assistance in meeting the human resources business needs of AG identified in the TMS business case. AG has quantified the productivity benefits for the implementation of the two modules and the Commission finds the analysis supports the business case.

408. In the oral hearing Ms. Wilson,[320] on behalf of AG and as confirmed in AG's argument,[321] stated that it was prepared to amend its TMS forecast to only include the capital cost of the two modules which will be implemented in the test years. The Commission finds that the evidence of Calgary and the HRchitect report support a reduction in the forecast TMS deployment and installation costs. In assessing the proposed costs the Commission notes that AG confirmed that TMS is an enterprise application. In these circumstances, the Commission considers that it should assess the total costs of the TMS program for the performance management and succession planning modules, regardless whether a SaaS or an ASP deployment model is used, relative to the application cost ratio of 15 per cent to25 per cent[322] of total implementation cost that was identified in the HRX business case for enterprise applications.

409. The Commission considered the confirmation from Mr. Hanscome that TMS is a reasonable system, as well as the recommendations of the HRchitect report that the costs for AG's deployment and turnover of the first two modules were high. AG confirmed that it had not been able to reasonably estimate the cost of TMS until the project scope and statements of work were completed in March 2011.

410. The Commission considers the HRchitect report which assumes a different platform, is helpful in providing directional guidance. Similarly, the Commission considered the 15 to 25 per cent application cost to total cost ratio as put forward by AG in the HRX business case. This analysis also provided directional guidance for a reduction in forecast costs for TMS. AG had agreed to address in testimony and rebuttal to remove the costs of the three TMS modules that will not be implemented in the test years. The Commission directs AG in its compliance filing to only include the forecast costs of the two modules to be implemented in the test years; performance management and succession planning. For all other costs in the business case, the Commission finds that in consideration of all the evidence before it, the TMS project is approved but that the forecast capital costs should be reduced by 10 per cent.

411. The Commission is satisfied with the evidence provide by AG with respect to increased operating costs and approves the applied for increases to O&M by $0.1 million in 2011 and

318 Transcript, Volume 7, page 1620, lines 12-17.
319 Transcript, Volume 7, page 1621, line 22 to page 1622, line 3.
320 Ibid., page 657.
321 Exhibit 203, page 34, paragraph 84.
322 Business Case 14, paragraph 28.

$0.4 million in 2012. The Commission notes that all ATCO I-Tek costs are placeholders pending determination in the ongoing 2010 Evergreen proceeding.

4.7.3 Other IT projects

Background

412. AG has submitted business cases numbered 15 to 20 related to other IT projects. AG addressed certain additional IT projects, which were not supported by business cases, in the application. Calgary disputed the capital costs of two of the IT projects that were supported by business cases, and questioned the need for CIS enhancements generally with specific reference to tariff billing enhancements.

Views of the parties

413. The general views of the parties were summarized in Section 4.7. Some key points relevant to this section are repeated here. Calgary argued that AG had not quantified the benefits of these programs and how the benefits would be realized.[323] Calgary stated that there was not adequate information to justify the forecast volume variance from year to year and argued that the requested IT volumes should not be approved. In reply Calgary stated that AG had not met the capital project criteria in Decision 2001-96 and AG had not met its statutory onus in relation to its IT capital expenditures.

414. In reply argument AG stated that it had provided a full set of documentation on IT capital projects,[324] including historical actual volumes and forecast volumes.

Summary of business cases

Instrument record system (IRS) (Business Case 15)

415. In Business Case 15 AG is applying for approval of a $0.5 million project to develop a new IRS stand alone database in Oracle to replace the existing IRS program. The IRS database documents all activities related to the pressure and temperature corrector fleet. AG must keep instrument records as long as the instrument is operating in the field and all inspection information must be retained for seven years after the instrument is retired. AG stated that its existing IRS, which was developed in [Microsoft] Access in 2000 has reached a size where it has become unreliable and needs replacement.[325] In addition IRS cannot be used over the company’s intranet. The new Oracle platform will meet user requirements in the future, allow for access by remote users, and alleviate slow response issues. The forecast capital cost to create an IRS stand alone database on Oracle is $0.5 million and is proposed for 2011. Tab 4-2, Attachment 1, page 15 of 16 to the application indicates the project will require 2088 units of labour at a cost of $0.3 million in 2011 and a software licensing cost of $0.2 million.

Oracle E Business (Business Case 16)

416. Business Case 16 is an application for approval of the Oracle E-Business Suite Upgrade (also referred to as the Oracle Enterprise Suite Upgrade or Oracle E). The purpose of this upgrade is to ensure AG’s Oracle suite of products remain supported. Support for the current

[323] Exhibit 109.02, Calgary evidence, page 33.
[324] Exhibit 218.01, AG reply argument, page 49 (PDF 51/143).
[325] See application, Section 2.1.1.8, page 2.1-51 and Tab 2.1, Business Case 15, Instrument Record System, pages 5 and 6.

version of Oracle E-Business Suite ends in 2013.[326] Oracle has issued a new version of Oracle E-Business Suite and the proposed upgrade will ensure that support is continued beyond 2013. The Oracle E-Business Suite is used by other applications within AG including Oracle Financial and HRX. AG stated that updating the suite is necessary to keep the Oracle systems integrated, reduce security threats, increase functionality for sub-ledger accounting and taxes, and to gain other improvements to strategic sourcing, human capital management, the inventory system and warehouse management. The total capital cost in 2011 for the new version of Oracle E-Business Suite is forecast at $2.7 million. The business case does not distinguish software costs from implementation costs but indicated that the upgrade costs were comprised of software fees to Oracle and labour costs associated with ATCO I-Tek and Oracle consultant effort to configure and implement the upgrade. Tab 4-2, Attachment 1, page 15 of 16 to the application indicates the project will require 19,130 units of labour at a cost of $2.748 million in 2011. Accordingly, there does not appear to be an Oracle licensing cost for the upgrade.

Views of the parties

417. Calgary stated in evidence that the forecast I-Tek volumes and costs for the Oracle E-Business Suite Upgrade have not been quantified in terms of related productivity benefits. The original business case submitted in the AG 2005-2007 GRA application did not include this 2011 upgrade. Calgary submitted that AG should have provided some quantification of the benefits of the re-architecting of the financial modules and other areas that were to benefit as a result of the new project including HR, procurement and spending analytics. Calgary stated that AG's request for the Oracle E-Business Suite Upgrade was not supported as the benefits were not quantified, was premature because the current software support does not expire until 2013, and that there was insufficient evidence to justify the I-Tek volumes and costs.

Oracle mid-size applications (Business Case 17)

418. AG is applying for an Oracle 11 Upgrade for mid-sized applications to support databases for a number of mid-sized distributed applications. The business case includes forecast capital costs of $20,000 in 2010; $505,000 in 2011 and $78,000 in 2012. These costs are to implement the software as the upgraded database software is included in the annual software license fees. AG stated in the business case that Oracle will withdraw support for its Oracle 10g in July 2013.[327] AG states that if it does not implement this upgrade, there is an increased level of risk for several of its distributed applications, many of which are essential to AG's operations. The new version would allow for a data recovery advisor, would increase application performance, and would provide the implementation of improved diagnostic tools to prevent application outages. The upgrade would affect multiple databases.[328] Tab 4-2, Attachment 1, pages 14 to 16 to the application indicates the project requires 142 units of labour at a cost of $20,000 in 2010, 3,515 units of labour at a cost of $505,000 in 2011 and 532 units of labour at a cost of $78,000 in 2012.

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[326] Application, Tab 2.1, Business Case, Oracle E-Business Suite R12 Upgrade, page 4.

[327] Business Case 16 at Volume 2.2 (Tab 2.1) page 2 states the end of support occurs July 2013. In paragraph 148 of the application, AG says the support will be withdrawn as of January 1, 2012.

[328] Application Tab 2.1, Business Case 17, Oracle Version 10G to 11 Upgrade Mid Sized Applications indicated the following databases would be affected: Distributed Gas Information System, Meter Proving System, PC Automate, Industry Dialogue Manager, Imbalance Reporting Information System, Client Management Module, Fleet Management (FAA Suite), Graphic Information Viewer (DRIV), Khalix, Landman, Premier Plus 4 (Itron), Trim Records Management, and Daily Forecast and Settlement System.

Windows 7 and MS Office 2010 (Business Case 18)

419. AG submitted Business Case 18 for a "Workstation Operating System Upgrade (Windows 7 and Office 2010)." AG provided two reasons in support of this business case: Microsoft has announced that support for Windows XP will end in April 2014 and AG predicted that new versions of many applications will no longer be compatible with XP starting in 2010 and becoming more common by 2012.[329]

420. AG expects to commence the Windows 7.0 and Office 2010 upgrade early in 2012 and to complete it by year end. AG stated that there was really no other viable option as it had to move off end of life software platforms prior to them being discontinued.[330] AG noted that Windows 7.0 has improved security and a number of other benefits. AG forecasts total costs of $3,445,600 for capital costs and $215,250 for operating and maintenance costs. Capital costs are further detailed as $2,745,000 for 1,220 computers ($2,250 each) plus related upgrade costs of $915,850. Tab 4-2, Attachment 1, page 16 to the application expressed the costs for the project as labour costs of $3,107,000 and $341,000 in licensing costs. Labour units are not provided.

Software enhancements to work management system (Business Case 19)

421. In Business Case 19 AG is applying for enhancements to the work management system implemented in October 2009. AG stated that the 2011 and 2012 enhancements to two work management software programs, Ventyx Service Suite 8.0 (Ventyx) and Maximo 6.2.3 (Maximo), would improve operational efficiencies through automatic features and provide a stable platform for future software and hardware upgrades.[331]

422. The first enhancement proposed for 2011 at a cost of $600,000 is related to the dispatch/mobile applications. The current version of the Ventyx software will not be supported after September 2011. AG stated that the new version Ventyx 8.1.2 is compatible with the next generation of proposed hardware for field staff, the personal data assistant (PDA). The new version of the software has a number of operational enhancements for order notations and cancellations, tracking unauthorized usage, managing return mail and mass printing functions.

423. Tab 4-2, Attachment 1, pages 14 to 16 to the application indicates that the Ventyx enhancement project requires 4,100 units of labour at a cost of $589,000 in 2011.

424. AG is also seeking approval for an upgrade in 2012 to the Maximo software used for order management at a forecast cost of $625,000. AG estimates that support will end in the fourth quarter of 2012 although the vendor has not announced an official support deadline. An upgraded version will automate the creation of work orders to complete site visits at idle premises for the annual idle inspection program, automate printing to re-assigned print locations for employees preferring paper and display warning notes on work orders for potential areas of concern on the premises e.g. dog or a locked fence.

425. Tab 4-2, Attachment 1, pages 14 to 16 to the application indicates that the Maximo enhancement requires 4185 units of labour at a cost of $614,000 in 2012.

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[329] Application Tab 2.1, Business Case 17, Workstation Operating System Upgrade (Windows 7 and Office 2010) page 5, paragraph 6.
[330] Ibid., pages 5 to 6, paragraph 8.
[331] Application Tab 2.1, Business Case 19, Software Enhancements to Work Management Systems for years 2011 and 2012, page 7.

Views of the parties

426. In evidence Calgary observed that the work management enhancements project had a post implementation review. Calgary stated that the Work Management Phase II Post-Implementation Review[332] conducted in May 2010 report indicated an actual capital cost of the project of $17 million compared to a forecast capital budget of $13.5 million, or a 26 per cent overrun. Calgary submitted that AG had failed to demonstrate through a detailed revenue requirement analysis whether there was a benefit to ratepayers. Calgary submitted that there are no quantified benefits to justify the forecast I-Tek volumes and costs. Calgary stated that Business Case 19 described the majority of the capital costs to be software where AG's forecast IT capital schedule[333] indicated the costs are nearly all I-Tek labour. Calgary concluded that this conflicting data makes it impossible for Calgary to accept the forecast I-Tek volumes in the IT capital schedule.

2010/2011 personal digital assistants (PDA) replacement project (Business Case 20)

427. In Business Case 20 AG is requesting approval to replace the existing PDAs. AG stated that PDAs are required to allow AG's distribution operation service employees to complete work orders involving residential, commercial, and industrial customers and to communicate with the dispatching system for maintenance, emergency and non-emergency service calls. AG stated that production of the current PDAs was discontinued in 2007 and that the devices are unsupported. The business case identifies the forecast capital cost of PDA replacements as $1.8 million in 2011, and $0.1 million in 2012. In an IR AG clarified that actual capital costs in 2011 were $1.7 million.[334] Tab 4-2, Attachment 1, pages 15 and 16 to the application indicated the project will require 377 units of labour at a cost of $53,000 and 174 units of labour at a cost of $25,000 in 2012.

Other projects addressed in the application

428. AG is applying for approval of costs for enhancements to the customer information system (CIS). AG stated that the CIS application is critical to billings and payments. AG further stated that the update is needed in response to demands on AG to collect, manage, and use data to ensure compliance with external clients and agencies such as the Commission and to meet internal needs for billing. Forecast costs for the CIS enhancements are $950,000 for 2011 and $625,000 for 2012.[335] Tab 4-2, Attachment 1, pages 15 and 16 to the application indicated the project requires 4,295 units of labour at a cost of $617,000 and 57,813 units of processing at a cost of $333,000 in 2011. In 2012, 2,769 units of labour at a cost of $406,250 and 38,377 units of processing at a cost of$218,750 are required.

429. AG is applying for approval of costs for further changes to CIS related to the tariff billing code. AG stated that these updates are required to comply with EUB Directive 012 Alberta Tariff Billing Code.[336] The costs of the tariff billing code project are forecast as $600,000 in 2011 and $625,000 in 2012. Tab 4-2, Attachment 1, pages 15 and 16 to the application indicated the project requires 2715 units of labour at a cost of $390,000 and 36,458 units of processing at a cost of $210,000 in 2011. In 2012, 2769 units of labour at a cost of $406,250 and 38,377 units of processing at a cost of $218,750 are required.

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332 Exhibit 94.01, Work Management Phase II Post Implementation Review, May 2010, page 4 (PDF 38).
333 Exhibit 28.00.
334 AUC-AG-79c.
335 Exhibit 28, page 1 of 16.
336 Now AUC Rule 004: *Alberta Tariff Billing Code Rules,* Version 1.4, as of January 2, 2008.

430. A third CIS project for which approval of costs is requested is the proposal to update from Visual Basic 6 (VB6), which cannot handle large data loads to C#.NET. Vendor support for VB6 ended in 2008. The forecast 2011 cost to update to VB6 is $225,000. AG stated that it has identified 103 programs in current use that will require this conversion. This project is related to the Windows 7.0 upgrade project as C#.NET is compatible with the Windows 7.0 operating system. Tab 4-2, Attachment 1, pages 15 and 16 to the application indicated the project requires 1018 units of labour at a cost of $146,250 and 13672 units of processing at a cost of $78,700 in 2011.

431. In addition to the above IT projects, AG has requested approval of forecast capital expenditures in the amount of $$1.66 million and $0.62 million for 2011 and 2012 respectively for additional minor IT capital projects identified in Table 19 below. These additional programs include a capital budgeting system, a daily forecast and settlement system, graphics enhancements, an imbalance reporting information system, a regulating facilities application upgrade, service initiation and billing system and enhancements to other distributed applications.

432. In Table 19 below is a summary of the cost for various other minor IT projects forecast during the test years.

Table 19. Various smaller IT project forecasts

$(000)	2011	2012
Capital budgeting	200	
DFSS development and enhancements	150	100
Graphics enhancements	150	155
IRIS development and enhancements	100	100
IRIS upgrade	500	
Reg. station upgrade	300	
SIBS enhancements	255	265
Total	**1655**	**620**

Views of the parties

433. In evidence Calgary submitted information provided by AG with respect to CIS enhancements.[337] AG indicated that there were three to five enhancement projects in each of the years 2007 though the forecast year of 2012.[338] Calgary stated that these enhancement projects only include costs and no unit volumes. Also, the differences in dollars from year to year are difficult to determine. The costs for CIS enhancements are not justified due to the lack of quantifiable benefits and insufficient data for I-Tek volumes.

[337] Exhibit 109.02, Tables 4 and 5 pages 46 to 48.
[338] AG's responses to the list of capital projects are found in Exhibits 82.01 CAL-AG-22 and 84.01 AUC-AG-43 and AUC-AG-79.

Commission findings

434. Decision 2001-96[339] requires that all major capital projects should include a detailed justification including demand, energy and supply information, a breakdown of the project cost, the options considered and their economics, and a discussion of the need for the project. The Commission continues to consider that these requirements are still in effect for the analysis of utility business cases.

435. For some proposed projects, the Commission found AG's business cases sufficient to justify proceeding with the projects. Consequently, the Commission will first consider whether the business case or application, supports proceeding with the capital project. Where the Commission finds support for a project, it will approve the project in principle and move to a discussion of the reasonability of the forecast labour and processing unit volumes and the forecast cost to be included as a placeholder in revenue requirement. The Commission notes that the approved forecast costs for 2011 and 2012 will be placeholders, subject to price adjustment after the 2010 Evergreen[340] proceeding. Actual capital costs incurred in implementing a project at the volumes approved in this proceeding at the prices approved in the 2010 Evergreen proceeding will be subject to Commission review for prudence when AG next applies to have the actual costs included in opening PP&Eaccounts.

436. The Commission finds that Business Case 15 for IRS database supports AG proceeding with the project. As the current system has been in place since 2000 and the new system will provide increased functionality the Commission considers it is reasonable to approve this project.

437. The Commission finds that the proposed update to Oracle E in Business Case 16 is premature. A major argument in support of this business case is that support of the current version of Oracle E will end in 2013. The Commission agrees with Calgary that the need for this project has not been demonstrated as the current software support does not expire until 2013 and the benefits were not quantified. For these reasons the Commission denies the application for this business case and directs that the forecast costs related to this business case should be removed from its revenue requirement in the compliance filing for this application.

438. Business Case 17 for oracle mid-size is proposed based on the fact that support of the current version will end in July 2013.[341] The application states that Oracle will terminate the existing level of support on January 1, 2012.[342] The Commission notes that there is a discrepancy in the dates of termination. According to AG's business case support will not be withdrawn but the level of support may change.[343] The Commission does not consider it has sufficient information to determine if support will be withdrawn, and whether any change in the existing level of support will impact AG's operations. The Commission directs AG in the compliance filing to this application to provide information from the vendor regarding the proposed withdrawal of support, including the level of support which will continue to be available. If the vendor provides the option of continuing support at a lower level, AG is directed to provide an analysis of any impact on its operations.

339 Decision 2001-96: ATCO Gas South, 2001-2002 General Rate Application Phase 1, December 21, 2011, Application No, 2000350, File No. 1307-1, December 12, 2001, page 29.
340 Application No. 1605338, Proceeding ID No. 240.
341 Application, Business Case 17, paragraph 1.
342 Application, page 2.1-53, paragraph 148.
343 Application, Business Case 17, paragraph 1.

439. With respect to Business Case 18 for Windows 7.0 and MS Office 2010, the Commission considered the reasons AG provided in support of the business case that: Microsoft has announced that support for Windows XP will end in April 2014 and AG predicted that new versions of many applications will no longer be compatible with XP starting in 2010. AG predicted that lack of compatibility would become a greater problem by 2012. Although XP will continue to be supported until 2014 the Commission considers that an update is justified on the basis of the need for compatibility with other applications. AG updates for every second Windows release and the Commission considers this approach strikes a balance between cost management and maintaining up to date software. The Commission notes than no interveners objected to this business case. For the preceding reasons the Commission finds it is reasonable to approve this business case. However, the Commission finds the cost per computer of $2,250 was not explained and in future filings the Commission will expect detailed support for costs incurred, including a calculation of unit cost and an analysis of resulting benefits.

440. With respect to Business Case 19, work enhancements, AG stated that the Ventyx software will not be supported after September 2011. The Commission finds that there are functional benefits of the Ventyx software related to manpower efficiencies and increased customer service. Given the identified functional benefits and the statement that support will be withdrawn in September 2011, the Commission considers it reasonable to approve the acquisition of the Ventyx software as proposed in the business case.

441. Business Case 19, work enhancements, also proposes a Maximo software upgrade in 2012. The Commission notes that functional benefits are forecast and that withdrawal of support is anticipated for the fourth quarter of 2012. The Maximo software appears to have been installed as part of work management Phase II in October 2009 at a cost of $3.9 million. As Calgary noted the entire work management Phase II project was installed at a cost of $17 million compared to a forecast cost of $13.5 million. Calgary also noted a discrepancy in the cost breakdown between the business case and the schedule provided at page 16 of Tab 4.2 Attachment 1.[344] The argument in support of the business case is premised on the withdrawal of support by the vendor. The Commission notes, as acknowledged by AG, that the vendor has not announced the withdrawal of support for the software. For the preceding reasons, the Commission denies approval of the forecasts costs for the Maximo software proposed in Business Case 19. The Commission directs AG to remove the forecast costs associated with this software package from its revenue requirement in the compliance filing for this application.

442. The Commission has reviewed AG's application which includes a number of IT projects not supported by business cases. Three CIS enhancements were proposed: a general CIS enhancement program, VB6 and tariff billing code.

443. AG has forecast costs for the general CIS enhancement program of $1 million in 2011 and $0.6 million in 2012. This program and the related benefits are not clearly described. The Commission finds the explanation in paragraph 129 of the application does not justify the requested capital expenditure for this project. Therefore, the Commission denies this proposed enhancement and directs that related costs be removed from the revenue requirement in the compliance filing to this decision.

[344] Exhibit 28.01.

444. AG proposed an upgrade to VB6, for which support ended in April 2008. The system supports 103 programs. For these reasons, the Commission considers it reasonable to update the VB6 programs to C#.NET.

445. The Commission relies on AG’s submission that the tariff billing code enhancements were necessary to conform with regulatory standards and considers that this update is required. The Commission approves the update of the tariff billing code as filed.

446. The other IT projects identified by AG in its application, have forecast capital costs of $1.66 and $0.62 million for 2011 and 2012 respectively. The Commission notes that interveners did not object to any of these IT capital projects. The Commission considers the forecasts of these projects are reasonably included in AG’s revenue requirement and approves the implementation of AG’s other IT projects.

447. Having identified the projects for which the business case supports the project, the Commission will now address the labour and processing volumes required to implement these projects and the forecast costs of these projects for the purpose of establishing a placeholder in revenue requirement. Labour and processing volumes for projects not approved are to be excluded from AG’s revenue requirement.

448. Calgary noted that it is not possible for an intervener or the Commission to reasonably assess unit volumes and that the assessment process was further complicated by the change in approach in the master service agreement (MSA). The Commission shares Calgary’s concerns regarding the information provided in the business cases.

449. The Commission is not able to assess the meaning of the volumes of labour units provided in Attachment 1 of Tab 4.2 of the application which relate to the business cases. This attachment provides information on capital projects from 2008 to 2012. For the projects forecast for 2010 to 2012 a single line item per project is provided with a single figure for labour units. The Commission is unable to assess the different classes of labour which could be included in the single labour unit and has no information on the relative costs of each unit. The Commission is concerned that a change to the mix of the labour components could result in a significant change to the cost of the IT project. The detailed project cost breakdowns for 2008 to 2009 identify many different labour components at various costs per unit. For example, there are multiple classes of analysts, classes of business service analysts, supervisors, consultants, project managers, as well as AG direct costs. Further, certain of the 2011 and 2012 projects are also ascribed a number of units of processing time without explanation.

450. For approved IT capital projects the Commission directs AG in its compliance filing to provide a description of volume metrics and a detailed breakdown of the labour units related to the different classifications with the current rates in support of theforecast labour costs. For any items without units, an explanation should be provided of the reason for inclusion in labour costs. Similarly, AG shall provide an explanation for all projects that have been allocated a volume of processing costs.

451. The Commission requires sufficient detail with respect to volumes to be able to assess the reasonability of forecast volumes to actual volumes forming the basis of costs in reviewing prudence when AG next applies to have the actual costs included in opening PP&E accounts.

452. With respect to the forecasted costs for each of the approved projects the Commission approves as reasonable the inclusion in revenue requirement of the license fee required for a project. The balance of the forecasted costs are labour and processing unit costs driven by volumes. Volume pricing is to be determined in the 2010 Evergreen proceeding. The Commission considers the forecasted costs reasonable for purposes of establishing a placeholder in revenue requirement for IT capital. The placeholder will be finalized when prices are determined in the 2010 Evergreen proceeding to apply to any volumes approved in the compliance filing process to this decision.

4.8 Balance of capital expenditures

453. The Commission has examined the 20 business cases filed in the application and the additional business cases filed in updates and made specific findings. The Commission has also made findings on the forecast costs related to distribution.

454. The lands and structures category included a number of building projects specifically discussed; the remainder not discussed included general land and structures, leasehold improvements, and the Grande Prairie shop extension and yard development.

455. In the moveable equipment category the following were not specifically discussed: transportation equipment, tools and work equipment, heavy work equipment, garage stores and shop equipment, office furniture and equipment, and technical support equipment.

456. Except with respect to Business Case 20 for PDA replacements, there was no specific discussion of the various areas in the communication equipment category.

457. The information technology, and demand side management categories were discussed separately.

Commission findings

458. The Commission notes that interveners have not raised concerns regarding the categories described above that are not specifically discussed elsewhere in this decision. The Commission has reviewed the costs for the above categories and considers costs of an ongoing nature are reasonable when compared to actual costs incurred in 2010. The project related costs were adequately supported in the application. Consequently, the Commission approves the forecast expenditures in 2011 and 2012 that were not specifically addressed.

5 Capital structure

5.1 Return on equity and equity ratio

459. AG incorporated the generic return on common equity (ROE) rate of 9.00 per cent over the test period as a placeholder for both 2011 and 2012 pending a decision in the 2011 generic cost of capital proceeding.[345] AG included a forecast equity percentage for 2011 and 2012 of 39 per cent,[346] consistent with Decision 2009-216.[347]

[345] Application No. 1606549, Proceeding ID No. 833.
[346] Application, Table 3.1.2(a).
[347] Decision 2009-216, page 107.

460. AG forecasted its 2011 and 2012 return on rate base at 7.200 per cent and 7.130 per cent respectively. When the forecast return is applied to the forecast 2011 and 2012 mid-year rate base the utility income is $112.8 million for 2011 and $125.5 million for 2012.[348]

Commission findings

461. In Decision 2009-216, the 2009 Generic Cost of Capital application, the Commission established a generic ROE for 2009 and 2010 of 9.0 per cent. The Commission also determined an ROE of 9.0 per cent for 2011 on an interim basis.[349] The Decision directed that individual utilities, or interveners, could apply for changes to equity ratios on the basis of significantly changed circumstances. AGs' current equity percentage as approved in Decision 2009-216 is 39 per cent.[350]

462. The 2011 Generic Cost of Capital application is currently before the Commission. That proceeding is considering both return on equity and capital structure for all Alberta utilities. Accordingly, an ROE of 9 per cent and a common equity percentage of 39 per cent are approved as placeholders for the 2011 and 2012 test years pending the decision of the Commission in the 2011 Generic Cost of Capital proceeding.

5.1.1 Prior preferred share issues

463. In Decision 2009-115,[351] the Commission approved the issuance by ATCO Gas and Pipelines Ltd. of 6.7 per cent, 1,080,000 Series 2 Preferred Shares dated March 27, 2009 to CU Inc. at $25.00 per share in respect of the advance of $27,000,000 made to ATCO Gas and Pipelines Ltd. by CU Inc. Net proceeds of $24,624,000 were allocated to AG.[352]

464. In its evidence[353] Calgary took issue with the reasonableness of the rate of preferred shares issued by AG on March 27, 2009. Calgary noted that:

> On March 31, 2009 Nesbitt Burns indicated that the market value of the share was $26 up from the issue price of $25 and that the current yield was 6.44%. Four days later the yield had dropped 32 basis points. Further, the reset price will be 481basis points over 5 year Canada's as compared to the spread of 136 basis points on the December 2010 issue.

465. ATCO Gas explained the rationale and the mechanics behind the March 27, 2009 issue in its rebuttal evidence:

> Calgary questions the reasonableness of the 6.7% March 27, 2009 preferred share financing rate. ATCO Gas notes that the preferred share issue was priced on March 10, 2009 as indicated in a CU Inc. press release of the same date. In a preferred share offering, there is normally a two week period between the filing of the preliminary short form prospectus with the securities regulatory authorities (i.e. the pricing date of March 10, 2009) and the closing date of the issue (March 27, 2009.) The spring of 2009 was a tumultuous time in the capital markets. Volatility was high and the availability of capital was low. The scarcity of capital at the time drove up market premiums, yet ATCO Gas

348 Application, Section 3.1.3.
349 Decision 2009-216, page 18, paragraph 75.
350 Decision 2009-216, Table 17, page 107.
351 Decision 2009-115: ATCO Gas and Pipelines Ltd. Issuance of Debentures and Preferred Shares, Application Nos. 1605229, 1605230, and 1605231, Proceeding ID. No. 224, Released: August 14, 2009.
352 Application, Schedule 3.2-D.
353 Exhibit 109.01, page 16.

required capital to finance capital expenditures and to repay existing indebtedness. Due to the market volatility, there was also no indication that waiting to finance would result in lower rates. Rather, the concern at the time was such that the rates would continue to increase.[354] (footnote omitted)

466. Further ATCO provided a table providing data on issuing companies and the terms of their share issuances for preferred shares during the first quarter of 2009:

Table 20. Comparable preferred share rates

Date	Issuer	Issue size (millions)	Ratings (S&P/DBRS)	Initial dividend rate	Premium	Fixed rate reset every
Jan-09	National Bank	$145	P-2(H)/Pfd-1(L)	6.60%	4.79%	5 yrs
Feb-09	CIBC	$200	P-1(L)/Pfd-1	6.50%	4.33%	5 yrs
Mar-09	CU Inc.	$160	P-2(H)/Pfd-2(H)	6.70%	4.81%	5 yrs
Mar-09	HSBC Bank Canada	$250	P-1/Pfd-1 (neg)	6.60%	4.85%	5 yrs
Mar-09	Bank of Montreal	$275	P-1(L)/Pfd-1	6.50%	4.58%	5 yrs

467. In Decision 2011-055,[355] the Commission approved the issuance by ATCO Gas and Pipelines Ltd. of 1,440,000, 3.80 per cent Cumulative Redeemable Second Preferred Shares Series 4 dated December 2, 2010 to CU Inc. at $25.00 per share in respect of the advance of $36,000,000. Net proceeds from the sale of the Series 4 preferred shares from ATCO Gas and Pipelines Ltd. to CU Inc. was estimated at approximately $35,008,000 after deducting a pro rata share of the fees and estimated expenses to be paid by CU Inc. in connection with the issue of CU Inc.'s Series 4 preferred shares. Of these net proceeds, $30,645,000 was allocated to AG.[356] The Commission confirmed that the proper place to review the prudence of that decision as well as the rate was a general rate application. The Commission stated:

> 31. In its argument, ATCO Gas and Pipelines Ltd. submitted that a proper testing of the prudence of any financing decisions takes place in the same forum as where the prudence of other utility decisions is undertaken, the utility specific GRA or General Tariff Application (GTA). AGPL submitted that "The prudence of the issue, the dividend rate, terms of the re-set, redemption and purchase for cancellation options, the interest rates and other material terms and conditions are not the fundamental concern of a funding application. The appropriate forum for a review of such matters is at a GRA or a GTA where these matters will be part of the revenue requirement determined by the Commission.
>
> 32. The Commission agrees with this and historically the GRA or GTA is where the Commission has tested the prudence of utility financing decisions.[357] (footnote omitted)

354 Exhibit 163.01, paragraph 142.
355 Decision 2011-055: ATCO Gas and Pipelines Ltd. Issuance of Preferred Shares to CU Inc., Application No. 1606853, Proceeding ID. No. 1004, Released: February 16, 2011.
356 Application, Schedule 3.2-D.
357 Decision 2011-055, paragraphs 31-32.

Commission findings

468. The Commission accepts that the March 27, 2009 share issuance was reflective of the market at the time and accepts AG's position quoted above that:

> Due to the market volatility, there was also no indication that waiting to finance would result in lower rates. Rather, the concern at the time was such that the rates would continue to increase.[358]

469. Accordingly, the Commission finds the preferred share issuance to have been prudent. However, given that preferred shares are subordinate to debt and in certain market conditions, the issuance of preferred shares may demand higher dividend rates than anticipated, alternative debt options should be examined in such circumstances. The Commission directs AG in its next preferred share application to provide a comparative analysis of the alternative of issuing debt.

470. The Commission notes that no party specifically objected to the December 2, 2010 Cumulative Redeemable Second Preferred Shares Series 4 although Calgary did object to the increased percentage of preferred shares, suggesting that if the increase was permitted by the Commission, it should reduce the cost of the preferred shares permitted in revenue requirement.[359] Decision 2011-055 reflects the dividend rate as follows:

> The dividend rate payable by ATCO Gas and Pipelines Ltd. on the series 4 preferred shares to be issued to CU Inc. is the rate payable by CU Inc. on its series 4 preferred shares. Until June 1, 2016, the dividend rate will be fixed at $0.95 per share per annum.[360]

471. Decision 2011-055 notes that the share issue will be used to finance capital expenditures and will help maintain a capital structure for ATCO Gas and Pipelines Ltd. at the levels established in Decision 2009-216.[361]

472. The Commission also notes the comments made in Decision 2011-055:

> 23. …the Commission takes comfort in the fact that AGPL stated that if at the time when the dividend rates reset, by the formula indicated in paragraph 12 above, and a cost rate results which is not reflective of the then current market rates of debt, then AGPL can and will redeem the preferred shares. Further, AGPL stated in its responses to AUC-AGPL-4 and AUC-AGPL-6 that the option to redeem shares is available at the individual specific utility level, i.e. AGPL can, at its option, redeem the series 4 preferred shares from CU Inc. which in turn would redeem the equivalent number of shares from the public. The Commission considers that this redemption option does not restrict nor limit the Commissions' ability to judge and approve prudence of the share issue going forward at the time of the relevant General Rate Application.[362] (footnote omitted)

473. The Commission finds that the issuance of the December 2, 2010 Cumulative Redeemable Second Preferred Shares Series 4 to have been prudent, however, noting that the dividend rate is subject to redetermination June 1, 2016, the Commission is unable to confirm the reasonableness of dividend rate upon renewal at this time.

358 Exhibit 163.01, paragraph 142.
359 Calgary evidence, page 52.
360 Decision 2011-055, page 3, paragraph 12.
361 Ibid., page 3, paragraph 14 and page 5, paragraph 19.
362 Decision 2011-055, pages 5-6, paragraph 23.

5.2 Preferred share financing forecast

474. ATCO Gas proposed to increase the preferred share component of its capital structure to approximately nine per cent and 10 per cent in the 2011 and 2012 test years, respectively. AG plans to issue $39.2 million in preferred shares in 2011 and $17.6 million in 2012.[363] The preferred share financing requirements are forecast to be met with perpetual five year rate reset preferred share issues.[364]

475. AG noted that the Series U and V preferred shares were issued in 1996, with a five-year term to reset the dividend rate. The dividend rates were reset in 2002 and once again in 2007. The last payment due at the current dividend rate will be due November 2012 and thereafter the dividend rate will be re-determined based on market conditions at the time. ATCO Gas has also forecast that rate to be 5.20 per cent.

476. In the application AG provided the following forecast preferred share rates:

Table 21. Application forecast preferred share rates

Table 3.2.4[365] Forecast Preferred Rates		
	2011	2012
5-Year Canada Bond Rate	3.00%-3.25%	3.5%-3.70%
Credit Spread	1.40%-1.80%	1.40%-180%
Preferred Rate	4.40%-5.05%	4.90%-5.50%
Recommended Rate	4.75%	5.20%

477. In its May 16, 2011 update AG provided the following adjusted preferred share rates:[366]

Table 22. Updated preferred share rates

	2011 GRA	2012 GRA
5-Year Canada Bond Rate	2.85%	3.75%
Credit Spread	1.40%	1.40%
Preferred Rates (Updated)	4.25%	5.15%
Preferred Rates (As Filed)	4.75%	5.20%
Reduction to Rates	(0.50%)	(0.05%)

478. In its rebuttal evidence, AG provided reasons supporting the increase in its percentage of preferred shares:

- the use of preferred shares at the 5 to 10 percent range results in a marginal increase to customer costs, their use also enhances the credit metrics for ATCO Gas and Pipelines Ltd. in support of CU Inc.'s A credit rating which more than offsets this increased cost to customers;

363 Application, page 3.2-2, paragraph 5.
364 Application, page 3.2-2, paragraph 6.
365 Application, Table 3.2.4, page 3.2-3, paragraph 10.
366 Exhibit 160.01, Table 3.2.3.

- the form of preferred shares issued by ATCO Gas and Pipelines Ltd. are perpetual in nature and although there is interest rate risk (exposure to movements in underlying Government of Canada benchmark bond yields) there is no refinancing risk (that replacement financing is not available) or credit spread risk (that spreads will widen for any given level of credit rating or that CU Inc. experiences a downgrading) associated with the reset preferred shares. Debt instruments, on the other hand, have exposure to all three risks; and

- the cost of preferred shares has declined to a greater extent than the cost of debt. Additionally, the decrease in income tax rates and the decrease in nominal dividend rates have also contributed to the improvement in the cost of preferred shares relative to other forms of financing. The 2010 preferred dividend rate of 3.8% and the reset spread of 136 bps are the lowest all-in rate and reset spread ever made available to CU Inc. and among the lowest rate available to any utility in Canada.[367]

479. Below is a comparison of actual 2010 capital structure[368] and the forecast for the test years:[369]

Table 23. Capital structure ratios

	2010	2011	2012
Debt	53.1%	51.6%	50.9%
Preferred shares	7.9%	9.4%	10.1%
Common equity	39.0%	39.0%	39.0%

Views of the parties

480. The CCA considered it inappropriate to increase preferred shares as a percentage of capital structure as there is no change in circumstance which would warrant such as a change. The CCA also recommended that the capital structure approved by the AUC in Decision 2009-216[370] remain in place for the test years.

481. Calgary submitted that Decision 2009-216 requires AG to demonstrate significantly changed circumstances before it could change its capital structure[371] from what it was at the time of that decision. Calgary submitted that AG had not demonstrated such significantly changed circumstances and therefore there should be no change to the level of preferred shares.

482. AG submitted that Decision 2009-216 required demonstration of significantly changed circumstances before a utility could change its equity ratios and that it did not pertain to preferred share equity ratios.[372] Decision 2009-216 states:

> 413. The equity ratios awarded in this Proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.

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367 Exhibit 163.01, paragraph 140, page 39 to 40.
368 Exhibit 160.01, Attachment 1, Schedule 2.
369 Application, Table 3.1.2(a).
370 Decision 2009-216: 2009 Generic Cost of Capital, Application No. 1578571, Proceeding 85, November 12, 2009.
371 Decision 2009-216, paragraph 413.
372 Exhibit 163.01, AG rebuttal evidence, page 37, paragraphs 134-135.

483. AG argued that the quote was clearly referring to common equity ratios and not preferred share equity ratios. Therefore a requirement to demonstrate significantly changed circumstances in order to change to the preferred equity ratio, as suggested by interveners, does not exist.

484. Further, AG noted that in the recent ATCO Electric Decision 2011-134, ATCO Electric has been directed to prepare an updated analysis to demonstrate whether the optimal range of five to 10 percent for preferred shares discussed in Decision 2006-100[373] is still relevant, concurrent with or prior their next preferred share application.[374] AG offered to provide a similar analysis, concurrent with or prior to AG's next preferred share application.[375]

Commission findings

485. In Decision 2006-100 the EUB reviewed both the need for preferred shares and the target ratio of preferred shares for the ATCO Group of utilities. The board stated:

> The ATCO Utilities proposed a preferred equity ratio of 6% and a debt ratio that approximates 57% across the four ATCO Utilities, which would then approximate 63% if the preferred shares were replaced with debt. In these proportions, the debt portion of capital is approximately 10 times larger than the preferred equity portion of capital. On this basis, the Board calculates that if the debt costs were to rise by any more than approximately 10 (i.e. 95/10) basis points, due to the replacement of preferred shares with debt, then the added cost of the (then) approximately 63% debt component would outweigh the approximate 95 basis points savings on the current 6% preferred share component. The Board notes that, in keeping with its steady-state approach, this calculation assumes that the added cost would apply to both existing and new debt….
>
> It is not clear how many basis points would be added to AU's debt costs if preferred shares were replaced with debt. However, the Board accepts that directionally it should expect some increase in debt costs in such a scenario. The Board accepts AU's submission that the debt cost impact would vary depending on market conditions. In the Board's view, a 10 basis points or greater increase in debt costs for AU resulting from the discontinuance of the use of preferred shares in AU's capital structure would be sufficient to demonstrate the continued cost effectiveness of employing preferred shares. The Board considers the evidence provided by AU and its experts persuasive that the discontinuance of the use of preferred shares could be expected in the present market conditions to increase AU's debt costs by approximately 10 basis points. The Board also notes that AU's evidence indicated that the impact could be as high as 60 basis points. Therefore the Board finds that the continued use of preferred shares is cost effective at this time.
>
> Therefore, the Board accepts that some level of preferred shares can to be utilized by AU at this time….
>
> Under cross-examination by Board Counsel, AU indicated the optimum amount of preferred shares had been estimated by AU to be within a range of five per cent to 10 per cent.

373 Decision 2006-100: ATCO Utilities 2005-2007 Common Matters Application, Application No. 1407946, Released: October 11, 2006.

374 AUC Decision 2011-134: ATCO Electric Ltd. 2011-2012 Phase I Distribution Tariff & 2011-2012 Transmission Facility Owner Tariff, April 13, 2011, paragraph 460.

375 Rebuttal evidence, page 40, paragraph 141.

> In Section 5.1 above, the Board concluded that the six per cent level of preferred shares was cost effective. This six per cent falls within the range identified by AU as being optimum. The Board accepts the evidence of AU on this point at this time.[376]

486. In Decision 2011-055[377] the Commission discussed its concerns when approving the issue of 1,440,000 Cumulative Redeemable Second Preferred Shares Series 4 at $25.00 per share to CU Inc., and up to 1,440,000 Cumulative Redeemable Second Preferred Shares Series 5 upon conversion of the Cumulative Redeemable Second Preferred Shares Series 4 at the option of the holder. The Commission stated:

> 32. ...about the increasing levels and expense of preferred shares and believes that long term debt provides a viable alternative which should be considered by ATCO Gas and Pipelines Ltd. when making future financing decisions.[378]

487. The Commission issued a similar decision with respect to the issuance of preferred shares with respect to ATCO Electric Ltd. in Decision 2011-056.[379]

488. In Decision 2011-134 the Commission found:

> 460. …that long term debt rates and preferred share dividend rates may reach a point in the future where it is no longer to the benefit of customers to increase the levels of preferred shares. The Commission reaffirms its statement in Decision 2011-056 that it continues to be concerned with the increasing levels and expense of preferred shares and finds that long term debt provides a viable option which should be considered by ATCO Electric in future financing decisions.[380]

489. The Commission notes that AG offered to prepare a similar analysis to the one directed from ATCO Electric, concurrent with or prior to AG's next preferred share application. The Commission considers such an analysis is required and directs AG to prepare an updated analysis concurrent with or prior to AG's next preferred share application to assess whether the optimal range of five to 10 per cent for preferred shares as discussed in Decision 2006-100 should be continued thereafter. This analysis should also include a number that represents the most cost effective level of preferred shares for AG and should be submitted to the Commission concurrently with or before AG's next preferred share application to the Commission. Accordingly, approval of the actual preferred share issue is subject to the Commission's approval of the directed analysis.

490. AG has forecast preferred share issues of $39.2 million and $17.6 million in 2011 and 2012 respectively. The forecast preferred share rate reflected in the May 16, 2011 update is 4.25 per cent in 2011 and 5.15 per cent in 2012. The Commission accepts the forecast dollar amount of the proposed preferred share issuances for both 2011 and 2012, subject to the direction set out in the preceding paragraph.

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376 Decision 2006-100, pages 19-21.

377 Decision 2011-055: ATCO Gas and Pipelines Ltd., Issuance of Preferred Shares to CU Inc., Application No. 1606853,Proceeding ID No. 1004, February 17, 2011.

378 Ibid., paragraph 32.

379 Decision 2011-056: ATCO Electric Ltd., Issuance of Preferred Shares to CU Inc., Application No. 1606854, Proceeding ID No. 1005, February 17, 2011.

380 Decision 2011-134, paragraph 460.

491. The Commission does not accept, however, the forecast preferred share rates for 2011 and 2012. AG issued the 3.80 per cent Cumulative Redeemable Second Preferred Shares Series 4 dated December 2, 2010, one day prior to filing the application on December 3, 2010, which contained a recommended preferred share rate of 4.75 per cent for 2011. Decision 2011-055 noted part of AG's explanation for issuing preferred shares in December 2, 2010 was "that the preferred dividend rate of 3.8 per cent and the reset spread of 136 are the lowest all-in rate and reset spread ever made available to CU Inc. and among the lowest rate available to any utility in Canada."[381] In response to UCA-AG-61(g) AG indicated that the Cumulative Redeemable Second Preferred Shares Series 4 were underwritten and priced on November 16, 2010 and that the underlying Government of Canada benchmark five-year bond had a yield of 2.44 per cent at the time of pricing the transaction.[382]

492. In light of the actual market experience of CU Inc. and AG in issuing preferred shares on December 2, 2010, the Commission can not accept as reasonable either the original 2011 forecast preferred share rate of 4.75 per cent in the application or the May 16, 2011 update of 4.25 per cent. The Commission has found the 2011 forecast to be unacceptable therefore the 2012 forecast must also be rejected.

493. Given the date of this decision, it is not practical to require AG to revise its 2011 forecast in a compliance filing. Further, the Commission notes that under Section 40 of the *Gas Utilities Act*, in fixing just and reasonable rates of an owner of a gas utility:

> (a) the Commission may consider all revenues and costs of the owner that are in the Commission's opinion applicable to a period consisting of
>
> (i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,
>
> (ii) a subsequent fiscal year of the owner, or
>
> (iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,
>
> and need not consider the allocation of those revenues and costs to any part of that period,

494. Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual preferred share rates for preferred shares issued in 2011, if any, for the purposes of calculating capital structure, forecast return on rate base, forecast utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 preferred shares in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 preferred share rate and the rate of any preferred shares issued in 2011.

381 Decision 2011-055, pages 6-7, paragraph 26.
382 Exhibit 83.01, UCA-AG-61(g).

5.2.1 Prior debt issue

495. In Order U2008-56[383] the Commission authorized AG to issue a 30-year, 5.556 per cent debenture to CU Inc. In Decision 2008-113 AG was directed to use a 2008 debenture rate of 5.62 per cent in determining the long term debt rate for the 2008-2009 test years.[384] In Schedule 3.2-C of the present 2011-2012 application AG provided the following table which provided the detail of its outstanding long term debt including its 20-year 5.563 per cent debentures and 30-year 5.183 per cent debentures issued May 26, 2008:

Table 24. Long-term debt

ATCO Gas
Calculation of Long Term Debt and Embeded Cost Rate
As at December 31
($000's)
2010 Forecast

Line No.	Series - Coupon Rate	Issue Date	Maturity Date	Embedded Cost Rate (a)	Outstanding Balance	Carrying Cost	Average Embedded Cost of Debt
1	11.770%	90/11/28	2020	11.910%	23,559	2,806	
2	9.920%	91/12/18	2022	10.050%	26,537	2,667	
3	9.400%	92/12/08	2023	9.510%	43,282	4,116	
4	6.800%	99/08/12	2018	6.850%	119,533	8,188	
5	7.050%	00/05/16	2011	7.130%	47,485	3,386	
6	6.145%	02/11/22	2017	6.210%	53,779	3,340	
7	5.432%	04/01/23	2019	5.489%	104,580	5,740	
8	5.096%	04/11/18	2014	5.160%	27,936	1,441	
9	5.896%	04/11/18	2034	5.940%	56,690	3,367	
10	5.183%	05/11/21	2035	5.230%	19,879	1,040	
11	4.801%	06/11/20	2021	4.850%	19,912	966	
12	5.032%	06/11/20	2036	5.070%	19,886	1,008	
13	5.556%	07/11/30	2037	5.620%	64,620	3,632	
14	5.563%	08/05/26	2028	5.620%	54,665	3,072	
15	5.580%	08/05/26	2038	5.610%	94,411	5,296	
16	Total Long Term Debt and Advances				776,754	50,065	6.445%
17	Mid Year Calculations				**782,372**	**50,719**	**6.483%**
18	Total Mid Year Short Term Debt (Financial)				0	0	2.000%
19	Total Long Term and Short Term Advances				782,372	50,719	6.483%
20	Adjustment for Deemed Debt				(29,661)	(1,923)	6.483%
21	Deemed Debt				**752,711**	**48,796**	6.483%

383 Order U2008-056 ATCO Gas and Pipelines Ltd. - 5.556% Debenture Application - December 06, 2007, February 7, 2008.

384 Decision 2008-113, page 53.

496. The Commission notes the previous GRA did specifically approve the prudence of the May 26, 2008 debt issues. The Commission considers that the two tranches of debt issued in 2008 were done at prudent rates and approves the inclusion of their cost rates in the calculation of forecast return on rate base, utility income and of revenue requirement.

5.2.2 Debt forecast financing requirements

497. AG indicated in the application that it anticipates issuing $120.9 million in long-term debt in 2011 and $89.9 million in 2012. The long-term debt financing requirements are forecast to be met with 30-year debenture issues.[385]

498. In the application AG provided the following forecast debenture coupon rates:

Table 25. Application forecast debenture rates

Table 3.2.3[386] Forecast Debenture Rates		
	2011	2012
Long Canada Bond Rate	4.10%-4.50%	4.50%-5.25%
Credit Spread	1.30%-1.50%	1.30%-1.50%
Debenture Rate	5.40%-6.00%	5.80%-6.75%
Recommended Rate	5.75%	6.35%

499. In its May 16, 2011 update AG provided the following adjusted forecast debt rates:[387]

Table 26. Debt rates

	2011 GRA	2012 GRA
Long Canada Bond Rate	3.90%	4.50%
Credit Spread	1.40%	1.40%
Debenture Rate (Updated)	5.30%	5.90%
Debenture Rates (As Filed)	5.75%	6.35%
Reduction to Rates	(0.45%)	(0.45%)

500. The proceeds from these debt issues, combined with internally generated funds, will be used to finance the capital expenditure program, to refinance maturing debenture issues and to maintain the approved capital structure. There is a scheduled financing retirement in 2011 for the 7.05 per cent debenture of $47.5 million.[388]

501. AG noted that no party has indicated that alternative financing rates should be used and that the financing rates have been developed in a manner consistent with past practice.[389]

385 Application, Section 3.0, Table 3.2.3.
386 Application, Table 3.2.3, page 3.2-3, paragraph 8.
387 Exhibit 160.01, page 1.
388 Application, page 3.2-2, paragraph 7.
389 AG argument, page, 40, paragraph 101.

Commission findings

502. AG has forecast issuing $120.9 million in long term debt in 2011 and $89.9 million in 2012. The forecast debenture rate reflected in the May 16, 2011 update is 5.30 per cent in 2011 and 5.90 per cent in 2012. The Commission accepts the forecast dollar amount of the proposed debenture issuances for both 2011 and 2012.

503. The Commission does not accept, however, the forecast debenture rates for 2011 and 2012. The Commission notes that on November 18, 2010, CU Inc. completed the sale of debentures in the principal amount of $125,000,000 at a coupon rate of interest of 4.947 per cent with a maturity date of November 18, 2050, at a price of 100.00 to yield 4.947 per cent. This debt issue was for the benefit of ATCO Electric Ltd. and was approved in Decision 2011-057.[390] ATCO Electric Ltd. was approved to issue a 4.947 per cent debenture to CU Inc. in the principal amount of $125,000,000 at a coupon rate of interest of 4.947 per cent at a price of 100.00 to yield 4.947 per cent dated November 18, 2010.

504. The Commission observes that in CAL-AG-06(b) AG stated:

> It should be noted that the long-term debt issuance completed by CU inc.[sic] in November 2010 was done at historically low rates and the company was able to achieve a 40 year term with no incremental cost over issuing a 30 year debenture.[391]

505. In light of the actual market experience of CU Inc. in issuing debentures for the benefit of one of its utility subsidiaries on November 18, 2010, the Commission can not accept as reasonable either the original 2011 forecast debenture rate of 5.75 per cent in the application or the May 16, 2011 update of 5.30 per cent. Given that the Commission has found the 2011 forecast to be unacceptable, the 2012 forecast must also be rejected.

506. As noted above with respect to forecast preferred share rates, given the date of this decision, it is not practical to require AG to revise its 2011 long-term debt forecast in a compliance filing. Further, pursuant to Section 40(a) of the *Gas Utilities Act*, in fixing just and reasonable rates, the Commission may consider all revenues and costs of an owner of a gas utility applicable to a period consisting of:

> (i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,
>
> (ii) a subsequent fiscal year of the owner, or
>
> (iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,
>
> and need not consider the allocation of those revenues and costs to any part of that period,

507. Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual long-term debt rates for long-term debentures issued in 2011, if any, for the

390 Decision 2011-057: ATCO Electric Ltd. Application to Issue Debentures to CU Inc.:4.947 Per cent in the Principal Amount of $125,000,000, Application No. 1606855, ID No. 1006, February 17, 2011.
391 Exhibit 82.01, CAL-AG-06(b).

purposes of calculating capital structure, forecast return on rate base, forecast utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 long-term debt in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 long-term debt rate and the rate of any long-term debt issued in 2011.

6 Operating and maintenance expense

6.1 Operating and maintenance expense general

508. In the application, AG forecast total operating and maintenance (O&M) expenses of $368.4 and $378.8 million for 2011 and 2012 respectively.[392] AG provided an April 21, 2011 update to its forecasted amounts of O&M and amended its forecast for the test years to $366.4[393] and $378.1[394] million respectively.

509. AG stated that the primary drivers for O&M cost increases were customer growth and inflation. AG forecasted total customer growth in each of the test years of 21,636,[395] an approximate two per cent increase above AG's 2010 actual number of customers. AG forecast three per cent inflation for labour costs[396] and two per cent inflation in all other costs or "supplies."[397]

510. In its April 21, 2011 update[398] AG revised its forecast inflation rate for supervisory labour in 2012 to four per cent, resulting in an increase of $0.3 million to the 2012 O&M expense.

511. AG categorized O&M costs in seven functional areas. The following table presents the 2011 and 2012 forecast O&M expense by functional area.

Table 27. ATCO Gas functional forecast[399]

	2011 Forecast	2012 Forecast
Function	($000)	
Gas Management	612	630
Transmission	107,899	109,349
Distribution	82,961	88,630
General	6,979	7,365
Sales & Transportation Promotion	7,951	9,505
Customer Accounting	51,140	53,134
Administrative	108,861	109,530
O&M Total	366,403	378,143

392 Application, Volume 1, pages 4.2-3 to 4.2-4.
393 Exhibit 118.02, AG April 21, 2011 update, Attachment 3. See also Exhibit 161.03, AUC-AG-113 Attachment.
394 Exhibit 118.02, AG April 21, 2011 update, Attachment 3. See also Exhibit 161.03, AUC-AG-113 Attachment.
395 Application, Section 7, Table 7.2(a) and 7.2(c).
396 Exhibit 3, AG application, Volume 1, page 8.0-1.
397 Exhibit 3, AG application, Volume 1, page 8.0-4.
398 Exhibit 118.01, AG April 21 update, at page 4.
399 AUC-AG-113, Attachment O&M History which include 2008-2009 actual and 2011-2012 forecast.

Views of the parties

512. The UCA submitted that AG's proposed increases are excessive in an environment of low expected inflation and modest system growth. AG has not demonstrated that its forecast is a reasonable estimate of the expenditures that will be required to operate the AG system in a safe and reliable manner in the test years. The UCA submitted that the most reliable and unbiased evidence of required general O&M expenditures is what the utility actually spent during the prior period.[400] The UCA recommended that the Commission only approve an increase to AG's O&M forecasts for the 2011 and 2012 test years consistent with inflation and system growth above the 2010 actual base year, unless AG has shown that external factors and circumstances warrant a further increase. The UCA indicated that an additional increase would be warranted for the following external factors: AG's defined benefit pension funding requirements, the integration of ATCO Pipelines and NOVA Gas Transmission Ltd. system services, and the implementation of low use AMR which will affect meter reading expense over the test years.

513. The UCA generally accepted AG's assumptions regarding inflation and system growth. The net effect of applying the UCA's reasoning to AG's forecasts is a reduction in forecast O&M expenditures of approximately $18 million in 2011 and $25 million in 2012.[401] In some categories, the UCA assumed that system growth would not affect costs at all. The net result is an average assumed "system growth effect" of approximately one per cent.

514. The UCA also noted that AG claimed that its aging workforce is an external factor or changed circumstance that should be reflected in increased forecast O&M costs.[402] The UCA argued that there was no evidence that showed a causal connection between an aging workforce and increasing O&M costs. The UCA noted that the aging workforce is not a new phenomenon, nor is it unique to AG.[403] If new programs and new expenditures are required to deal with an aging workforce, they would have been required in previous years as well, and would have been reflected in actual expenditures for 2008, 2009 and 2010. The UCA argued that it is not plausible that an aging workforce has had no noticeable or identified effect on AG's costs over the past several years, but the incremental aging of its workforce by one year in 2011 generated numerous cost increases. The UCA stated in evidence[404] that whatever effects an aging workforce may potentially have on AG have already been accounted for in the market and in the optimization of the system to date.

515. The UCA also submitted that AG failed to file evidence to support O&M cost increases with respect to AG's argument that the forecast cost increases were due to aging infrastructure and increased safety standards (for example: CSA Z662).[405] The UCA stated that AG:

> …did not identify any costs associated with meeting the standard, or demonstrate any actual connection between Z662, in either its current or its proposed form, and any of the cost increases proposed in the Application. There is no evidence in any of the material related to CSA Z662 of any new standard that will directly require ATCO to increase its O&M expenditures.[406]

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400 Exhibit 200.02, UCA argument, page 26, paragraph 92.
401 Exhibit 142.02, response to AUC-UCA-16 Attachment – Revised Section 4 Attachments.
402 Exhibit 163.01, AG rebuttal evidence see general discussion re retirements at paragraphs 207-211.
403 See Exhibit 110.07, UCA general evidence at page 36, Q.54.
404 Exhibit 110.07, UCA evidence pages 36-37.
405 Exhibit 200.02, UCA argument, pages 36-38.
406 Exhibit 200.02, UCA argument, page 38, paragraph 127.

> To the contrary, leak frequencies appear to have been essentially stable for a considerable period.[407]

516. In rebuttal evidence AG stated: "[T]he Z662 code change in 2011 will codify society's reduced tolerance towards a distribution system leak."[408] AG stated further:

> The standards under which ATCO Gas is required to deliver gas safely and reliably have become more demanding in 2011 and 2012. There is a reduced tolerance for leaks and system failure. ATCO Gas has responded to the higher standard by appropriately increasing its inspection and maintenance activities. These evolving standards are precisely the reason why ATCO Gas has proposed a thorough external review of its inspection and maintenance practices in 2012. The review will provide ATCO Gas with an unbiased assessment of its inspection practices to ensure that they are aligned appropriately with the risks.[409] (footnote omitted)

517. In its general comments, the CCA stated that the Commission has the discretion to take either a broad brush cost analysis or line by line approach towards establishing and approving the revenue requirement of AG for the 2011 and 2012 test years. The CCA submitted that the preceding points could support general reductions to the applied for revenue requirement should the AUC be so inclined.[410] The CCA submitted that AG applied for significant increases to its revenue requirements for 2011 and 2012 supported by general assertions regarding safe and reliable service. The CCA noted that the revenue requirement from this application will form the basis for the going in rates for performance-based regulation.

518. Calgary filed evidence with respect to ATCO I-Tek (I-Tek) O&M expenses, demand side management (DSM) and automated meter reading. Calgary expressed concerns regarding the allocation of costs between the north and south systems.[411]

519. AG submitted that O&M costs warrant increases beyond inflation and customer growth for the following reasons:

- the aging workforce is driving AG's increased costs related to retirements, hiring activity and associated training costs
- a tightening in the labour marketplace is starting to be reflected in increasing voluntary turnover[412]
- stringent operating standards are leading to increased costs such as increased leak inspection, commercial station inspection and line heater inspection[413]

Commission findings

520. AG has the burden of proof to show that forecast cost increases and changes are reasonable.[414] The Commission must consider each material expense and assess whether or not AG has satisfied its onus in light of the overall record.

[407] Exhibit 83.01, response to UCA-AG-06(c).
[408] Exhibit 163.01, AG rebuttal evidence, page 55, paragraph 199.
[409] Exhibit 163.01, AG rebuttal evidence, page 55, paragraph 201.
[410] Exhibit 204.01, CCA argument, paragraph 81, page 26-27.
[411] Exhibit 109.02.
[412] Rebuttal evidence, paragraph 212, page 57.
[413] AUC-AG-63 Attachment, Exhibit 118, April 21 update.

521. The UCA has proposed that the Commission employ an analysis that would increase 2010 actual expenditures by a factor equivalent to system growth and inflation, except where circumstances would warrant a further increase. While the Commission would consider it reasonable to use 2010 actual O&M expenses adjusted for growth and inflation factors, it only considers it appropriate to do so when warranted in respect to particular functional or prime accounts.

522. The Commission does not accept the option put forward by CCA for an aggregate broad brush approach for the purposes of this proceeding because it is the Commission's obligation to consider the entirety of the evidence in respect of each functional area and to make a determination on the basis of the evidence.

523. The Commission has not been persuaded that an aging workforce and a tightening labour market are driving higher O&M costs. AG noted "Every workforce is aging, so the phenomenon is not new to AG."[415] The Commission finds the UCA's discussion regarding the impact of aging workforce to be persuasive. AG's recruitment, training, mentoring, employee development and safety programs have been evolving with the aging workforce and these labour related issues are not unique to this GRA. Accordingly the Commission has denied in the sections that follow aspects of programs which have incremental costs attributable to an aging workforce.

[414] Section 44(3) *Gas Utilities Act.*
[415] Rebuttal evidence, paragraph 207, page 56.

Comparison of actual expenses to forecasts

524. The following table presents the forecast and actual O&M functional expenses for the years 2008 to 2010:

Table 28. Comparison of actual expenses to forecasts

		ATCO Gas					
		O&M Forecast Variance Analysis ($000)					
		2008 Forecast	2008 Actual	2009 Forecast	2009 Actual	2010 Forecast	2010 Actual
FUNCTION		($000)					
GAS MANAGEMENT	**Total**	**700**	**500**	**800**	**630**	**592**	**600**
Forecast Variance versus Actual (per cent)			-28.6		-21.3		1.4
TRANSMISSION	**Total**	**76,900**	**80,000**	**93,900**	**102,285**	**106,965**	**107,000**
Forecast Variance versus Actual (per cent)			4.0		8.9		0.0
DISTRIBUTION	**Total**	**74,100**	**73,400**	**79,200**	**76,948**	**74,579**	**73,600**
Forecast Variance versus Actual (per cent)			-0.9		-2.8		-1.3
GENERAL	**Total**	**7,700**	**7,216**	**8,200**	**7,158**	**6,877**	**6,600**
Forecast Variance versus Actual (per cent)			-6.3		-12.7		-4.0
SALES AND TRANSPORTATION PROMOTION	**Total**	**4,500**	**4,439**	**4,800**	**5,190**	**5,238**	**4,800**
Forecast Variance versus Actual (per cent)			-1.4		8.1		-8.4
CUSTOMER ACCOUNTING	**Total**	**42,800**	**44,585**	**44,800**	**46,200**	**49,819**	**48,800**
Forecast Variance versus Actual (per cent)			4.2		3.1		-2.0
ADMINISTRATIVE	**Total**	**75,400**	**75,642**	**84,100**	**76,814**	**98,039**	**96,600**
Forecast Variance versus Actual (per cent)			0.3		-8.7		-1.5
O&M	**Total**	**282,100**	**285,782**	**315,800**	**315,225**	**342,110**	**338,000**
Forecast Variance versus Actual (per cent)			1.3		-0.2		-1.2

525. The Commission has reviewed AG’s forecasting record from 2008 to 2010, with the understanding that AG’s 2010 forecast was not subject to detailed scrutiny through a litigated proceeding. The Commission is satisfied that AG’s forecasting history appears reasonable when compared against actuals from 2008-2010, subject to the caveat noted above with respect to 2010. Therefore, the Commission sees little merit in scrutinizing functional areas by prime account on the basis of forecasting variance.

526. The Commission considers that an assessment of AG’s forecast by functional area and prime account expenses for the test years should be compared against actual expenses to determine the reasonableness of AG’s forecast.

527. The following table provides the variances of AG’s actual costs for 2008 to 2010 and variance of 2011 forecast to 2010 actuals and 2012 forecast to 2011 forecast.

Table 29. ATCO Gas functional history and forecast

	2008 Actual	2009 Actual	2010[416] Actual	2011 Forecast	2012 Forecast
Function			($000)		
Gas Management	530	630	600	612	630
Annual Variance (per cent)		18.9	-4.8	2.0	2.9
Transmission	79,989	102,285	107,000	107,899	109,349
Annual Variance (per cent)		27.9	4.6	0.8	1.3
Distribution	73,442	76,948	73,600	82,961	88,630
Annual Variance (per cent)		4.80	-4.40	12.70	6.80
General	7,216	7,158	6,600	6,979	7,365
Annual Variance (per cent)		-0.8	-7.8	5.7	5.5
Sales & Transportation Promotion	4,439	5,190	4,800	7,951	9,505
Annual Variance (per cent)		16.9	-7.5	65.6	19.5
Customer Accounting	44,585	46,200	48,800	51,140	53,134
Annual Variance (per cent)		3.6	5.6	4.8	3.9
Administrative	75,642	76,814	96,600	108,861	109,530
Annual Variance (per cent)		1.5	25.8	12.7	0.6
O&M Total	285,843	315,225	338,000	366,403	378,143
Annual Variance (per cent)		10.3	7.2	8.4	3.2

528. Based on the data presented in Table 28 ATCO Gas functional history and forecast above, the Commission considers AG's overall operating and maintenance forecast is generally consistent with actual results. However, the functional variance analysis identifies certain functional areas where forecast costs have increased by large percentages for the test years. For example, the sales and transportation function forecast costs have increased by 65.6 per cent and 19.5 per cent above 2010 actual for 2011 and the 2011 forecast for 2012, respectively. Demand side management, the centennial program, and AG's proposed expansion of the Blue Flame Kitchen (BFK) are key drivers of the increases in forecast costs for the 2011 and 2012 test years for this functional area.

529. Further, AG has forecasted increases in the distribution function of over 12 per cent in 2011 and a further increase of 6.8 per cent in 2012, while 2010 expenses declined by 4.4 per cent. The Commission also notes that AG has forecasted an approximately 12.7 per cent increase in 2011 for the administrative function, which is incremental to the 2010 increase of 25.8 per cent above the 2009 actual.

530. Given the material increases in certain functional areas as identified above, the Commission will undertake a detailed review of the prime accounts in these functional areas and undertake a high level review of the other functional areas.

531. Two of the key underlying drivers for increases to AG's O&M expense forecasts for 2011 and 2012 relate to inflation and customer growth. AG forecast a three per cent inflation rate for labour costs[417] and two per cent inflation rate in all other costs or "supplies."[418] In its April 21,

[416] UCA-AG-62(a), Attachment 2.
[417] Exhibit 3, AG application, Volume 1, page 8.0-1.

2011 update[419] AG revised its forecast inflation rate for supervisory labour in 2012 to four per cent, resulting in an increase to the 2012 O&M expense of $0.3 million. AG based its forecasts on information from the Conference Board of Canada Winter 2011 Provincial Outlook and the Alberta Finance Outlook 2011. The following table presents the forecast rates:

Table 30. Labour inflation

	2011 (%)	2012 (%)
Conference Board of Alberta (May 2010)	2.80	3.30
Conference Board of Canada (Winter 2011)	2.70	3.50
Government of Alberta (2010 Budget)	3.00	3.20
Government of Alberta (2011 Budget)	4.20	4.10

532. AG forecasted total customer growth in each of the test years of 21,636,[420] an approximate two per cent increase above AG's 2010 actual number of customers. The forecasts for customer growth were based on primary service line forecasts which were developed by each urban and rural area of its service territory based on Canada Mortgage and Housing Corporation housing forecasts.[421]

533. Interveners did not object to either the inflation forecast or the growth forecast.

Commission findings

534. The Commission finds that AG's inflation forecast for the 2011 and 2012 test years for labour and supplies appears reasonable when compared against the forecasts noted in the preceding table. AG's two per cent inflation forecast for supplies in 2011 and 2012, three per cent labour inflation forecast for 2011 and 2012, and four per cent increase for supervisory staff for 2012 are therefore accepted for the purpose of forecasting O&M costs.

535. With respect to AG's customer growth forecast of two per cent, the Commission is satisfied that AG's customer forecast is based on a reasonable method and the result is in line with recent history as discussed in more detail in Section 9.1 of this decision.

6.2 Full time equivalents forecast

536. In this application, AG forecast an increase in FTEs to 2,238 in 2011 and 2,257 in 2012. AG forecast a 2010 FTE complement of 2,148; actual FTEs in 2010 were 2,090.9.[422] In response to UCA-AG-72(a), AG explained that it does not track FTEs by O&M and capital, but provided an estimate based on a review of costs and activities in UCA-AG-72 attachment. The number of FTEs estimated for O&M is 1,243.4 in 2011 and 1,250.6 in 2012, which is a small reduction from 2010 actual of 1,259.5.

537. AG explained that there are modest increases in total FTEs over the forecast years largely due to the forecasts of increased capital work and a lower vacancy rate. AG proposed an average

418 Exhibit 3, AG application, Volume 1, page 8.0-4
419 Exhibit 118.01, ATCO April 21 update at page 4.
420 Application, Section 7, Table 7.2(a) and 7.2(c).
421 Application, Section 2.1.1.3, page 2.1-23, paragraph 65.
422 Exhibit 83.31, UCA-AG-72(a) attachment.

vacancy rate of six per cent for 2011 and 2012. Actual vacancy levels were 7.5 per cent in 2008, 6.4 per cent in 2009, and 10.9 per cent in 2010.[423]

Commission findings

538. The Commission has not been persuaded that the proposed decrease to a six per cent vacancy rate due to an increasing proportion of vacancies caused by retirements is warranted. A six per cent vacancy rate is inconsistent with historical results and unsupported by the evidence filed in this proceeding. AG is therefore directed to increase its forecast vacancy rate for 2011 and 2012 to 8.3 per cent based on a three-year historical average and to revise its forecast FTE levels and revenue requirement in the compliance filing to this decision.

6.3 Functional analysis of O&M

539. The following sections consider and address specific O&M expenses. The Commission findings in the following sections are subject to above findings with respect to costs attributable to inflation, growth and an aging workforce. The sections are organized by functional area. The three functional areas gas management, transmission and general will be examined below followed by general findings. Other functional areas will be examined individually.

6.3.1 Gas management function – Account 625

540. The forecast costs for the gas management function include expenses relating to the development, administration and maintenance of operational procedures and processes necessary to provide gas distribution services to retailers and the default supply provider.

Table 31. Gas management function

Gas Mgmnt	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
Total	**500**	26.0%	**630**	-4.8%	**600**	2.0%	**612**	2.9%	**630**

6.3.2 Transmission function – Account 663

541. The forecast costs for the transmission function relate to the forecasted transmission service charges from ATCO Pipelines and NOVA Gas Transmission Ltd. (NGTL) over the test period for delivering gas to the AG distribution system. The rates used in the 2011 and 2012 forecasts for transmission charges are based on the final 2010 rates approved for ATCO Pipelines in Decision 2010-475.[424] Any subsequent changes to the transmission rates are subject to deferral account treatment. After implementation of the integration (integration)[425] of ATCO

423 AUC-AG-61 Attachment.

424 Decision 2010-475: ATCO Pipelines 2010 Final Revenue Requirement, Final Rates Filing and Deferral Accounts Disposition, Application Nos. 1606306 and 1606326, Proceeding ID. 706, October 1, 2010.

425 AP and NGTL entered into the Alberta System Integration Agreement dated April 7, 2009 which provides for AP and NGTL to swap ownership of certain physical assets within distinct operating territories or “footprints” in Alberta and to work together in Alberta under a single rates and services structure, while maintaining separate ownership, management and operation of their assets. The integration was approved by the Commission in Decision 2010-228 and 2011-260 and by the National Energy Board. Integration, with the exception of the contemplated swap of assets, was implemented on October 1, 2011.

Pipelines and NGTL, AG will receive gas transportation services only from NGTL. The NGTL transmission charge will be the aggregate amount of all AG's contract demand quantities multiplied by the higher of the ATCO Pipelines firm service utility (FSU) rate in effect at the time of transition and the NGTL FT-D3 rate. AG indicated that it did not expect that there would be any difference in the methodology to determine peak billing demand or contract demand volume when transitioned to NGTL.[426] AG requested that the Commission confirm that the existing deferral account for approved transmission rate changes will apply to transmission charges from NGTL post integration.[427]

Table 32. Transmission function

	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
Total	**80,000**	27.9%	**102,285**	4.6%	**107,000**	0.8%	**107,899**	1.3%	**109,349**

6.3.3 General function

542. General function costs include the cost of operating and maintaining communication equipment, operating centres, agency offices and general environmental costs.

Table 33. General function

	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
General									
Total	**7,216**	-0.8%	**7,158**	-7.8%	**6,600**	5.7%	**6,979**	5.5%	**7,365**

Commission findings

543. The Commission observes very little change in the gas management forecast costs compared to the actual costs incurred in the previous two years and notes that interveners did not take issue with the forecasted costs.

544. The forecast transmission costs are flow-through. They are based on the latest approved rates for AP and are subject to deferral account treatment. None of the interveners objected to these forecasts. Integration between AP and NGTL was effective October 1, 2011, with all customers, including AG, now subject to NGTL rates and terms and conditions of service. The Commission confirms that a deferral account for approved transmission rate changes will apply to NGTL transmission charges post integration.

Under the agreement NGTL will be the party that interfaces contractually with customers for regulated gas transmission services using the combined regulated AP and NGTL gas transmission systems within Alberta. AP's revenue requirement will be collected by AP through monthly charges to NGTL. NGTL will include AP's monthly charge in NGTL's revenue requirement which will be collected from customers using the Alberta System.

426 Application, Volume 1, page 4.2-8.

427 Application, Volume 1, page 4.2-8.

545. The forecast costs included in the general function in the test period have increased approximately 5.6 per cent over actual expenses for 2010. The 2010 costs were less than actual costs incurred in 2008 and 2009. The 2012 costs are forecast to be approximately the same as the experience in 2008 and 2009. Interveners did not object to the forecast costs.

546. Accordingly, the Commission is satisfied that the updated forecast costs for the gas management function, transmission function and general function for the test years are reasonable and are approved, subject to other findings in this decision.

6.3.4 Distribution function

547. The distribution function relates to operating and maintaining the distribution system facilities. The costs related to this function include the inspection and maintenance of distribution mains and services, testing, inspection, removing and resetting meters, maintenance and operating costs of regulating stations and providing customer service. Table 34 below shows the actual costs for the distribution function for 2008, 2009 and 2010, and the forecast amounts for 2011 and 2012.[428]

Table 34. Distribution function

DISTRIBUTION	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
PRIME ACCOUNT BREAKDOWN									
Distribution Supervision - 670	16,644	2.1%	17,000	-5.3%	16,100	10.6%	17,803	12.2%	19,978
Remove & Reset Meters - 673	5,006	5.4%	5,277	-5.2%	5,000	8.4%	5,421	0.0%	5,419
Service on Customer Premises - 674	13,914	10.2%	15,332	-4.1%	14,700	7.9%	15,862	5.8%	16,779
Mains & Services - 675	30,030	2.2%	30,670	-3.3%	29,700	14.2%	33,923	6.1%	36,004
Measuring and Regulating -677	5,752	7.9%	6,208	-5.0%	5,900	25.0%	7,374	3.1%	7,600
Meters - 678	1,360	20.3%	1,636	-8.3%	1,500	13.4%	1,701	11.5%	1,897
Other Distribution Operation - 679	736	12.2%	826	-15.3%	700	25.3%	877	8.7%	953
Total	**73,442**	4.8%	**76,948**	-4.4%	**73,600**	12.7%	**82,961**	6.8%	**88,630**
Accounting change re meters							**4,200**		**4,200**
Adjusted total						18.3%	**87,161**	11.9%	**92,830**

428 Exhibit 161.03 AUC-AG-113 Attachment.

6.3.5 Distribution supervision – Account 670

548. Account 670 includes the labour and supplies for the support and supervision of the distribution function. In the application, AG explained the cost drivers for its forecast increases for the distribution supervision account for the 2011 and 2012 test years as follows:[429]

- In 2011, the cost increase stemmed from $0.5 million of inflation, increased training costs, increased work for ATCO Pipelines, and safety initiatives.
- The $0.3 million of increased work for ATCO Pipelines will attract incremental revenues.
- Incremental costs of $0.6 million in 2011 and $0.8 million in 2012 relate to an increase in training, mentoring and coaching due to past and forecast retirement activity.
- A $0.5 million cost increase in 2011 and 2012 is attributable to safety initiatives to maintain and improve AG's safety performance due to significant workforce changes and retirements.
- In 2012 AG forecasted an additional two occupational health nurses at a cost of $0.2 million to proactively implement preventative programs to address potential injuries in an aging workforce.
- AG is expanding its inspection program. In 2012, AG will retain an external consultant to assess AG's inspection practices regarding risks of its aging infrastructure at a cost of $0.5 million.

549. The UCA accepted AG's submission that it will incur additional costs of $0.3 million in the test years related to work to be performed for ATCO Pipelines. With respect to the remaining supervisory expenses, the UCA submitted that AG failed to justify its forecast 2011 O&M expenses beyond the 2010 actual costs escalated for inflation and system growth. The UCA submitted that AG's forecast costs should be reduced to $17.2 million and $18.1 million for the 2011 and 2012 test years.

550. AG in rebuttal evidence referred to the UCA suggestion that the basis for this account should be 2010 costs adjusted for inflation and customer growth. AG's comprehensive forecast includes a forecast cost related to addressing the effects of an aging workforce, an increase in retirement activities and a review of AG's inspection practices in 2012. Because the UCA believes that AG is immune to the impact of an aging workforce and increased retirement activities, the UCA has rejected AG's forecast and supplanted the judgment of the UCA. As discussed above, the foundation of the UCA's argument is fundamentally flawed and should be rejected.[430]

551. With respect to the $0.5 million forecast costs for an external consultant to assess AG's inspection practices, the CCA submitted that one-time costs should not form the basis of revenue requirement. The CCA also submitted that if the AUC considers that this activity is needed, it could either be forecast for 2011 or removed from the revenue requirement for 2012 for determining going in rates for PBR. The CCA noted that AG identified other non-ongoing expenses in section nine of its application.

[429] Application, Volume 1, pages 4.2-11 to 4.2-12.
[430] AG reply argument, page 77, paragraph 176.

Commission findings

552. For Account 670, distribution supervision, the Commission accepts cost increases of $0.5 million for inflation and $0.3 million for the increased work provided to ATCO Pipelines. As discussed earlier in this decision, the Commission does not accept AG's arguments with respect to cost increases being driven by an aging workforce and retirements. Accordingly, the forecast cost increases of $0.6 million for training, mentoring and coaching related to forecast retirement activity, $0.5 million for safety initiatives related to changes to the workforce and retirements, and $0.2 million in 2012 for the costs of two new occupational health nurses to proactively implement preventative programs to address potential injuries in the aging workforce are denied.

553. AG forecast the addition of an external consultant in 2012 at a cost of $0.5 million to assess AG's inspection practices to ensure that the inspection activities are aligned appropriately with risks.

554. Interveners did not oppose this expenditure but the CCA submitted that it should be a one time charge. The Commission agrees with the CCA that this expenditure should be treated as a one-time cost in 2012 revenue requirement. The Commission approves the forecast costs of $0.5 million for an assessment of inspection practices as a one time expense. AG is directed to incorporate these costs as a one time expense in its compliance filing to this decision.

6.3.6 Remove & reset meters – Account 673

555. Account 673 includes the costs related to labour and supplies to change, test, service, inspect, remove and reset meters. AG has forecast additional costs of $0.65 million in 2011 and $0.4 million in 2012 related to a commercial inspection program. AG explained that after a review of its inspection activity, a gap was identified in its inspection practices. In 2011 AG introduced an inspection program for commercial meter stations which have not historically been inspected on a routine basis.

556. AG has also requested approval of an accounting change with respect to retired meters. AG has requested permission to commence the capitalization of costs related to meter exchanges when a meter is being permanently retired. The primary reason for change in accounting treatment relates to Measurement Canada's new compliance regulation (S-S-0-6) that AG stated requires it to replace meters prior to failure to measure within acceptable tolerances. The previous standard required AG to replace meters after they failed to measure within acceptable tolerances. AG stated that it must be fully compliant with the new standards by January 1, 2014. If the AUC does not approve this proposed accounting treatment, AG will need to revise its O&M forecast upwards by $4.2 million in each of 2011 and 2012. AG is initiating changes in 2011 to ensure compliance by 2014. AG will no longer be repairing residential meters because the new shorter seal periods for refurbished meters increases sampling and replacement cycles when compared with new meters, making refurbishment uneconomic for residential meters.[431] AG submitted that it is proposing to treat the costs associated with the removal of the meter which will be retired as removal costs, and it will capitalize the costs to install the new meter consistent with the Uniform Classification of Accounts Regulation. AG stated that the proposed

[431] Exhibit 3, application, page 4.2-14.

accounting treatment is also consistent with the Uniform System of Accounts for electric utilities in Alberta.[432]

557. The UCA accepted AG's forecast[433] and took no position with respect to the capitalization of meter costs.

Commission findings

558. The Commission recognizes the necessity to comply with changing standards and accepts AG's proposed cost increases for the test years for the proposed commercial inspection program. However, the Commission does not approve AG's request for an accounting change to capitalize costs related to meter exchanges when a meter is being permanently retired. The cost of the "original installation of house regulators and meters"[434] is capitalized in Account 474. "Expenses incurred in connection with removing, resetting, changing, testing and servicing customer meters and house regulators"[435] are recorded in Account 673. AG's change in policy to use only new meters does not change the accounting requirement. AG has stated that without the approval requested the expenses in 2011 and 2012 would need to be increased by $4.2 million. However, this amount does not agree with the $3.1 million in 2011 and $2.8 million in 2012 that AG planned to capitalize for the same activity.[436] The Commission directs AG in its compliance filing to deal with this apparent discrepancy. AG is directed to revise its revenue requirement accordingly in the compliance filing to this decision.

6.3.7 Service on customer premises – Account 674

559. Account 674 includes costs related to labour and supplies costs incurred for services on customer premises including emergency calls for gas odors, carbon monoxide, no heat, appliance checks, and the labour and supplies for the first-line supervisors of distribution operator service. AG indicated that inflation and customer growth account for most of the forecast increase in costs in this account. The remainder is largely the result of increased training costs that AG submits will be incurred as a result of increased employee turnover.[437]

560. Consistent with its general treatment of forecast increases in training costs not directly attributable to external factors, the UCA has not included those costs in its estimates. The UCA recommended an escalation factor resulting in forecast costs for Account 674 of $15.3 million for 2011 and $16.0 million for 2012.[438]

Commission findings

561. AG stated that most of the forecast cost increase over 2010 actual costs was driven by inflation and customer growth. However, AG indicated in AUC-AG-65(c)[439] that 1.2 per cent of the total increase in 2011 and an additional 0.5 per cent of the total increase in 2012 related to training in anticipation of higher employee turnover due to aging workforce and a tightening of the market. The Commission previously rejected the justification of forecast cost increases due to

432 Transcript, Volume 6, pages 1226-1229.
433 UCA argument, paragraph 134.
434 Uniform Classification of Accounts Regulation, Account 474.
435 Uniform Classification of Accounts Regulation, Account 673.
436 Exhibit 3, application, page 2.1-25, Table 2.1.1.4(a).
437 Exhibit 82.01, response to AUC-AG-65.
438 Exhibit 142.02, response to AUC-UCA-16 Attachment, Revised Schedule 4 Attachments.
439 Exhibit 084.01, AUC-AG-65(c).

an aging workforce and a tightening of the labour market. Accordingly, the Commission directs AG to reduce the forecasted costs in Account 674 by 1.2 per cent in 2011 and 1.7 per cent in 2012 in the compliance filing to this decision.

6.3.8 Mains and services – Account 675

562. Account 675 mains and services includes the inspection and maintenance costs to operate the distribution system and the labour and supplies cost of front-line supervisors of distribution operators, field (DOF). This account also includes costs of repairs for any third party damages to the distribution pipeline system, line locates, odorant, training, and cathodic protection. AG has applied for approval of forecast costs for Account 675 of $33.9 million in 2011 and $36.0 million in 2012.

563. AG indicated that cost increases in the test years are the result of employee wage increases, the effects of addressing customer growth on the system, and inflation of general supplies and contractor costs. Inflation and distribution system growth accounts for a $1.5 million increase in costs in this account over the 2010 forecast costs.

564. Forecast costs for the test years include two proposed initiatives. The first initiative is an increase in leak inspection activities. AG stated that only 60 per cent of leaks are found through inspection activities and only 18 per cent of the most critical leaks are identified through leak inspection.[440] To improve its record, AG proposed to increase leak inspection activities at a cost of $1.3 million in each of 2011 and 2012. As a result of the increased inspection activities, AG is anticipating a 20 per cent increase in repair activities at a forecast cost of $0.6 million.

565. AG is proposing to add four damage prevention coordinators to work with the excavating community to increase the awareness, knowledge and skill level of those working around AG's buried facilities. The coordinators are expected to start mid-2011 and are forecast to cost $0.2 million in 2011 and $0.4 million in 2012. AG submitted that due to the existing damage prevention program more excavators have been calling for locates and the percentage of facilities damaged as a result of no locates has dropped from 43 per cent in 2009 to 30 per cent in September 2010. AG forecast a $0.5 million increase in locate costs in 2011 due to the anticipated success of the expanded program.

566. The UCA submitted that the proposed increases do not reflect the operation of relevant external factors.[441] However, the UCA suggested, out of an abundance of caution, that an incremental amount of $1.0 million beyond what is suggested by inflation and system growth should be included in the forecast costs for this account.[442] The UCA recommended that $32.0 million and $33.4 million be approved for 2011 and 2012, respectively.[443]

Commission findings

567. AG has applied for approval of forecast costs for Account 675 of $33.9 million in 2011 and $36.0 million in 2012. AG has forecast cost increases of $1.5 million for inflation and system growth for this account in 2011. As noted above, AG's inflation and growth forecasts have been approved.

[440] Application, page 4.2-16, paragraph 41.
[441] UCA argument, page 40, paragraph 136.
[442] Ibid.
[443] Exhibit 142.02, response to AUC-UCA-16 Attachment, Revised Schedule 4 Attachments.

568. AG has forecast an additional $1.3 million of costs for leak detection in each of 2011 and 2012. AG stated that only 60 per cent of leaks are found through inspection activities and only 18 per cent of the most critical leaks are identified through leak inspection. The Commission finds the additional expenditure for leak detection to be warranted in the public interest in the test years. The Commission approves the forecast cost of $1.3 million per year for leak detection and the anticipated leak repair activities of $0.6 million in each of 2011 and 2012.

569. AG also proposed adding four damage prevention coordinators beginning in the middle of 2011 to increase awareness of buried gas lines within the excavating community. The Commission commends activities to reduce line hits and notes the 40 per cent reduction in hit lines on the AG system from a high of 1,000 in 2007 to 601 in 2010,[444] which resulted from the combined activities of AG and other programs such as Alberta One Call "Dial Before You Dig." The Commission approves the forecast costs and encourages AG to explore cost-effective coordination on an industry wide basis.

570. AG requested an approval of an additional $0.5 million due to an anticipated increase in requests for line locate costs in 2011. Having approved the requested damage prevention coordinators, the Commission considers there will likely be an increase in requests for line locates and accordingly approves the forecasted cost of line locates.

571. The Commission approves the costs forecast over the test period for mains and services.

6.3.9 Measuring and regulating – Account 677

572. Account 677, measuring and regulating, includes maintenance and operating costs for the over 4,000 points where AG receives gas transmission service. AG forecast costs with respect to 677 for the test years of approximately $7.4 million and $7.6 million. AG explained that inflation of three per cent and customer growth of two per cent account for $0.32 million of the $1.4 million increase from 2010 actual costs to 2011 forecast costs. AG noted that additional meters were forecast to be acquired from ATCO Pipelines as a result of integration between ATCO Pipelines and NGTL, resulting in the need to add two technologist positions at a forecast cost of $0.2 million.

573. In the April 21, 2011 application update, AG discussed differing maintenance requirements between line heaters at upstream well sites subject to the *Oil & Gas Conservation Act* and its Regulations[445] and line heaters operating on AG's distribution system operating under the *Pipelines Act*. AG proposed a new line heater inspection program at a forecast annual cost of approximately $0.9 million per year.[446] AG indicated that similar inspection programs are mandated for line heaters in upstream gas production and that its proposal is to follow that standard even though it acknowledged that it is not legally bound by the same requirement.[447] AG noted in the oral hearing that downstream line heaters on the AG system would still have corrosion risks event though the content of the gas stream would contain less liquids and water than upstream flows. Mr. Feltham stated:

444 Exhibit 83.01, UCA-AG-81(a).
445 *Oil and Gas Conservation Regulations* 151/1971.
446 Exhibit 163.01, AG rebuttal evidence at paragraph 205.
447 Transcript, Volume 3, page 536, lines 18 to 24.

> Actually, the biggest concern that we have with the -- it's a high pressure pipe coil inside of a glycol bath, and the biggest concern we have there is corrosion. And glycol you can't see through, so there's no way to visually inspect it.[448]

574. AG has 607 line heaters and AG estimates the cost of inspection as $7,000[449] per unit for a total forecast cost of $4.2 million. AG states that it would inspect 125 units per year over a five-year period.

575. The UCA argued that AG has never performed the proposed type of inspection in the past[450] and it did not indicate that it had ever experienced internal corrosion problems with any of its over 600 line heaters. The UCA submitted that the $0.9 million of annual expenditures on a program that AG is not legally required to undertake could not be supported without empirical justification

576. The UCA noted that AG had forecast costs for additional technologists to work with meters proposed to be purchased from ATCO Pipelines. The UCA stated that the application does not include a business case or any other support to demonstrate a necessity for additional technologists to maintain and operate additional meters transferred from ATCO Pipelines as a result of integration. The UCA did acknowledge, however, in response to AG-UCA-21(a),[451] costs related to the integration of the ATCO Pipelines system may be a new and externally driven expense.

577. In reply argument, AG noted that unlike the oil and gas industry, most of its line heaters are situated near populated areas, which increases the consequences of a failure.[452]

Commission findings

578. The evidence submitted by AG with respect to the line heater inspection program has not persuaded the Commission that these inspections are required during the test period. The Commission notes that AG stated that line heaters on well sites have a legal requirement for inspection every five years but AG is not legally bound to abide by this same inspection requirement.[453] Further AG has not inspected its line heaters in the past and AG has not supplied any evidence to suggest that it should begin inspecting line heaters during the test period. Given the above, the Commission denies the line heater inspection costs of $0.9 million per year. The Commission also observes that it has approved the forecast costs associated with AG's line heater improvements program to meet OH&S standards and improved reliability enhancements on non-compliant meters during the test years.

579. AG is forecasting additional meters to be transferred from ATCO Pipelines as a result of integration and AG proposes to add two technologists to maintain these meters at a forecast cost of $0.2 million for each of 2011 and 2012. However, in Section 2.1 of the application AG states that there is uncertainty surrounding what additional metering equipment AG may purchase from ATCO Pipelines.[454] As confirmed by Mr. Schmidt in testimony, the proposed costs relate to

448 Ibid., page 537, lines 17-21.
449 Exhibit 118.01, Attachment 5, paragraph 4.
450 Transcript, Volume 2 at page 277, line 18.
451 Exhibit 143.02.
452 Exhibit 218.01, AG reply argument, page 79, paragraphs 181 to 182.
453 Ibid., paragraph 3.
454 Exhibit 3, AG application, Section 2.1, page 21, paragraph 59.

technologists required to maintain non-SCADA meters to be transferred by ATCO Pipelines in the 2012 test year.[455] Accordingly, the Commission approves the forecast cost of $0.2 million for the two technologists for the 2012 test year.

580. The Commission considers the costs forecast over the test period for measuring and regulating, Account 677, after the above adjustments, are reasonable and are approved.

6.3.10 Metering and other – Accounts 678 and 679

Table 35. Metering and Other

	2008 Actuals	2009 Act vs. 2008 Act	2009 Actuals	2010 Act vs 2009 Act	2010 Actual	2011 Fcst. vs. 2010 Act	2011 Forecast	2012 Fcst vs. 2-11 Fcst.	2012 Forecast	2012 Fcst vs. 2010 Act
	($000)		($000)		($000)		($000)		($000)	
Meters - 678	1,360	20.3%	1,636	-8.3%	1,500	13.4%	1,701	11.5%	1,897	26.5%
Other - 679	736	12.2%	826	-15.3%	700	25.3%	877	8.7%	953	36.1%

581. AG has requested approval for $1.7 million in 2011 and $1.9 million in 2012 for account 678; and for $0.9 million and $1.0 million in 2011 and 2012 respectively for account 679.

582. ATCO Gas indicated that the increase in Account 678 relates to the sampling of pressure and temperature correction instruments starting in 2011. The instruments were given a seven-year seal period in 2005 by Measurement Canada, making 2011 the first year where sampling is required.[456]

583. The UCA submitted that the forecast costs for account 678 should be $1.6 million for each of 2011 and 2012 and for account 679 $0.7 million for 2011 and $0.8 million for 2012, representing a 4.4 per cent increase over 2010 actuals.

Commission findings

584. AG provided limited support for the forecast increase to the costs for accounts 678 and 679. Accordingly, in the absence of any other substantive information, the Commission considers that an adjustment of five per cent for inflation and growth is justified for each of the test years. The Commission directs AG in its compliance filing to forecast costs for accounts 678 and 679 by escalating 2010 actual costs by a factor of five per cent per year.

455 Transcript, Volume 2 at page 377, lines 18 to 22.
456 Exhibit 163.01, AG rebuttal evidence, page 56, paragraph 206.

6.3.11 Sales and transportation promotion function

O&M Total	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
Supervision – 700	196	71.4%	336	-40.5%	200	69.5%	339	3.2%	350
Advertising – 701	2,230	6.0%	2,364	-11.2%	2,100	35.3%	2,841	35.6%	3,853
Demonstration and Selling Expense – 702	1,097	35.6%	1,487	0.9%	1,500	107.5%	3,112	12.1%	3,490
Home Service – 705	916	9.5%	1,003	-0.3%	1,000	65.9%	1,659	9.2%	1,812
Total	**4,439**	16.9%	**5,190**	-7.5%	**4,800**	65.6%	**7,951**	19.5%	**9,505**

585. AG has applied for approval of forecast costs of 7.9 million in 2011 and $9.5 million in 2012 for the sales transportation promotion function. The 2011 forecast is an increase from the actual costs in 2009 of $3.1 million with a further increase of $1.6 million to 2012.

586. AG submitted that as part of its responsibility to safely and reliably deliver natural gas, AG has the responsibility to communicate safety, energy efficiency and conservation information to its customers, employees, and the public.[457] AG submitted that there are a number of factors that affect this responsibility, including growth in population, location of AG assets, the goals and objectives of government and AG customers, and evolving media.[458] AG submitted that several communication channels had proven effective for AG. AG requested Commission approval for forecasted costs in respect of each of the three primary areas: customer relations and communications, DSM, and BFK.

587. In the application, in addition to the functional expense account breakdown presented in the table above, AG provided the following summary of costs by primary area in the following table:

Table 36. Primary areas of sales and transportation promotion function[459]

	2008 Actual ($million)	2009 Actual ($million)	2010 Actual ($million)	2011 Forecast ($million)	2012 Forecast ($million)
Cust. Relations & Communications	2.2	2.2	1.9	2.4	3.5
DSM	1.3	1.9	1.7	3.5	3.9
BFK	1.0	1.1	1.2	2.0	2.1
Total	**4.5**	**5.2**	**4.8**	**7.9**[460]	**9.5**

457 Exhibit 3, application, page 4.2-21.
458 Exhibit 3, application, pages 4.2-21-4.2-22.
459 Exhibit 3, application, Table 4.2.2.5(b).
460 The application AG had an amount of $8.5 million which was reduced by $0.6 million for the comprehensive DSM program research expenditure forecast which was moved to 2012 as a one-time adjustment.

588. Some of the projects within these areas discussed below include an event to mark AG's centennial anniversary, the BFK Calgary Learning Centre, a school program which includes the Energy Education Mobiles (EEM), an Incentive/Rebate Program and DSM.

589. This section of the decision will consider customer relations and communications and the BFK. Section 6.3.14 will consider demand side management. The account specific comments of the interveners are address in the relevant sections below.

6.3.12 Blue Flame Kitchen

590. AG is requesting approval of forecast costs of \$2.0 million in 2011 and \$2.1 million in 2012 for the BFK. This is an increase from the 2010 actuals of \$1.2 million.[461] AG indicated that the increases in forecast costs are due to the re-introduction of a physical presence for the BFK in Calgary, inflation, and the addition of a home economist in 2012.[462] AG opened its BFK Calgary Learning Centre in 2010. AG has requested the inclusion of \$1.9 million for the Calgary BFK in rate base as of 2011 and operating costs of \$1.0 million for 2011 and \$1.1 million for 2012.[463]

591. The forecast costs associated with the BFK in Calgary were denied in Decision 2008-113. In that decision, the Commission commented on both the "legacy" nature of the Edmonton BFK and the proposed re-opening of a physical presence in Calgary. In relation to the Calgary, the Commission stated:

> With respect to the re-opening of the BFK in Calgary, the Commission considers that AG has not demonstrated to the Commission's satisfaction that the facility in Calgary is warranted. AG has not shown how direct communication with customers will be established or the amount of customer traffic that it expects will use the facility in any given year, particularly if communication with customers has trended more to the electronic format (the high-tech world). The Commission is not convinced that the service cannot be provided through the Edmonton office.
>
> Further, the Commission notes that the BFK in Edmonton was considered to be a "legacy" service. The Commission views that this legacy service was related to AG's former involvement in the retail gas business. Given the responsibilities of retailers and their ability to offer product differentiation to customers the Commission does not consider that additional BFK resources should be approved in this Application. The Commission accepts the submissions of the interveners that the facility is not needed at the present time and denies inclusion of capital costs in revenue requirement for the BFK facility in Calgary.
>
> If AG wants to reopen this issue, the Commission considers that AG should address the reasons it used for originally closing the facility in Calgary, and how circumstances have changed which would justify these costs being included in future revenue requirements.[464] (footnotes omitted)

592. AG responded to the Commission's direction in Decision 2008-113 to address the closing of the original Calgary BFK facility and the changing circumstances justifying its reintroduction stating:

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461 Exhibit 93.01, AUC-AG-62, page 12 of 21.
462 Exhibit 3, application, pages 4.2-28-4.2-30.
463 Exhibit 110.07, page 53, A.75.
464 Decision 2008-113, page 48.

> While ATCO Gas may have mistakenly thought that the entire province could be served from a single location, the fact remains that the combined effect of ATCO Gas needing to engage a growing base of customers, and a much changed media environment, challenges old approaches to deliver utility messaging.
>
> By having a Blue Flame Kitchen in Alberta's two major centres, ATCO Gas is able to create multiple touch points to create a favorable environment to deliver safety and energy efficiency messages to customers and gain valuable earned advertising opportunities.[465]

593. By "earned advertising," AG was referring to favourable publicity that is gained when stories and articles are produced about a product. AG indicated that a mix of media is required in order to reach consumers and to build awareness of living and working safely around natural gas facilities. AG also indicated that a physical presence will allow AG to include an interactive EnergySense kiosk allowing communication with respect to demand side management initiatives.

594. AG argued that expanding the BFK to Calgary will "help to ensure that AG is able to get its safety and conservation messages out to a wider audience than it otherwise would."[466] AG indicated that the physical presence of a BFK facility provides the opportunity for a "sustained presence through all mainstream media (print, electronic, broadcast, social media)."[467]AG provided historic and forecast information about the use of the BFK in several IR responses providing statistics on public contact with the BFK via internet, telephone and personal visits.[468] AG indicated that traffic to the BFK website was 311,966 in 2010 and forecast learning center program participants of 1,130 in 2011.[469]

595. The UCA submitted that AG has not met the Commission's requirements for the establishment of a Calgary BFK outlined in Decision 2008-113. AG has not demonstrated any quantifiable benefits in terms of cost savings or identified how the delivery of messages via this "communication channel"[470] is required for the distribution services and the delivery of public safety messages for ". . . public safety in the context of the delivery of safe, reliable, natural gas delivery service."[471]

596. The UCA also argued that BFK in Calgary is not a "legacy service" and was not provided on a continual basis and was discontinued by AG.[472] The EUB found in Decision 2006-024[473] for ATCO Electric, who was at the time a partner with AG, that the services provided by the BFK are not necessary for the provision of distribution service.[474] AG is the only Canadian distribution utility that has facilities with demonstration kitchens.[475] While AG may claim that the Calgary

465 Exhibit 3, application, page 4.2-29.
466 Application, page 4.2-23, paragraph 60.
467 Application, page 4.2-29, paragraph 82.
468 Exhibit 84.01, AUC-AG-81, Exhibit 83.01, UCA-AG-87 and UCA-AG-88.
469 Exhibit 84.01, AUC-AG-81(a) and (e).
470 Exhibit 163.01, paragraph 224, page 59 (PDF).
471 Exhibit 3, Section 4.2.2.5, paragraph. 84 and Exhibit 110.7, page 49, A.69.
472 Exhibit 110.07, page 55, A.78.
473 Decision 2006-024: ATCO Electric Ltd., General Tariff Application, Application No. 1399997, March 17, 2006.
474 Cited in Exhibit 110.07, page 55 A. 80.
475 Exhibit 84.01, AUC-AG-81 d).

BFK or the BFK programs are necessary "to cut through the media clutter that exists today,"[476] AG only spends $50,000 per year promoting safety messages in the ATCO BFK[477] compared to the $2 million per year it takes to operate and maintain the BFK.[478] The UCA argued that the cost does not justify the necessity of having the BFK as a communication channel.

597. The UCA submitted that all costs, including the capital costs, incurred for the Calgary BFK should be denied for the test period 2011-2012. Capital costs for assets that were incurred in the past but were not approved should be removed from rate base. The UCA stated "There is no need to promote safety through nutritional, lunch programs or cooking demonstrations."[479]

598. The UCA did not address in evidence whether the Edmonton BFK should be disallowed[480] and in testimony made general comments with respect to DSM but had no specific position with respect to the Edmonton BFK.[481] In argument, however, the UCA stated that the costs for the Edmonton BFK should be disallowed for the reasons outlined by the UCA for the disallowance of DSM programs.[482]

599. The CCA does not support the expansion of the BFK into an educational role. The CCA considers that the AUC should not permit AG to enter into or expand its offering of educational services. The CCA does not support the increase of positions from 12 to 21 for the BFK and recommended that staffing levels should be reduced.[483] Given the AUC's previous ruling concerning the Calgary BFK, all associated costs should be removed from the revenue requirement for the test years.

600. AG submitted that it has a legislated responsibility to communicate with its customers.[484] In order to ensure the safe, reliable delivery of natural gas, AG "needs to not just control the behavior and influence the behavior of its employees, but also anybody that comes close to or interacts with our system, so not just our customers, but the public too."[485] Because the BFK has an audience that is already actively soliciting information from the utility, AG submitted that it is able to capitalize on that fact and use this communication channel to cut through the media clutter.[486]

601. AG submitted that the UCA appears to contradict its evidence on the record with regard to the expenditures related to the BFK. In argument, for the first time, the UCA took the position that not only the Calgary BFK but all costs related to the BFK, including costs related to the Edmonton BFK, should be removed from AG's revenue requirement forecast[487] contrary to its evidence which only opposed the expansion of existing programs.[488] Given the change in position

476 Exhibit 163.01, paragraph 224, page 59 (PDF).
477 Exhibit 84, AUC-AG-80, page 2 of 3.
478 Exhibit 3, application, Volume 1, Section 4.2, Table 4.2.2.5 (b).
479 Exhibit 110.07, page 56, Q/A 81.
480 Transcript, Volume 8, pages 1729-1731.
481 Ibid.
482 UCA Argument, page 71, paragraph 239.
483 Transcript, Volume 2, page 385.
484 AUC-AG-70(b), Section 4 Roles, Relationships and Responsibilities Regulation (Alberta Regulation 186/2003), rebuttal, paragraph 215.
485 Transcript, Volume 2, page 390, lines 16-17.
486 Exhibit 218.01, AG reply argument, page 82.
487 UCA argument, page 71, paragraph 239.
488 Transcript, Volume 8, pages 1728-1729, commencing at line 21.

at this late stage in the proceeding, and the lack of evidentiary support, the Commission should give zero weight to the new positions of the UCA.

602. AG submitted that a change in circumstances warrants the opening of the Calgary BFK.[489] The number of customers that AG serves today has increased significantly from the level back in 1998. Media clutter has similarly increased as technology has advanced.

Commission findings

603. AG has requested approval of forecast O&M costs of $2.0 million for 2011 and $2.1 million in 2012 for the BFK. The costs relate to the continuing operation of the Edmonton BFK, referred to as a "legacy" service and the new BFK's Calgary Learning Centre.

> The Commission considered the status of the Edmonton BFK in Decision 2008-113. The Commission pointed out that the BFK service started with AG's former role in the retail gas business and found that the Edmonton BFK was a "legacy" service. With respect to the re-opening of the BFK in

604. In regards to AE, which was at one time a partner with AG in the BFK, the Commission's predecessor, the EUB took a more firm position in relation to the BFK. In Decision 2006-024 for the 2005-2006 General Tariff Application for ATCO Electric, the EUB, stated: "However, the Board does not consider that the services provided by the Blue Flame Kitchen are necessary for the provision of distribution services."[490]

605. In this application, the Commission was asked to approve forecast costs related to both the "legacy" Edmonton BFK and the new Calgary BFK. Prior to considering the applied for costs, the Commission must first address the question of whether the BFK service should continue to be provided by AG as a regulated gas distribution utility.

606. AG primarily supports the inclusion of BFK costs as one method of communicating with customers to deliver safety and energy efficiency messages. Another justification for the BFK is the ability to communicate with customers regarding DSM.

607. The Commission has considered the responsibilities of gas distributors as set out in the *Roles, Relationships and Responsibilities Regulation.* The role of a gas distributor in providing services relating to energy efficiency and DSM will be examined relative to Section 4(1)(b) of the *Roles, Relationships, and Responsibilities Regulation* in the following section on DSM.

608. With respect to the distribution of safety information, Section 4(1)(k) provides that a gas distributor must distribute public safety information. The BFK distributes safety information and provides education with respect to the gas distribution system. In order to determine if the costs associated with the public safety and gas distribution information aspects of the BFK are reasonable and should be included in customer rates, the Commission will consider the applied for costs and the alternatives available to perform these functions.

609. Although the Commission notes the AG data and statistics on the use of the BFK in Calgary and Edmonton, the Commission is not persuaded that the operation of the BFK program

[489] AUC-AG-81.
[490] Page 43.

is a cost effective means to communicate distribution service information or natural gas safety information.

610. AG explained that it spends $50,000 per year on "cross-promotion of safety messages" through the BFK[491] while the forecast for the test period for the BFK is $2 million per year.[492] The Commission considers that BFK provides a disproportionate amount of costs for the safety and gas distribution service communication benefits received. Further, AG is the only Canadian distribution utility that has a facility like the BFK Calgary Learning Centre.[493] The Commission is not persuaded that the Edmonton BFK is required in light of the limited benefit that customers receive through safety and gas distribution communication through the BFK. The Commission finds that the BFK is not a cost effective means of proving public safety communication. Further, AG has other options to meet its responsibility to distribute public safety information. For the preceding reasons, AG is directed to remove all Edmonton BFK costs from 2011 opening rate base and from revenue requirement for the test years, including both capital and O&M related costs. For the same reasons the request to include in revenue requirement costs associated with the Calgary BFK is denied.

611. The Commission does, however, continue to support the expenditure of $50,000 per year on safety messaging that the BFK has provided in the past. AG may add this expenditure to its Customer Relations and Communications forecast for the test years. AG is directed to advise the Commission in the compliance filing to this decision as to the mechanism it will use to promote natural gas safety matters and gas distribution education information to customers.

6.3.13 Customer relations and communications

612. Customer relations and communications includes the following areas: employee communications, customer communications, media relations, community relations, public safety education, and information programs. AG applied for costs of $2.4 million in 2011 and $3.5 million in 2012[494] for customer relations and communications. This is an increase from $2.2 million actual costs in 2009 and $1.9 million actual costs in 2010. AG submitted that the increase in costs in 2011 was due to inflation, AG becoming a year-round presence in the marketplace with safety messaging, and the development of communications plans for the ATCO 100th Anniversary (Centennial Anniversary) in 2012.[495] The Centennial Anniversary forecast costs were $0.25 million in 2011 and $1.1 million in 2012,[496] which accounts for the majority of the incremental costs in this area.

613. The UCA expressed concern about the increase in forecast costs and pointed out that there was little demonstrated need for AG incremental costs in this area, and some of these costs were to the benefit of shareholders.[497]

614. In evidence,[498] Calgary concurred with the UCA that the primary purpose of the Centennial expenditures is for the benefit of the shareholders and as such should not be included in the revenue requirement.

491 Exhibit 84, AUC-AG-80, page 2 of 3.
492 Exhibit 3, application, Vol. 1, Section 4.2 Table 4.2.2.5(b).
493 AUC-AG-81(d).
494 Exhibit 3, application, page 4.2-25.
495 Exhibit 3, application, page 4.2-27.
496 Exhibit 83.01, UCA-AG-90(b).
497 Exhibit 83.01, UCA-AG-86(b); Exhibit 84.01, AUC-AG-80.

615. AG submitted that its Centennial Program in 2012 is another element of AG's integrated strategy to promote awareness of the services provided by AG and its facilities, address natural gas safety issues, promote conservation of non-renewable resources, and promote recruitment and retention of employees in the various communities it serves.

Commission findings

616. Similar to the Commission's finding with respect to AG's BFK program above, the Commission is of the view that the increase in costs for the purpose of the Centennial Anniversary celebration is not justified as a cost effective means to communicate safety matters and is unnecessary for the provision of safe and reliable delivery of natural gas. Accordingly AG is directed to remove the forecast costs associated with the Centennial Anniversary from the sales and transportation promotions function for the 2011 and 2012 test years.

617. The Commission approves the balance of the forecast costs in this area.

6.3.14 Demand side management (DSM) programs

618. AG has requested approval of O&M costs and the capital expenditures detailed in Section 6.3.14 for the 2011 and 2012 test years for a number of projects collectively described as DSM programs. These projects and the related costs are presented in the following table. AG noted that it has been providing "DSM programs" and services since 2001 through ATCO Energy Sense (EnergySense).[499] AG's DSM activities have primarily been focused on education and outreach.[500] AG has also been evaluating alternative and renewable thermal energy technologies which have been explored through pilot projects. AG's actual DSM for labour and supplies was $1.65 million in 2010 which are currently recorded in the sales and transportation promotion function. AG requested approval:

- to expand or enhance certain existing DSM related programs
- for expenditures related to research and a rebate/incentive pilot to be used to determine what future DSM programs might be best managed on a utility sponsored basis and how to structure those programs and
- to offer a limited Renewable Energy Program service offering

[498] Exhibit 110.07.
[499] Application, Section 4.4.1, page 4.4-2, paragraph 5.
[500] Ibid.

Table 37. DSM forecast[501]

DSM Labour Supplies Breakdown	2010 Forecast (000)	2011 Forecast (000)	2012 Forecast (000)
Labour			
Current Program	1,205	1,288	1,482
Energy Education Mobiles		149	262
Commercial Program		120	124
Total Labour	**1,205**	**1,557**	**1,868**
Supplies			
Current Program	441	639	781
School Program		725	725
How To Videos		50	150
DSM Market Analysis Study		600	-
Home Energy Report Program		350	300
Small Commercial Program		96	96
Total Supplies	**441**	**2,560**	**2,052**
Total	**1,646**	**4,117**	**3,920**

619. AG has delivered a school program targeted at grade four students since early 2010 which included the use of an Energy Education Mobile (EEM) vehicle. AG is requesting approval of costs related to an expansion of this program. Forecast costs include the acquisition of two additional EEMs at a capital cost of $2 million, staffing costs of $149,000 in 2011 and $262,000 in 2012, and incremental supplies costs of $725,000 for each of 2011 and 2012.[502]

620. AG plans to develop a series of "How-To Videos" that customers would be able to access at the Company website or view at other outreach events such as home shows and tradeshows with regard to energy efficiency matters. AG is requesting approval of the production costs of $150,000 in each of 2011 and 2012.[503]

621. AG plans a residential pilot program which will provide 25,000 customers with a comparative analysis of their energy consumption and information and advice that they can utilize to reduce energy consumption. The forecast cost of this pilot is $350,000 in 2011 and $300,000 in 2012.[504]

622. In 2001 AG became involved in the administration of government energy incentive programs. Since 2007, AG has been providing residential assessments province-wide.[505] In AUC-AG-75 (b), AG forecast approximately $1.0 million in residential assessment costs in revenue requirement in each of 2011 and 2012. In discussion with Commission Member Holgate at the oral hearing Mr. Morishita and Ms Wilson confirmed that although the costs of these programs

501 Exhibit 3, application, page 4.4-21, Table 9.
502 Exhibit 3, application, page 4.4-22.
503 Exhibit 3, application, page 4.4-22.
504 Exhibit 3, application, page 4.4-23.
505 Exhibit 3, application, pages 4.4-18-19.

are included in revenue requirement, these are unregulated programs and are priced in a manner to ensure that costs are recovered over time.[506]

623. In 2011 AG plans to introduce a small commercial customer assessment service more tailored to these customers' needs. Two additional commercial energy analysts would be required at a forecast cost of $0.12 million per year. The cost of supplies associated with this program, are forecast at $0.1 million per year for each of 2011 and 2012.[507]

624. AG also applied to introduce a Renewable Energy Program[508] (REP) for alternative and renewable energy technologies which would supplement or replace traditional natural gas and water heating markets. AG requested approval for:

- the capital and operating costs related to three existing REP projects (McKenzie Towne, Town of Hinton and Drake Landing)[509]
- capital expenditures of $1.5 million in 2011 and $3.0 million in 2012 for new REP projects[510] and
- the concept used to determine the pricing of renewable energy services related to the implementation of geothermal and solar energy delivery systems[511]

625. AG has completed renewable energy (geothermal and solar thermal) pilot projects in McKenzie Towne and the Town of Hinton. The capital and operating costs associated with these projects were included in forecast revenue requirement. AG is also a part owner of the Drake Landing Corporation for the Drake Landing Solar Community demonstration project, and is currently the operator of these assets. AG included the forecast revenues and operating costs related to the Drake Landing Solar Community project commencing in the year 2011. AG has the opportunity to assume full ownership of the Drake Landing renewable energy assets effective January 1, 2012 and has reflected this in the forecast revenues and operating costs for 2012. In response to UCA-AG-62(a), AG provided the actual capital expenditures for the McKenzie Towne project as $0.2 million and $0.6 million in 2008 and 2009 respectively. Actual capital expenditures for the Town of Hinton project were $0.1 million in 2009. AG did not specify the operating costs for these projects.

626. AG also requested approval for a $600,000 research study[512] to assist in developing its own comprehensive DSM plan, and included a forecast of $1.0 million as a one-time adjustment in 2012 for a rebate/incentive pilot program.[513] A utility delivered DSM plan and associated programs proposal would be filed with the Commission for approval at a future time.[514]

627. AG noted that the Alberta Government's policy documents, including the current Provincial Energy Strategy and the Climate Change Strategy indicate a "high level objective … for the province to become a sophisticated energy consumer and a solid global environmental

506 Transcript, Volume 3, pages 528 to 529.
507 Exhibit 3, application, page 4.4-23.
508 Application, Section 4.4.6, paragraphs 64-75.
509 Section 4.4.6 of the AG application.
510 Section 4.4-26 of the AG application, paragraph 64.
511 Section 4.4-27 of the AG application, paragraph 71.
512 Section 4.4.7, paragraph 81 of AG application.
513 Section 4.4.7, paragraph 81 of AG application.
514 Application, Section 4.4.7, paragraphs 76-85.

citizen."[515] AG submitted that its existing and expanded DSM programs serve to narrow the gap in terms of achieving the Alberta Government strategy for energy and climate change.[516]

628. AG referred to Section 28(e) of the *Gas Utilities Act* and Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*, A.R. 186/2003 as support for the inclusion of DSM programs in revenue requirement.

629. Sections28(e), (f) and (h) of the *Gas Utilities Act* provide:

> (e) "gas distribution service" means the service required to transport gas to customers by means of a gas distribution system, and includes any services the gas distributor is required to provide by the Commission or is required to provide under this Act or the regulations;
>
> (f) "gas distribution system" means a gas utility that delivers gas to customers through a system of pipelines, works, plan and equipment that is primarily a low pressure system;
>
> (h) "gas distributor" means the owner, operator, manager or lessee of a gas distribution system;

630. Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation* provides:

> **4(1)** A gas distributor must do the following:
>
> (b) make decisions about building, upgrading and improving the gas distribution system for the purpose of providing safe, reliable and economic delivery of gas to customers in the service area served by the gas distribution system;

631. AG explained that these legislative provisions supported AG's DSM projects because:

> The legislative requirement for "economic delivery of gas" means, in ATCO Gas' view, that it is required to consider mechanisms for reduction of natural gas use/conservation.[517]
>
> The legislative requirement for safety and "economic delivery of gas" means, in ATCO Gas' view, that it is required to develop effective mechanisms for safe use of gas and distribution facilities, as well as for energy efficiency and conservation.[518]

632. In argument AG commented on this position further by stating:

> ATCO Gas notes that the term "gas distribution system" is defined in Section 28 of the Gas Utilities Act ("GUA") as "a gas utility that delivers gas to customers through a system of pipelines, works, plant and equipment that is primarily a low pressure system" (emphasis added). Based on this definition, AG is of the view that the phrase "…building, upgrading and improving the gas distribution system…" in Section 4(1)(b) of the 3R Reg is not restricted to building, upgrading and improving the pipes in the ground. Rather,

[515] Transcript, Volume 2, page 399, lines 1-4.
[516] Transcript, Volume 2, page 399-400.
[517] AUC-AG-51(b).
[518] AUC-AG-70(b).

> this provision requires a gas distributor to make decisions about building, upgrading and improving its delivery of gas through the system. By providing DSM programs to its customers, ATCO Gas submits that it is making decisions that serve to improve its delivery of natural gas through the system for the purpose of providing economic delivery of natural gas to customers. As was noted by ATCO Gas, DSM provides the opportunity in the longer term to reduce the expansion of its distribution system, and reduce its transmission peak requirements.[519] (footnote omitted)

633. AG also stated in its rebuttal evidence that the *Roles, Relationships and Responsibilities Regulation* requires the company to develop and implement effective programs and communications for its customers regarding safe use of natural gas as well as for energy efficiency and conservation.[520] Further, AG submitted that costs for renewable energy services form part of its "gas distribution service" and its *Roles, Relationships and Responsibilities Regulation* responsibilities.[521]

634. AG indicated that the Commission and its predecessors, the Alberta Public Utilities Board (PUB) and the EUB, have approved forecast costs associated with DSM programs on several occasions.[522]

635. AG noted that it serves over 85 per cent of the homes in the Province of Alberta.[523] Therefore, AG's DSM efforts will have broad application that will reach the vast majority of natural gas customers in Alberta. Further, given the dispersion of customers, some customers would not have had the opportunity to participate in certain DSM programs such as energy assessment audits, if left to the competitive marketplace alone.

636. In its application, AG also provided its rationale for providing regulated renewable energy program (REP) services:

- Support for renewable energy development was consistent with the Alberta Provincial Energy Strategy.
- The necessary economic drivers do not exist at this time to effect substantive market penetration of renewable energy solutions.
- Utilization of renewable energy technologies to supplement or replace traditional natural gas technologies will reduce natural gas consumption.[524]

637. AG submitted that the purpose of the renewable energy program services is to stimulate interest in renewable energy technologies by making them more visible in the marketplace and to help consumers overcome the cost barrier that exists today.[525]

Views of the parties

638. Climate Change Central (C3) characterized itself as a not-for-profit organization which administers and delivers province-wide DSM programs for the Alberta government, the federal

519 AG argument, pages 84-85, paragraph 216.
520 Rebuttal evidence, page 75, paragraph 298.
521 AG argument, page 88, paragraph 223.
522 AUC-AG-70(b).
523 Transcript, Volume 1, page 75, line 13.
524 Application, Section 4.4.6, page 4.4-24.
525 Rebuttal evidence, page 81, paragraph 321.

government, various cities and municipalities in Alberta and corporate clients. C3 only participated in this proceeding with respect to the DSM costs being proposed by AG to be included in revenue requirement.

639. C3 submitted that the DSM components of AG's application should be denied for the following reasons:

- There is no mandate or governing legislation for ratepayer funded, utility administered DSM overseen by the Commission.
- There is no framework in place to review and assess the DSM components of the application and prior EUB decisions do not provide a precedent to approve the DSM components of the current application.[526]
- There is no evidence that the research and pilot program proposed by AG will add value to existing DSM research and program knowledge.
- Approval of the DSM components of the application represents a "slippery slope"[527] and sets a precedent in support of a ratepayer funded, utility administered model for DSM in Alberta which could lead to other utilities (electricity, water and gas) making similar, uncoordinated applications to the Commission.
- Approval of the DSM components of the application is premature given the broader consultation process that C3 has initiated.
- The appropriate model of delivering DSM should be determined through a broader, more inclusive, stakeholder consultation process than a general rate application by a single utility.[528]
- There is no government policy direction on DSM in Alberta, and the Alberta Government has not asked AG to initiate a DSM program.[529]

640. The primary focus of C3's intervention is the $600,000 research program and the $1,000,000 incentive/rebate pilot that has been proposed by AG.[530] C3 is not opposed to ATCO EnergySense continuing its public education and outreach services at existing levels, or at expanded levels, if the services are shown by AG to be cost-effective.[531] However, AG should not be permitted to expand existing programs.

641. C3, Calgary and the UCA each argued that there is no legislative support for AG's expanded DSM programs. In support of this position, the following arguments have been raised:

- Section 4(1)(b) of the*Roles, Relationships and Responsibilities Regulation*[532] does not support DSM activities.[533]

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526 Transcript, Volume 7, page 1522, lines 16-23.
527 Transcript, Volume 7, page 1522, line 11.
528 Exhibit 202.02.969, paragraph 49.
529 Transcript, Volume 1 at page 56, lines 9-11.
530 C3 argument, page 5, paragraph 10 referring to programs outlined in the application at page 4.4-31, paragraph 80 to page 4.4-32, Table 11.
531 Transcript, Volume 7, page 1446, lines 17-20; page 1450, line 24 to page 1451, line 21; page 1453, lines 5-17.
532 Section 28 of the *Gas Utilities Act*. Section 4(1) of the *Roles, Relationships and Responsibilities Regulation*.
533 C3 argument, pages 6-9, paragraphs 13-19. Calgary argument, page 34-35. UCA argument, pages 67-68, paragraphs 226-227, as well as page 75, paragraph 250.

- The scope of the phrase "gas distribution service." as defined in Section 28 of the *Gas Utilities Ac*t, suggests that AG should not conduct DSM programs (unless expressly directed by the AUC).[534]
- Prior AUC decisions support the position that there is no legislative authority for AG's DSM programs.[535]
- There is a need for legislative change in this area and there is no Alberta Government or AUC "mandate" for DSM, and thus the AUC should deny AG's expanded DSM program.[536]

642. C3 and Calgary argued that "economic delivery" of gas referred to in Section 4(1)(b) of the *Roles, Reglationships and Responsibilities Regulation* does not include DSM initiatives. C3 stated that "economic delivery" relates to the commodity and "…building, upgrading and improving the gas distribution system is intended to provide <u>the same level of gas</u> at the lowest (most economic) acceptable cost to ratepayers…[which] does not address energy efficiency"[537] (emphasis provided by C3).

643. C3 referred to the list of functions of a gas distributor enumerated in Section 4(1) of the *Roles, Reglationships and Responsibilities Regulation* and referred to principles of statutory interpretation in support of its position that DSM programs are not proper activities of a gas distributor. C3 stated:

> It is a general principle of statutory interpretation that a partial enumeration of things, such as that set out in subsection 4(1) of the 3R Regulation, is meant to be exhaustive, and anything left off the list is, by implication, meant to be excluded. This is known as the implied exclusion rule. Ruth Sullivan, in her text, *Statutory Interpretation*, describes the implied exclusion rule as follows:
>
> > An intention to exclude may legitimately be implied whenever a thing is not mentioned in a context where, if it were meant to be included, one would have expected it to be expressly mentioned. Given an expectation of express mention, the silence of the legislature becomes meaningful. An expectation of express reference legitimately arises wherever a pattern or practice of express reference is discernible. Since such patterns and practices are common in legislation, reliance on implied exclusion reasoning is also common.[39]
>
> Pierre Côté, in his text, *The Interpretation of Legislation in Canada*, also provides the following guidance:
> Legislation is deemed to be well drafted, and to express completely what the legislature wanted to say: "It is a strong thing to read into an Act of Parliament words which are not there, and in the absence of clear necessity it is a wrong thing to do." [40]
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> [39] Ruth Sullivan, *Statutory Interpretation*, 2d ed (Toronto: Irvin Law Inc., 2007) at 192.

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[534] UCA argument, page 68, paragraph 227.

[535] C3 argument, page 10-11, paragraphs 23-24 and 26. Calgary argument, pages 38-39. UCA argument, pages 68-69, paragraphs 229-231.

[536] C3 argument, paragraph 39 (re: legislative change), as well as page 5-17 (re: mandate). Calgary argument, page 38. UCA argument, paragraph 243 and 253.

[537] C3 argument, page 7, paragraph 15.

[40] Pierre Côté, *The Interpretation of Legislation in Canada*, 3d ed (Scarborough: Thomson Canada Limited, 2000) at 276 per Lord Mersey, *Thompson v Goold & Co*., [1910] A.C. 409, 420.[538]

644. C3, Calgary and the UCA cited Decisions 2009-238[539] and 2010-483[540] to support the position that there is no legislative authority to include customer education and energy efficiency-related costs in AG's revenue requirement.[541] C3 also cited Decisions 2009-238 and 2010-483 to suggest that AG's existing public education and outreach services should be excluded from its revenue requirement.[542]

645. Calgary submitted that the DSM and renewable energy program services should not be approved because there should be a province-wide strategy in place.[543] Calgary was concerned that an individual utility initiated DSM program would lead to regulatory inefficiencies and would not lead to coordinated and integrated province-wide DSM and renewable energy program service portfolios.[544] Calgary stated that until a province-wide thorough analysis and consultation on possible models for funding and delivery of DSM programs was conducted, it would be premature to conclude that AG's proposed initiatives are in the best interest of ratepayers.[545] Calgary indicted that it was not looking to have the existing approved amounts rolled back but Calgary did object to any expansion of DSM related expenditures.[546]

646. Calgary argued that the implementation of renewable energy program services could result in ratepayer funded initiatives that could be substantially different from those of unregulated providers. Calgary submitted that this type of scenario would not maximize the benefits to ratepayers in respect to the level of costs and would establish precedents on funding and programming for Alberta ratepayers.[547] Renewable energy programs are generally provided in the competitive marketplace. Calgary stated, "Ratepayers should not be obligated to support and subsidize this type of operation within a regulated utility competing in a competitive market place with an inherent competitive advantage."[548]

647. The CCA agreed with AG's interpretation of the *Roles, Relationships and Responsibilities Regulation* that utilities should be responsible for delivering information and economic support for the conservation and efficient use of natural gas.[549] However, the CCA stated AG has not met its onus and has failed to demonstrate the increased level of expenditures on its DSM programs. AG's expenditures for its $0.6 million research study should be approved regarding possible DSM projects but the specific cost of the DSM rebate programs, the renewable energy programs and the pilot projects should be excluded from rate base pending the results of the research study.

538 C3 argument, pages 8-9, paragraphs 17-18.
539 Decision 2009-238: Direct Energy Regulated Services, 2009/2010/2011 Default Rate Tariffs and Regulated Rate Tariffs, Application No. 1600749, Proceeding ID. 149, December 3, 2009.
540 Decision 2010-483: ENMAX Energy Corporation, 2009-2011 Regulated Rate Option Non-Energy Tariff Application, Part 2 – Tariff Application, Application No. 1605947, Proceeding ID. 521, October 7, 2010.
541 C3 argument, page 11, paragraph 26. Calgary argument, page 39. UCA argument, pages 68-69, paragraphs 229-230.
542 C3 argument, page 11, paragraph 27.
543 Exhibit 109.02, page 1 lines 12 to 13.
544 Ibid., page 2.
545 Transcript, Volume 7, page 1625, Exhibit 201.01, Calgary argument, page 36.
546 Transcript, Volume 7, page 1446, lines 17 to 18.
547 Exhibit 201.01, Calgary argument, page 37.
548 Ibid.
549 Exhibit 204.01, CCA argument, page 12, paragraph 32 and 33.

648. The UCA submitted that the fact that AG has provided some DSM services since 2001[550] is not a sufficient reason to approve existing, new or enhanced programs. Direct Energy Regulated Services had provided information on energy efficiency education or DSM services since 2004,[551] however, these costs were later denied by the Commission for the 2009-2011 test years.[552] Prior approval of costs of customer education was not sufficient reason for the costs to be approved in the future. Similarly, the energy efficiency education costs for ENMAX Energy Corporation (EEC) were denied by the Commission in Decision 2010-483, despite being approved in past periods. In Decision 2010-483, the Commission noted: "EEC has not provided any evidence that there are legislative changes that require the requested customer education costs to be incurred."[553] The UCA compared the case advanced by AG to the case put forward by EEC and concluded that AG had not provided any evidence that there is a legislative change that requires it to incur customer education costs on conservation or DSM.

649. The UCA submitted that the costs incurred for customer education are neither required nor necessary for gas delivery service.[554] The UCA also submitted that all of the capital and operating costs for new school programs and the energy education mobiles be denied, stating:

> There is no mandate, law, regulation or decision that compels AG to provide customer education to students, nor are there any identifiable benefits to justify the cost, which is to be paid by current ratepayers.[555]

650. In evidence, the UCA submitted that there did "not appear to be any law or regulation that requires AG to offer DSM services nor has AG been requested to provide the services by the Alberta Government."[556] The UCA submitted that unless the Commission or the government specifically requires AG to provide a service that it not otherwise required for transportation of gas to customers, there is no justification for these services to be provided and funded by ratepayers.[557]

651. The UCA acknowledged there is a legislative requirement for AG to provide public safety information but this requirement is only within the context of natural gas delivery, and not for the use or reduction in use of natural gas.[558]

652. The UCA submitted that AG's prior administration of unregulated federal government rebates to provide home inspection services[559] that could be and are provided by unregulated companies/competitors,[560] does not suggest that that utility sponsored incentive/ rebate programs should continue.

653. In argument, the UCA objected to the proposed renewable energy program as it is a different type of program than has been previously approved and "entails AG supplying energy

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[550] Exhibit 3, Volume 1, Section 4.4.4, paragraph 40.
[551] As approved in Decision 2003-106. As noted in the UCA's evidence, Exhibit 110.07, page 49-50, A.71.
[552] Decisions 2009-238 and 2010-483. As noted in the UCA's evidence, Exhibit 110.07, page 50-51, A.72.
[553] Decision 2010-483, page 17, paragraph 81, cited in Exhibit 110.7, pages 50-51, A.72.
[554] Exhibit 200.02, UCA argument, page 69, paragraph 231.
[555] Exhibit 200.02, UCA argument, page 730, paragraph 243.
[556] Exhibit 110.07, UCA evidence, page 66.
[557] Exhibit 200.02, UCA argument, page 68, paragraph 227.
[558] Exhibit 200.02, UCA argument, page 69, paragraph 231.
[559] Exhibit 110.07, page 60, A.87.
[560] Transcript, Volume 7, page 1512, lines 10-25 and page 1514, line 10.

sources from geothermal/solar rather than natural gas."[561] The UCA argued that there are competitors in the market supplying both geothermal and solar equipment and that the market is both unregulated and competitive. The UCA asserts that if the projects are approved in this proceeding, AG will obtain a competitive advantage in the market for these services and will not contribute to a more viable market. Existing legislation, regulation and government mandates in Alberta do not require AG to offer DSM service in the form of alternative energy.[562] Ratepayers should not pay the capital costs or operating costs for these expenditures and these expenditures should not be approved.

654. The UCA submitted that Section 4(1) of the *Roles, Relationshiups and Responsibilities Regulation* enumerates various obligations for a gas distribution utility, all of which are concerned with gas distribution service. Nowhere in Section 4(1) is it contemplated that a gas distribution utility should or must pursue alternative energy projects. As such, the UCA submitted that AG's proposed renewable energy projects fall well outside its mandate as a regulated gas distributor and the costs associated therewith should not be properly recoverable in AG's tariff. The UCA submitted that ratepayers should pay none of the capital or operating costs for the McKenzie Towne, the Town of Hinton or for the Drake Landing Solar Community. Nor should the proposed $4.5 million forecast for new projects expenditures be approved.

655. The UCA submitted that there is no requirement, as a gas distributor, nor a need for AG to duplicate C3's role as an administrator of incentives and rebates for DSM in the province.[563] All the AG proposed funding for the study incentives and rebates should be denied.[564]

656. With respect to the renewable energy programs, interveners opposed the programs for the following reasons:

- That this type of service is not part of the functions prescribed by the regulations regarding the role of gas distributors.[565] [566] [567]
- That this service can be obtained by existing service providers and that this service if approved would provide AG with a competitive advantage.[568] [569] [570] [571] [572] [573]
- That this service is subsidized by rate payers.[574]

657. In reply to intervener submissions, AG stated that neither C3 nor Calgary, provided any precedents or authorities to support their interpretation of Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*. AG noted in argument that the "gas distribution system" definition in the *Gas Utilities Act* must be considered to assess the appropriate scope of

561 Exhibit 200.02, UCA argument, page 75, paragraph 249.
562 Exhibit 200, paragraphs 248-254.
563 Transcript, Volime 7, page 1451, lines 14-21 and page 1471, lines 1-5.
564 Exhibit 2002.02, UCA argument, page 74, paragraph 246.
565 UCA evidence Q100.
566 UCA evidence Q100.
567 UCA evidence Q100.
568 Transcript, Volume 7, pages 1589-1590, commencing at line 20.
569 Transcript ,Volume 7, pages 1603-1604, commencing at line 11.
570 Information response AUC-C3-5 (c).
571 Transcript, Volume 7, page 1494, lines 22-24.
572 UCA evidence Q93 and Q94.
573 Transcript, Volume 7, page 1494, lines 22-24.
574 Transcript, Volume 7, page 1494, lines 22-24.

Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*. AG submitted that Section 4(1)(b) requires a gas distributor to "make decisions about building, upgrading and improving the gas distribution system" for the safe, reliable and economic delivery of gas (which DSM serves to accomplish).[575]

658. AG submitted that Decisions 2009-238 and 2010-483 confirm that the distributor of natural gas is the appropriate party to perform DSM functions, not default supply providers and retailers who should not, without express authority, duplicate the functions previously performed by the distributor prior to and after the separation of retail functions. Moreover, retailers operate in a competitive environment, and thus there is significant overlap in markets. As a result, AG submitted, retailer conservation efforts would be more fragmented, and less efficient.[576]

659. AG also submitted that Decision 2010-222[577] fully supports the AG position. Decision 2010-222 dealt with a dispute between the Town of Redcliff and the City of Medicine Hat regarding the rates charged by the City for natural gas service provided to customers in Redcliff in the years 2006-2008. The application was brought by the Town under Section 44 of the *Municipal Government Act*. The rates were charged under a Gas Supply Agreement between the City and the Town. One of the rates charged by the City to the Town was an energy conservation charge which applies to residential customers using more than 22 gigajoules per month. AG relies on this decision in support of its position that costs for renewable energy services fall within the ambit of "gas distribution service" and the *Roles, Relationships and Respnsibilities Regulation* responsibilities for natural gas distributors.[578] AG submits that the relevant definitions used in the *Municipal Government Act* and in the *Gas Utilities Act* each refer to the delivery of gas service leading AG to make the following statement:

> It is ATCO Gas' view that the scope of the City's gas delivery service under the MGA and a distributor's delivery service under the Gas Utilities Act are the same. Consequently, it follows that costs relating to renewable energy services, which were allowed under the MGA as part of the City's gas delivery service (as per Decision 2010-222), should also be allowed for a natural gas distributor under the GUA.[579]

660. In reply argument AG referred to the use by C3 of the implied exclusion rule of statutory interpretation. AG submitted that the rule did not apply to an interpretation of Section 4(1) of the *Roles, Relationships and Responsibilities Regulation*. AG stated:

> A critical component of the "implied exclusion rule" is that the subject words (in this case, "DSM") must be expressly included in a provision elsewhere in the legislation (so as to suggest that its exclusion in Section 4(1)(b) of the 3R Reg was intended by the legislature)….In this case, AG notes that neither the GUA, nor the Regulations under the GUA, refer to DSM or energy conservation initiatives.[580]

575 AG argument, paragraph 216.
576 AG rebuttal evidence, paragraph 300.
577 Decision 2010-222: Town of Redcliff, Dispute with City of Medicine Hat, Regarding Gas Supply Rates, Application No. 1551749, Proceeding ID. 144, May 21, 2010.
578 AG argument, paragraphs 224-229.
579 AG argument, page 90, paragraph 228.
580 AG reply argument, page 103, paragraph 247.

Commission findings

661. AG has requested Commission approval to include in rates the costs of various assessment and education outreach programs, research and pilot programs and renewable energy programs, collectively described as demand side management.

662. The evidence on the record with respect to DSM focused on whether the proposed programs fell within the legislative scope of a gas distributor and issues of general public policy and societal considerations including energy conservation, climate change, renewable energy, the development of government policy, customer preferences, the coordination of DSM efforts, the efficient delivery of DSM programs, practices in other jurisdictions, and the availability of certain services in the competitive market.

663. The Commission must first determine if the requested DSM projects fall within the scope of the the Commission's jurisdiction under the relevant legislation. If the Commission determines these projects are within the scope of its jurisdiction to approve, it will proceed to assess the reasonableness of the forecast DSM costs for the purposes of determining just and reasonable rates.

664. The Commission sets out the applicable legislative provisions for ease of reference.

665. Sections 28(e), (f) and (h) of the *Gas Utilities Act* provide:

> (e) "gas distribution service" means the service required to transport gas to customers by means of a gas distribution system, and includes any services the gas distributor is required to provide by the Commission or is required to provide under this Act or the regulations;
>
> (f) "gas distribution system" means a gas utility that delivers gas to customers through a system of pipelines, works, plan and equipment that is primarily a low pressure system;
>
> (h) "gas distributor" means the owner, operator, manager or lessee of a gas distribution system;

666. Section 4 of the *Roles, Relationships and Responsibilities Regulation* provides:

> **Functions of gas distributor**
> **4(1)** A gas distributor must do the following:
>
> (a) provide gas distribution service that is not unduly discriminatory;
> (b) make decisions about building, upgrading and improving the gas distribution system for the purpose of providing safe, reliable and economic delivery of gas to customers in the service area served by the gas distribution system;
> (c) arrange for adequate upstream transmission capacity for the purposes of clause (b);
> (d) operate and maintain the gas distribution system in a safe and reliable manner;
> (e) carry out gas distribution tariff billing for gas distribution service under the gas distributor's approved gas distribution tariff;
> (f) connect and disconnect customers in accordance with the gas distributor's approved gas distribution tariff;

(g) perform metering, including verifying meter readings and verifying accuracy of meters;

(h) maintain information systems relating to the consumption of gas by customers;

(i) perform load balancing for the gas distribution system;

(j) perform functions that a settlement system code requires a gas distributor to perform;

(k) distribute public safety information;

(l) provide to a retailer or the gas distributor's default supply provider sufficient, accurate and timely information about the retailer's or default supply provider's customers, including metering information about the gas consumed by those customers, in order to enable the retailer or default supply provider to bill and to respond to inquiries and complaints from customers concerning billing for gas services;

(m) act as a default supply provider to customers who pay a default rate for gas;

(n) respond to inquiries and complaints from customers respecting gas distribution service;

(o) if a customer makes an inquiry related to the functions of retailers or default supply providers, direct the customer to the customer's retailer or default supply provider;

(p) on the request of a customer, direct the customer to a source where the customer may obtain the current list of licensed retailers maintained in accordance with the *Fair Trading Act* and the regulations made under that Act.

(2) Each gas distributor must maintain records relating to the functions set out in subsection (1) and make the records or the information in them available, or otherwise provide the records or information, as required by the Act and the regulations.

(3) A gas distributor is entitled to recover in its tariffs the prudent costs as determined by the Commission that are incurred by the gas distributor to meet the requirements of subsection (1).

667. The Commission notes that no party took issue with the responsibility of AG to distribute public safety information under Section 4(1)(k). While public safety messaging may be a minor part of some DSM activities, this, by itself, does not justify DSM expenditures.

668. Parties agreed that the legislative authority to approve the inclusion of DSM costs in revenue requirement depends on the definitions in the Act and Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*.

669. The term "gas distribution services" refers to services the gas distributor is required to provide under the act, Section 4(1) of the *Roles, Relationships and Responsibilities Regulation*, under other regulations, or by direction of the Commission.

670. The Commission considers that there are two essential components of Section 4(1)(b). First there is a requirement of a gas distributor to make decisions about "building, upgrading, and improving the gas distribution system." Secondly, those decisions must be made for the "purpose of providing safe, reliable and economic delivery of gas to customers in the service area served by the gas distribution system." Both of these components of Section 4(1)(b) must be interpreted to determine whether the proposed DSM projects are a necessary function for a gas distributor.

671. AG and CCA have argued for a broad interpretation of Section 4(1)(b), while the other interveners have suggested a more narrow interpretation. The Supreme Court of Canada commented on the approach to take to statutory interpretation in *Bell ExpressVu Limited Partnership v. Rex* [2002] 2 S.C.R. 559 stating:

> In Elmer Driedger's definitive formulation, found at p. 87 of his Construction of Statutes (2nd ed. 1983):
>
> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.[581]

672. Ruth Sullivan in *Sullivan on the Construction of Statute*[582] states that under Driedger's modern principle, three things must be considered in interpreting a statutory provision:

- what is the meaning of the legislative text?
- what did the legislature intend?
- what are the consequences of adopting a proposed interpretation?[583]

673. The author goes on to state: "The rules associated with textual analysis, such as implied exclusion or the same-word-same-meaning rule, assist interpreters to determine the meaning of the legislative text."[584]

674. In addressing the first of the three matters suggested by Sullivan, namely the text of the legislation, the legislation does not contain further definitions that may help in understanding what was intended by the words used in sections 26(e) and (f) of the *Gas Utilities Act* or Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*. Accordingly, the Commission finds that it should consider the ordinary meaning of the words.

675. The Commission finds that Section 4(1)(b) is intended to relate to the physical aspects of the facilities and the improvement or upgrading of service quality. System improvements and upgrades are not without constraints. Decisions made about building, upgrading and improving the gas distribution system, must be made "for the purpose of providing safe, reliable and economic delivery of gas." The Commission considers that the words "safe and reliable" relate to the facilities used to provide gas distribution service and the quality of that service. Decisions made on building, upgrading and improving the gas distribution system must be made to ensure or improve the safety of the delivery of gas distribution service, the reliability of gas distribution service and the economic delivery of gas distribution service.

676. The term "economic delivery" must be construed in the context of the *Gas Utilities Act* and the *Roles, Relationships and Responsibilities Regulation* taken as a whole. The legislation provides for the regulation of gas utility rates and services. The Commission must determine just and reasonable rates for the provision of gas distribution service by the owner of a gas utility. The Commission finds that in this context "economic delivery" means the delivery of gas

581 *Bell ExpressVu Limited Partnership v. Rex* [2002] 2 S.C.R. 559 paragraph 26-30.
582 Ruth Sullivan, *Sullivan on the Construction of Statutes*, 5d ed (Markam: LexisNexis Canada Inc., 2008).
583 Ruth Sullivan, *Sullivan on the Construction of Statutes*, 5d ed (Markham: LexisNexis Canada Inc., 2008) at 3.
584 Ruth Sullivan, *Sullivan on the Construction of Statutes*, 5d ed (Markham: LexisNexis Canada Inc., 2008) at 3.

distribution service at an economically efficient cost to ratepayers, so as to ensure rates remain just and reasonable.

677. AG submitted that DSM is related to the building, upgrading and improving of the gas distribution system for the purpose of providing safe, reliable and economic delivery of gas to customers because it provides the opportunity in the longer term to reduce the expansion of its distribution system, and reduce its transmission peak requirements.

678. The object of DSM is not the cost efficient delivery of gas distribution to customers. Rather, it is aimed at altering customers' behaviour over the long term with a view to lowering consumption. While lower consumption may reduce the growth in costs in the long term, Dr. Cicchetti noted the importance of conducting DSM initiatives, in the longer term, on the basis of earnings neutrality in the form of lost margin protection. As well, direct performance-based incentives to AG should be considered in order to sustain energy efficiency efforts.[585]

679. The Commission finds that the reduction in consumption is not intended to be captured in Section 4(1)(b). The Commission does not agree that the wording of Section 4(1)(b) is expansive enough to allow the utility to engage in DSM activities funded by ratepayers simply because there is the potential for an unquantifiable, consequential impact to future facilities or to customer demand for gas distribution services.

680. The Commission finds that the proposed DSM programs do not relate to building, upgrading and improving the gas distribution system for the purpose of providing safe reliable and economic delivery of gas to customers. Accordingly, the Commission finds that based on the meaning of the legislative text, the DSM programs proposed do not fall within the intended meaning of Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*.

681. Turning to the second consideration suggested by Sullivan, the Commission will consider the apparent intention of the legislature in drafting the statutory definitions and Section 4(1) of the *Roles, Relationships and Responsibilities Regulation*. In discerning the intention of the legislature, the Commission has considered the context of the *Gas Utilities Act* and the regulations thereunder. The legislative scheme is intended to provide for the regulation of gas utilities and to provide the Commission with various responsibilities, including the authority to set just and reasonable rates and standards of service in the public interest. AG noted in its reply argument that "…neither the GUA, nor the Regulations under the GUA, refer to DSM or energy conservation initiatives."[586]

682. Sullivan stated that the rules of statutory interpretation such as the rule of implied exclusion may assist in determining the meaning of the text. The Commission agrees with C3 that the implied exclusion rule of statutory interpretation can be applied in this instance. The Commission does not agree with AG's submission that a reference to DSM must be included elsewhere in the legislation before the implied exclusion rule can apply. The Commission notes that AG did not provide any authorities to support this position. Sullivan refers to the application of the rule in the following words:

[585] Exhibit 3, Application, Section 4.4, Appendix A, Written evidence of Dr. Charles Cicchetti, page 5; Transcript Volume 3, May 26, 2011 page 558 to 565; also see Ms. Wilson and Mr. Schmidt at Transcript Volume 3, page 558.

[586] AG Argument, page 103, paragraph 140.

> An implied exclusion argument lies whenever there is reason to believe that if the legislature had meant to include a particular thing within its legislation, it would have referred to that thing expressly. Because of this expectation, the legislature's failure to mention the thing becomes grounds for inferring that it was deliberately excluded. Although there is no express exclusion, exclusion is implied.[587]

683. Application of the implied exclusion rule suggests that the legislature in enumerating a lengthy list of gas distributor functions in Section 4(1) of the *Roles, Relationships and Responsibilities Regulation* considered in a comprehensive manner the functions intended to be performed by a gas distributor. Functions not provided in the list were not indented to be functions of a gas distributor, unless a function was directed by the Commission as contemplated by the definition of "gas distribution service" or the function is provided for elsewhere in the legislation. DSM is not among the listed functions. As noted above, AG stated in its reply argument that "…neither the GUA, nor the Regulations under the GUA, refer to DSM or energy conservation initiatives."[588] Consequently, the Commission concludes that DSM was not intended by the legislature to be among the functions of a gas distributor.

684. The third step in the Sullivan analysis requires the Commission to consider the consequences of adopting a proposed interpretation. The consequence of the interpretation placed on the definitions of the statute and Section 4(1) of the *Roles, Relationships and Responsibilities Regulation* by the Commission is that the costs associated with AG's DSM programs, both existing and proposed are not properly included within the regulated rates of a gas distributor and should be removed entirely from rate base, revenue requirement and rates. The Commission finds the consequences of the interpretation placed on the wording of the above provisions to be reasonable.

685. The Commission has also considered the arguments of AG with respect to prior decisions of the EUB and the Commission and is not persuaded by these submissions. If the legislative scheme does not provide for DSM activities to be carried out by a gas distributor, that is sufficient to conclude that DSM activities would not result in just and reasonable rates and should be denied.

686. The Commission denies AG's request to include in revenue requirement for the test years all costs associated with current and proposed DSM activities. The Commission directs that all DSM related costs, both capital and operating, be removed from rate base and revenue requirement for the test years. The Commission further directs that the DSM capital expenditures incurred during the period 2008 to 2010 are to be excluded from opening rate base.

6.3.15 Customer accounting function

687. The customer accounting function includes meter reading, the billing of retailers, and responding to customer inquiries related to the provision of delivery service. AG performs the meter reading function at the customer's premise while ATCO I-Tek Business Services has been contracted to perform the customer contact and retailer billing activities. Table 37 below shows

587 Ruth Sullivan, Sullivan on the Construction of Statutes, 5d ed (Markham: LexisNexis Canada Inc., 2008) at 244.

588 AG Argument, page 103, paragraph 140.

the actual costs for the customer accounting function for 2008 to 2010, and the forecast amounts for 2011 and 2012.[589]

Table 38. Customer accounting function

O&M Total	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
Supervision - 710	1,695	-26.3%	1,250	-12.0%	1,100	38.9%	1528	24.9%	1,909
Customers' Contracts and Orders -711	2,314	2.9%	2,381	-100.0%	0	100.0%	16	6.3%	17
Meter Reading and Bill Delivery -712	17,591	4.2%	18,330	-2.89%	17,800	7.7%	19,176	3.9%	19,929
Customers' Billing and Accounting-713	21,916	2.6%	22,476	22.3%	27,500	3.2%	2,8385	2.4%	29,072
Credit and Collection - 714	1,441	23.2%	1,776	23.9%	2,200	-14.8%	1,875	9.0%	2,043
Uncollectible Accounts - 718	-372	-96.5%	-13	-1638.5%	200	-20.0%	160	2.5%	164
Total	**44,585**	3.6%	**46,200**	7.8%	**48,800**	2.7%	**51,140**	3.9%	**53,134**

6.3.15.1 Supervision – Account 710

688. AG forecasted supervision expenses for 2011 and 2012 of $1.5 million and 1.9 million respectively.

689. In its general evidence[590] the UCA observed that in the application AG did not discuss the significant increase in this account, and on that basis, the UCA recommended that these expenses be reduced to the escalated level of $1.1 million in 2011 and $1.2 million in 2012.

690. AG disagreed with the UCA assertion that AG did not discuss the increase in forecast costs with respect to Account 710. In rebuttal, AG outlined the forecast costs for governance.[591] The governance amounts in 2012 include $0.3 million for CC&B benchmarking.[592]

Commission findings

691. The Commission considers that AG has not provided an adequate explanation for the forecast increases in the account. The discussion of governance provides no explanation of which accounts are impacted by the governance amounts. In the absence of a satisfactory explanation for the increase, the Commission directs AG to revise its forecasts for Account 710 to the amount calculated as the actual expenditure for 2010 increased by a five per cent per year, to reflect inflation and growth, for each of 2011 and 2012. The $0.3 million for CC&B benchmarking is also approved in 2012.

589 Exhibit 3, AG application, page 4.2-34.
590 Exhibit 110.07, UCA evidence, Q.65 on page 42.
591 AG rebuttal, paragraph 132.
592 Exhibit 218.02, AG reply argument, page 85, paragraph 194.

6.3.15.2 Impact of AMR on meter reading and bill delivery – Account 712

692. AG has requested approval of forecast meter reading and billing delivery costs of $19.7 million in 2011 and $20.5 million in 2012. AG explained that the low use AMR project allows AG to limit its meter reading cost increases during the test years to inflation and step salary increases.[593]

693. AG has proposed a low use AMR project that is expected to result in a decrease in the manual meter reading, with meter readers expected to fill other positions vacated through the significant level of retirements which are expected to occur in the next three to five years. AG assumed that no severance costs will be incurred as a result of this project, through the use of resource planning to provide existing meter readers opportunities to continue employment with AG in other areas of the company. AG indicated that the reduction of meter reading positions is not immediate upon the installation of the new AMR devices for a number of reasons.[594]

Views of the parties

694. The UCA does not object to the AG low use AMR[595] but was concerned that the timing of the reduction in meter reading positions does not reflect the timing of the installation of AMR meters.

695. The UCA indicated that, AG had forecast to have installed AMR devices on 13.79 per cent of its meters by the end of 2011, and 47.13 per cent by the end of 2012.[596] In contrast, AG is forecasting a 2.75 per cent reduction in meter readers in 2011 and an 11.67 per cent reduction in meter readers in 2012,[597] resulting in a proposed reduction in meter readers by AG of 6.1 positions in 2011 and 25.9[598] positions in 2012.[599] If the percentage of meter readers displaced were to match the installation of AMR devices, the UCA submitted that the meter readers should be reduced by 30.6 in 2011 and 104.6 in 2012.[600]

696. The UCA rejected AG's explanations that justified the large discrepancy between the number of meters converted and the reduction in meter reader positions. In its evidence, the UCA recommended a reduction in the forecast meter reading O&M costs of $456,000 for 2011 and $2,997,500 for 2012.[601] The UCA maintained that this is a reasonable estimate, which could represent the upper end of the forecast range of meter reader cost reductions. During the hearing, there was discussion of the possibility of using a mid-year calculation for the reduction in meter reader FTEs.[602] The UCA argued that the mid-year calculation represented a bottom of the forecast range of meter reader cost reductions. The lower end of the range of forecast cost reductions would be $247,500 for 2011 and $1,965,300 for 2012.[603]

593 Exhibit 3, AG application, page 4.1-31, paragraph 88 and Table 42.2.6(a) Customer Accounting Function.
594 UCA-AG-56.
595 Exhibit 110.07, UCA general evidence, A29.
596 Exhibit 110.07, UCA general evidence, A31.
597 Exhibit 110.07, UCA general evidence, A31.
598 The Commission notes that the 25.9 figure is a double counting of the 13 meter readers referred to in the Business case 7 and the 12.9 in response to UCA-AG-49(a) attachment as indicated in UCA evidence response to Question 31.
599 Exhibit 110.07, UCA general evidence, A31.
600 Exhibit 110.07, UCA general evidence, A34.
601 Exhibit 83.01, UCA-AG-56(a) as cited in Exhibit 110.07, UCA general evidence, A34.
602 Transcript, Volume 8, page 1697, lines 2-4.
603 Exhibit 200.02, UCA argument, pages 18-19.

697. The UCA acknowledged its meter reader reduction calculation excluded certain minor incremental O&M costs associated with AMR implementation. The excluded costs relate primarily to increased meter reading requirements related to metscan AMR devices, which the UCA agrees should be reflected in the forecast. Based on the UCA-AG-49(a) Attachment[604] the UCA submitted that the required positive adjustment appears to be approximately $0.1 million in 2011 and $0.2 million in 2012. AG also explained that the $1.3 million of meter reading expense reduction for 2012 was incremental to the reduction in 2011.[605] Accepting that correction the UCA submitted that a further $0.8 million reduction in 2012 meter reading expenses is required. With these various adjustments, the UCA recommended that AG's forecast meter reading expenses should be reduced to $17.8 million in 2011 and $14.7 million in 2012.

698. Calgary submitted that AG's evidence showed that the redeployment of the meter readers is based upon an unknown timetable of retirements, attrition, training time and qualifications of the former meter readers.[606] Calgary submitted that it cannot support the AMR project as proposed, due to the lack of reasonable assurance that the former meter readers will actually assume open positions due to retirement and attrition. Calgary recommended that the cost of the underemployed meter readers should be removed from the revenue requirement. Based upon the proposed number of AMRs to be installed in the test period, and the forecast cost per meter reader, the reductions should be $1.340 million in 2011 and $5.332 million in 2012.[607] If the Commission does not reduce the cost to reflect the redundant or underemployed meter readers, then the program should not be approved. However, Calgary submitted that it could envision, at least, three scenarios under which it could support an AMR program:

1. When a meter reader is no longer required, neither used nor useful, the meter reader could simply be laid off or terminated as is common in industry when an employee's services have been superseded by technology. AG indicates that average severance cost would be around $40,000 per meter reader.[608]
2. If AG desires to retain the now redundant meter readers in a reserve employee status, the fully loaded cost of the meter readers could be booked to a deferral account until such time that the meter reader legitimately assumed a position made available by retirement or attrition. This approach would require that at the next rate case AG provide an analysis of how the forecast compared to the actual retirements or attrition took place, how they were filled and the costs, if any, associated with meter readers assuming those positions and a comparison of all the costs AG proposes to include in it forecast costs for 2011 and 2012.
3. The cost of the underemployed meter readers could simply be removed from the revenue requirement for 2011 and 2012.[609]

699. The CCA agreed with the concerns expressed by the UCA and argued that AG should have more appropriately matched the realization of productivity benefits in 2011 and 2012 via reduced meter readers with the timing of corresponding investments or capital costs associated with the deployment of AMR. The CCA submitted that AG's reasons for delaying the

604 Exhibit 83.01.
605 Exhibit 163.01, AG rebuttal evidence at paragraph 187.
606 Exhibit 82, responses to CAL-AG- 40 and 41.
607 Exhibit 109.02, page 26, footnotes 52 to 54. Average of 82,000 AMR in 2011 and 4500 reads per reader is 18 readers at $74,443 or $1.340 million and in 2012 an average of 318,000 AMRs and using 4,500 reads per reader is 77 readers at $76, 175 is $5.332 million. (The Commission notes that 318,000 divided by 4,500 equals 70 meter readers.)
608 Exhibit 95, CAL-AG-36(b).
609 Exhibit 201.01, Calgary argument, pages 41-42.

recognition of productivity benefits, primarily to 2013 and thereafter, are not supported. The CCA recommended that the labour cost component of Account 712 should be reduced by $0.5 million in 2011 and $3.3 million in 2012. Additionally, the CCA suggested that the supply and software costs corresponding to meter reader position reductions should also be reflected in the refiling of AG's application.[610]

700. In rebuttal evidence, AG stated that a transition period is required to plan, install, commission and verify the new system before the full benefits can be realized.[611] The AMR project will not abruptly make meter readers redundant. It is a four-year project which won't be completed until 2014. Throughout the four years of the project, meter readers will continue to be required to obtain manual meter reads during the transition to 100 per cent AMR. In the early stages meter readers will play a role in the installation program itself. However, the number of meter readers required will decrease slowly as each of the 4,128 meter reading routes is successfully and completely converted to an AMR system.[612]

701. Sites with existing Metscan devices will require manual meter reading once the Metscan device has been replaced with an Itron device, until the new AMR collection process is implemented. This means AG will actually be performing more manual meter reading on its system than it currently does.[613]

702. The transitional nature of the project requires manual meter reading to continue owing to the fact that routes will contain a changing mixture of manual and AMR meter reading. Until such time as 100 per cent of the AMR units have been installed and have been verified to be functioning correctly, manual meter reading will be required to ensure that meter reads continue to be provided on a timely and accurate basis for every customer.[614]

703. AG explained that operational savings forecast related to the installation of AMR in the test years are $0.5 million and $1.3 million in 2011 and 2012 respectively, which are primarily related to the avoidance of six additional meter reading positions in 2011 and a further seven positions in 2012.[615]

704. If the Commission agrees that additional meter reading position reductions should be assumed by AG in its forecasts it must be recognized that not all low use devices will be implemented on January 1st of each year. In 2011 the actual implementation will not commence until the proof of concept stage has been completed, and any required process changes identified, which will be after June 2011. The calculations must reflect the reduction in meter readers AG has already incorporated into its forecasts for 2011 and 2012.[616] Furthermore, AG should be compensated for severance related to those positions. AG submitted that there is no negative impact to customers associated with AG's intention to use meter readers to fill vacant positions as meter readers become available. AG has expressed concern that Calgary's high level

610 Exhibit 204.01, CCA argument, page 23, paragraph 73.
611 Exhibit 163.01, AG rebuttal evidence, page 21, paragraph 71.
612 Exhibit 163.01, AG rebuttal evidence page 21, paragraph 72.
613 Exhibit 163.01, AG rebuttal evidence page 22, paragraph 76.
614 Exhibit 163.01, AG rebuttal evidence page 24, paragraphs 77-78.
615 UAC-AG-49(a).
616 Transcript, Volume 7, page 1582, lines 11-12.

mathematical calculations are fraught with errors.[617] Similarly, AG expressed concerns with respect to the UCA's mathematical calculations regarding meter reading reductions.[618]

Commission findings

705. The interveners recommended adjustments to forecast costs related to the expected reduction in meter readers based on the number of AMR units installed. The Commission agrees that a reduction to AG's forecast meter reading costs is warranted as a number of meter readers will no longer be required.

706. The quantification of the reduction is complicated by the transitional issues associated with AMR installation addressed below and the uncertainty regarding the number and timing of meter reader displacements. AG has proposed to utilize displaced meter readers to address vacant positions within AG due to employee turnover and retirements.[619] The Commission agrees with Calgary that AG's evidence shows that the redeployment of the meter readers is based upon an unknown timetable of retirements, attrition, training time and qualifications of the former meter readers.[620] To the extent that underutilized meter readers move to other existing positions within AG, their wages or salaries, will already be reflected in forecast costs for the position being filled. Failure to recognize the benefit of movement to other positions in 2011 and 2012 results in a duplication of forecast costs. Although Calgary and the UCA have attempted to quantify the impact of redundant meter readers, there are calculation errors in the evidence of both parties.

707. AG has recognized in their cost forecasts the benefits of AMR to the extent that additional meter readers will not be hired to accommodate growth or the additional meter reads required for the Metscan units. AG identified that absent this program an additional 6.1 meter readers would have been required in 2011 and a further 6.8 meter readers in 2012 for a cumulative total of 12.9 FTEs

708. AG's analysis does not reduce the number of meter readers in proportion to the number of meters on which AMR units have been installed. At the end of 2011, approximately 14 per cent of meters will have had AMR units installed and at the end of 2012, 47 per cent of meters will have had AMR units installed.[621]

709. The Commission is prepared to give some weight to the following explanation provided by AG as to why the reduction of meter reading positions is not immediate upon the installation of the new AMR devices:

i. AMR deployment does not begin until April 2011 and the initial work will be done slowly while installation processes are refined.

ii. Meter readers cannot be reduced until enough AMR has been deployed to free them up for a significant number of days in the month, which is achieved through installing AMR over a number of different billing cycles. It will take some time before this can be achieved.

iii. One to three months after the AMR deployment has been completed, the meter readers will have to complete an additional manual meter reading cycle to validate a manual read against the AMR reading.

617 Transcript, Volume 7, pages 1585-1587.
618 Exhibit 163.01, AG rebuttal evidence, page 52, paragraph 185.
619 Exhibit 3, page 1.0-4, paragraph 12.
620 Exhibit 82, responses to CAL-AG- 40 and 41.
621 Exhibit 1, Tab 2.1, Business Case 7, page 33.

iv. 25,000 of the AMR units that will be retrofit in the months of April through August will be in Metscan saturated areas where full manual meter reading has not been required.

v. An increase in customer requests for validation readings may be experienced until customers become more comfortable with the new technology. A manual meter reading will be required to complete these requests.[622]

710. The Commission notes that point i) above relating to starting the installations in April applies only to 2011.[623] Point iv) relating to the replacement of the Metscan meters appears to be addressed in the additional 1.3 positions in 2011 and 2.0 position in 2012 forecast to address the reduction in active metscans. The impact appears to have been addressed by 2012. The remaining points would apply equally to both test years.

711. For 2011, the Commission accepts AG's forecast reductions to meter readers and the related forecast costs based on the explanations provided above. However, by the end of 2012, the Commission notes that 47 per cent of the AMR units will have been installed and that AG has anticipated savings related only to 12.9 meter readers.

712. The Commission has calculated assuming a mid-year installation in 2012 that 318,000[624] meters will have been converted to AMR units by the end of 2012. AG stated that the average meter reader will be able to read 4500 meters per year.[625] Theoretically this represents a reduction of approximately 70 meter readers in 2012. AG has forecast an opportunity savings of 12.9 meter readers, which is 57 less than the theoretical reduction based on the number of meters removed. At a fully loaded cost of $76,175[626] per meter reader an adjustment of approximately $4.3 million would be warranted. The Commission considers the transition factors identified in paragraph 714 and the redeployment of meter readers to other areas or potential severance costs[627] must be considered. Given the lack of detailed information on the record regarding these matters, the Commission recommends a reduction of the estimated $4.3 million by 25 per cent. The Commission directs AG in its compliance filing to reduce the forecast costs for Account 712 by $3.2 million in 2012.

713. The Commission approves AG's forecast meter reading costs for the 2011 and 2012 test years, subject to the adjustments noted above.

622 UCA-AG-56.
623 Application, page 2.1-27, paragraphs 76 and 77.
624 Business Case 7, page 31, 134,000 units installed to the end of 2011 plus 50 per cent of the 348,000 units installed in 2012.
625 Exhibit 82.01 CAL-AG-40(f).
626 Exhibit 82.01 CAL-AG-40(f).
627 Exhibit 95, CAL-AG-36(b).

6.3.15.3 Customer billing and accounting expenses – Account 713

Table 39. Customer billing and accounting

	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
Customers' Billing and Accounting - 713	21,916	2.6%	22,476	23.2%	27,500	2.5%	28,385	2.4%	29,072

714. AG requested that volumes for customer care and billing services (CC&B) as detailed in Tab 4.2 of the application be approved by the Commission. The prices for these services for 2010 and onward will be finalized following the completion of the "ATCO Utilities Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Service Post 2009" (2010 Evergreen) application (Proceeding ID No. 240). AG has forecast CC&B costs of $28.4 million and $29.1 million in 2011 and 2012 respectively. The forecast amounts are slightly higher than the 2010 actual cost of $27.5 million. The 2010 to 2012 forecast for CC&B services is based on the master service agreement (MSA) rates negotiated with ATCO I-Tek Business Services Ltd. The forecast for the test years is based on the forecast volumes provided and the CC&B rates as submitted in the 2010 Evergreen proceeding. The approval of the CC&B MSA, and all rates and terms and conditions contained therein, will be subject of a separate 2010 Evergreen regulatory proceeding.[628] AG requested approval of only the CC&B volumes, and IT volumes as the unit costs or pricing under the MSA is subject to the 2010 Evergreen proceeding.

715. Calgary noted that AG provided the 2008 to 2010 actual and 2011 to 2012 forecast numbers of customers[629] and service accounts,[630] which provided the following annual percentage growths:

Table 40. Customer and service growth

Annual Growth	Customer Growth Percent	Service Account Growth Percent
2008A to 2009A	1.49 %	1.27%
2009A to 2010A	1.92%	1.93%
2010A to 2011F	1.88%	2.74%
2011F to 2012F	2.01%	2.50%

716. Calgary proposed that the Commission use an increase based on a four-year average of customer growth.[631] Calgary recommended that CC&B forecast volumes should be reduced to

628 Exhibit 3, AG application, page 4.2-33, paragraph 91.
629 Year-End Customers: 2008A – 1,022,167, 2009A – 1,037,412, 2010A – 1,057,369, 2011F – 1,077,246, 2012F – 1,098,882 from Volume 1, Tables 7.2 (b) and 7.2 (c) and Exhibit 83.01 UCA-AG-62(a) Attachment 4, page 4, Table 7.2(b) and 7.2(d) Tab.
630 Annual Service Accounts: 2008A – 12,292,475, 2009A – 12,448,977, 2010A – 12,689,445, 2011F – 13,037,528, 2012F – 13,363,464 from Volume 2-1, Tab 4-1 Attachment, Billing Services Tab and Exhibit 171.01.
631 Calgary evidence, page 63, Table 11.

12,961,210 for 2011 and 13,285,241 for 2012 to accord with the customer growth rate forecast by AG.[632]

717. AG submitted that it has developed the forecast for billing volumes for CC&B consistent with past practice, based on the actual service accounts with the incorporation of forecast customer growth plus accounting for the effect of incremental service account activities for customers switching retailers and other service billing events. AG argued that Calgary's recommendation would not result in the service account volumes increasing by the customer growth forecast of two per cent.

Commission findings

718. The Commission is not persuaded by Calgary's recommendation to reduce CC&B volumes in 2011 and 2012 to levels consistent with customer growth as Calgary's recommendation ignores the impact of customers switching retail service providers and potential other billing events. In AUC-AG-78, AG explained that billing units or volumes forecast assumed a 2.5 per cent growth in services account billings. The Commission considers a 2.5 per cent escalation factor is not unreasonable when weighed against customer growth and the impact of other billing system activity.

719. The Commission approves AG's CC&B volumes forecast for 2011 and 2012 of 13,037,528 and 13,363,464 respectively. As noted earlier, the approval of the CC&B MSA, and all rates, terms and conditions is the subject of a separate 2010 Evergreen proceeding. AG's forecast I-Tek CC&B costs of $28.4 million and $29.1 million in 2011 and 2012 are considered placeholders pending Commission determination with respect to the 2010 Evergreen proceeding.

6.3.15.4 Credit and collection – Account 714 and Account 718 – uncollected accounts

720. These accounts were not discussed by AG in the application. The Commission has reviewed the forecasts against actual expenditures in 2008 to 2010 and finds that AG's forecast costs are reasonable. The forecast costs for accounts 714 and 718 are approved as filed.

6.4 Administration and general function

721. AG explained that this function includes costs incurred in the general administration of the company as well as support costs that are not chargeable to a specific operating function. Table 40 below shows the actual costs for the administration and general function for 2008 to 2010, and the forecast amounts for 2011 and 2012.[633]

[632] Exhibit 109.02, Calgary written evidence, page 62.
[633] Exhibit 161.03, AUC-AG-113 Attachment.

Table 41. Administration and general function

O&M Total	2008 Actuals ($000)	2009 Actual vs 2008 Actual	2009 Actuals ($000)	2010 Actual vs 2009 Actual	2010 Actuals ($000)	2011 Forecast vs 2010 Actual	2011 Forecast ($000)	2012 Forecast vs 2011 Forecast	2012 Forecast ($000)
ADMINISTRATIVE									
Labour	14,591	2.5%	14,955	-3.7%	14,400	19.8%	17,245	3.8%	17,904
Supplies	61,051	1.3%	61,859	32.9%	82,200	11.5%	91,616	0.0%	91,626
Total	**75,642**	1.5%	**76,814**	25.8%	**96,600**	12.7%	**108,861**	0.6%	**109,530**
Administrative Expense -721	52,291	1.7%	53,179	5.5%	56,100	12.1%	62,884	3.6%	65,131
Special Services - 722	574	134.7%	1,347	-40.6%	800	43.3%	1,146	5.0%	1,203
Insurance - 723	1,271	7.2%	1,363	-4.6%	1,300	5.2%	1,367	-1.0%	1,353
Injuries and Damages -724	1,327	-60.7%	522	-4.2%	500	4.4%	522	0.0%	522
Employee Benefits - 725	16,143	1.8%	16,436	97.7%	32,500	8.6%	35,294	-4.5%	33,700
Other Administrative & General Expenses - 728	4,037	-1.7%	3,967	36.1%	5,400	41.6%	7,648	-0.4%	7,621
Total	**75,642**	1.5%	**76,814**	25.8%	**96,600**	12.7%	**108,861**	0.6%	**109,530**

6.4.1 Administrative expense – Account 721

722. The administrative expense includes a number of support costs that are not chargeable to a specific operating function. AG is requesting approval of forecast costs for administrative expense of $63.5 million in 2011 and $65.2 million in 2012.

Table 42. Administrative expense

	2008[634] Forecast ($million)	2008[635] Actual ($million)	2009[636] Forecast ($million)	2009[637] Actual ($million)	2010[638] Forecast ($million)	2010[639] Actual ($million)	2011[640] Forecast ($million)	2012[641] Forecast ($million)
Labour	14	13.8	15.5	14.0	14.0	13.5	17.3	17.8
I-Tek	14	14.7	17.8	16.6	19.8	18.8	20.5	20.8
Office Rent	8	8.6	9.5	9.4	9.5	9.4	9.6	9.8
ATCO Corp. Services	6.8	7.6	7.1	7.8	7.9	8.1	8.4	8.6
Stationary Printing Photocopier	1.4	1.1	1.4	0.8	0.9	0.9	1.0	1.0
Aircraft	0.4	1.0	0.5	0.9	0.6	0.4	0.5	0.5
Relocation	1.6	1.1	1.6	0.6	1.0	1.0	1.0	1.0
Facilities Management	0.9	1.0	0.9	1.0	0.9	0.9	0.9	1.1
Advertising	1.3	0.5	1.3	0.4	0.2	0.2	0.5	0.5
Other	2.6	2.9	2.9	1.7	2.2	2.9	3.8	4.1
Total	**51.0**	**52.3**	**58.5**	**53.2**	**57.0**	**56.1**	**63.5**	**65.2**

6.4.2 Administrative labour

723. The majority of the increase in administrative labour is due to a forecast increase in labour. AG forecast an increase in administrative labour expense from 2010 actual costs to 2011 forecast cost of $3.8 million or approximately 28 per cent with an additional increase of approximately $0.5 million in 2012. AG identified the primary drivers of its forecast cost increases related to administrative labour:

- inflation for $0.4 million in 2011 and $0.5 million in 2012
- the filling of vacancies and growth positions for $1.7 million in 2011, and
- $1.1 million in 2011 is associated with increased Variable Pay Program ("VPP") costs[642]

634 Exhibit 4, GRA Volume 2-1, Tab 8.2.2.
635 Exhibit 3, GRA Volume 1.0, Table 4.2.2.7(b).
636 Exhibit 4, GRA Volume 2-1, Tab 8.2.2.
637 Exhibit 3, GRA Volume 1.0, Table 4.2.2.7(b).
638 Ibid.
639 Exhibit 83.01, UCA-AG-62(a) attachment 2.
640 Exhibit 3, GRA Volume 1.0, Table 4.2.2.7(b).
641 Ibid.

724. The UCA noted that AG's "Administrative Expense – Labour" category increased significantly over the forecast labour inflation rate of three per cent.[643] The UCA acknowledged that part of this increase was due to the VPP. While AG attributes cost increases to employee turnover associated with an aging workforce, the UCA submitted that AG presented no analysis or study demonstrating that employee turnover, let alone forecast increased retirements, has a negative impact on AG. AG also failed to provide any analysis of whether the replacement of older retiring employees by younger workers would or could result in lower total wages and salaries or benefits costs.[644]

725. Absent any evidence on these issues, the UCA has assumed a generic wage inflation factor that would not be sensitive to changes of that kind.[645] The UCA suggested that AG has not identified any changed circumstances or external factors to support the forecast cost increase of $3.3 million or 28 per cent. The UCA also considered that the VPP is simply a form of labour expense where any increases are already accounted for in the relevant inflation estimates.[646] The UCA recommended that administrative expense labour be reduced to $13.9 million in 2011 and $14.3 million in 2012.[647]

726. Calgary suggested that given the minimal growth in customers, throughput and demand that AG should be able to operate in its test years with the same level of FTE's that it did in 2010.[648]

727. In its rebuttal evidence and in testimony, AG explained that the key reasons for the increase in administrative labour expense forecast of $3 million and $0.5 million in 2011 and 2012 respectively were:

- Inflation of three per cent which was not objected to by either the UCA or Calgary.
- VPP increases, where the $1.1 million increase in 2011 represents the impact of the proposed expansion of the VPP. The increase relates to moving from 118.6 positions in 2010 to 130.6 positions in 2011 and also the component of VPP relating to net income.
- Growth positions, where the $0.6 million is comprised of three accountants and seven administrative support positions.
- Vacancies – In the 2010 GRA forecast there were 13 vacant positions that were forecasted to be filled in 2011. These positions relate to staff that have been on maternity leave, been promoted and moved into other areas within the organization or to other companies.[649] At the hearing in response to questioning by the UCA's counsel, Mr. Cook stated,[650] seven of the vacant positions have been filled to date, four positions are currently being recruited and two others are maternity leaves that are returning in the June/July timeframe.

642 Exhibit 163.01, rebuttal evidence, at paragraph 233.
643 See Exhibit 110.07, UCA general evidence at page 40, Q. 63.
644 As suggested by the UCA at Exhibit 110.07, UCA general evidence, page 36, Q.54.
645 UCA argument, pages 34-35.
646 UCA evidence, pages 40 and 41.
647 Exhibit 142.02, AUC-UCA-A6 Attachment, UCA proposed reductions to ATCO Gas O&M.
648 Calgary evidence, page 15.
649 Exhibit 163.01, AG rebuttal evidence, pages 61-63.
650 Transcript, Volume 2, page 312, lines 16-20.

728. AG disagreed with the UCA that 2010 was a good base year to use as 2010 was an anomaly with low retirements and turnover as a result of the recession. AG argued that its 2011 and 2012 forecasts should not be adjusted because the stable workforce experienced in 2010 is no longer occurring.[651]

729. AG has forecasted an increase in retirements of 10 per cent in 2011 and 50 per cent in 2012.[652] Furthermore, those retirement forecasts are conservative when compared to the number of employees eligible to retire in those years.[653] AG submitted that it has demonstrated that a considerably lower level of turnover was experienced in 2009 and 2010.[654]

Commission findings

730. AG explained that 2009 to 2010 was a period of lower level employee turnover and that it expected retirements to be a key cost driver for cost increases in 2011 and 2012. The Commission has reviewed AG's explanation of the various cost drivers for the increases associated with administrative labour and considers that AG has failed to adequately justify the increase in forecast costs associated with this account. Given the minimal growth in customers, throughput and demand, the Commission is not persuaded that there has been a significant change in circumstances between 2010 and 2011. The Commission finds that the increase in administrative labour should be limited to an adjustment for inflation and growth of 5 per cent per year, except for the variable pay which is addressed below.

731. AG is directed to revise its 2011 and 2012 forecast for administrative labour, excluding the VPP component, utilizing AG's 2010 actual costs increased by five per cent per year.

6.4.3 Variable pay program

732. AG has forecasted an increase in its variable pay program (VPP) costs of approximately $1.1 million for both the 2011 and 2012 test years.[655]

733. AG noted that in Decision 2008-113,[656] the Commission approved the expansion of the VPP to 396 supervisory positions in 2008 and 404 supervisory positions in 2009. The Commission also upheld the continued use of deferral account treatment for payments made under the plan. However, AG is seeking a change to that deferral account process.[657]

734. In Decision 2008-113, the Commission clarified that the deferral account for the VPP was only for the difference between the amount forecast to be paid out to the 15 employees included in the VPP forecast and the actual amount paid out. AG was not allowed to recover the cost of the VPP paid out to 19 additional employees in 2006 and 22 additional employees in 2007. The AUC acknowledged the clarification of its decision was not explicit in

651 UCA argument, page 34, paragraph 116.
652 AG rebuttal evidence, page 57, paragraphs 209 to 211.
653 AG rebuttal evidence, page 57, paragraph 211.
654 AG rebuttal evidence, page 57, paragraph 212.
655 Exhibit 3, AG application, page 4.1-11, Table 4.1.6 Deferred VPP Costs.
656 Decision 2008-113: ATCO Gas 2008-2009 General Rate Application Phase I, Application No. 1553052, Proceeding ID. 11, November 13, 2008.
657 Exhibit 3, AG application, page 4.1-9, paragraph 16.

Decision 2006-004.[658] AG stated that as a result of the clarification AG was required to absorb $0.3 million of VPP expense.[659]

735. AG cited Decision 2010-189,[660] in which the Commission reviewed the factors used to evaluate the appropriateness of a deferral account. AG submitted that the deferral account for VPP is not symmetrical. It can only provide symmetry if it addresses the requirement for AG to expand or contract the number of employees eligible for the plan as circumstances dictate. This will be especially important once AG's rates are determined through a performance-based regulation plan. AG therefore requested that the deferral account be treated in the same fashion as the majority of AG's other approved deferral accounts. AG is requesting that all differences from the amounts included in AG's approved revenue requirement with respect to VPP will be deferred, whether those amounts be higher or lower than forecast, and whether AG has expanded or contracted the number of employees eligible for VPP.[661]

736. AG has not expanded VPP to the extent forecast in the 2008/2009 GRA because the economic downturn warranted a more measured approach to the expansion. As a result, AG is proposing a one-time $1.9 million true-up in 2011 that is payable to customers. AG is forecasting a continued modest expansion of VPP, moving from 118.6 positions in 2010 to 140.6 positions in 2012. Included in the forecast for 2011 and 2012 is the component of VPP relating to net income. This represents $0.8 million of the total VPP forecast to be paid out in each of 2011 and 2012. The balance of the VPP relates to the achievement of operational metrics.[662]

737. The UCA does not support including increased amounts to reflect the addition of new participants to the program in the O&M forecast.[663] The UCA has accepted a three per cent increase in unit labour costs as being reasonably reflective of market conditions. The fact that the Commission has previously approved significant potential increases in the number of employees that participate in VPP should not, in the UCA's submission, be interpreted as pre-approval of whatever incremental costs AG might incur by adding more employees to the program.[664]

738. The UCA noted that Decision 2011-134[665] approved the inclusion of a net income component in the ATCO Electric VPP, with the conditions that the components reflect only ATCO Electric's net income and that the net income component not exceed 10 per cent of the program total. That approach was premised on the idea that net income components in variable pay programs can lead to operational efficiencies that ultimately benefit customers. If a 10 per cent limitation is appropriate for rate-making purposes, as it was for ATCO Electric, that condition should be imposed effective January 1, 2011 and the allowed amount adjusted accordingly. In this application,[666] AG also requested changes in the operation of the deferral

658 Decision 2008-113, page 65.
659 Exhibit 3, AG application, page 4.1-9, paragraph 17.
660 Decision 2010-189: ATCO Utilities Pension Common Matters Application No.1605254, Proceeding ID. 226, April 30, 2010, paragraphs 72-73.
661 Exhibit 3, AG application, page 4.1-10, paragraph 19.
662 Exhibit 3, AG application, page 4.1-10, paragraph 20.
663 UCA argument, page 47, paragraph 162.
664 UCA argument, page 47, paragraph 163.
665 Decision 2011-134: ATCO Electric Ltd. 2011-2012 Phase I Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011, page 62, paragraph 309.
666 Exhibit 3, AG application, Volume 1 at pages 4.1-9 and 4.1-10.

account related to VPP. The UCA does not support any changes to the operation of the VPP deferral account.

739. The CCA considered that AG should be limited to both a 10 per cent overall VPP program tied to AG net income and each individual participant in the program. The CCA is concerned that AG was counting on adding additional employees to the VPP. This would have the effect of weighting the current employees in the VPP down to the level of 10 per cent of AG's net income. The CCA considered that AG should not be able to undertake changes which undo the AUC's reasoning in AltaLink Decision 2009-151[667] by increasing the number of employees in the program.[668] VPP programs which are tied to net income of a utility benefit the shareholders of the utility, not the customers.The CCA would prefer that no part of the bonus system be based on a utility's net income. The CCA considered that customers benefit when VPP programs are tied to low customer rates, high service standards and safety.

740. The CCA recommended that the forecast O&M expense should be reduced by $950,000 per year, the amount by which AG over-forecast the expense in 2008 to 2010. This recommendation is in addition to the one time adjustment.[669]

741. The CCA submitted that AG has not justified an increase in the number of employees eligible for VPP and that the number of FTEs eligible should be capped at the 2010 number of 118.6.[670]

742. The CCA argued that customers should be protected from unnecessary expansion of the VPP program and growth of the deferral account. The CCA submitted that this deferral account should have a set maximum relative to the total O&M and capital expense per year. In any event, excess expenses should be returned to customers. The CCA considers this is appropriate because AG has control over payments from the account, unlike other deferral accounts.

743. The CCA objected to the change in the ratio of funding between capital and O&M for this account. The CCA noted that for 2009 actual and 2010 forecast, 65 per cent of the provision was expensed to O&M, while 35 per cent was capitalized. AG applied to change this ratio to 83per cent and 17 per cent.[671] The CCA considered that 65 per cent of this account should continue to be attributed to O&M and 35 per cent to capital.[672]

744. AG noted that ATCO Electric can now be added to the list of utilities with a net income component included in their VPP as per Decision 2011-134. That decision directed ATCO Electric to ensure that the net income component of VPP relates to ATCO Electric earnings and not ATCO Group earnings. AG has reflected consistency with Decision 2011-134 by only including net income related to AG's earnings. AG has forecasted its VPP to reflect a 10 per cent net income component based on the net income of AG consistent with Decision 2011-134, as

[667] Decision 2009-151: AltaLink Management Ltd. and TransAlta Corporation 2009 and 2010 Transmission Facility Owner Tariffs, Application No. 1587092, Application No. 1594573, Proceeding ID. 102, October 2, 2009.
[668] Exhibit 204.01, CCA argument, page 33, paragraph 100.
[669] Exhibit 204.0,1 CCA argument, page 34, paragraph 102.
[670] Exhibit 204.01, CCA argument, page 353, paragraph 105.
[671] 2,600,000/(2,600,000+525,000) and 525,000/(2,600,000+525,000).
[672] Exhibit 204.01, CCA argument, pages 34-35, paragraph 104.

detailed in Exhibit 174.[673] AG argued that setting maximum weightings or limits on any one individual's set of performance objectives would in effect be micromanagement.[674]

745. AG noted that the CCA had proposed a reduction to the VPP expense of $950,000 in each of 2011 and 2012, which related to excess VPP accruals not paid out to employees. This proposed adjustment would be in addition to the one time adjustment requested by AG related to VPP.[675] AG argued that this would require it to fund VPP on its own, which would require an adjustment to its working capital.

746. Finally, the CCA objected to the proposed change in allocation of VPP between O&M and capital.[676] AG noted that the allocation is consistent with the allocation of labour costs related to specific VPP employees. The allocation of VPP costs will be adjusted to be consistent with actual VPP payments, and adjusted in the deferral account.

747. AG submitted that its VPP forecast should be approved as filed.

Commission finding

748. In Decision 2011-134 the Commission approved the inclusion of a net income component in the ATCO Electric VPP, with the conditions that the components reflect only ATCO Electric's net income and that the net income component not exceed 10 per cent of the program total.[677] In Decision 2009-151, the Commission also approved a net income goal of 10 per cent for AltaLink's short term incentive plan[678] and an earnings component of EDTI's short-term incentive program in Decision 2010-505.[679]

749. AG is requesting approval of a VPP with a 10 per cent net income component based on the net income of AG. The Commission is concerned that allowing a 10 per cent net income component based on total forecast VPP may result in specific individuals receiving compensation that unreasonably weights VPP towards income targets that might be a detriment to customers' interests and operation measures.

750. In AG's application and as explained in AUC-AG-58(c),[680] AG initially proposed an overall net income performance component of 27 per cent for the test years. For officers, the net income performance component was 52 per cent of their target VPP. For top-level managers, approximately 50 per cent had a net income performance component, which accounted for up to 50 per cent of their target VPP. For the remaining VPP eligible employees there was no net income performance component.

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673 Exhibit 174, Schedule 1.6-A, line 22.
674 Exhibit 203.01, AG argument, page 74, paragraph 190.
675 Exhibit 204.01, CCA argument, page 34, paragraph 102.
676 Exhibit 204.01, CCA argument, page 34, paragraph 104.
677 Decision 2011-134, page 62, paragraph 309.
678 Decision, 2009-151: AltaLink Management Ltd. and TransAlta Corporation, 2009 and 2010 Transmission Facility Owner Tariffs, Application No. 1587092, Application No. 1594573, Proceeding ID. 102, October 2, 2009, page 22, paragraphs 120-122.
679 Decision 2010-505: EPCOR Distribution and Transmission Inc. 2010-2011 Phase I Distribution Tariff, 2010-2011 Transmission Facility Owner Tariff, Application No. 1605759, Proceeding ID 437, October 28, 2010, paragraph 208.
680 Exhibit 84.01, AUC-AG-58(c).

751. The Commission finds that the inclusion of net income component within a VPP is reasonable when there is a balance struck between the benefits that customers may receive through reduced costs versus increased earnings for the benefit of shareholders. A net income component greater than 10 per cent for officers and senior managers might result an inherent conflict between shareholder interests and customers. The Commission finds that setting limits to individual performance objectives will ensure that management is not incented to maximize shareholder value at the expense of customers. If AG wishes to include a net income component for specific individuals higher than 10 per cent of their VPP compensation, those costs are to be borne by shareholders. AG is directed to revise its VPP forecast to reflect a maximum individual net income component of VPP of 10 per cent in its compliance filing to this decision with a supporting explanation to its revised VPP forecast.

752. With regard to AG's forecasted increases in 2011 and 2012 for VPP, the Commission concurs with the UCA that AG did not justify an increase to the VPP forecast cost in excess of inflation. In its April 21 update,[681] AG revised its forecast inflation rate for supervisory labour in 2012 to 4.0 per cent. The Commission finds that AG's four per cent inflationary adjustment for supervisory labour for 2012 is reasonable. The Commission directs AG in its compliance filing to revise its forecast VPP for 2011 by utilizing the 2010 forecast cost (which is consistent with the 2009 actual expense) by three per cent for 2011 and increasing the 2011 amount by four per cent for 2012.[682]

753. The Commission approves the forecast costs for VPP expense and the forecast increase in eligible positions, moving from 118.6 positions in 2010 to140.6 positions in 2012.

754. AG applied to revise its existing VPP deferral account based on an asymmetrical methodology to a fully symmetrical deferral account. The VPP is controlled by the utility, who determines which employees are eligible to receive payments and the basis on which those payments will be calculated, subject to the 10 per cent net income component set by the Commission. If the utility had the discretion to increase the variable pay program costs and participants, customers would be exposed to a significant risk of additional costs. The Commission is not persuaded that a change in the deferral account is required, and finds that the status quo parameters of AG's VPP deferral account should be maintained.

755. The Commission approves the one-time payment to customers of $1.9 million in 2011 to true-up the deferral account balance.

756. With regard to the CCA's recommendation on the allocation of VPP expenses between O&M and capital, the Commission is satisfied with AG's explanation that AG reconciles the difference between the actual VPP and forecast, and that reconciliation will reflect the actual weighting between O&M and capital.

6.4.4 Administrative expense – office rent – Account 721

757. AG has requested approval of forecast costs for office rent of $9.6 million and $9.8 million in 2011 and 2012 respectively.[683] AG requested a deferral account to address any

[681] Exhibit 118.01, ATCO April 21 update, at page 4.
[682] Exhibit 3, page 4.1-11, Table 4.1.6 Deferred VPP costs.
[683] Exhibit 3, application, Table 4.2.2. 7(b) Administrative Expense (Account 721).

difference between the forecast and the actual lease rate for the ATCO Center in Calgary similar to what was done for the expiry of the ATCO Centre Edmonton lease.[684]

758. AG indicated that it entered into a new 10-year lease for the ATCO Centre in Edmonton effective December 1, 2008 at a starting lease rate of $25.00 per square foot as well as a five-year lease for the Milner Building space effective January 1, 2009 at a rate of $21.00 per square foot. AG received Commission approval for a temporary deferral account[685] for the difference between the approved forecast rate and the actual rate. The increase in rent costs for 2009 over 2008 was primarily due to the new lease rates for ATCO Centre Edmonton and the Milner Building. Forecast increases in rent costs from 2010 to 2012 relate to operating cost increases.

759. AG's lease of certain floors in the ATCO Centre in Calgary expires October 1, 2011. AG stated that it had no binding agreement to extend the term of the lease[686] but that the rent will be subject to a third party appraisal fairly close to the time that the lease will expire agreed to by all parties.[687] AG has used the previously approved rate of $14.50 per sq/ft to forecast lease costs in the test years for the ATCO Center Calgary. AG requested a deferral account to address any difference in the forecast and the actual lease rate for the ATCO Center in Calgary. AG stated that it could potentially finalize this matter in its compliance filing for this GRA[688] and that would be its intention.[689] AG submitted that if the Commission does not agree that any further proceeding to review the lease rate should occur, and that no deferral account is to be used, then AG must be allowed the right to update its placeholder lease rate, which is currently based on the last approved lease rate.

760. Calgary recommended that the Commission deny AG's request for a deferral account to address any difference in the forecast and actual lease rate for the ATCO Centre in Calgary, and that the rate approved by the Commission should be no greater than the current rate.[690] Calgary stated that it appeared AG made up its mind not to change locations and was prepared to pay whatever rent the landlord required. It does not appear that AG did any analysis to determine whether a general review of market rents was applicable as an alternative to remaining in the ATCO Centre in a period of 10 per cent plus vacancy rates in Calgary.[691] Calgary submitted that the justification for a deferral account has not been met, and it might be argued that a prudent person would not take the types of risk that AG is proposing with respect to required office space in Calgary.

761. In rebuttal evidence, AG explained that office space alternatives generally must be pursued one to two years before the space is required. AG is undergoing significant changes with regard to some of its capital and maintenance programs, the low use AMR project has commenced, which as discussed above is a complex undertaking, AG adopted International Financial Reporting Standards (IFRS) in 2011, and it is experiencing one of the heaviest regulatory schedules in its history. A move to a new facility within a year or less is not a viable

684 Exhibit 3, application, page 4.2-38, paragraph 103.
685 Decision 2009-109, Direction 21 at Tab 1 in application.
686 Transcript, Volume 4, page 684, lines 14-19.
687 Transcript, Volume 4, page 683, lines 17-24.
688 Transcript, Volume 6, page 1271, lines 5-10.
689 Exhibit 163.01, AG argument, paragraph 191.
690 AUC-CAL-5 (c).
691 Exhibit 109.02, Calgary evidence, page 12, Q.13.

option for AG when one considers these matters. AG cannot put its business on hold because it has a lease renewal coming up. Furthermore, the 55,000 square feet of contiguous office space required by AG is not readily available in the Beltline office market, which generally means that AG would have to consider a move to downtown Calgary, with higher lease rates. AG would have to incur leasehold improvement costs and moving costs, while also continuing to recover existing leasehold improvement costs for the Calgary ATCO Centre. AG would also have to incur lease costs for the new facility while still incurring lease costs related to the existing facility in order to facilitate the move. Calgary has factored none of these considerations into its recommendation.

762. In its response to AUC-CAL-5, Calgary provided a publication from Barclay Street Real Estate Ltd. for the fourth quarter of 2010. AG submitted that its actions should not be judged on the basis of information that it could not act upon without a major disruption of its business. The Barclay Street publication provided by Calgary does not give any indication of the contiguity of the vacant space in the Beltline.

763. AG also notes that in AUC-CAL-5(c) Calgary suggests that ATCO Centre would not be considered a Class A building and indicates that the maximum lease rate should be based on the Class B rate in the Barclay Street publication of $12 per square foot. AG notes that in the Beltline, ATCO Centre is considered a Class A building. According to the Barclay Street publication, average lease rates for Class A buildings in the Beltline in 2009 were $20 to $25 per square foot. As at the fourth quarter of 2010, the Barclay Street publication cites lease rates of $16 to $20 per square foot. Calgary has made no provision to account for the impact of additional costs that AG would be required to incur.

764. In its evidence at page 12, lines 19 and 20, Calgary indicates that by waiting to renegotiate the lease, AG is essentially prepared to pay whatever rent the landlord seeks. AG argued that this is a false characterization of the facts. A market assessment will be performed by a third party shortly before the lease expiry. AG will file that market assessment as support for the new lease rate in a future regulatory proceeding. AG views that this matter would be better addressed once the final lease rate is known.[692]

Commission findings

765. The Commission recognizes that AG might have been challenged to find 55,000 square feet of lease space to meet its needs in the Beltline area of Calgary and that a move of this size would offer operational challenges for AG. However, the Commission is not persuaded that AG investigated all lease options, including space outside of the Beltline. AG should have taken steps to address its lease requirements on a timely basis and weigh the cost/benefits of continuing its lease at the ATCO Centre in Calgary versus other alternatives.

766. The Commission considers that a lease or lease extension should have been negotiated well before the expiry of the lease term. The record indicates that leases are typically negotiated one to two years in advance of expiry. Failure to do this limits AG’s options and hence impacts its ability to negotiate leasing arrangements. In these circumstances, the Commission does not consider that a deferral account is warranted. Further the Commission does not consider that the actual rate should be accepted as the basis for the revenue requirement.

[692] AG rebuttal evidence, paragraph 204.

767. The Fourth Quarter 2010 Office Space Review indicates rents in the Beltline have declined throughout 2010. Average rates for Class A buildings decreased from $20 to $25 per square foot to $22 to $24 per square foot. Class B building rents decreased from a range of $13 to $17 per square foot in 2009 to a range of $11 to $14 per square foot in 2010. AG indicated that the ATCO Centre is a Class A building while Calgary indicates that the ATCO Centre is a Class B building. The Commission notes that AG's rental rate during 2009 was $14.50 per square foot which is mid-range for Class B buildings for that year. The Commission also notes that the Barclay Street publication repoed a downward pressure on rents at that time and that the range of rents for all classes of building space had decreased. However, the Commission agrees with AG that there would be significant costs both out of pocket and from operational disruptions which should be considered if AG were to move to other premises.

768. Weighing all the above factors the Commission considers that the existing rental rate should be used for the revenue requirement in 2011 with a three per cent escalation for inflation in 2012.

769. AG is directed in the compliance filing to this decision to include in its revenue requirement a rental rate for 2011 of $14.50. For 2012, rent should be forecast based on $14.50 per square foot increased by a three per cent inflation factor.

6.4.5 ATCO corporate aircraft and office costs – Account 721

770. ATCO corporate services (corporate or head office costs) costs are allocated using a methodology which was recently approved by the AUC in Decision 2010-447.[693] This methodology is based on revenues, total assets and capital expenditures to allocate corporate office costs to the operating entities. Inflation rates for corporate services costs are forecast at three per cent for both of the test years.[694] Both corporate office costs and aircraft cost are determined through the approved allocation methodology. As noted previously, the next corporate cost allocation methodology proceeding has been advanced to advanced to April 2, 2012. Consequently, the 2012 forecast amount for this account will be a placeholder.

6.4.5.1 ATCO corporate office costs – Account 721

771. AG has requested approval of forecasted corporate services costs for 2011 and 2012 of $8.6 million and $8.8 million respectively.[695]

772. AG submitted that in the preparation of its GRA, it reviewed relevant decisions issued by the Commission since the release of Decision 2008-113 (Decisions 2009-087,[696] 2010-447 and 2011-134), for relevance in this application.[697] AG submitted that corporate costs and related cost increases for the 2009 and 2010 years had been reviewed and approved by the Commission for ATCO Electric in Decision 2009-087. AG submitted that in light of the ATCO Electric approval for the very same corporate office costs, and the immateriality of the increases in these costs in 2011 which AG has supported, these costs should be approved as forecast. AG noted that the

[693] Decision 2010-447: ATCO Utilities Corporate Cost Allocation Methodology, Application No. 1605473. Proceeding ID. 306, September 20, 2010.
[694] Exhibit 3, application, page 4.2-39, paragraph 105.
[695] Exhibit 3, application, page 4.2-39, Table 4.2.2.7(d).
[696] Decision 2009-087: ATCO Electric Ltd. 2008-2009 General Tariff Application-Phase I, Application No. 1578371, Proceeding ID. 86, July 2, 2009.
[697] AG rebuttal evidence, pages 66-67.

Commission approved the head office costs for ATCO Electric for 2011 and 2012 in Decision 2011-134.[698]

773. The UCA expressed its concern with respect to the transparency and justification of inter-affiliate costs and noted that the Commission's predecessor and the Commission have expressed concerns in Decisions 2002-069,[699] and 2008-113. The UCA submitted that over time, there have been significant increases in head office costs with little or no detailed visibility into the nature and magnitude of various costs.[700]

774. The UCA submitted that the reference by AG in rebuttal to Decision 2009-087 regarding the approval of corporate costs for ATCO Electric for the 2009 and 2010 revenue requirements is not relevant.

775. Based on AG's history of providing insufficient detail for inter-affiliate costs, and actual costs being above approved costs for 2008-2009 by approximately 11 per cent, the UCA recommended reductions to head office costs of $921,000 in 2011 and $945,000 in 2012.[701]

776. With respect to future proceedings, the UCA recommended that AG must provide more detailed analysis of the head office costs it recovers from customers, and that:

- time spent on business development should be tracked
- business development costs should not be recovered from customers
- advertising costs should not be recovered from customers
- other inappropriate costs should be identified and removed from revenue requirement[702]

777. In evidence Calgary supported the recommendations of the UCA.

778. The UCA expressed concern with the proposed allocated corporate advertising costs. AG is forecasting its share of advertising costs will be $73,000 in 2011 and $75,000 in 2012.[703] This advertising includes items such as Calgary Flames, North of 60, and Spruce Meadows,[704] none of which should be paid by AG customers. The largest item is for "Other," which includes newspapers, magazines, journals, banners, and visual media.[705] This broad category also should be excluded.

Commission findings

779. As noted previously 2012 forecast costs for Account 721 are placeholders.

780. The Commission relies on the approval of the corporate cost allocation methodology in Decision 2010-447 for 2011. The Commission has reviewed the corporate costs in Table 42, Administrative expense and notes that actual costs for 2008, 2009 and 2010 exceeded forecasts.

698 AG argument, paragraph 198.
699 Decision 2002-069: ATCO Group Affiliate Transactions and Code of Conduct Proceeding, Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues, Application No. 1237673, July 26, 2002, page 92.
700 Exhibit 200.02, UCA argument, page 55.
701 Exhibit 110.07, UCA general evidence, A125.
702 Exhibit 200.01, UCA argument, page 67, paragraph 224.
703 Exhibit 0110.07, UCA general evidence, A120.
704 Exhibit 0083.01, UCA-AG-67(e).
705 Ibid.

However, for 2008 an explanation of the variance is provided.[706] The Commission accepts AG's explanation and considers that the increase, which was with respect to HRX, would be a recurring cost. A comparison of actual 2008 costs to forecast 2011 costs is an increase of 10.5 per cent over a three-year period. The Commission considers an increase of approximately 3.5 per cent per year to be reasonable. However, the Commission agrees that the $73,000 for 2011 and $75,000 for 2012 of allocated corporate advertising, as noted above by the UCA, should not have been included in the corporate costs and directs that this amount should be removed.

781. The Commission is satisfied that except as noted above for advertising, AG's forecast corporate office costs for 2011 are reasonable. The Commission notes that the same costs formed part of the 2011 revenue requirement for ATCO Electric in Decision 2011-134.

6.4.5.2 Aircraft costs

782. AG has forecasted corporate aircraft costs of $.5 million in each of 2011 and 2012. Corporate aircraft costs reflect AG's direct use of the corporate aircraft. Fixed costs relating to the head office use of the corporate aircraft were charged to corporate aircraft in 2008 and 2009; effective 2010 they are charged to ATCO corporate services and allocated to AG.[707]

783. The UCA noted that there is an inconsistent record on the issue of the allocation of fixed costs. Decisions 2007-071,[708] 2007-104,[709] and 2008-113[710] indicated that the fixed aircraft costs allocated to the Office of the Chair (OOC) should be a shareholder cost. In Decision 2011-134,[711] the Commission approved these costs for ATCO Electric. The UCA requested that the Commission reconfirm its earlier position that the reallocation of fixed costs related to the use of aircraft by the OOC be disallowed. The UCA submitted that the forecast costs should be reduced by $391,000 in 2011 and $401,000 in 2012 to remove the fixed costs of the Citation X aircraft.[712]

784. AG argued that its forecast aircraft costs for 20011 and 2012 are consistent with the corporate aircraft costs accepted in Decision 2011-134.[713]

Commission findings

785. With respect to aircraft costs, in Decision 2011-134 the Commission noted that the inclusion of the fixed costs of the Citation X to the OOC is consistent with the corporate allocation methodology approved in Decision 2010-447. There is a benefit to ATCO Electric from the use of the aircraft and the Commission found that ATCO Electric had complied with its intent in Decision 2007-071.

786. Although Decision 2011-134 dealt specifically with ATCO Electric, the Commission notes that the it relied on the allocation methodology approved in Decision 2010-447 that also

[706] Application, Tab 8.1, Attachment page 46 of 139. "Increase due to Oracle HRX which was not in forecast."
[707] Exhibit 3, application, page 4.2-40, paragraph 110.
[708] Decision 2007-071: ATCO Electric Ltd., 2007-2008 General Tariff Application – Phase I, Application No. 1485740, September 22, 2007, page 121.
[709] Decision 2007-104: ATCO Electric Ltd., 2007-2008 General Tariff Application – Refiling, Application No. 1544572, December 21, 2007, page 12.
[710] Decision 2008-113, page 68.
[711] Exhibit 163.01, AG rebuttal evidence, paragraph 253.
[712] Exhibit 200.02, UCA argument, page 52, paragraphs 180-181.
[713] Exhibit 203.01, AG argument, pages 75-76, paragraph 194.

applies to AG. The Commission considers that there is no evidence on the record of the current proceeding to support a different treatment for AG. As such, the Commission finds that including Citation X fixed costs in AG's forecasted expenses is reasonable. As aircraft costs are subject to corporate cost allocation, aircraft costs for 2012 are subject to placeholder treatment, pending the outcome of ATCO Utilities Corporate Office costs and the Allocation Methodology proceeding.

6.4.6 Administrative expense – mass media advertising – Account 721 and other supplies – Account 721

787. AG forecasted increases to mass media advertising of $0.5 million in both the 2011 and 2012 test years.[714] AG requested approval of forecast costs for other supplies for the 2011 and 2012 test years of $3.8 million and $4.1 million respectively.[715]

788. For the Mass Media Advertising Account 721, AG submits that the increase is due to recruitment advertising necessary to address growth in labour resource requirements and the replacement of positions for increased retirements.

789. For Other Supplies Account 721, AG submits that the increase over the test years is to address employee training needs.[716]

790. The UCA argued that both the media advertising and other supplies expenses involve proposed increases beyond what is suggested by inflationary pressures. The proposed increases in other supplies relate primarily to leadership training that AG justifies on the basis of its aging workforce. In its evidence, the UCA suggested that the cost increases are not justified because whatever effects an aging work force may potentially have on AG have already been accounted for in the market and in the optimization of the system to date.[717] The UCA recommended a decrease in AG's 2011 and 2012 forecast costs relating to mass media advertising of $295,000 in 2011 and $290,000 in 2012; and other supplies of $830,000 in 2011 and $1,059,000 in 2012.[718]

791. Calgary submitted in its evidence that a general statement about the number of employees eligible for retirement in the near term does not justify the $1.2 million increase from 2010 actual costs to the 2012 forecast for other supplies.[719]

792. AG submitted that the UCA and Calgary have not provided any support for their positions. In rebuttal evidence, AG explained that a significant contributor to the 2010 decrease in mass media advertising costs incurred was the temporary stabilization of its workforce arising from the economic crisis. As the economy continues to recover, a competitive labour market is expected resulting in the requirement for increased levels of recruitment advertising. AG's 2011 forecast increase in mass media advertising costs, back to pre-economic crisis levels, arose from changed circumstances of a more competitive labour market, and an increased need for labour resources.[720]

[714] Exhibit 3, AG application, page 4.2-35, Table 4.2.2.7 Administrative Expense (Account 721).
[715] Exhibit 3, AG application, page 4.2-35, Table 4.2.2.7 Administrative Expense (Account 721).
[716] Exhibit 3, AG application, page 4.2-41, paragraph 113.
[717] UCA evidence, pages 36 and 37.
[718] Exhibit 142.02, AUC-ACA-16 Attachment, UCA proposed O&M reductions to 2011 and 2012.
[719] Calgary evidence, page 15.
[720] AG rebuttal evidence, page 69, paragraph 269.

793. With regard to other supplies, AG noted that the UCA indicated that training activities are related to the overall workforce demographic theme and are not justified because these impacts have already been accounted for in the market and in the optimization of the system to date.[721] Calgary submitted that the number of employees eligible to retire in the near term did not justify the requested increase.[722] AG submitted that its demographic profile shows a significant number of employees eligible to retire over the next several years with a potential peak occurring between 2011 and 2015. By the end of 2015, close to 500 of AG's current employees will be eligible to retire.[723]

794. Leadership training costs are forecast to increase in 2011 by $0.9 million and stabilize in 2012.[724]

795. AG submitted that it has identified not only the cause of the increases for mass media advertising and other supplies, but the dollar impact related to each cause. The causes for the increase in forecast costs for mass media advertising and other supplies is not limited to the aging work force issue as indicated by the UCA.

Commission findings

796. The Commission, earlier in Section 6.1 above, found that it was not persuaded that the aging workforce and tightening labour market are driving higher O&M costs. The Commission is persuaded by the UCA's argument that there has not been a sufficient change in circumstances between 2010 and the test years to warrant the requested increases forecast by AG.

797. The Commission therefore approves mass media and other supplies expenses for 2011 and 2012 calculated as 2010 actual costs increased by five per cent per year for inflation and growth. AG is directed to include this revision in its compliance filing.

6.4.7 IT and CC&B governance costs

798. AG indicated[725] its IT and CC&B governance costs included the following amounts:

- The ATCO Group IT governance related to the Office of the CIO, for which the allocated forecast[726] is $0.6 million for 2011 and $0.6 million for 2012.
- ATCO Gas IT governance forecast to be $0.8 million for 2011 and $1.7 million for 2012. 2012 includes IT benchmarking costs of $0.6 million.
- ATCO Gas CC&B governance forecast to be $0.5 million for 2011 and $0.9 million for 2012.
- 2012 includes CC&B benchmarking costs of $0.3 million.

AG did not fully detail which accounts, O&M or capital, included these governance costs.

721 UCA evidence, page 36.
722 Calgary evidence, page 15.
723 Exhibit 163.01, AG rebuttal evidence, page 69-70, paragraph 272.
724 AG rebuttal evidence, page 70.
725 Exhibit 163.01, AG rebuttal evidence, Q 131 and Q 132.
726 Exhibit 82.11, CAL-AG-15(a) Attachment, 2011 - $562,000, 2012 - $579,000.

Views of the parties

799. Calgary submitted that the governance functions in ATCO Group and AG are not fulfilling their roles to ensure competitive prices (and volumes) for IT capital projects and IT and CC&B O&M costs. I-Tek should not be allowed to play any role in selecting the best solution for the ATCO Group or AG because it is in a conflict of interest position.[727] Calgary submitted that there is an absence of evidence to demonstrate that the governance function has been cost effective to ratepayers. Specifically, good governance would have provided better support for a service provider's forecast of operating and capital expenditures than has been provided in the current application.

800. Calgary noted that during cross examination,[728] Mr. Schmidt stated that Oracle Financials, Oracle HRX and SumTotal TMS were ATCO Group decisions and subject to the IT governance of all ATCO companies including ATCO I-Tek. For IT projects that were just for the use of AG, the AG governance group was responsible.

801. Calgary indicated that ATCO has requested the approval of two ATCO Group IT projects, Oracle HRX (or HRMS) and SumTotal TMS, to be added to rate base and operating costs. Calgary submitted that both of these projects have poor cost/benefit plans. Neither project's business case examined competitive alternatives to I-Tek. Calgary submitted that the evidence indicated that I-Tek had been involved in defining the selection criteria used in the requests for proposal.

802. Calgary recommended that the governance costs allocated from the ATCO Group for 2011 and 2012 should be reduced to zero. Further, Calgary recommended that the AG governance costs with respect to IT and CC&B should be reduced to zero. These latter personnel have not demonstrated that they are exercising a governance function on behalf of AG. Their activities and results seem to indicate that they are functioning on behalf of the ATCO Group.[729]

803. In reply argument, AG stated that Calgary implies that ATCO is not complying with the Inter-Affiliate Code of Conduct without providing any evidence to support such a claim. Calgary stated that one indication of the Governance groups not properly performing their functions is the poor cost/benefit analysis related to Oracle HRX and TMS. AG submitted that it had demonstrated in the business cases the benefits of the chosen alternatives. AG further submitted that the use of third party software demonstrated that there was no conflict of interest and no violation of the Inter-Affiliate Code of Conduct.[730]

Commission findings

804. The Commission reviewed the merits of each of the HRX and TMS projects in the rate base section of this decision.

805. As noted above, AG has not fully described which accounts, O&M or capital, include corporate governance costs. The Commission directs AG in its compliance filing to indicate the allocation of the governance costs identified above to specific capital and O&M accounts,

727 Exhibit 201.01, Calgary argument, pages 55 to 57.
728 Ibid., noting Transcript, Volume 3, page 600 to Volume 4, page 630.
729 Calgary argument, pages 55-57.
730 Exhibit 218.02, AG reply argument, page 53 and 54, paragraph 123.

including the corresponding amounts approved in Decision 2011-228 and the actual amounts incurred in 2010.

6.4.8 IT expenses – Volumes

6.4.8.1 ATCO I-Tek (included in Account 721)

806. In the application, AG requested approval of all O&M IT volumes and specified expenses. Specified expenses were defined by AG as expenses from third-party vendors such as annual maintenance fees. The I-Tek O&M volumes are provided in the application and the forecast placeholder costs for these volumes are $21.1 million in 2011 and $21.3 in 2012.[731]

Table 43. I-Tek forecast placeholder costs for 2011 and 2012[732]

	Actuals	GRA Forecast		
MSA Schedule Reference	2010	2010	2011	2012
2. Specified Expense	$1,740,284.98	$1,846,287	$1,130,932.8	$1,156,936
3. Express Request Service Fee	$20,591.22	$16,435	$16,867.1	$17,436
4. Application Service Provider Service	$304,539.72	$320,307	$336,097.3	$340,291
5. Distributed Server and Managed Services	$4,963,838.40	$5,101,450	$5,285,565.0	$5,250,569
6. Mainframe Services	$2,415,711.49	$2,999,658	$2,967,344.1	$2,944,381
7. Disaster Recovery Service	$360,722.76	$460,438	$489,971.8	$494,134
8. Project Labour Service	$670,562.91	$665,621	$1,563,263.3	$1,690,248
9. Storage Service	$904,623.29	$793,903	$778,779.9	$794,447
10. User Connectivity Service	$321,755.94	$340,889	$350,188.6	$359,569
11. Network Connectivity Service	$1,112,387.11	$1,107,592	$1,124,611.0	$1,129,497
12. Voice Service	$829,762.70	$782,519	$840,041.7	$858,800
13. Workstation Service	$2,605,006.05	$2,810,894	$2,819,414.5	$2,843,806
Schedule E	$3,138,791.10	$3,135,621	$3,365,331.4	$3,441,916
Non I-Tek		$35,000.00	$-	
Total	**$ 19,388,577.66**	**$ 20,416,613.55**	**$ 21,068,408.71**	**$21,322,029.64**

807. All AG IT volumes for O&M were presented in AG's application, at Tab 4.2 and updated in Exhibit 180.

808. AG stated that it provided volume information for O&M in the application. The forecasts are laid out in detail and structured identically to Schedules D and E of the master services agreement (MSA) filed in the 2010 Evergreen proceeding.[733]

809. Calgary reviewed AG's O&M I-Tek volumes and submitted that AG failed to provide sufficient cost/benefit support for the requested I-Tek volumes in its application, and IR responses. Calgary argued that AG did not provide evidence in the proper level of detail to support its forecasts for the operate component of IT volumes for O&M and also that AG did not

731 Exhibit 3, application, Volume 1, pages 4.2-35 and 4.2-36 have costs of $20.5 million for 2011 and $20.8 million for 2012; and Exhibit 27.01 Excel spreadsheet of Tab 4.2 which shows $21.1 million in 2011 and $21.3 million in 2012.

732 Exhibit 82.01, CAL-AG-17(a).

733 Exhibit 163.01, AG rebuttal evidence, page 35, paragraph 125.

follow the Evergreen Strategy Report[734] that requires AG to separate IT volumes into the operate components of daily operation and operations support for new projects. AG stated that Calgary's claims that AG has not clearly identified base operating volumes. AG in rebuttal evidence,[735] noted that the O&M volume information provided in Tab 4.2 of the application includes 2008-2009 actual volumes. In the hearing, AG was asked to undertake[736] to provide a table to convert the volumes under the old MSA to the volumes under the new MSA. AG provided a spreadsheet[737] with actual volumes for 2008 to 2010 and forecast volumes for 2010 to 2012.

Commission findings

810. Calgary brought forward issues with respect to the Evergreen Strategy Report, O&M IT volumes and the lack of comparability due to the differences in structure and terms of the two MSAs. The Commission is satisfied that Exhibit 180 provided sufficient detail of volumes in a standardized format to allow the Commission to assess the reasonability of the forecast volumes. The Commission accepts the O&M forecast volumes as filed. The Commission notes the dollars are placeholders and directs AG to use the amounts provided in Table 42 above for the test years.

6.4.9 Legal and consulting – special services – Account 722

811. The special services account includes both legal and audit fees. AG forecast legal and consulting fees of $0.9 million and $1.0 million for 2011 and 2012 respectively. These forecasts include costs of $150,000 in 2011 and 2012 relating to the potential requirement for AG to participate in NGTL proceedings with the NEB.[738] AG submitted that it used an average of the prior three years actual costs plus inflation to develop the legal and consulting fees forecast for the test period. AG submitted that costs included in this category were consistent with the Commission scale of costs.

812. AG requested a placeholder for AG's legal and consultant costs on the basis that it should be able to recover the full amount of its prudently incurred regulatory costs which may be in excess of the Commission's scale of costs. It also stated that it should be able to recover legal costs related to the review and variance or appeal of Commission decisions.

Commission findings

813. The Commission has not been persuaded that the $150,000 forecast costs in each of the test years for potential involvement in hearings before the NEB relating to integration are justified because no supporting rationale was provided. The Commission is satisfied that the balance of AG's forecast costs for its audit, legal and consulting fees is reasonable based on AG's explanation that it is an average of its previous three-year costs. AG's forecast with regard to legal and consulting expenses is approved, subject to the above reduction.

814. With respect to AG's request for a placeholder for legal and consulting costs, the Commission notes that in Decision 2006-004[739] the EUB denied an application by AG for recovery of costs in excess of the scale of costs with respect to proceedings before the EUB,

734 2008-2009 Evergreen.
735 Exhibit 163.01, page 35 of 82, paragraph 125.
736 Transcript, Volume 4, page 524, lines 1-6.
737 Exhibit 180.
738 Exhibit 83.01, UCA-AG-85(a).
739 Decision 2006-004: ATCO Gas, 2005-2007 General Rate Application, Phase I, Application No. 1400690, January 27, 2006.

including review and variance proceedings, and for costs associated with appeals of EUB decisions.[740] The Commission confirms the findings and reasoning of the EUB and finds that the reasoning is applicable to the present application.

815. The Commission's Rule 022: *Rules on Intervener Costs in Utility Rate Proceedings* (Rule 022) addresses the recovery of costs in AUC regulatory proceedings, including review and variance proceedings, for all parties to a proceeding. The Commission finds that Rule 022 sets out the parameters for cost recovery and therefore there is not justification to support a placeholder for forecast legal and consulting costs. AG's request for a placeholder related to legal and consultant costs is denied.

6.4.10 Reserve for injuries and damages (RID) – Account 724 – late payment

816. AG has forecast annual expense levels of $.5 million for the Reserve for Injuries and Damages account for both 2011 and 2012.[741] AG also proposed a one-time recovery from customers related to the reserve for injuries and damages of $2.1 million ($1.2 million for the North and $0.95 million for the South). A one time adjustment arising from the settlement of litigation related to late payment penalty charges accounts for $1.8 million of the $2.1 million. AG indicated that the one-time recovery is necessary in order to maintain the reserve balance at $600,000 in total.[742]

817. The evidence of the parties focused on the proposal to include the costs of the late payment penalty charges litigation and settlement into the RID account.

818. In AG's 2008/2009 general rate application, AG advised the Commission that it was involved in litigation related to an action commenced against Canadian Western Natural Gas by a customer in the style of a class action against AG related to late payment charges. Beginning in 1982 AG had included within its terms and conditions of service approved by the Commission's predecessors, a provision requiring customers who do not pay their monthly bill by the due date to pay a late payment penalty of five percent of the unpaid charges.[743] The law suit alleged that the late payment charge contravened Section 347(1)(b) of the *Criminal Code* which prohibits receipt of a payment of interest at a criminal rate. Section 347(2) of the *Criminal Code* defines "criminal rate" as "an effective annual rate of interest calculated in accordance with generally accepted actuarial practices and principles that exceeds sixty per cent advanced under an agreement or arrangement." In Decision 2008-113 the Commission noted that the litigation was ongoing and directed AG to maintain a separate accounting of the legal and other payments in it reserve for injuries and damages (RID) account.[744]

819. On July 20, 2009, the Court of Queen's Bench of Alberta approved a settlement agreement (settlement) related to the late payment charge litigation covering the period November 1, 1998 to May 1, 2004. AG paid a settlement amount of $1.5 million. AG incurred legal costs of $0.3 million in defending the claim.[745] The total $1.8 million was recorded to the RID account. The settlement and legal costs of $1.8 million substantially accounts for the

740 Decision 2006-004, pages 100-102.
741 Exhibit 3, AG application, page 4.2-34, Table 4.2.2.7(a) Administrative and General Function.
742 Exhibit 3, AG application, Section 9.1.4, paragraph 6.
743 Application, Volume 2-1, Decision 2008-113, Other Commission Direction, PDF page 88.
744 Decision 2008-113, page 82.
745 In Application, Volume 2-1, Decision 2008-113 Other Commission Direction, PDF page 89, AG indicates that the legal fees amount to $406,000 resulting in a charge to the reserve of $1.9 million.

$2.1 million of the requested one- time adjustment to be recovered from customers.[746] The allocation of the settlement amount between north and south was done on the basis of the total late payment revenues recognized by each area.

820. The CCA stated in argument that the action filed against AG was founded on a similar action commenced against Consumers' Gas Co. that was considered by the Supreme Court of Canada in *Garland v. Consumers' Gas Co.*, [1998] 3 S.C.R. 112 (Garland No. 1 decision). In that decision, the Supreme Court found that Section 347(1)(b) of the *Criminal Code* applied to the late payment penalty of five per cent of the unpaid charges for the month charged by Consumers' Gas (now Enbridge Gas Distribution Inc.). The late payment penalty was found to be an interest charge within the meaning of Section 347(2) of the *Criminal Code*. By implication, in entering into a settlement of the claim against it, the CCA argued that AG must have engaged in similarly prohibited conduct.

821. The CCA opposed ATCO recovering the $1.8 million from customers as the CCA views this proposal by ATCO as an inappropriate use of the RID. The CCA submitted that the settlement was reached in 2009 and therefore should not be collected in 2011 and 2012 revenue requirement. AG should not be allowed to recover this amount through the RID. The CCA submitted that the RID operates as a reserve account, the amount of which is determined using a reserve methodology with respect to legal claims. AG, however, is using the RID in this case to recover amounts related to the settlement on a deferral basis. Further, given that the settlement was not filed on the record, there was insufficient information to conclude whether AG had acted prudently in negotiating the settlement.

822. The CCA also submitted that recovery of the settlement amount should not be permitted because the subject matter of the claim is founded upon AG having potentially engaged in prohibited conduct when it charged a late payment penalty which arguably exceeded the allowed rate of interest provisions of the *Criminal Code*.[747] The CCA stated in argument: "CCA submit AG does not bear any risk for its prohibited conduct…"[748]

823. In reply argument the CCA stated:

> The CCA concern is the utility, in this instance ATCO, must be liable for its acts or omission. To that end, ATCO as a corporation must bear the liability or responsibility. The CCA submit it is manifestly unfair to expect customers to bear the liability for the actions of the company which are arguably prohibited by law.[749]
>
> The PUB, AEUB, AUC or interveners are not responsible for the inappropriate conduct of AG or its predecessor companies. The conduct of AG and its predecessor companies and the cost related to inappropriate conduct is the responsibility of AG.[750]

824. AG reiterated its argument from the 2008-2009 general rate application on this matter:

> ATCO Gas submits that it is evident that customers received the benefit of late payment charges as an offset to revenue requirements and as such, it is appropriate that the

[746] Exhibit 3, AG application, page 4.2-43, paragraph 117.
[747] Exhibit 204.01, CCA argument, page 49, paragraphs 150-151.
[748] Exhibit 204.01, CCA argument, page 50, paragraph 155.
[749] CCA reply argument, pages 15-16, AP 53.
[750] CCA reply argument, page 17, paragraph 57.

> litigation costs and the cost of any potential payments be charged against the reserve for injuries and damages for future recovery from customers.[751]

825. In testimony, Ms. Wilson stated in an exchange with counsel for the CCA that the fact that customers benefited from the late payment charges was not their primary reason for including the settlement amount in the RID. Ms. Wilson stated:

> A. MS. WILSON: So, sir, you made reference that ATCO Gas had indicated that customers benefitted from the late payment fee.
>
> To be clear, that is secondary to our position, which really is that we were required to charge a late payment fee. The methodology and the rate that was to be used was reviewed in an opening [sic] process.
>
> Every time Northwestern and Canadian Western came before the regulator, the treatment of the revenues that were to be recovered through that late payment fee was also addressed in those regulatory proceedings. So everything that occurred with regard to that fee was reviewed and approved by the regulator.
>
> As a matter of fact, the Canadian Western and Northwestern were actually directed to move to a percentage basis for their fee, more like other distribution utilities in Canada. At the time I believe they were using a commodity base fee. So we were actually directed to make our late payment penalty fee look more like other utilities in Canada.[752]

826. AG submitted that it had not been found guilty of engaging in any prohibited conduct and that even if it had, such a finding would not be relevant. AG stated in reply argument: "[T]he regulator has never indicated that ATCO Gas is not entitled to use the RID simply because it may have been found guilty of something."[753]

827. With respect to the CCA's suggestion that because the class action suit was founded on the Garland No. 1 decision, AG must have engaged in similarly prohibited conduct, AG stated in reply argument: "The fact that the claim was based on a similar case does not by extension make ATCO Gas guilty."[754] In testimony, Ms. Wilson stated in response to a question from counsel for the CCA:

> Q. Okay. So in the end, how is ATCO Gas punished for having the late fee, which did not comply with the Criminal Code?
>
> A. MS. WILSON: Well, sir, I have said several times now that there was no finding of guilt on the part of ATCO Gas.
>
> This isn't about punishment. This is about the fact that we used a rate. It was a rate used by practically all natural gas distribution utilities across Canada; there was no understanding at the time of its use that there may be an issue with regard to it.

751 Exhibit 4, AG application, Volume 2-1, Tab 1 Decision 2008-113, Other Commission Direction, page 4, PDF page 91.
752 Transcript, Volume 2, page 251, line 16 to page 252, line 9.
753 AG reply argument, page 94, paragraph 222.
754 AG reply argument, page 94, paragraph 222.

> And, however, a Court case occurred for Enbridge, and based on that, ATCO Gas made a prudent decision with regard to the settlement of this claim.[755]

828. AG submitted that the settlement obtained by AG is prudent and avoids the potential for significantly higher costs as well as future litigation related to this matter. The regulator approved the late payment rate and structure each time it approved AG's (and predecessors') rates. AG indicated that the Ontario Energy Board had found it appropriate for customers to be responsible for the settlements reached by Enbridge Gas Distribution Inc. and Union Gas. AG indicated that the Enbridge circumstances regarding late payment charges were very similar to AG's and that it should be allowed to recover the total amount of the settlement and legal costs from customers in its rates.[756]

829. AG submitted that the Ontario Energy Board has approved the recovery of settlements related to late payment suits in all cases in Ontario to date, regardless of whether a finding of guilt existed or not.[757] The CCA has not been able to demonstrate any distinguishing aspect that would warrant a different outcome occurring in Alberta. AG submitted that it prudently settled this claim without any finding of guilt on the part of a court of law.[758] AG stated in reply argument:

> As noted by ATCO Gas in its Argument, this isn't a matter of whether different utilities were subsequently found guilty under the Criminal Code because of the late payment charge rate that was used by them, and the fact that ATCO Gas charged a similar rate. It is about the fact that ATCO Gas prudently settled this claim at a cost of $1.9 million, considerably less than the Enbridge settlement of $22 million dollars. ATCO Gas also thereby avoided the considerable costs of litigating this class action lawsuit. Finally, it is about the fact that the RID does not distinguish between those cases where a finding of guilt occurred versus where a settlement occurred before any finding on the part of the courts.[759]

Commission findings

830. It is of assistance in analyzing the issues raised with respect to the settlement and the ability of AG to recover the settlement and associated legal fees in the amount of $1.8 million from ratepayers to review the chronology of the relevant events on the record. Section 347 of the *Criminal Code* came into effect on April 1, 1981.[760] Beginning in 1982 AG had included within its terms and conditions of service approved by the Commission's predecessors, a provision requiring customers who do not pay their monthly bill by the due date to pay a late payment penalty of five percent of the unpaid charges.[761] The Garland No. 1 decision was issued on October 30, 1998. The litigation leading to the settlement was commenced in February, 2001. On July 20, 2009 the court approved the settlement covering the period November 1, 1998 to May 1, 2004.

755 Transcript, Volume 2, page 258, line 23 to page 259, line 11.
756 Exhibit 4, AG application, Volume 2-1, Tab 1 Decision 2008-113, Other Commission Direction, pages 4-5, PDF pages 91-92.
757 AG reply argument, pages 94-95, paragraph 222.
758 Exhibit 218.01, AG reply argument, pages 94-95.
759 Exhibit 218.01, AG reply argument page 95, paragraph 224.
760 Garland No. 1 decision, paragraph 23.
761 Application, Volume 2-1, Decision 2008-113 Other Commission Direction, PDF page 88.

831. AG takes the position that the payments made under the settlement and associated legal costs should be collected from ratepayers through the RID account mechanism because AG relied on the approval of the predecessors of the Commission and the late payment charges benefited ratepayers. Further, there has been no finding of guilt on the part of AG and even if there was it would not be relevant. The settlement of the class action claim is no different than any other settlement reached in litigation filed against the company and included in rates through the RID account. The inclusion in the RID account of these costs would be similar in treatment to the way in which the Ontario Energy Board has dealt with this issue.

832. The CCA takes that position that settlement and related legal costs should not be included in the RID account and collected from ratepayers because it doesn't properly fit within the RID account. Further, AG should not be entitled to recover payment of these amounts from ratepayers because the late payment penalty rate may infringe the provisions of Section 347 of the *Criminal Code*. In support of this position the CCA relies on the finding of the Supreme Court in the Garland No. 1 decision. The CCA summarized its position as follows:

> In summary, the Court held Consumers' Gas actions regarding its late payment penalty charges mounted to prohibited conduct. By implication, in entering into a settlement of the claim against it, AG must have engaged in similarly prohibited conduct.[762]

833. The Commission considers the analysis in the second Garland case decided by the Supreme Court of Canada to be of assistance in making a determination on the present issues. In *Garland v. Consumers' Gas Co.*, [2004] 1 S.C.R. 629 (Garland No. 2 decision) the Supreme Court determined that Consumers' Gas had to repay the late payment penalty charges collected from ratepayers after the commencement of the class action suit on the basis of a finding of unjust enrichment. The fact that ratepayers benefited from the collection of the late payment penalty charges was not accepted as a defense to a claim of unjust enrichment in a civil suit with respect to the period commencing with the filing of the law suit. The court stated:

> In this case, the respondent says that any "benefit" it received from the unlawful charges was passed on to other customers in the form of lower gas delivery rates. Having "passed on" the benefit, it says, it should not be required to disgorge the amount of the benefit (a second time) to overcharged customers such as the appellant. The issue here, however, is not the ultimate destination within the regulatory system of an amount of money equivalent to the unlawful overcharges, nor is this case concerned with the net impact of these overcharges on the respondent's financial position. The issue is whether, as between the overcharging respondent and the overcharged appellant, the passing of the benefit on to other customers excuses the respondent of having overcharged the appellant.
>
> The appellant submits that the defence of change of position is not available to a defendant who is a wrongdoer and that, since the respondent in this case was enriched by its own criminal misconduct, it should not be permitted to avail itself of the defence. I agree.[763]

834. With respect to the argument advanced by Consumers' Gas that the late payment penalty charges had been approved by the Ontario Energy Board, the court determined that because the late payment penalty charge infringed the provisions of Section 347 of the *Criminal Code*, it followed that the regulatory approvals of that charge were constitutionally inoperative to the

762 CCA argument, pages 46-47, paragraph 145.
763 Garland No. 2 decision, paragraphs 62-64.

extent of the conflict with Section 347. However, Consumers’ Gas had the reasonable expectation that it was entitled to rely on the Ontario Energy Board approvals even though these approvals were inoperative, up until the point in time when the law suit was filed. This reasonable expectation provided Consumers’ Gas with a juristic reason for the enrichment received with respect to the period of time up until the law suit was commenced. After the law suit was commenced, Consumers’ Gas “…was put on notice of the serious possibility that it was violating the *Criminal Code* in charging the LPPs”[764] and therefore was no longer to rely on the Ontario Energy Board orders. The court stated:

> Consumers’ Gas could have requested that the OEB alter its rate structure until the matter was adjudicated in order to ensure that it was not in violation of the *Criminal Code* or asked for contingency arrangements to be made. Its decision not to do this, as counsel for the appellant pointed out in oral submissions, was a "gamble". After the action was commenced and Consumers' Gas was put on notice that there was a serious possibility the LPPs violated the *Criminal Code*, it was no longer reasonable for Consumers' Gas to rely on the OEB rate orders to authorize the LPPs.[765]

835. Consumers’ Gas was required to repay the late payment penalty charges collected after the law suit was commenced because it could not rely on the prior Ontario Energy Board approvals to prevent recovery by the plaintiff after the date that the lawsuit was filed.

836. In the present proceeding, there has been no judicial finding that AG has infringed Section 347 of the *Criminal Code*; the Commission has not been asked to decide a question of unjust enrichment as was the case in the Garland No. 2 decision; and the Commission is not being asked to decide who, as between AG and the customers who paid late payment charges, should bear the cost of the late payment charges. Nevertheless, the Commission considers the guidance supplied by the Garland No. 2 decision is directly applicable in certain respects to the present application.

837. AG has acknowledged that “ATCO Gas charged a similar rate”[766] to the late payment penalty rates collected by Consumers’ Gas. Although the Commission’s predecessors continued to allow late payment penalty charges in this form to be included in AG’s terms and conditions of service, the Commission considers that AG should have been aware of the Garland No. 1 decision when it was issued on October 30, 1998. Accordingly, at that time, AG should have been aware that a late payment penalty rate, similar to the rate being charged by AG “amounted to charging a criminal rate of interest under s. 347.”[767]

838. The Commission considers that AG’s corporate governance and legal responsibilities, the costs of which are paid by ratepayers, include the responsibility to ensure that AG’s terms and conditions of regulated service comply will all applicable law. Ensuring that AG’s terms and conditions of service comply with all applicable law is not the responsibility of interveners, nor is it the responsibility of the Commission. AG, like Consumers’ Gas in the Garland No. 2 decision, could have requested the regulator to “…alter its rate structure until the matter was adjudicated in order to ensure that it was not in violation of the *Criminal Code* or asked for contingency arrangements to be made”[768] at any time after it should have become aware of the

[764] Garland No. 2 decision, paragraph 59.
[765] Garland No. 2 decision, paragraph 59.
[766] AG reply argument, page 95, paragraph 224.
[767] Garland No. 2 decision, paragraph 6.
[768] Garland No. 2 decision, paragraph 59.

Garland No. 1 decision. Consumers' Gas could not rely on prior Ontario Energy Board orders to avoid a claim of unjust enrichment after it was put on notice of the lawsuit. The Supreme Court considered that Consumers' Gas' decision not to take steps to address the issue after it received notice, was a "gamble."[769] Similarly, the Commission considers that AG and its predecessors' inaction after the issuance of the Garland No. 1 decision in requesting a change to the late payment penalty charge on the basis of a possible infringement of Section 347 of the *Criminal Code*, amounted to a "gamble."[770] AG and its predecessor organizations gambled that it would not be sued on the same basis as the Garland No. 1 decision and AG further gambled that if it were sued, that the Commission would allow recovery of any resulting award or settlement amount to be recovered from ratepayers. AG's inaction is even more noticeable given the passage of time between the issuance of the Garland No. 1 decision in October 1998 and the commencement of the lawsuit against AG's predecessor in February 2001.

839. Given that the settlement relates to a period (November 1, 1998 to May 1, 2004) subsequent to the issuance of the Garland No. 1 decision, the Commission considers that the entire amount paid under the settlement and the applicable legal costs is at issue. AG should have been aware of the issues associated with Section 347 of the *Criminal Code* at least from the October 30, 1998 issue date of the Garland No. 1 decision and it is AG's responsibility to ensure that its terms and conditions of service comply with all applicable law. There is no evidence on the record to indicate that AG requested a change from the regulator to the late payment penalty rate in its terms and conditions of service on the basis of the criminal rate of interest provisions of the *Criminal Code* during the period November 1, 1998 to May 1, 2004. In these circumstances, the Commission considers that AG is not entitled to rely on approvals of the late payment penalty rate by the predecessors to the Commission to include the settlement in the RID account.

840. It follows from the above that AG must also fail in its argument to include the settlement amount in the RID account based on the fact that ratepayers benefited from the collection of the late payment penalties through lower rates. AG fails in this argument because AG (not ratepayers or the Commission) has the responsibility to ensure that its terms and conditions of service comply with all applicable law and because AG can not rely in the present circumstances on prior approvals by the regulators of the late payment penalty rate to avoid responsibility. The Commission agrees with the CCA that to hold otherwise would remove all accountability and risk from AG and that it would be "… manifestly unfair to expect customers to bear the liability for the actions of the company which are arguably prohibited by law."[771]

841. The set of circumstances surrounding the settlement discussed above, distinguishes the recovery of the settlement costs from the recovery of other litigation costs through the RID. It is for these reasons that the Commission finds that ratepayers should not be required to pay for the costs of the settlement and the associated legal expenses.

842. AG's request for a recovery of $1.8 million related to the settlement and associated legal expenses is denied. The Commission therefore directs AG to remove the settlement and associated legal expenses from AG's forecast for reserve for injuries and damages and revenue requirement in its compliance filing. The $300,000 balance of the proposed $2.1 million recovery in order to maintain a reserve balance of $600,000 is approved.

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769 Garland No. 2 decision, paragraph 59.
770 Garland No. 2 decision, paragraph 59.
771 CCA reply argument, pages 15-16, AP 53.

843. The Commission also approves the forecast expense levels of $.5 million for the reserve for injuries and damages account for both 2011 and 2012.

6.4.11 Employee benefits – Account 725

844. Employee benefits Account 725 includes statutory benefits, costs related to pensions, flex benefits and other employee benefits. AG forecast costs for employee benefits in the test years of $35.3 million in 2011 and $33.7[772] million in 2012.

845. Statutory benefits, comprised of Canada Pension Plan (CPP), Employment Insurance (EI) and Workers' Compensation Board (WCB) premiums account for approximately $0.6 million of the increase in 2011 and $0.2 million of increase in 2012. AG attributes these increases to inflation, an increase in the number of employees and increases in EI premiums announced by the federal government.

846. There are three components related to pension costs: amortization of deferred pension, pension expense and other post-employment benefits (OPEB), and pension funding. The amortization of deferred pension of $2.7 million in 2011 is a result of a direction by the EUB in Decision 2006-100.[773] Pension expense and OPEB was $1.2 million in 2010 and has increased to $1.5 million in each of 2011 and 2012.

847. Pension funding in the test years is a placeholder in this application subject to determination by the Commission in a Common Pension Matters proceeding. Decision 2011-391[774] requires that a compliance filing be made by November 30, 2011. Therefore, the pension funding in the 2011-2012 GRA is considered to be a placeholder.

848. Flex benefits include long term disability and health and dental premium costs for benefits offered by the ATCO Group. AG stated that there was a decrease to long term disability rates in 2010 offset by higher rates for dental and health premiums.

849. AG explained the increase in other employee benefits as arising from increased communication costs, education reimbursement costs and retirements gifts and staff recognition awards, and inflation.[775]

850. The UCA recommended that the Commission approve $33.5 million and $31.8[776] million for 2011 and 2012 respectively for Account 725. In argument the UCA explained the basis for its proposed adjustment as tracking labour inflation at three per cent, with an adjustment in 2012 to reflect the end of recovery of deferred pension amortization amounts.[777]

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772 April 21, 2100 update.

773 Decision 2006-100: ATCO Utilities 2005-2007 Common Matters Application, Application No. 1407946, October 11, 2006.

774 Decision 2011-391: ATCO Utilities (ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd.) 2011 Pension Common Matters, Application No. 1606850, Proceeding ID No. 999, September 27, 2011.

775 AG rebuttal evidence, pages 72-73.

776 Exhibit 110.07, UCA general evidence at page 42, Q.66.

777 Exhibit 200.02, UCA argument, page 49-50, paragraphs 169 to 171.

851. In its rebuttal evidence AG criticized the UCA for not also providing for increases in employee benefits to account for growth in the number of employees.[778] AG suggested that a 4.4per cent growth factor would be more appropriate.

Commission finding

852. The Commission is satisfied that AG has adequately explained why employee benefits are increasing for the test years. Further the Commission notes that the largest component of employee benefits is the pension funding which is subject to a placeholder. In Decision 2011-391 the Commission made a determination of pension funding for AG to be included in revenue requirement for 2011 and 2012. AG is directed to maintain the current placeholders for pension funding, pending a decision in relation to the compliance filing for Decision 2011-391 noted above. AG is directed to submit an application to replace the placeholders within a reasonable time following the issuance of the decision in the compliance filing. With the exception of the placeholder for pension funding, the Commission approves the forecast costs for employee benefits.

6.4.12 Other administrative and general expenses – Account 728

853. Other administrative and general expenses are comprised of hearing costs, a charge for the consumer advocate, bank charges, company memberships and other supplies. The largest sub-account is hearing costs, which will be discussed below. A second significant account is bank charges, which is of interest due to the proposed change in classification of certain components from financing costs to O&M expenses.

6.4.13 Bank and short-term financing charges – Account 728

854. AG forecast bank and short-term financing costs for 2011 and 2012 of $1.2 and $1.1 million respectively.[779] AG explained that in order to maintain the flexibility regarding timing and size for the issuance of long term financing, CU Inc. and Canadian Utilities Limited maintain sizable short term credit facilities, the costs of which are shared between the subsidiaries using a shared cost formula. When these fees were introduced in 2008 they were charged as financing costs. In 2010 they are now charged as operating costs which is the more appropriate treatment.[780]

855. In its evidence Calgary's position was that AG did not justify the increase in the bank charges or more particularly credit facility fees including forecast increases to standby fees, credit extension, and guarantee fees.[781]

856. In its rebuttal, AG submitted that it fully justified the increased costs incurred to maintain these credit facilities as mainly relating to increased standby fees stemming from the economic crisis.[782] Further, in paragraphs 289 and 290 on page 73 of its rebuttal, AG indicated that bond rating agencies require CU Inc. to maintain an adequate level of liquidity to fund operations and maintenance and capital expenditures. Failure to achieve this level of liquidity could impact CU Inc.'s credit rating. The credit facilities held by CU Inc. and Canadian Utilities Limited allow the achievement of these liquidity requirements, and thus allow CU Inc. to maintain its credit rating.

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778 Exhibit 163.01, at paragraph 189.
779 Exhibit 3, page 4.2-49, Table 4.2.27(k).
780 Exhibit 3, page 4.2-48.
781 Calgary evidence, page 15.
782 Rebuttal evidence, paragraph 289, page 73.

Customers benefit directly from this as CU Inc. is able to access lower market rates based on its credit rating. Additionally, these credit facilities provide CU Inc. flexibility regarding the timing and sizing of long term financings which also translates to lower costs to customers.[783]

857. AG submitted that credit facility costs incurred at the CU Inc. / Canadian Utilities Limited level are allocated to the ATCO Utilities using the corporate cost allocation methodology approved in Decision 2010-447. These credit facility costs were recently approved by the Commission in ATCO Electric Decision 2011-134. These are the very same credit facility costs that AG's credit facility cost forecast is based on. AG has properly supported its 2011 and 2012 credit facility costs and the Commission has found those costs to be reasonable for ATCO Electric. AG submitted that these costs should be approved as filed.[784]

Commission findings

858. The Commission is satisfied with AG's explanation that credit facility costs and standby fees have increased as a result of the recent economic crisis. Further, the Commission recognizes that ensuring liquidity levels are maintained at levels required by bond rating agencies results in CU Inc. being able to maintain its existing credit rating and allows AG access to lower market rates for financing its operations. The forecast bank charges are consistent in total with the 2009 charges and the Commission finds the amounts to be reasonable. As these costs are allocated using the ATCO Utilities corporate cost allocation methodology approved in Decision 2010-447 the Commission accepts the allocation methodology for 2011. As noted earlier, ATCO Utilities corporate cost allocation methodology is subject to review in 2012. As a result, all costs for 2012 including "bank and short term financing costs" are subject to a placeholder pending the outcome of the aforementioned proceeding. AG is directed to maintain a placeholder for 2012.

859. The Commission has concerns with the reclassification of these bank and short term financing costs from financing to O&M costs. AG has stated that charging these costs as operating costs is more appropriate but has not provided supporting rationale. AG has submitted that these costs are incurred for credit facilities which are required by bond rating agencies and to allow flexibility for CU Inc. Consequently, the Commission finds that the costs are more appropriately treated as financing costs rather than O&M costs.

860. The Commission directs AG in its compliance filing to reclassify bank and short-term financing costs as financing costs.

6.4.14 Hearing costs – Account 728

861. AG has forecast hearing costs for 2011 and 2012 of $3.9 million for each test year, an increase of $2 million over 2010 actual costs of $1.9 million.[785] In addition to the increase in forecast expenses of $2 million per year, AG also requested a one time adjustment of $7.5 million related to hearing costs to recover prior year costs and an increase in the hearing expense for the years 2011 and 2012 to $3.9 million as a result of higher anticipated costs.[786]

862. AG explained that its forecast hearing costs have increased due to its past GRA, rate setting applications, which are individually identified in the application, and stated that it

783 Exhibit 203.01, AG argument, page 82, paragraph 208.
784 Exhibit 203.01, AG argument, page 82, paragraph 209.
785 Exhibit 93.01 AUC-AG-62.
786 Exhibit 3, AG application, page 4.2-47, paragraphs 128-129.

anticipates increased costs for the current GRA, rate setting applications, Generic Cost of Capital, Pension, Performance-based Ratemaking and Benchmarking proceedings. The CCA noted that the response to AUC-AG-62 stated that the actual hearing cost reserve (HCR) expense is $1.3 million. The CCA considered that the 2011 deferred hearing account opening balance should reflect 2010 actual hearing payments. AG has over-forecast intervener and external AG hearing costs. Pursuant to the current AUC Rule 022, the number of intervener groups eligible for funding has been limited. The CCA recommended a reduction of the forecast expense of $300,000 for each of the test years.[787]

863. The CCA submitted that the one-time adjustment should be amortized over the test years and a further five years being an estimate of the term of PBR. The CCA expects that regulatory activity will diminish once a PBR mechanism is put into place as this GRA will form the basis of the PBR going in rates.[788]

864. AG noted that in response to AUC-AG-62 page 19 of 21, it provided the 2010 actuals in the same format as Table 4.2.2.7(i) of the application. AG stated that it appears the CCA is missing the fact that the annual AUC assessment payment, which was $2.4 million in 2010, is also included in the deferred hearing account. Taking this into consideration, the closing balance for the 2010 actuals is the same as the 2010 forecast closing balance and as such no adjustment to the 2011 opening balance is required.[789]

865. AG stated that CCA's proposal of a $300,000 reduction is arbitrary and without basis.[790]

866. AG submitted that the proposed $7.5 million one-time adjustment is a specific cost adjustment relating to prior years activity, not future years activity. Additionally, a one-time adjustment is consistent with how adjustments to the deferred hearing account have been handled in the past.[791]

Commission findings

867. Given AG's explanation that under-forecasting of the AUC assessment payment offsets the over-forecasting of hearing payments the Commission is satisfied that no 2011 opening balance adjustment is required. The Commission approves AG's one-time adjustment of $7.5 million to address prior years' activity as being reasonable.

868. The CCA expressed the view that with the limitation to intervener costs pursuant to Rule 022 that intervener costs may have been over-forecast. The Commission finds that hearing costs were accurately forecast in 2010 and accepts the $3.9 million of hearing costs as filed. Given the deferral treatment accorded to hearing costs any over or under accrual will be trued up in the future.

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787 Exhibit 204.01, CCA argument, page 36-37, paragraphs 110-111.
788 Exhibit 204.01, CCA argument, page 37, paragraphs 111.
789 Exhibit 218.01, AG reply argument, page 97, paragraph 226.
790 CCA argument, page 37, paragraph 111.
791 Exhibit 218.01, AG reply argument, page 97, paragraph 228.

6.5 North and South O&M allocation

869. Calgary argued that AG has failed to provide O&M information in its application for AG North and AG South and has for the most part allocated the costs between the two systems on the basis of the number of customers. As the Commission stated in Decision 2008-113:

> …the Commission will require that AG first satisfy the Commission that it has established a cost allocation method capable of capturing costs causal to the North and South systems.[792]

870. Calgary requested that the Commission direct AG to provide actual 2010 and forecast 2011 and 2012 O&M expenses by account for each of AG North and AG South.[793]

871. The CCA agreed with AG that allocations of revenue requirement are more appropriately addressed in the upcoming Phase II proceeding.[794]

872. While the Commission expressed a concern with regard to the use of the weighted customer allocation methodology in Decision 2008-113, AG submitted that this concern had been addressed in the first compliance filing for the 2008-2009 GRA. In Decision 2009-109, the Commission found:[795]

> It appears from these submissions that ATCO Gas has now abandoned the Weighted Customer allocation methodology in favour of separately tracking certain accounts. **The Commission considers this separate tracking to be a preferable approach.** [emphasis added]

873. AG submitted that Calgary is raising matters that have already been determined by the Commission. AG also argued that:

- The Commission approved the use of one revenue requirement in its Phase I proceedings in Decision 2008-113.[796]
- AG is not using customers as an allocation method for its distribution operations and maintenance expense, nor for its capital expenditures, which appear to be the main focus of Calgary's concern.[797]
- If Calgary has a concern with the allocation methodology that AG intends to use in the development of rates, it should be addressed in the Phase II proceeding related to this application.[798]

Commission finding

874. In Decision 2008-113 the Commission approved the use of one revenue requirement in AG's Phase I GRA proceedings.[799] In Decision 2009-109 the Commission found that AG has

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792 AUC Decision 2008-113, dated November 13, 2008, page 113.
793 Exhibit 201.01, Calgary argument, page 47.
794 Exhibit 216.01, CCA reply argument, page 8.
795 Decision 2009-109, paragraph 123.
796 AG argument, page 58, paragraph 144.
797 AG rebuttal evidence, page 50, paragraph 179 and Attachment 2.
798 AG argument, page 59, paragraph 148.
799 AG rebuttal evidence, page 50, paragraph 179 and Attachment 2.
799 AG argument, page 58, paragraph 144.

improved the direct tracking of costs. The Commission concurs with the CCA and AG that allocations of revenue requirement to the North and the South are more appropriately addressed in the upcoming Phase II proceeding.

7 Depreciation

875. In commencing an analysis of the depreciation evidence filed in this proceeding the Commission considers it beneficial to first review the purpose of depreciation expense in a utility rate making context. The purpose of depreciation accounting, applicable in any context, is to allocate the original cost of an enterprise's assets over the estimated service life of those assets. The actual recovery of an enterprise's investment is a function of the prices determined for its products or services in the marketplace. For a regulated enterprise, recovery of investment is dependant, in part, upon the inclusion of depreciation expense in rates approved by the regulator. The direct relationship between depreciation, rates and cash flow to a utility may result in differences in perspectives relative to depreciation. For example, in certain circumstances a utility may prefer to accelerate the recovery of an investment while ratepayers may favor a slower recovery of the investment to reduce rates in the short term. The dynamics of establishing depreciation rates that are fair to both the utility and ratepayers was explored in Decision U96001[800] by the EUB as follows:

> The Board believes the depreciation expense to be charged customers in any year should reflect an appropriate allocation of the cost of utility plant over the periods that benefit from the plant's use in providing utility service. This allocation should be fair to both NGTL's shareholders and customers. The Board acknowledges that estimating the appropriate portion of capital assets to be recovered in any one year is not exact and requires consideration of a large number of factors, such as past retirement experience and the assets in question, new technology, salvage values of assets and the ultimate economic life of assets independent of the engineering life of the plant. Given the combination of these and other factors, the precise selection of appropriate depreciation rates for any one test year is a matter requiring considerable judgment.

876. The Commission notes that the estimation of utility depreciation expense in any given test period is not an exact exercise and accordingly experts may justifiably differ on approach, judgment and findings. Experts apply experience and judgment to the available facts and relevant circumstances in weighing the information available including the factors identified in the above quote.

877. The Commission will assess the persuasiveness of the depreciation evidence presented by the parties in the above context and relative to the record in its entirety.

878. AG filed company sponsored evidence[801] on depreciation and a depreciation study prepared by Gannett Fleming.[802] AG proposed the adoption of the recommendations of the depreciation study.

[800] Decision U96001: NOVA Gas Transmission Ltd., 1995 General Rate Application - Phase I, File 1600-1, January 4, 1996, page 66.
[801] Exhibit 3, AG application, Section 5.0.
[802] Ibid., Attachment 1.

7.1 Depreciation rate changes – overview

879. AG included the following table describing the forecast amounts for 2010, 2011 and 2012.

Table 44. Depreciation and amortization expense[803]

($ millions)			
	2010 Forecast	**2011 Forecast**	**2012 Forecast**
ATCO Gas (North)	55.6	62.4	68.7
ATCO Gas (South)	48.2	53.3	58.3
ATCO Gas	103.8	115.7	127.0

880. The actual 2010 depreciation and amortization expense was $115.2 million.

881. The increase in total depreciation expense in revenue requirement is forecast at $11.9 million for 2011 and from 2010 forecast with a further increase for 2012 of $11.3 million. AG indicated that the increase in depreciation expense is due in part to:

- changes in capital vintage distribution and depreciation parameters of Average Service Life, Iowa Curve and Net Salvage which will increase depreciation expense by $3.4 million; and
- changes in the amortization of Reserve Differences which will increase depreciation expense by $5.1 million.[804]

882. Depreciation rates are determined based on depreciation parameters of average service life, Iowa Curve and net salvage. The following table summarizes all proposed changes to the current depreciation rates:

[803] Ibid., Section 5.1-1.
[804] Ibid., Section 5.1-2.

Table 45. Proposed depreciation rate changes[805]

Account	Account title	Current Rate %	Forecast Rate %
47200	Structures and Improvements	2.76	2.74
47300	Services	4.44	4.03
47400	Regulator and Meter Installations	3.02	3.49
47401	Meter Equipment Installations	7.45	6.69
47500	Mains	2.94	3.20
47700	Measuring and Regulating Equipment	4.08	3.82
47701	Measuring and Regulating Equipment – Electronic	6.44	5.59
47800	Meter Equipment	3.68	5.08
47801	Meter Equipment – Electronic	6.89	7.05
47802	Meter Equipment – AMR	0.00	7.44
48200	Structures and Improvements	2.76	2.99
48201	Structures and Improvements – Security Systems	10.56	10.00
48300	Office Furniture and Equipment	4.90	5.00
48400	Transportation Equipment	8.74	10.26
48401	Transportation Equipment – NGV	10.22	9.79
48500	Heavy Work Equipment	5.65	7.53
48600	Tools and Work equipment	4.50	5.18
48800	Communication Structures and Equipment	5.82	5.36
48801	Communication equipment – Mobile	7.71	6.25
48900	Stores, Shop & Garage Equipment	3.60	3.95
49001	Natural Gas Vehicle Refueling Equipment	5.15	4.31
49600	Specialized Computer & Electronic Office Equipment	9.77	9.04

883. AG is seeking approval for the following:

- changes to the depreciation rates
- approval of depreciation rates for proposed six new accounts for Geothermal and Solar assets set out in Table 46 below
- a new account for low use AMR devices, Account Number 47802 at a depreciation rate of 7.44 per cent
- changes to the existing net salvage rates
- approval of contract life depreciation methodology for customized gas delivery service covered by a custom service letter agreement
- change in the methodology used to amortize leasehold improvements

805 Exhibit 3 AG application, Section 5.0, Attachment 1, Part III, Schedule 3.

Table 46. Proposed geothermal and solar asset depreciation rates[806]

Account Title	Proposed Rate %
Geothermal – Plumbing, Controls & Meters	6.74
Geothermal – Ground Loop	2.38
Geothermal – Heat Pumps	8.15
Solar – Tube & Plate Collectors	4.86
Solar – Tanks	9.10
Solar – Plumbing, Controls & Meters	6.91

884. Gannett Fleming stated that the primary factors utilized to determine each appropriate survivor curve and resultant depreciation rate were:

- the statistical analysis of data;
- current policies and outlook as determined through conversations with operations and management personnel over a number of years; and
- survivor curve estimates from previous studies of this company and other natural gas distribution and transmission companies.[807]

885. In conducting the depreciation study that resulted in the proposed rates Gannett Fleming did not conduct field inspections. Gannett Fleming held meetings with management and operational staff of AG and provided copies of the interview summaries in an information response.[808] Gannett Fleming relied on industry experience in determining whether the resulting depreciation rates were reasonable.[809]

886. With respect to the negative salvage component of the depreciation study, Gannett Fleming submitted that the change in net salvage was based primarily on their professional judgment, in part based on historical data from 1995 to 2009, and in part on a comparison to peer natural gas distribution companies. The salvage analysis in the Gannett Fleming study indicated a range of salvage values from +23 to -533 per cent.[810] Gannett Fleming did not always recommend adjusting the net salvage percentages to those indicated in the net salvage study.[811] Gannett Fleming instead sometimes proposed minor changes to the existing net salvage percentages.

887. AG proposed a contract life depreciation methodology for assets that are dedicated to custom service. AG submitted that it would be appropriate to depreciate facilities specific to custom service over the life of the custom service contract.

888. AG proposed, in response to Directive 45 from Decision 2008-113, a change in the methodology of how it amortizes its' leasehold improvements.

806 Exhibit 3, 2011-2012 GRA application, Section 5.0, Attachment 1, page III-4.
807 Exhibit 3, 2011-2012 GRA application, Section 5.0, Attachment 1, page II-19.
808 Exhibit 84.01, AUC-AG-91, Attachment 2.
809 Response to AUC-AG-91.
810 Depreciation study, V-3.
811 Exhibit 3, 2011-2012 GRA application, Section 5.0, Attachment 1, page II-28 to II-29.

Views of the parties

889. UCA raised concerns regarding the results of the depreciation study. Jacob Pous, the UCA's depreciation expert, concluded after reviewing the information provided by Gannett Fleming and other information, that "…the depreciation request is not well-supported and results in excessive depreciation expense."[812]

890. Mr. Pous asserted that the Gannett Fleming study failed to properly recognize life-lengthening impacts on assets reflected in the record. In his evidence he explained the principle behind his concern:

> As discussed later for several accounts, the Company's historical data reflects the impact of early retirements due to problems with early generation PVC and plastic pipe, as well as a program to move meters from interior locations to the exterior of residences. While these programs have resulted in retirements of investment prior to normal anticipated ages, they no longer impact meaningful portions of the remaining investment in service. Therefore, their impacts as reflected in the historical observed life tables must be normalized or compensated for in making predictions for the remaining investment currently in service, which are not subject to these historical programs. ... lack of recognition of such investment mix versus retirement mix would yield noticeably inaccurate expectations for future events.[813]

891. During the oral hearing Mr, Pous was asked to comment on what the impact would be to the Gannet Fleming depreciation study if it had considered the impact of the life lengthening information provided in the manner Mr. Pous considered proper. Mr. Pous provided the following example:

> For example, the early retirement of plastic and what impact that may have.
>
> I asked for the data to demonstrate what the life characteristics were for the plant that was at issue with the earlier plastic, and it showed a lower survivor curve for that investment; which means if you removed it, you would elevate the remaining investment.
>
> So you take that into account. That has an impact, and it's a quantifiable impact, from the standpoint of knowing it's going to increase the average service life.[814]

892. Mr. Pous considered four of the larger utility plant depreciation accounts[815] and recommended average life cycle adjustments that would result in a reduction to depreciation expense of $8,367,000 and $8,980,000 for 2011 and 2012 respectively.[816] The UCA proposed the following changes to depreciation rates:

[812] Exhibit 110.02, page 4, Question 7.
[813] Ibid., page 6, Question 13.
[814] Transcript, Volume 8, page 1778.
[815] Accounts 47300, 47400, 47500 and 48400.
[816] Exhibit 110.02, page 4, Question 7.

Table 47. UCA proposed depreciation rate adjustments[817]

Account	Account Title	Current Rate[818]	ATCO Proposal	UCA Proposal	Reduction to Forecast Depreciation Expense Proposed by the UCA[819]	
					2011	2012
47300	Services	4.44%	4.03%	3.92%	$993,000	$1,075,000
47400	Regulator & Meter Installations	3.02%	3.49%	2.71%	$1,557,000	$1,652,000
47500	Mains	2.94%	3.20%	2.67%	$4,169,000	$4,509,000
48400	Transportation Equipment	8.74%	10.26%	8.90%	$1,647,000	$1,744,000
	Total				$8,366,000	$8,980,000

893. Mr. Pous also submitted that the net salvage estimates in the Gannett Fleming study are based on generalized claims of professional judgment and a comparison with a limited number of other gas distribution companies. Mr. Pous submitted that a lower negative salvage amount would be appropriate for two accounts[820] (47400 - Regulator and Meter Installations, and 47500 - Mains) and would result in a further reduction to depreciation expense of $5,816,000 and $6,283,000 for 2011 and 2012 respectively.[821]

894. Since changes to average life cycle estimates and net salvage parameters for the same account impact each other, the combined impact of the recommended life and salvage adjustments to depreciation expense would be a net reduction of $13,499,000 in 2011 and $14,527,000 in 2012.

895. The CCA generally agreed with the view of the UCA.

896. Calgary generally agreed with the view of the UCA. In addition Calgary raised concerns with respect to the depreciation reserve account and the production abandonment accounts. Calgary submitted that these accounts were inappropriate in light of certain court decisions.

7.2 Average service life

897. Gannett Fleming calculated the annual and accrued depreciation using the straight line method and the equal life group (ELG) procedure. The calculated annual depreciation amounts were determined on a whole life basis, meaning that if the annual amount from age zero to the maximum age was recovered it would result in complete capital recovery assuming the life and net salvage forecasts are realized. The methodology used to determine the annual service life estimates was explained as follows:

> The method of estimating service life consisted of compiling the service life history of the plant accounts and subaccounts, reducing this history to trends through the use of analytical techniques that have been generally accepted in various regulatory jurisdictions, and forecasting the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of the historical trend and the estimated future trend yielded a complete

817 Exhibit 110.05.
818 Application, Section 5, Depreciation Study, Part 9-III, Schedule 3.
819 Exhibit 110.02, Depreciation Evidence UCA, page 11, Q/A 20, page 14, Q/A 25, page 18, Q/A32, page 20, Q/A37.
820 Exhibit 110.02, page 23, Question 45.
821 Ibid., page 3, Question 7.

> pattern of life characteristics from which the average service life was derived. The service life estimates used in the depreciation calculation incorporated historical data compiled through December 31, 2009. Such data included plant additions, retirements, transfers and other plant activity.[822]

898. Gannett Fleming discussed the factors that it considered in determining the appropriate Iowa curve to determine the average live for a property group in the following manner:

> The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined through conversations with operations and management personnel over a number of years; and survivor curve estimates from previous studies of this company and other natural gas distribution and transmission companies.[823]

899. In his critique of the Gannett Fleming evidence Mr. Pous submitted that:

> … as standard Iowa Survivor curves normally do not match observed life tables at all points of the two curves, it is necessary to employ appropriate, but justifiable, judgment. A particularly important aspect of the curve-fitting process is to be cognizant of the dollar level of plant exposed to retirement forces at each point in the observed life table. The normal basis for curve fitting is to accept the "best" fit.[824]

900. Mr. Pous submitted that Gannett Fleming has incorrectly understood and misapplied the underlying premise of the impact of dollar level of exposures during the curve fitting process. Gannett Fleming therefore had not exercised its judgment appropriately in the curve-fitting process. This principle is set forth in "Depreciation Systems" by Frank K. Wolf and W. Chester Fitch:

> The analyst also must decide which points or sections of the curve should be given the most weight. Points at the end of the curve are often based on fewer exposures and may be given less weight than points based on larger samples. The weight placed on those points will depend on the size of the exposures. Often the middle section of the curve (that section ranging from approximately 80% to 20% surviving) is given more weight that the first and last sections. This middle section is relatively straight and is the portion of the curve that often best characterizes the survivor curve.
>
> Begin fitting with the left modal curves and identify the two or three curves that appear to best fit the data. Note the curve type and the corresponding average life, which is typically estimated to the nearest year. Continue with the symmetrical, right modal, and origin modal curves. Some groups may not give a suitable fit.
>
> Continue by reexamining the contenders selected during the first pass. Often the choice between two or three tentative selections is difficult to make. The conservative choice is toward the lower life and right modal curve.[825]

901. Mr. Pous submitted that: "…the dollar levels of exposures dictate the portion of the survivor curve on which to focus, rather than simply assuming the area between 80% and 20% is

[822] Application, Section 5, Depreciation Study, Part I-3, page 7.
[823] Exhibit 3, 2011-2012 GRA Application, Section 5.0, Attachment 1, page II-19.
[824] Ibid., page 4, Question 10.
[825] *Depreciation Systems*, Frank K. Wolf, W. Chester Fitch, Iowa State University Press, 1994, pages 46-47.

the critical area."[826] Mr. Pous suggested that Mr. Kennedy, appearing on behalf of Gannett Fleming, had improperly placed more weight on the end of the curve than is appropriate, stating:

> While Mr. Kennedy recognizes that the dollar level of exposures for a particular account has an impact on the curve-fitting process, he has incorrectly understood and misapplied the underlying premise.[827]

902. Mr. Pous further expanded on this point during testimony:

> He, from my review of the information, was more generous to the tail portion of the curve, which is less statistically valid, than to the middle portion and the upper portion of the curve, which is a much more stable portion of the curve.[828]
>
> So you match the points of the curve not necessarily as closely at the top because of some of the infant mortalities that occur at that level, but you sure don't match the points of curve at the bottom and sacrifice the middle and upper portion as Mr. Kennedy has done in his process.[829]

903. Mr. Pous submits that actuarial analysis is not the only the factor that should be considered in determining average service life and dispersion patterns. When referring to the impact of early retirement programs, Mr. Pous stated:

> While these programs have resulted in retirements of investment prior to normal anticipated ages, they no longer impact meaningful portions of the remaining investment in service. Therefore, their impacts as reflected in the historical observed life tables must be normalized or compensated for in making predictions for the remaining investment currently in service, which are not subject to these historical programs.[830]

904. Mr. Pous further comments that when the asset mix within a single depreciation account contains a broad range of assets of various vintages:

> … lack of recognition of such investment mix versus retirement mix would yield noticeably inaccurate expectations for future events.[831]

905. In the depreciation rebuttal evidence, Mr. Kennedy discussed his use of a residual measure to quantitatively determine the quality of fit for Iowa curves:

> However, the only way to quantitatively determine the quality of fit is through a mathematical calculation of fit. An index of mathematical fit is determined through the calculation of "Residual Measure". The most commonly accepted method of mathematically fitting survivor curves is to determine the algebraic differences between the percents surviving on the smoothed Iowa curve and the original survivor curve as plotted from the retirement ratios as calculated in the retirement rate analysis. The algebraic differences are squared and summed. The Residual Measure (or standard error of estimate) is the square root of the average difference squared between the percents surviving on the fitted smooth curve and the original life curve. The residual measure

826 Exhibit 110.02, page 5, question 12.
827 Ibid.
828 Transcript, Volume 8, page 1762, lines 4-8.
829 Transcript, Volume 8, page 1762, lines 20-25.
830 Exhibit 110.02, page 6, Question 13.
831 Exhibit 110.02, page 6, Question 13.

> represents the mathematical criterion of "goodness of fit" and is the commonly used statistic for comparing the conformity among the various Iowa curve types. As the mathematical goodness of fit is a calculation differences between the observed life table and the smoothed Iowa curve, the lower the residual measure, the better the degree of mathematical conformity.[832]

906. Mr. Pous criticized the use of the residual measures method as a means to determine the best fitting Iowa stating:

> The residual measure is absolutely wrong, and even if the publication that Mr. Kennedy relies upon for his 80/20 example, they indicate that you have to get different weighting to different points on the curve. Doing a residual measure gives every point on the curve the same weighting. It's just not done. You use visual curve fitting, which Mr. Kennedy only did really at the beginning. He only brought in the residual measure in rebuttal, and it's inappropriate.[833]

907. The Commission will next consider the four accounts for which the UCA is proposing a different depreciation rate from that forecasted by AG.

7.2.1 47300 – services[834]

908. The utility plant in this account is the installed cost of the urban service lines used to connect the customer premises to the main.

909. In the depreciation study Gannett Fleming indicates that this account represents 32 per cent of the utility plant studied. Gannett Fleming reviewed the retirements, additions, and other plant transactions from 1912 to 2009 using the computed mortality and retirement rate method. AG's current Iowa curve for this account is 52-R2.5.

910. Interviews between Gannett Fleming and ATCO operations and management have indicated that the account has been subjected to a significant level of retirement activity due to the meter relocation programs. The relocation has resulted in the partial retirement of a significant number of service lines over a range of ages. The operations staff of AG also indicated to Gannett Fleming that the retirement activity over the past number of years is reflective of the expected retirement activity of plant currently in service, in part due to known issues with early generation plastic pipe.

911. Gannett Fleming submitted that the proposed Iowa Curve of 55-R3 fits the historic data, the indications from management and operations of AG, and the professional judgment of Gannett Fleming.

912. Mr. Pous disagreed with the recommendation made by Gannett Fleming with respect to the appropriate depreciation rate for the services account. Mr Pous noted the early retirement activity in relation to early generation PVC and plastic pipe and observed that removing the related data from the observed life table would have the effect of lengthing the average service life. With respect to the program to move meters from inside to outside residences Mr. Pous observed that the dollar value at issue was approximately three per cent of this account. He noted

832 Exhibit163.01, Attachment 1, page 4.
833 Transcript, Volume 8, page 1763, lines 1-13.
834 Application, Section 5.0, Attachement 1, pages II-24 to II-25.

that while the meter program has shortened the average service life due to retirements reflected in the historical life table it is no longer material on a going forward basis for the remainder of investment in service. He also stated that the input from company personnel was misapplied by Mr. Kennedy in limiting the level of increase in average service life.[835]

913. Mr. Pous also suggested that future retirement activity connected with early generation PVC and plastic pipe and the meter relocation program should further increase the average service life to a greater extent than reflected in Mr. Kennedy's analysis. Mr. Pous recommends an Iowa curve of 59-R2.5.

Commission findings

914. The Commission notes that both experts recommend extending the average service life of assets in this account. The Commission is comforted by the fact that both experts propose the same directional change. Mr. Kennedy recommended moving from a 52-R2.5 Iowa curve to a 55-R3 Iowa curve, while Mr. Pous recommended moving to a 59-R2.5 Iowa curve. The standalone impact of Mr. Pous's recommendation would be a reduction in depreciation expense of approximately of $993,000 in 2011 and $1,075,000 in 2012. The Commission did not find the evidence of either expert to be clearly preferable and given the inexact nature of depreciation estimates, the Commission is reluctant to choose either expert. Accordingly, the Commission finds that the midpoint of the two proposed average service lives of 57 retaining the current modal value of R-2.5 which is also recommended by Mr. Pous will provide a reasonable estimate of depreciation expense for Services in the test period.

915. AG is directed in the compliance filing to calculate depreciation expense using a 57-R2.5 Iowa curve for Account 47300, Services.

7.2.2 47400 – regulator & meter installations[836]

916. The utility plant in this account includes the cost of house regulators, whether installed or held in reserve and the cost of labour and materials used in installation of house regulators and meters.

917. In the depreciation study, Gannett Fleming indicates that this account represents 11 per cent of the utility plant studied. Gannett Fleming reviewed the retirements, additions and other plant transactions from 1912 to 2009 using the computed mortality and retirement rate methods. AG's current Iowa curve for this account is 45-R4.

918. Interviews between Gannett Fleming and ATCO operations and management have indicated that the account has been subjected to a significant level of retirement activity due to meter relocation programs. Gannett Fleming submits that the retirement rate analysis provides a good fit based on the currently approved Iowa curve of 45-R4, and is recommended based on indications from management and operations staff of AG and the professional judgment of Gannett Fleming.

919. Mr. Pous submitted that Mr. Kennedy's proposal incorrectly takes into account the significant level of retirement activity associated with the program[837] to move meters from inside

[835] Ibid.
[836] Application, Section 5.0, Attachment 1, pages II-25 to II-26.

installations to outside residences. Mr. Pous observes that at most five percent of the remaining assets would be subject to this program. Mr. Pous submits that "Mr. Kennedy's proposed life-curve combination is not a good fit for the meaningful portion of the curve."[838] He explains this statement by stating that at approximately 50 years of age the dollar level of exposure drops to such a low level that the curve-fitting process becomes insignificant.[839] Exposures from 50 years onward range from $21,000 to $2 million compared to an initial dollar level of exposures in excess of $280 million. Mr. Pous recommends an Iowa curve of 51R3.

Commission findings

920. Mr. Kennedy recommended maintaining the status quo of an Iowa curve of 45-R4. Mr. Pous is recommending an Iowa curve of 51-R3. The standalone impact of Mr. Pous's recommendation would be a reduction in depreciation expense of approximately of $1.6 million per year during the test period. The Commission finds Mr. Pous' curve to be a better visual fit.

921. AG is directed in the compliance filing to calculate depreciation using an Iowa curve of 51-R3 for Account 47400, Regulator & Meter Installations.

7.2.3 47500 – mains

922. This account includes the installed cost of distribution system mains from the transmission line to the customer service line.

923. In the depreciation study, Gannett Fleming indicated that this account represents 37 per cent of the utility plant studied. Gannett Fleming analyzed the retirements, additions and other plant transactions from 1912 to 2009 using the retirement rate method. AG's current Iowa curve for this account is 62-R2.5.

924. Gannett Fleming submits that discussions with operations and management of AG have indicated that a significant amount of early generation PVC and plastic pipe installed throughout AG's system needs to be retired early. Gannett Fleming notes that AG is commencing a program to retire PVC and plastic pipe installed from 1966 to 1977 which will have a life shortening impact beyond that indicated in the retirement rate analysis. As well the retirement rate analysis indicates that that a higher mode Iowa curve would be appropriate. Gannett Fleming recommends basing depreciation for this account on Iowa curve 60-R3. The supporting rationale for this recommendation is the analysis of historic data, indications from management and operations staff of AG, and the professional judgment of Gannett Fleming.

925. Mr. Pous submitted that Mr. Kennedy's proposal is a movement in the wrong direction and inappropriately reacted to the problems associated with early generation PVC and plastic pipe installed from 1966 to 1977.[840] As stated in the following excerpt from his evidence, Mr. Pous submitted that his proposed Iowa curve 69-R2.5 is a better fit than Mr. Kennedy's. The fit is superior even before considering the impact of other factors that would warrant a longer average service life such as the early retirement of PVC and early generation plastic pipe. Mr. Pous stated:

[837] Transcript, Volume 5, page 904, Gannet Fleming software uses 80-15 per cent, professional judgment looks at the middle section to be considered significant.
[838] UCA evidence, page 12 of 28, Q/A24.
[839] UCA evidence, direct testimony of Jacob Pous, Q22/A22 and Q24/A24.
[840] UCA depreciation evidence, Q/A 28, page 15/28.

> First, my recommendation for a 69 R2.5 life-curve combination is a better fit than Mr. Kennedy's proposed "good fit" to the full depth observed life table, as shown on the graph below. My recommendation is a superior fit for all ages except for the limited period from approximately 28 through 33 years of age. The noted superior fit of my recommendation is prior to the impact of other considerations that also warrant a longer average service life. Indeed, the observed life table should actually be elevated if the retirement activity associated with early generation PVC and plastic pipe were removed from the database.31 In other words, as is logical, the premature retirement of early generation PVC and plastic pipe has caused a shorter life expectancy than what is appropriate for the current remaining pipe in service. The remaining pipe in service does not have the same problem with becoming brittle and the problems associated with joints that the early generation of PVC and plastic pipe has experienced. Therefore, notwithstanding the previously-noted superior fit of my recommendation, a longer average service life than that proposed by Mr. Kennedy is warranted.[841]

926. Mr. Pous observed that the entire remaining investment associated with all mains installed from 1966 to 1977 comprises less than eight per cent of the outstanding balance, such that the observed life table is already lowered from what it would be otherwise due to the early retirement of problematic PVC and plastic pipe.

927. In his rebuttal evidence Mr. Kennedy discussed the use of the residual measure method as a means of mathematically determining the best Iowa curve fit in the following excerpt:

> However, the only way to quantitatively determine the quality of fit is through a mathematical calculation of fit. An index of mathematical fit is determined through the calculation of "Residual Measure". The most commonly accepted method of mathematically fitting survivor curves is to determine the algebraic differences between the percents surviving on the smoothed Iowa curve and the original survivor curve as plotted from the retirement ratios as calculated in the retirement rate analysis. The algebraic differences are squared and summed. The Residual Measure (or standard error of estimate) is the square root of the average difference squared between the percents surviving on the fitted smooth curve and the original life curve. The residual measure represents the mathematical criterion of "goodness of fit" and is the commonly used statistic for comparing the conformity among the various Iowa curve types. As the mathematical goodness of fit is a calculation differences between the observed life table and the smoothed Iowa curve, the lower the residual measure, the better the degree of mathematical conformity.[842]

928. In rebuttal, Mr. Kennedy took issue with Mr. Pous' comment that the remaining pipe in service does not have the same problems associated with early generation PVC and plastic pipe. Mr. Kennedy believes the conclusion is premature and that newer generations of plastic pipe have not been in service for a long enough time to determine whether there will be structural issues associated with modern generation plastic pipe. Mr. Kennedy stated "There is simply no reason to be assured that this will not re-occur with other generations of plastic pipe."[843]

929. Mr. Kennedy also indicated in rebuttal evidence that steel pipe has exhibited a requirement to be replaced beginning at approximately 50 to 60 years of age. Mr. Kennedy indicated that the Iowa curve 60-R2.5 will become "more fit" over the next couple of years given

841 Ibid., Q/A 29, page 15/28.
842 Exhibit 163.01, AG rebuttal evidence, Attachment 1 Q/A 7, page 4/11.
843 Rebuttal evidence of Mr. Kennedy, Attachment 1 to the AG rebuttal evidence Q/A 13, page 6.

the continued retirements of 55 to 65-year old steel mains and older generation PVC and plastic pipe.[844]

930. In testimony Mr. Pous explained his concern with the used of residual measure method used by Mr. Kennedy in his rebuttal evidence in the following exchange with Commission counsel:

> Q. Sir, you took issue with the residual measure analysis that Mr. Kennedy filed in his rebuttal evidence. And, sir, Mr. Kennedy takes the position that the use of the residual measure is a highly acceptable form to use in trying to mathematically verify a visual selection of a curve. Do you disagree with that?
>
> A. Absolutely.
>
> Q. Could you explain why, sir?
>
> A. Because, as I've indicated before, a mathematical curve fitting or least squares residual measure gives every point the equal weighting in the process. Every point has a different weighting. There's only one consultant I know that does mathematical curve fitting, and he does what's called a hazard matrix of analysis which gives every point on the curve a different mathematical weighting. But if you're doing visual curve fitting, you don't use it.
>
> If you do a mathematical residual calculation like Mr. Kennedy did and you do not give every point on the curve a different weighting, I don't know what you've got. You've done a mathematical calculation, yes. The results are absolutely meaningless.[845]

Commission findings

931. The Commission believes the depreciation expense to be charged customers in any year should reflect an appropriate allocation of the cost of utility plant over the periods that benefit from the plant's use in providing utility service. This allocation should be fair to both shareholders and customers. The Commission acknowledges that estimating the appropriate portion of capital assets to be recovered in any one year is not exact and requires consideration of a large number of factors, such as past retirement experience and the assets in question, new technology, salvage values of assets and the ultimate economic life of assets independent of the engineering life of the plant. Given the combination of these and other factors, the precise selection of appropriate depreciation rates for any one test year is a matter requiring considerable judgment.

932. The Commission notes that the experts recommend changing the average service life of assets in this account in different directions. Mr. Kennedy recommended moving from a 62 to a 60-year life, while Mr. Pous recommended moving to a 69-year life. The standalone impact of Mr. Pous's recommendation would be a reduction in depreciation expense of $4.169 million in 2011 and $4.509 million in 2012.

[844] Ibid., page 7, Q/A 13.
[845] Transcript, Volume 8, page 1769, lines 5 to 25.

933. The Commission finds the evidence of Mr. Pous more persuasive for this account. The Commission agrees with Mr. Pous' position that the Iowa 69-R2.5 is a better visual fit to the actual data than the 60-R3 curve proposed by Mr. Kennedy.

934. The Commission agrees with Mr. Pous that the residual measure method used by Mr. Kennedy is not a helpful tool in determining the best visual fit.[846]

935. As noted in the introduction to this section, the Commission and its predecessors have noted that:

> …estimating the appropriate portion of capital assets to be recovered in any one year is not exact and requires consideration of a large number of factors, such as past retirement experience and the assets in question, new technology, salvage values of assets and the ultimate economic life of assets independent of the engineering life of the plant. Given the combination of these and other factors, the precise selection of appropriate depreciation rates for any one test year is a matter requiring considerable judgment.[847]

936. With respect to this account, in addition to the Iowa curve analysis provided by the experts, the Commission has also considered a number of factors as being relevant in determining a fair and reasonable expense. The Commission acknowledges that both experts have indicated that they considered some other factors in exercising their judgment.

937. The factors examined below directionally support an increase in average service life of mains in service:

- Statements on the record that the expected working life of modern plastic pipe is expected to exceed 100 years.[848]

- Statements on the record that the steel mains subject to the proposed proactive steel mains replacement program are targeted to be removed over a 100-year program.[849] The Commission notes Mr. Dixon's statement[850] that this must be reassessed over the life of the project and notes that depreciation will similarly be reassessed over time.

- The following exchange with Commission counsel estimating an approximate average age of steel mains at the time they would be replaced under the proposed replacement program:

> Q. I understand, sir. I'm just trying to understand what the average life will be of the pipe when it's replaced underthe program as far as you can estimate now based on existing assumptions.
> MR. DIXON: I would go with about 80, 80 years old.[851]

846 Transcript, Volume 8, page 1769, lines 5-25.
847 Decision U96001, page 66.
848 Application, page 2.1-17, paragraph 46; application, Volume 2-2, Tab 2.1, Business Case 4, page 6, paragraph 6; and UCA-AG-18(a,b), page 2 of 5.
849 Application, page 2.2-2, paragraphs 5 and 22; Exhibit 84.01, AUC-AG-4, page 5 of 10; Exhibit 84.01, AUC-AG-59(c).
850 Transcript, Volume 5, page 1011, lines 4-5.
851 Transcript, Volume 5, page 1053, lines 7-12.

- The impact of improved coatings on steel pipe.
- The introduction of cathodic protection in the 1940s.[852]

938. The impact of improved coatings on steel pipe and cathodic protection on service life was discussed by Mr. Dixon with Commission counsel:

> Question: Okay. And what I'm trying to understand, sir, is there was some suggestion, and we'll get into depreciation tomorrow, Mr. Kennedy, but some suggestion that around 60 years is the present foreseeable average useful life of this class of steel mains, but your program is aimed at replacing the mains over a hundred years. So perhaps you can explain why 100 as opposed to 60 or something else?
>
> A. MR. DIXON: Well, as I mentioned a little bit earlier, that, you know, we anticipate that the coatings on steel pipe and cathodic protection have got better and better over time, so I fully expect that 60 year life that we have now is going to get longer as we move out through the program. I'm depending on that actually.[853]

939. The Commission has acknowledged that the experts have considered these factors in their analyses. As noted in Decision U96001 above, the assessment of the relevant factors requires considerable judgment. In the Commission's judgment, these factors suggest a directional increase in the forecast physical life for a significant proportion of the value of plant in service is warranted and should be reflected in the determination of a reasonable depreciation rate for this account. The Commission recognizes that physical life is not the only determinant of service life for the mains. For example, pipe may be retired based on market factors, capacity factors, line relocations or third party impacts. Consequently, the Commission will temper the extent to which it relies on the factors indicating an increase in average service life.

940. Based on all the considerations analyzed above, the Commission considers that there is support for an increase in the average service life of this account. As noted, the Commission prefers the visual fit of Mr. Pous' Iowa curve 69-R2.5, which is directionally supported by the review of the other factors analyzed above. Despite the good visual fit, moving to a 69-year average service life for the account as proposed by Mr. Pous would have a sizeable impact on depreciation expense, cash flow and rates. Given the inherent uncertainty in estimating physical lives of plant and service, and the uncertainty regarding the extent to which factors other than physical life will impact average service life, the Commission favours a gradual increase in the estimated average service life for this account. Accordingly, the Commission finds that the use of an average service life that is the approximately the midpoint of the existing depreciation life of 62 years and Mr. Pous' recommended life of 69 years, retaining the modal value of R-2.5 currently in use and proposed by Mr. Pous would result in a reasonable estimate of depreciation expense for mains in the test period.

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[852] Ibid., pages 1026 to 1027; UCA-AG-07 (b). The Commission notes the discrepancy that Mr. Dixon stated in the transcript that cathodic protection was introduced in the 1960s.

[853] Transcript, Volume 5, page 1010, lines 5-17.

941. AG is directed to calculate depreciation using an Iowa curve for 66-R2.5 for account 47500, mains in the compliance filing to this decision.

942. The Commission considers that the determination of a depreciation rate for this account has been particularly difficult given the size of the account and the mix of non-homogeneous assets of different vintages. The Commission notes the discussion at the hearing about the possibility of introducing accounting mechanisms to segregate the account into multiple accounts of a more homogeneous nature. The lack of detailed historical records was an impediment to further segregation at this time. The Commission directs AG to report in the compliance filing to this application on the feasibility of further segregation of significant accounts on a go-forward basis.

7.2.4 48400 – transportation equipment

943. Account 48400 is the account for the vehicles that AG utilizes and represents approximately 2.5 per cent of the utility plant studied. Gannett Fleming and AG provided limited evidence regarding the proposed change to a 9-L1.5 Iowa curve. The current depreciation rate is 8.74 percent compared to the proposed depreciation rate of 10.26 per cent.

944. Gannett Fleming justified its recommendation of Iowa curve 9-L1.5 on the following:

> A review of the average service life selections of the peer group related to this company indicated that four out of the five peer companies have approved average service life estimates less than the nine years as recommended in this proceeding. Gannett Fleming views that the recommended Iowa 9-L1.5 curve best combines all relevant factors including:
>
> • The fit of the observed life table as presented at page IV-38 of the Gannett Fleming study;
> • The comments of operational management as summarized in Information Request Response AUC-AG-91 – Attachment 2; and
> • A review of the approved average service lives of the peer utilities as presented in response to Information Request UCA-AG-110(b).[854]

945. Mr. Pous submitted that the all-in analysis that Gannett Fleming uses, which includes vehicles dating back to 1947, is inappropriate for an account in which 92 per cent of the assets were placed in service subsequent to 1996. Based on Mr. Pous' analysis the observed life tables elevate as more recent experience bands are employed. Mr. Pous submits that this is indicative of a clear trend towards longer average service lives compared to the singular observed life table that Gannett Fleming used.[855] Mr. Pous proposes the use of an 11-L2 Iowa curve and a corresponding depreciation rate of 8.90 per cent.

Commission findings

946. The Commission notes that both experts recommend a higher depreciation rate for the assets in this account. Mr. Kennedy recommended a nine year life, while Mr. Pous recommended an 11-year life. Mr. Pous' recommendation would result in a reduction of depreciation expense of approximately $1.7 million per year during the test period. The Commission finds the Iowa curve proposed by Mr. Pous to be a better visual fit to the data. Further, the Commission does

[854] Exhibit 163.01, Attachment 1to AG rebuttal evidence page 8, Q/A 15.
[855] UCA evidence, direct testimony of Jacob Pous, page 19, Q36/A36.

not find the other evidence relied on by Mr. Kennedy, namely management discussions and peer utilities analysis provides sufficient justification for his recommendations. Accordingly, the Commission finds that the use of the 11-R2 Iowa curve proposed by Mr. Pous would result in a reasonable estimate of depreciation expense for transportation equipment in the test period.

947. AG is directed in the compliance filing to calculate depreciation using the 11-R2 Iowa curve for Account 48400, Transportation Equipment.

7.2.5 Other depreciation accounts

948. In addition to the accounts discussed above, AG also applied for changes to the depreciation rates for the following accounts:

Table 48. Depreciation rates for balance of asset accounts

Account	Account Title	Current Rate %	Forecast Rate %	Current Iowa Curve[856]	Proposed Iowa Curve	Depreciation Expense Change $
47200	Structures and Improvements	2.76	2.74	55R2.5	55R3	-2,915
47401	Meter Equipment Installations	7.45	6.69	13R4	15R2	-104,972
47700	Measuring and Regulating Equipment	4.08	3.82	38R2	40R2.5	-199,750
47701	Measuring and Regulating Equipment – Electronic	6.44	5.59	15R5	17R3	-9,585
47800	Meter Equipment	3.68	5.08	25R2.5	20R0.5	1,647,498
47801	Meter Equipment – Electronic	6.89	7.05	14R4	15R2	50,377
48200	Structures and Improvements	2.76	2.99	40S1	40R2	223,913
48201	Structures and Improvements – Security Systems	10.56	10.00	10R2.5	10R2.5	-25,918
48300	Office Furniture and Equipment	4.90	5.00	20SQ	20SQ	16,300
48401	Transportation Equipment – NGV	10.22	9.79	9SO	9R1	-14,017
48500	Heavy Work Equipment	5.65	7.53	13L2.5	10L2.5	420,219
48600	Tools and Work equipment	4.50	5.18	20SQ	15SQ	178,142
48800	Communication Structures and Equipment	5.82	5.36	17L2.5	20S0.5	-86,504
48801	Communication equipment – Mobile	7.71	6.25	12R5	15R5	-85,363
48900	Stores, Shop & Garage Equipment	3.60	3.95	25SQ	15SQ	24,792
49001	Natural Gas Vehicle Refueling Equipment	5.15	4.31	19R4	22R2.5	-27,526
49600	Specialized Computer & Electronic Office Equipment	9.77	9.04	10R4	10R4	-14,152

949. Aside from Account 47800 – Meter Equipment, Gannett Fleming and AG did not provide any supporting rationale for the proposed changes.

950. With respect to Account 47800 Gannett Fleming submitted in the depreciation study that more stringent compliance requirements recently introduced by Measurement Canada will result

856 AG 2008-2009 GRA, Section 5.01, Attachment 1, pages 11-12.

in a shorter life than indicated in the retirement rate analysis. Additionally, AG no longer intends to refurbish residential meters. Accordingly Gannett Fleming views that the Iowa 20-R0.5 will represent the future retirement trends of the account.[857]

Views of the parties

951. No parties provided comments on these proposed depreciation rates changes. Mr. Pous did not provide an analysis with respect to these accounts.[858]

Commission findings

952. The Commission will consider Account 48400 separately from the other accounts. With respect to the balance of the "other depreciation accounts" identified above, the Commission notes that the interveners did not file evidence with respect to these accounts and that the aggregate net change in depreciation expense is $1,990,539 in the test period. The Commission has denied a number of programs in other parts of this Decision which may have assets reflected in some of these accounts. Accordingly, the Commission directs that the assets associated with denied programs be removed from these accounts and reflected in the compliance filing to this decision. Subject to the removal of the denied assets, the Commission approves the depreciation expense for these other depreciation accounts.

953. For Account 48400 the Commission notes that a change in depreciation rate is proposed based on a change in standards and a change in company policy regarding the repair of meters. Given the direction earlier in this decision, the Commission will defer its decision on this account to the compliance filing.

7.2.6 New depreciation accounts

954. AG is seeking approval for the following accounts:

Table 49. Proposed new depreciation accounts

Account	Account Title	Forecast Rate	Proposed Iowa Curve
47802	Meter Equipment – AMR	7.44%	18R2
	Geothermal – Plumbing, Controls & Meters	6.74%	20R2
	Geothermal – Ground Loop	2.38%	55R3
	Geothermal – Heat Pumps	8.15%	15R3
	Solar – Tube & Plate Collectors	4.86%	20R1
	Solar – Tanks	9.10%	12R3
	Solar – Plumbing, Controls & Meters	6.91%	20R2

Views of the parties

955. Interveners did not provide comments on the above new proposed accounts in the depreciation sections of their evidence. However, as discussed in Section 6.3.14, interveners questioned the inclusion of these assets in rate base.

[857] ATCO GRA filing 2011-2012, Section 5, Attachment 1, page II-26.
[858] Transcript, Volume 8, page 1784, line 8-10.

Commission findings

956. With respect to the proposed Account 47802 for low use AMR, the Commission notes the evidence on the record regarding the expected battery life on the AMR devices to be twenty years.[859] As discussed in Section 4.7 the Commission has approved the AMR program and also approves the forecast depreciation rate and Iowa curve.

957. As discussed in Section 6.3.14 of this decision, the Commission has denied the programs related to geothermal and solar energy and directed that the related assets be removed from rate base.

7.3 Contract life depreciation for custom service

958. The contract life method of depreciation is presently used only to amortize the cost of leasehold improvements. AG applied to use contract life depreciation to depreciate the cost of custom built facilities constructed to provide delivery service to specific customers. Such "Custom Services" are provided under a fixed term contract, accordingly, AG submitted, it would be appropriate to recover the cost of facilities for the service over the life of the contract.

959. In UCA-AG-117,[860] the AG noted that ATCO Pipelines used the proposed method of contract deprecation for similar facilities. AG indicated that the terms of the custom services contract included provisions requiring the customer to pay out the remaining value of the contract should they leave the system prior to the end of the term.

960. Interveners did not object to the proposed depreciation treatment of contract services.

Commission findings

961. A custom service agreement is entered into to provide service to a customer where service cannot otherwise be provided by existing AG facilities. These agreements require the installation of custom facilities to serve the specific customer. No other customers on AG's system benefit from the installation of the custom facilities. In these circumstances the Commission agrees with AG that the costs of depreciation, which include the costs of salvage, removal and retirement, with respect to the custom facilities should be allocated to the specific customer over the term of the contract.

962. Should additional customers be added to such customer facilities, the Commission would expect that the appropriate amendments would be made to the custom services agreement with the original customer to reflect a sharing of future costs with the additional customers.

[859] Business Case 7, paragraph 21.
[860] Exhibit 83.01.

7.4 Net salvage rate changes

963. AG applied for changes to its net salvage rates for certain accounts presented in the following table:

Table 50. Proposed net salvage rate changes (Table 5.4.1)[861]

Account	Account Title	Current Rate %	Forecast Rate %
47400	Regulator and Meter Installations	-30	-50
47401	Meter Equipment Installations	-10	-20
47500	Mains	-60	-75
47800	Meter Equipment	10	0
48400	Transportation Equipment	25	10
48401	Transportation Equipment - NGV	0	5
48500	Heavy Work Equipment	30	25
48600	Tools and Work Equipment	10	0
48900	Stores, Shop & Garage Equipment	10	0

964. Gannett Fleming described its "Traditional Approach" methodology for estimating net salvage percentages as follows:

> The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data for the years 1995 through 2009, and in part through a comparison to peer natural gas distribution companies. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on both annual and five-year moving average bases.[862]

965. In testimony Mr. Kennedy clarified the above statement by indicating "…the priority is given based on the circumstances of each account, and in the circumstances of most accounts the priority would have been given to the statistical analysis."[863]

966. Gannett Fleming indicated that the results of its salvage analysis demonstrated very significant increases on costs of retirement. However, certain increases were related to meter relocation programs and other increases were not consistent with rates approved for other natural gas utilities. Accordingly, Gannett Fleming recommended:

> …only minor revisions to the net salvage percentages in this study, but also notes that the next net salvage study may require significant increases in the net salvage percentages if the recent trends continue.[864]

Views of the parties

967. Mr. Pous submitted that the net salvage estimates of Gannett Fleming were based on generalized claims of professional judgment and comparison with a limited number of other gas

861 Response to AUC-AG-89 (c), Attachment, page 1 of 2.
862 Depreciation Study, pages II-27-28.
863 Transcript, Volume 6, page 1332, line 9 to page1333, line 2.
864 Depreciation Study, page II-29.

distribution companies. Mr. Pous reviewed three accounts. For Account 47300, Services, Mr. Pous agreed with Mr. Kennedy that the existing rate of -100 per cent net salvage should be retained. For accounts 47400 and 47500, Mr. Pous recommended retention of the existing negative salvage rates as indicated in the table below which would result in a standalone reduction to forecasted depreciation expense of $5,816,000 and $6,283,000 for 2011 and 2012 respectively.[865]

Table 51. UCA proposed net salvage adjustments[866]

Account	Account Title	ATCO Proposal	UCA Proposal
47400	Regulator & Meter Installations	-50%	-30%
47500	Mains	-75%	-60%

968. Mr. Pous submitted that neither AG nor Gannett Fleming provided an explanation why AG's historical data yields negative net salvage values much more negative than other peer utility companies, making the position of AG unacceptable.[867] In argument the UCA summarized the evidence of Mr. Pous in the following way:

> 282. Mr. Pous explains why investigation into the database is necessary given the unusually high levels of negative net salvage. Mr. Pous identified potential problems such as unreasonable and disproportionate allocation between the cost of new installation and cost of removal where replacement activity occurs, a disproportionate level of emergency situations reflected in the historical data, or the impact of the meter moving program that can be expected to result in increased cost of removal compared to normal retirement activity. It is the Company's total failure to explain or justify the values in its database, but arbitrarily reducing actual values to an unsupported level, that causes the entire net salvage presentation to be lacking as an appropriate basis upon which to make net salvage proposals.[868] (footnotes omitted)

969. Because of the difficulties with the AG data and lack of explanation for why the AG data is different from its peer group, Mr. Pous believes it would be more reasonable for AG to retain the currently approved net salvage percentages.

970. In rebuttal, Mr. Kennedy responded to the suggestion that Gannett Fleming relied solely on judgement and a peer review to determine the net salvage percentages. Mr. Kennedy indicated that the net salvage percentages for all accounts were based, first and foremost, on a mathematical calculation of historical data which was then moderated.

Commission findings

971. The Commission agrees with the UCA and the evidence of Mr. Pous that AG has failed to provide sufficient justification for the proposed changes to the net salvage rates. Neither Mr. Kennedy nor AG have provided a reasonable explanation for the large changes in net salvage percentages calculated by Mr. Kennedy in his analysis. The explanation provided by Mr. Kennedy for the proposed modified net salvage rates, based on the calculated percentages, lacks the robustness and precision necessary to support the determination of the proposed net

865 Ibid.
866 UCA evidence, direct testimony of Jacob Pous, Q45/A45.
867 UCA evidence, direct testimony of Jacob Pous, Q42/A42.
868 UCA argument, page 90, paragraph 282.

salvage rates. In the absence of probative evidence the Commission is inclined to deny the requested increase in net salvage rates for the test period. However, the Commission is concerned that should the current net salvage rates be insufficient, continuation of existing rates for an extended period of time may result in intergenerational inequity for ratepayers and unfairness to the utility. Accordingly, the Commission would entertain a timely separate application outside of the compliance filing process on net salvage rates for the test period. AG is directed to indicate in the compliance filing to this decision whether it will be submitting a separate application and if proceeding, the anticipated filing date. If AG chooses not to submit a separate application the existing net salvage rates will remain in place for the test years. If AG chooses to file a separate application, the compliance filing will use the existing salvage rates as placeholders pending a decision on the separate application.

7.5 Depreciation reserve deficiency

972. A depreciation reserve difference for an asset class is the cumulative difference between the depreciation expense as recognized and the balance needed in the accumulated depreciation account based on the surviving assets and the identified parameters. Two factors contribute to the reserve difference: changes in depreciation parameters (the Iowa curve specified) and a change in the composition of the asset account due to a different weighting by asset vintage.[869]

973. AG has calculated its depreciation reserve differences at December 31, 2009 based on the proposed depreciation rates. The net depreciation reserve deficiency for all asset classes was calculated to be $160,240 million. AG is requesting approval of recovery of the annual amortization of the depreciation reserve differences of $6.66 million.

974. In evidence, Calgary objected to the recovery of this amount.[870] Calgary submitted that the recovery of a depreciation reserve deficiency is inconsistent with the decision of the Supreme Court of Canada in *ATCO Gas & Pipelines Ltd. V. Alberta (Energy & Utilities Board)*. 2006 SCC 4, [2006] 1 SCR 140 (Stores Block decision). The Stores Block decision dealt with a disposition of property previously included in rate base. Calgary submitted that the Stores Block decision denied ratepayers the ability to recover from the proceeds of disposition an amount in respect of depreciation expense attributable to the asset and previously collected through rates.

975. Calgary submitted that the recovery by AG of an amount in respect of the depreciation reserve deficiency through future rates should similarly be disallowed. Calgary stated:

> If the refund of over collected depreciation – based upon the ultimate selling price – is considered to be retroactively changing rates, then charging customers based upon an under collection of depreciation over prior periods has to similarly be retroactively changing rates, since it is just the converse of the situation that [sic] Court found to be inappropriate.[871]

976. Calgary submitted that any amortization of the depreciation reserve deficiency of $160.2 million would be contrary to the Stores Block decision. The appropriate adjustment would reduce the revenue requirement by $6.66 million plus the tax impact in each of the test years.

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869 Application, Section 5.0, Attachment 1, page 9.
870 Exhibit 109.02, page 20-21.
871 Exhibit 109.02, page 21, lines 17-21.

977. AG submitted in rebuttal evidence that:

> …the use of a depreciation reserve is a long-standing and necessary depreciation practice. It is a forward looking process that adjusts future depreciation expense to ensure full recovery of costs and to distribute the cost of the asset over its service life as evenly as possible. While Calgary takes the position that the recovery of a reserve deficiency is not legal, it remains silent about situations where the reserve is in effect reducing future depreciation expense. It should be noted that the depreciation reserve deals with both situations.[872]

978. The UCA submitted in argument that "…in order to assess whether the recovery of a depreciation reserve deficiency amounts to retroactive rate-making, it is necessary to consider the nature and function of the depreciation reserve."[873] The UCA then proceeded to illustrate the difference between the recovery of under-collected depreciation expense and the matter at hand in the Stores Block decision which dealt with the jurisdiction of the board to distribute the gain resulting from the sale of a utility asset to customers. In particular the UCA submitted:

> While such distribution was compared by one of the parties in that case to a refund of the accumulated depreciation calculated for prior years, the Supreme Court did not equate the gain resulting from the sale of a utility asset to an over collection of depreciation in connection with that asset. Indeed, the Stores Block decision did not directly deal with the issue of depreciation reserves at all. Rather, the crux of the issue in Stores Block was whether customers acquired an ownership interest in the assets themselves through the payment of utility rates. The Supreme Court held that this was not the case…[874] (footnote omitted)

979. The UCA stated that depreciation expense in rates represents a way of allocating depreciation over the life of the asset. As the life of the asset is an estimate and subject to revision, it is reasonable to assume that variances between the amount in the depreciation reserve and accumulated depreciation would occur. The amortization of this variance would not amount to prohibited retroactive rate-making. The UCA also stated that it would expect that a depreciation reserve surplus would be returned to customers through an adjustment to rates. The UCA did not object to the recovery of a depreciation reserve deficiency.[875]

Commission findings

980. The Commission agrees with AG and the UCA that collection of the depreciation reserve deficiency is not retroactive rate making and is not contrary to the court's findings in the Stores Block decision. Annual depreciation expense should reflect a proper allocation of the cost of a utility asset over the life of the asset. By necessity, the determination of depreciation expense in respect of any particular class of assets is an estimate based on the best available data and on professional judgment. As better information becomes available, the depreciation rates are revised with a cumulative adjustment to the depreciation reserve account. This account is amortized on the same basis as the related asset account with the amortized amounts recovered through or offset against revenue requirement.

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872 Exhibit 163.01, AG rebuttal evidence, paragraph 152, page 44.
873 UCA argument, paragraph 293, page 94.
874 Exhibit 200.02, page 96, paragraph 297.
875 UCA argument, pages 96-97, paragraphs 298-299.

981. The Stores Block decision did not address the depreciation rate adjustment practice for assets continuing to provide utility service. The periodic adjustments to these accounts when depreciation rates are updated are intended to refine and improve the allocation of costs over service life. The Stores Block decision was focused on the entitlement to proceeds of disposition of an asset formerly used in providing utility service. It does not deal with a readjustment of depreciation rates for assets remaining in utility service. The court concluded that the proceeds of sale could not be taken from the utility and given to customers on the basis that there and been an over-collection of depreciation expense during the period of time that the asset was in service. Such a refund would amount to a retroactive rate change.

982. The court stated:

> There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation.[876]

983. The collection from customers of a depreciation reserve deficiency or the refund to customers of a depreciation reserve surplus does not amount to retroactive rate making, rather it is a prospective rate setting mechanism designed to ensure that the costs of an asset are recovered over its anticipated service life. The Commission directs AG in its compliance filing to this Decision to update it depreciation reserve deficiency account in accordance with the revised depreciation rates.

984. Accordingly the request of Calgary to deny the collection of the incremental and current amortization of the reserve deficiency is denied.

7.6 Production abandonment costs

985. AG is seeking the recovery of $2.18 million in 2011 and $1.5 million in 2012 with respect to production property abandonment costs. These costs are in respect of production properties which have no carrying value in rate base.[877] AG explained the nature of these costs in the application as follows:

> Production abandonment costs relate to ATCO Gas' obligation to abandon production properties which were previously used to provide utility service. Costs mainly relate to the two following areas: environmental remediation of well and other production sites; and management of issues with previously abandoned properties, such as leaks causing gas migration to the surface. The use of a production abandonment deferral account for each of the north and the south was approved in Decision 2006-004. Accordingly an annual expense amount is included in the revenue requirement forecast for these costs. ...
>
> ATCO Gas retains responsibility for in the order of 371 north and 119 south abandoned production properties. Costs will continue to be incurred to maintain the abandonment of these properties consistent with current standards and statutes.[878]

[876] Stores Block decision, paragraph 71.
[877] Exhibit 82.01, Cal-AG-05(a)(iii).
[878] Exhibit 3, page 5.5-5, paragraphs 14 to 15.

986. A further detailed explanation of the history of these costs can be found in Section 9.7 of Decision 2006-004.[879] [880] Of particular note in this discussion is the description of the costs associated with the Bow Island field which dates back to the early 1900s and was finally retired from utility service in 1996.

987. During the test period, AG proposes to continue to work at 21 well sites and one former compressor site in the north at a forecast cost of, $550,000 per year.[881] In the south, AG will continue to work at 23 well sites and two former compressor sites. As well, AG anticipates remediation of two sites, environmental assessment work at eight sites, and ground water sampling at the remaining sites. The forecast cost for this work is $950,000 per year.[882]

988. An annual expense amount has been included in the revenue requirement forecast for these costs, subject to deferral account treatment. The expense is currently $350,000 for the north account and $700,000 for the south account. AG is proposing that the annual expense account be increased to $550,000 for the north account and $950,000 for the south. The closing deferral account balances in the north and south for 2010 are $0.76 million and $0.24 million respectively, indicating an under-recovery from customers. AG is requesting a one-time deferral account adjustment of $1.1 million in 2011 to recover the difference between the approved expense and the actual costs incurred from 2008 to 2010.

989. Calgary questioned the entitlement of AG to recover the abandonment costs. Calgary referred to the decision of the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2008 ABCA 200[883] (Carbon decision), stating:

> This request comes after the recent Carbon proceedings and decisions, when those production properties that had value and were producing income were removed from rate base, and the customers were required to repay the operating revenues from those properties. One of the criteria was that the properties were not required for operational purposes. The abandoned properties are not required for operational purposes. Further the Court also indicated that the Board's as it then was, reliance on historical use was not appropriate.[884] (footnotes omitted)

990. Calgary referred to the court's finding in the Carbon decision if assets are to be included in rate base in accordance with Section 37 of the *Gas Utilities Act*, they must be "used in an operational sense" by the utility in providing utility service. Calgary referred to paragraph 25 of the Carbon decision which states:

> Thirdly, the only reasonable reading of s. 37 is that the assets that are "used or required to be used" to provide service are only those <u>used in an operational sense</u>. It strains the meaning of the word "used" when applied to "property" to suggest that merely accounting for the revenue generated by the asset constitutes "using" the asset.[885] (emphasis added by Calgary, footnotes omitted)

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879 Decision 2006-004: ATCO Gas, 2005-2007 General Rate Application Phase I, Application No. 1400690, January 27, 2006.
880 ATCO GRA filing 2011-2012, page 5.1-5, paragraph 14.
881 ATCO GRA filing 2011-2012, page 5.1-7, paragraph 17-18.
882 ATCO GRA filing 2011-2012, page 5.1-7 to 5.1-8, paragraph 20-21.
883 Leave to Supreme Court of Canada dismissed [2008] S.C.C.A. No. 347 (S.C.C.).
884 Exhibit 109.02, pages 18-19.
885 Ibid., page 20.

991. Calgary stated that the abandoned production properties do not qualify for inclusion in rate base based on the Carbon decision whether they have carrying value or not because they are not used in an operational sense.[886]

992. Calgary stated that costs associated with properties not properly included in rate base should be for the sole account of the shareholder and not included in revenue requirement. Calgary relied on the following excerpt from the Stores Block decision in support of this position:

> The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. In fact, the wording of the sections quoted above suggests that the ownership of the assets is clearly that of the utility; ownership of the asset and entitlement to profits or losses upon its realization are one and the same. The equity investor expects to receive the net revenues after all costs are paid, equal to the present value of original investment at the time of that investment.[887] (footnotes omitted)

993. Based on the Carbon decision and Stores Block decision, Calgary submitted that the negative net present value of the properties and the associated costs are costs properly directly attributable to AG shareholders.[888]

994. Calgary expressed the view that there is no guarantee that amounts in a deferral account will be included in the revenue requirement in subsequent periods and that there does not appear to be a legal ability to include the amounts requested in the revenue requirement in the test years.

995. AG submitted that the abandoned properties have nothing in common with the assets that were the subject the Carbon storage facility series of proceedings. The properties for which AG is seeking to recover abandonment costs were retired from utility service because the asset had been fully consumed in the provision of utility services, unlike the Carbon assets which had not been fully consumed but which were no longer required to provide utility service. The Carbon assets could still be put to some other, non-utility use. AG submitted that the abandoned production property assets "more closely resemble every other type of utility asset that is fully consumed in the provision of utility service where customers have already derived their full benefit."[889] AG submitted that in this way, the applied for abandonment costs are similar to the use of the depreciation deficiency reserve account; the abandonment costs associated with the assets in question are the difference between estimated cost of removal and the actual cost of removal. Establishing that the abandoned properties qualify for inclusion in rate base is not a pre-requisite for the recovery of the applied for abandonment costs.[890]

996. AG submitted that the Stores Block decision supports AG's position that customers should expect to pay the full cost of service through rates. AG quoted the Stores Block decision where the court stated:

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886 Ibid., page 20.
887 Ibid., page 19, Stores Block decision, paragraph 67.
888 Ibid., page 19.
889 Exhibit 163.01, AG rebuttal evidence, page 44, paragraph 154.
890 Ibid., pages 44 to 45, paragraphs 154 to 155.

> Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources.[891]

997. Because the assets have been fully consumed in the provision of utility service these costs form part of the utility's cost of service, which is recoverable from customers.

998. AG submitted that should the Commission disallow the applied for costs, well after the properties have been fully consumed in the provision of utility service, it "…would represent a change in the regulatory compact which would indicate a significant increase in the level of risk for utilities."[892]

999. AG also referred to previous decisions of the EUB which approved the inclusion of abandonment costs in revenue requirement, including several decisions which approved settlement agreements with customers dealing with the sale of production assets and the allocation of the sale proceeds.[893]

Commission findings

1000. The Commission considers that the issues raised with respect to production abandonment costs are similar to those discussed in connection with the Irma agency office in Section 4.9.4 of this decision. In that section the Commission determined that assets which no longer have an operational purpose are no longer used or required to be used to provide utility service as required by Section 37 of the *Gas Utilities Act* should be retired and removed from rate base. Further if the asset is not disposed of at the time of retirement, it should be moved to a non-utility account whether or not the asset had been fully consumed in providing utility service or whether it had residual value at the time it was retired. Accordingly, all ongoing costs of any nature, including operational and remediation costs (except to the extent that remediation costs are notionally offset by the net salvage component of depreciation expense previously included in rates and collected from ratepayers) associated with the asset after it ceases to have an operational purpose should be removed from revenue requirement and be for the account of the utility shareholder.

1001. AG confirmed that the "production abandonment costs relate to ATCO Gas' obligation to abandon production properties which were previously used to provide utility service."[894] It is not disputed by the parties that the assets to which these costs relate are no longer "used in an operational sense" as required by the Carbon decision. It is also not disputed that the assets are no longer used or required to be used to provide utility service as required by Section 37 of the *Gas Utilities Act* and accordingly would not qualify for rate base consideration. AG takes the position, however, that establishing that the abandoned properties qualify for inclusion in rate base is not a prerequisite for recovery of the applied for abandonment costs. AG refers to the Stores Block decision in support for its position that the ongoing costs of abandonment in respect of an asset that has not been moved to a non-utility account but which is no longer used or required to be used in providing utility service, should be considered as part of the cost of providing utility service and should be recovered from ratepayers as part of the cost of service.

891 Stores Block decision, paragraph 68.
892 Exhibit 163.01, AG rebuttal evidence, page 48, paragraph 170.
893 Ibid., pages 46 to 48.
894 Exhibit 3, page 5.5-5, paragraph 14.

1002. The Commission disagrees. The Stores Block decision can not be relied on for the premise advanced by AG. The court stated that the "utility absorbs losses and gains, increases and decreases in the value of assets."[895] As was the case with the Irma agency office, the Commission considers that all costs, including the ongoing operational and remediation costs associated with assets that no longer have an operational purpose and are no longer used or required to be used to provide utility service, such as the abandoned production assets, should be removed from revenue requirement and be for the account of the utility shareholder as of January 1, 2011.

1003. AG referred to several EUB decisions which approved the inclusion of production abandonment costs in rates in the past. Among these decisions were several which approved settlement agreements reached with customers. These decisions pre-date the Stores Block decision and the Carbon decision and accordingly the Commission has not considered them to be relevant to a consideration to the costs to be allowed in revenue requirement during the current test period.

1004. Given the above determination, all production abandonment costs applied for during the test period are disallowed and shall be removed from forecast revenue requirement in the compliance filing to this decision. Similarly, the deferral account in respect of these costs will be discontinued as of January 1, 2011. The closing deferral account balances in the north and south for 2010 are $0.76 million and $0.24 million respectively. Given that these balances relate to prior periods and the decisions that relate to those periods, AG will be permitted to include a one time recovery of those balances in 2011 revenue requirement.

1005. The Commission directs AG to remove the 2011 and 2012 production abandonment costs of $2.18 and $1.5 million respectively from revenue requirement.

7.7 Methodology change to amortize leasehold improvements

1006. In Decision 2008-113, contained the following Commission direction:

> In its rebuttal evidence, AG committed to review alternative methods for depreciating its leasehold improvement costs and this information will be filed as part of its next GRA. Therefore, the Commission directs AG in its next GRA to provide the referenced study as indicated in rebuttal evidence.[896]

1007. Pursuant to the Commission's direction, AG applied for a change in the methodology used to amortize leasehold improvements. Effective January 1, 2011, AG is proposing to amortize the net book value of leasehold improvements over the remaining life of the associated lease plus one renewal period provided it will not be less than a minimum of five years. In situations where the lease expires prior to the Leasehold Improvement costs being fully amortized, the amortization period would begin declining each year by one year (with no five-year minimum period being applied) until all costs have been recovered.

Commission findings

1008. The Commission finds that the proposed change to the amortization of leasehold improvements complies with the directive and notes that no concerns were raised by interveners

[895] Stores Block decision, paragraph 69.
[896] Decision 2008-113, Commission Direction 45, page 93.

with respect to the proposal. Therefore, the Commission approves the proposed change to amortization of leasehold improvements.

8 Income taxes

1009. ATCO Gas proposed a one-time payment to customers related to the income tax deductible costs of $1.3 million for the North and $4.0 million for the South.[897] The Commission finds that this is consistent with the direction from Decision 2009-214.[898]

9 Utility revenue

9.1 Customer growth

1010. AG forecasted total customer growth of 21,636 in each of the test years.[899] The table below compares this forecast to the 2008, 2009 and 2010 actual and forecast customer growth numbers.[900]

Table 52. Total average customers and growth

	2008 Forecast	2008 Actual	2009 Forecast	2009 Actual	2010 Forecast	2010 Actual	2011 Forecast	2012 Forecast
Total average number of customers	1,015,037	1,010,900	1,048,157	1,026,813	1,055,610	1,045,567	1,067,203	1,088,839
Year over year actual difference				15,913		18,754	21,636	21,636

1011. The Commission has reviewed the 2008 and 2009 customer forecast to actual variances and observes that the variance was -0.64 per cent, 1.63 per cent and -0.96 per cent in 2008, 2009 and 2010 respectively. The Commission notes that no interveners took issue with AG's customer growth forecast. The Commission considers that AG customer forecast has shown to be accurate in the past and would expect that to continue in the test years.

9.2 Throughput forecast and normalization calculation

1012. AG forecast modest throughput growth in each of the test years. The table below compares this forecast to the 2008, 2009 and 2010 actual and forecast customer growth numbers.[901]

897 Application, Section 9.1.2.
898 Decision 2009-214: ATCO Gas, 2008-2009 General Rate Application Phase I, Income Tax Module, Application No. 1553052, Proceeding ID. 11, November 12, 2009, page 24, paragraph 135.
899 Application, Section 7, Table 7.2(a) and 7.2(c).
900 The 2009 and 2010 numbers are found in Exhibit 160.01, Attachment 2, Schedule 6. The 2008 numbers are found in Exhibit 71.02.
901 The 2009 and 2010 numbers are found in Exhibit 160.01, Attachment 2, Schedule 6. The 2008 numbers are found in Exhibit 71.02.

Table 53. Total annual throughput

	2008 Forecast	2008 Normalized	2009 Forecast	2009 Normalized	2010 Forecast	2010 Normalized	2011 Forecast	2012 Forecast
Throughput (TJ's)	233,586	235,676	237,225	235,080	236,997	236,901	240,888	244,034

1013. Consistent with previous GRA filings, ATCO Gas prepared the throughput forecasts for the various rate classes and weather zones using the multiple regression model approach.[902] However, commencing in 2011, ATCO Gas incorporated the use of six weather zones in the development of its throughput forecast as it was directed to do in Decision 2008-113.[903] The addition of the new miduse rate group and the use of six weather zones have significantly increased the number of regression models used by ATCO Gas in the development of its throughput forecast.[904]

Views of the parties

1014. During the oral hearing the CCA questioned whether ATCO Gas should incorporate segmented linear regression analysis in the gigajoules per customer (GJPC) forecasting models.[905] The CCA presented an aid to cross (Exhibit 169) which compared 2008 and 2009 GJPC forecasts to normalized actuals for the residential, low use apartment, and low use commercial customer groups. The charts show that the forecasts were lower than the normalized actuals for those years. The CCA in the oral hearing asked for assurance that those results are not indicative of an under forecasting bias in the forecasting models.[906] As noted by Ms. Hagan under cross-examination:

> Well, one thing that we have done is, when we're using all the data, we are incorporating that higher usage level into the forecast. And the multiple regression models try to get the best fit so that the forecast *(sic)* that come out should not be biased in either way.[907]

1015. In argument the CCA recommended that:

> AG be required to recognize changes in the relationships between temperature and GJPC for the summer, shoulder and non-summer/non shoulder periods, as well as restricted temperatures, when normalizing actual GJPC to normalized GJPC, for purposes of the weather deferral account.[908]

902 The variables are defined in Table 7.1.1.1(a) of the application.
903 Commission Direction 49.
904 The Explanatory Variables by Model are detailed in Table 7.1.1.1(b) of the application.
905 Transcript Volume 1, page 159, line 22 to page 160, line 2.
906 Transcript Volume 1, pages 185, lines 7-10.
907 Transcript Volume 1, pages 185, lines 11-15.
908 Exhibit 204, CCA argument, page 46.

1016. ATCO Gas responded to the CCA in their reply argument that:

> The CCA's discussion of the forecasting methodology and changes to the models that it recommends are very detailed and should have been filed as evidence, rather than as argument. ATCO Gas has had no opportunity to ask questions or rebut this new evidence. As previously noted, the Commission should give no weight to the new positions of the CCA advanced for the first time in Argument.[909]

Commission findings

1017. The Commission is satisfied that the regression models used by AG are consistent with the Direction provided in Decision 2008-113 and are sufficiently accurate to forecast throughput and normalized consumption. The multiple regression approach has been reviewed and approved in the three previous GRA's for AG. The CCA raised concerns with the relationship between temperature and GJPC during various times of the year and the normalization process. The Commission accepts the evidence of AG at the hearing that the multi-regression forecast methodology attempts to get the best fit available to the actual data. The Commission accepts the throughput forecast for the test years.

1018. The Commission notes that in the presentation provided during its SPC Forecast Workshop on June 14, 2010,[910] AG made mention that gas price has not been included in the regression models in past GRA's. In its compliance filing AG is directed to provide information on why it has added gas price as a variable into the regression model and the impact the gas price variable has on its revenue forecast.

9.3 Other revenue

1019. AG provided a table in its application detailing other revenue.[911] The largest component of other revenue is related to services provided to AP for engineering, land services and mechanical services.

Table 54. Other revenue forecast

	2008 Actual	2009 Actual	2010 Forecast	2011 GRA	2012 GRA
ATCO Pipelines	5.4	6.3	5.5	5.9	6.1
Other Affiliates	4	4.2	4.4	4.1	4.5
Total Affiliate	9.4	10.5	9.9	10	10.6
Jobbing	0.9	0.8	0.8	0.8	0.9
Facility Repairs	1.4	1.3	1.4	1.3	1.3
Reinstatement Fees	2.7	2.8	2.8	3.9	3.9
Other	1.1	1.9	1.9	2.9	3.1
Total	15.5	17.3	16.8	18.9	19.8

1020. The Commission notes that in its May 16th update AG provided actual other revenue for 2010 at $18.7 million.

909 Exhibit 218, AG reply argument, page 125.
910 Included in the Application Response to Commission Directions, Decision 2008-113 Commission Direction 50.
911 Application, page 7.0-8, North and South Tables have been combined.

Commission findings

1021. The Commission notes that 2010 actual revenue was very close to the forecast for 2011. Further the Commission notes that the largest component of other revenue is services provided to AP. The Commission directs AG in its compliance filing to discuss if the recently approved integration of AP with NGTL will have an impact on its other revenue from AP including any change to the basis on which the work will be priced. The Commission accepts the revenue forecast for the rest of the components of other revenue for the test years.

10 One-time adjustments and deferral accounts

10.1 One-time adjustments

1022. AG proposed certain one-time adjustments to address balances that have built up in deferral accounts in addition to a specific request in 2012 relating to the DSM incentive/rebate pilot program. In an information request[912] AG provided reasons for its proposed one-time adjustments;

- instances where actual costs incurred have been significantly higher or lower than Commission approved annual recoveries resulting in accumulated balances that are better addressed as a one-time adjustment rather than incorporating the amount into the future expense for the deferral account;
- instances where there is an approved deferral account to defer costs with no recovery/refund mechanism (e.g. Income Tax Deductible Capital Cost deferral Account); and
- instances where the Commission has approved a deferral account that had a specific purpose but is no longer required (e.g. Deferred Schedule C Charge Impact and Deferred Rent).

1023. In an undertaking during the oral hearing AG provided an update to its one-time adjustments.[913] The table below presents the dollar amount associated with each adjustment and the amounts approved in this decision. The table is followed by a summary of the direction provided and a reference to where the direction can be found in this decision.

[912] Exhibit 84.01, AUC-AG-105.
[913] Exhibit 174.02.

Table 55. One-time adjustments

	AG Proposed		Approved	
	2011	2012	2011	2012
	($ millions)			
Deferred Hearing Costs	7.5	0.0	7.5	0.0
Income Tax Deductible Capital Cost Deferral Account	(5.3)	0.0	(5.3)	0.0
Carbon 2008/2009 Revenue Requirement Adj.	1.8	0.0	1.8	0.0
Reserve for Injuries and Damages	2.2	0.0	0.3	0.0
Variable Pay Program (VPP)	(1.9)	0.0	(1.9)	0.0
Production Abandonment	1.01	0.0	1.01	0.0
Deferred Schedule C Charge Impact	(0.5)	0.0	(0.5)	0.0
Rider T Over-collection	(0.7)	0.0	(0.7)	0.0
Deferred Software Training Costs	0.2	0.0	0.2	0.0
Deferred Rent (CD 21) Receivable (Payable)	0.1	0.0	0.1	0.0
DSM Incentive / Rebate Pilot Program	0.0	1.0	0.0	0.0
Total	4.3	1.0	2.4	0.0

1024. The Commission has made determinations on each of these one-time adjustments which are summarized below:

(a) Hearing costs are addressed in Section 6.4.14. The adjustment is approved.

(b) Income tax is addressed in Section 8. The adjustment is approved.

(c) The Carbon revenue requirement deferral account was approved in Decision 2010-291.[914] AG indicated in the application that this adjustment was required in 2011 in order to finalize the impact of removing the Carbon assets from the 2008 and 2009 revenue requirement forecasts.[915] The adjustment is approved.

(d) Reserve for injuries and damages is addressed in Section 6.4.10. The amounts related to the late payment penalty settlement are not approved.

(e) Variable pay program is addressed in Section 6.4.3. The adjustment is approved.

(f) Production abandonment is addressed in Section 7.6. The adjustment is approved.

(g) The deferred Schedule C charge deferral account was approved in Decision 2010-291.[916] In the application AG indicted that the Phase II Negotiated Settlement between AG and customer groups required AG to defer monthly revenue once the new Schedule C charges had been implemented. AG has deferred six months worth of charges and is therefore requesting a one-time payment to customers. The adjustment is approved.

914 Decision 2010-291: 2008-2009 General Rate Application – Phase 2 Negotiated Settlement, Application No. 1604944, Proceeding ID 184, June 25, 2010.
915 Application, page 9.0-2, paragraph 5.
916 Ibid.

(h) The Rider T over-collection was provided in Exhibit 174.02 and discussed in AUC-AG-105(b). The over-collection relates primarily due to colder weather. The adjustment is approved.

(i) Deferred software training costs is addressed below.

(j) The deferred lease costs deferral account was approved in Decision 2009-109.[917] AG is requesting a one-time recovery of $57,000 relating to the difference between the actual and forecast lease costs for the ATCO Center in Edmonton and the Milner Building. The adjustment is approved.

(k) The proposed DSM program is addressed in Section 6.3.14. The adjustment is not approved.

1025. AG requested a one-time adjustment for $0.1 million in each of the North and the South for deferred software training costs.[918] AG indicated that these adjustments result from the adoption effective January 1, 2009 of the Canadian Institute of Chartered Accountants (CICA) recommendations for intangible assets which prohibit the capitalization of training costs related to software additions. Effective January 1, 2009 AG was unable to continue to capitalize these training costs as part of property, plant and equipment. AG referred to Section 6(2)(g) of Rule 026: *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards* (Rule 026) which provides that a utility may apply for recovery of any financial difference that arises as a result of the adoption of the International Financial Reporting Standards arising in connection with a change to the capitalization of training costs.

1026. AG is not requesting further deferral treatment in the test years as these costs will be included in operating and maintenance expense in the test years.

Commission findings

1027. The Commission considers this one-time adjustment for software training costs is consistent with the intent of Rule 026 Section 6(2)(g) and approves the $0.1 million one-time adjustment in each of the North and South. However, as noted by AG a deferral account is not required for the test years and the Commission does not approve an ongoing deferral account for software training costs for the test years

10.2 Existing and proposed deferral accounts

1028. AG provided the following table summarizing existing deferral accounts, proposed new deferral accounts and the carrying cost methodology applicable to each one.

917 Decision 2009-109, 2008-2009 GRA Phase Compliance Filing.
918 Application, Section 9.1.8.

Table 56. Deferral accounts and carrying costs[919]

Deferral Accounts	Current / Proposed	AUC Rule 023 / WACC / Other
Weather	Current	WACC
Load balancing	Current	WACC
Hearing costs	Current	NWC
Utilities Consumer Advocate	Current	NWC
Variable pay program	Current	NWC
Pension costs	Current	NWC
Production abandonment costs	Current	NWC
Income tax deductible capital cost	Current	NWC
Pension special funding payments	Current	NWC
Impact of IFRS	Proposed	None
ATCO Pipelines / NGTL integration rate impacts	Proposed	None
Deferred transmission	Current	None
Schedule C charges	Current	None
Lease costs - Edmonton / Milner	Current	None
Lease costs - Calgary	Proposed	None
Software training costs	Proposed one-time adjustment	None

1029. Intervener concerns with respect to particular existing deferral accounts have been addressed in the applicable section. In this section, the Commission will consider the carrying charges for all deferral accounts and the proposed new deferral accounts.

10.3 Carrying charges

1030. AG indicated that it proposes to use the carrying cost methodology previously approved for each of the existing deferral accounts.[920] AG is not requesting approval of carrying charges for the new deferral accounts proposed in the application. Interveners did not object to the basis for calculating carrying charges for each of the deferral accounts.

Commission findings

1031. Given that AG is proposing to extend the carrying cost methodology previously approved by the Commission, the Commission approves the carrying cost methodology for the test years on the continuing existing deferral accounts.

10.4 New deferral accounts

1032. AG requested approval for three new deferral accounts in its application:[921]

- Impact of IFRS[922]
  - AG also requested approval of a second deferral account in relation to insurance proceeds as per section 6(2)(l) of Rule 026;
- ATCO Pipelines / NGTL Integration Rate Impacts; and

919 Exhibit 84.01, AUC-AG-103.
920 Exhibit 136, AUC-AG-103.
921 Application, Section 9.2.0.
922 International Financial Reporting Standards.

- Deferred Lease Costs – ATCO Center Calgary.

1033. AG referred to Decision 2003-100[923] where the EUB found the following four factors to be reasonable criteria to be used in evaluating proposed deferral accounts:

- Materiality of the forecast amount,
- Uncertainty regarding the accuracy and ability to forecast the amount,
- Whether or not the factors affecting the forecast are beyond the utility's control,
- Whether or not the utility is typically at risk with respect to the forecast amount.

1034. AG noted that in Decision 2010-189[924] the Commission added a fifth "symmetry factor" to consider in assessing the merits of proposed deferral accounts. The Commission stated:

> 73. …the Board, when examining the merits of an application for a deferral account on the facts of that proceeding, took the view that "deferral accounts should not be for the sole benefit of either the company or the customers." Deferral accounts, rather, should "provide a degree of protection to both the Company and the customers from circumstances beyond their control," and hence "[s]ymmetry must exist between costs and benefits for both the Company and its customers." The Board also noted that it expected that "the individual mechanisms involved in the use of each deferral account should be applied in a consistent and fair manner in both test years and non-test years." This will be referred to as the symmetry factor.[925] (footnotes omitted)

10.5 Impact of IFRS

1035. AG requested a deferral account to capture any unanticipated differences that arise as a result of implementing IFRS. The ATCO Group decided to adopt IFRS effective January 1, 2011.[926] In response to AUC-AG-104 AG stated:

> In developing its Application, ATCO Gas made certain assumptions that are currently under review within ATCO. ATCO Gas is requesting the use of a deferral account to address any differences that may arise. Due to the uncertainty of the outcome of ATCO's internal review, ATCO Gas believes that consequences could result that are (i) uncertain; (ii) potentially material; (iii) beyond ATCO Gas' control; and (iv) a forecast risk to both customers and ATCO Gas.

Commission findings

1036. Interveners did not object to the creation of an impact of IFRS deferral account. This deferral account is not intended to cover costs associated with the implementation of IFRS but to capture any unanticipated differences that arise as a result of the implementation of IFRS. The Commission does not consider that an impact of IFRS deferral account satisfies the deferral account criteria established by the EUB and the Commission in Decision 1003-100 and Decision 2010-189 because the materiality has not been established and the accuracy and ability to forecast is largely within the control of AG or within the control of the ATCO Group. However, the Commission notes that one of the principles of Rule 026 provides:

923 Decision 2003-100: ATCO Pipelines 2003/2004 General Rate Application Phase 1, Application No. 1292783, December 2, 2003, page 116.
924 Decision 2010-189: ATCO Utilities Pension Common Matters, Application No. 1605254, ID. 226, April 30, 2010.
925 Decision 2010-189, paragraph 73.
926 Application, Section 9.4.1, paragraph 37.

> Future Regulatory Accounting and regulatory reporting requirements established by the Commission will, in considering IFRS requirements, balance the effects on customer rates and shareholders' return. Any shifting of risk between customers and shareholders will be minimized.[927]

1037. The Commission considers the establishment of the requested deferral account is consistent with the above principle because it establishes a mechanism to monitor and address any shifting of risk between customers and shareholders with respect to the unanticipated differences. Accordingly the Commission approves the establishment of a deferral account in accordance with AG's proposal provided however that the deferral account shall include only unanticipated differences that are within the scope of Rule 026. The Commission directs that this deferral account be closed and an application filed along with AG's proposal for the method for settling each deferral account adjustment within three months of the public release of the 2011 annual financial statements for Canadian Utilities Limited.

1038. The Commission also approves the creation of a second deferral account related to the adoption of IFRS as required by Section 6(2)(l) of Rule 026 related to insurance proceeds.

10.6 ATCO Pipelines/NGTL integration rate impacts

1039. ATCO Gas requested a short term deferral account to capture the potential impacts related to certain matters that still need to be finalized with respect to the integration of ATCO Pipelines (AP) and Nova Gas Transmission Ltd. (NGTL). In response to AUC-AG-104 AG stated:

> The finalization of these other matters is: (i) uncertain; (ii) potentially material; (iii) beyond ATCO Gas' control; and (iv) a forecast risk to both customers and ATCO Gas. Once all of the impacts of integration on ATCO Gas are known, ATCO Gas proposes to file an application with the Commission to dispose of the Integration deferral account and incorporate the effects of the integration into its rates going forward.

Commission findings

1040. The Commission does not consider that the proposed deferral account satisfies the materiality factor criterion for the establishment of a new deferral account and accordingly denies AG's request. However, the Commission is sensitive to the concerns raised by AG with respect to possible unknown costs of integration and the difficulty of forecasting these costs prior to integration occurring. Contract integration between ATCO Pipelines and NGTL occurred October 1, 2011. While the Commission denies the requested deferral account, the Commission will permit AG in the compliance filing to this decision to identify any additional specific costs that AG has incurred due to integration and to include a request for approval of such costs in revenue requirement.

10.7 Calgary lease costs

1041. ATCO Gas is requesting a short-term deferral account to capture the differences in forecast and actual lease rates for the ATCO Centre in Calgary. The lease was scheduled to expire on October 1, 2011. AG argued that the use of a deferral account is consistent with the approach that was used for the ATCO Center lease renewal in Edmonton in the 2008/2009 GRA, in order to not impede ATCO Gas' ability to negotiate the lease rate.

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927 Rule 026, Appendix I – Guiding Principles, page 9.

Commission findings

1042. In Section 6.5.4 of this decision, the Commission directed that rental expense for the ATCO Centre in Calgary should be based on the existing rental rate for the test years. Accordingly, a deferral account to track rental adjustments is not necessary.

11 Order

1043. It is hereby ordered that:

(1) AG is directed to file a compliance filing to this decision no later than January 9, 2012.

Dated on December 5, 2011.

The Alberta Utilities Commission

(original signed by)

Moin A. Yahya
Panel Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Kay Holgate
Commission Member

Appendix 1 – Proceeding participants

Name of organization counsel or representative
ATCO Gas (AG) L. Smith (counsel) K. Beattie (counsel) D. Werstiuk R. Gordon D. Wilson
AltaGas Utilities Inc. R. Koizumi N. McKenzie
BP Canada Energy Company C. Worthy G. Boone
Climate Change Central (3) L. Estep (counsel) J. Reading L. Sveinson
The City of Calgary (Calgary) D. Evanchuk (counsel) H. Johnson M. Rowe
Consumers' Coalition of Alberta (CCA) J. Wachowich (counsel) J. Jodoin R. Retnanandan
FortisAlberta Inc. J. Walsh
TransAlta Corporation K. Perley
Office of the Utilities Consumer Advocate (UCA) T.D. Marriott (counsel) M. Stauft R. Bell J. Pous S. Radway

The Alberta Utilities Commission

Commission Panel
- M. A. Yahya, Panel Chair
- B. Lyttle, Commission Member
- K. Holgate, Commission Member

Commission Staff
- B. McNulty (Commission counsel)
- A. Sabo (Commission counsel)
- B. Whyte
- R. Armstrong. P.Eng.
- B. Leung
- M. McJannet
- C. Taylor

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
ATCO Gas (AG) L. Smith, QC K. Beattie	Panel No. 1 C. Cicchetti (Navigant Consulting, Inc.) D. Cook G. Feltham A. Hagan B. Mikila W. Morishita G. Schmidt D. Wilson Panel No. 2 L. Kennedy (Gannett Fleming, Inc.) D. Cook A. Dixon B. Hahn G. Schmidt D. Wilson G. Zurek
Climate Change Central (C3) L. Estep	R. Boyd K. Gorecki F. Walter J. Reading
Consumers' Coalition of Alberta (CCA) J. Wachowich	
The City of Calgary (Calgary) D. Evanchuk	Panel No. 1 H. Johnson (Stephen Johnson, Chartered Accountants) J. Stephens (Consultant) R. Hanscome (HRchitect, Inc.)
The Office of the Utilities Consumer Advocate (UCA) T. Marriott	Panel No. 1 M. Stauft (Consultant) R. Bell (Russ Bell & Associates Inc.) S. Radway (Radway Consulting Ltd.) Panel No. 2 J. Pous (Diversified Utility Consultants, Inc.)

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Commission will review the prudence of some of the 2008 to 2010 capital expenditures in the other sections of this report. The Commission directs AG in its compliance filing to update its 2011 opening rate base in accordance with the findings in other sections of this decision. The 2011 opening property, plant, and equipment accounts are approved subject to the Commission's directions relating to specific assets addressed in subsequent sections of this decision. .... Paragraph 83

2. The Commission directs AG in the compliance filing to this decision to provide the Commission with the actual number of Tier 2 meters replaced in 2010 and the actual capital costs incurred. AG is directed to indicate the number of Tier 2 meters and Tier 3 meters with a medium risk factor left to be replaced in 2011 and 2012 and to provide the forecast capital costs in each year using the forecast capital costs calculated from Tables 2.1.1.2(c) and (d) in the application. .... Paragraph 163

3. The Commission further directs AG to plan the replacement of the Tier 2 and the portion of the Tier 3 meters with a medium risk factor in a manner that achieves efficiencies and distributes the costs evenly over the period 2011 to 2014. .... Paragraph 164

4. With respect to the second UCA recommendation the Commission acknowledges that pre-1973 plastic pipe and 1973 to1975 plastic pipe were subject to different certification practices and approved for different operating pressures. However, the Commission notes that neither vintage group was required to meet the CSA standard which became mandatory in 1975. Accordingly, the Commission considers it in the public interest to remove all pipe manufactured prior to 1973. With respect to pipe manufactured from 1973 to 1975, the Commission notes AG's comment that it is acting with an "abundance of caution." With regard to the UCA's first recommendation, the issue for the Commission to address is the extent to which inventory practices may have resulted in the installation in 1976 or 1977 of interim certified pipe from the 1973 to1975 period. AG's records are inadequate. AG is neither able to identify whether pipe purchased during the interim 1973 to1975 period was certified nor has it the ability to determine how long pipe remained in inventory and therefore, what portion, if any of the pipe was installed in 1976 and 1977. These facts have made the consideration of this program difficult. Nonetheless, the Commission considers the risk of brittle failure associated with plastic pipe and PVC pipe when subjected to stress to be a serious safety and reliability issue, and therefore, the Commission approves the entire program. However, the Commission directs that the program be implemented over a 20-year period considered in alternative three in the business case rather than the 17-year proposed in alternative two. Given the fact that the pipe manufactured during the 1973 to1975 period was of a higher quality than the pre-1973 pipe and some of the 1973 to 1975 pipe may have met the then voluntary CSA standard and noting that this vintage of pipe was proposed to be removed last, the Commission considers the extended installation period to be warranted. Lengthening the time period over which replacement occurs will reduce the magnitude of

the impact on rates to customers but does put in place a comprehensive plan to replace PVC and early generation PE. .... Paragraph 191

5. As additional leak history data on pipe installed from the 1973 to1977 period becomes available it may be appropriate to reconsider the program scope and timelines. The Commission directs AG to continue to provide plastic pipe leak history in future capital program applications. .... Paragraph 192

6. The Commission directs AG in the compliance filing required by this decision to indicate what the 2011 and 2012 plastic pipe replacement program revenue requirement would be based on a 20-year program, without considering the actual 2011 expenditures. .... Paragraph 193

7. The Commission relies on AG's statement that OH&S regulations require AG to update its line heaters. A three-year program has been proposed to complete the work to bring the non-compliant line heaters into compliance and to do reliability work at the same time. The plan by AG to complete the compliance work in three years seems reasonable and the Commission approves this portion of the program for inclusion in revenue requirement. The Commission finds that when reliability improvements are to be made on heaters for which compliance work is to be done, it is practical to do both at the same time over the three year period. However, the Commission does not consider that justification has been made for a three-year period to complete work on line heaters that do not have a compliance component. Therefore the Commission directs AG to exclude from its program, line heaters that are in compliance with OH&S regulations. The Commission directs AG in the compliance filing to this decision to reflect two years of the three-year replacement and upgrading of the non-compliant line-heaters. .... Paragraph 200

8. The UCA's primary concern with the AMR program was the magnitude of the contingency included in the forecast estimates. The Commission agrees that the contingency may be too high, but notes that AG was expected to complete a "proof of concept" by the end of June 2011. The Commission directs AG to report in the compliance application to this decision on the results and effects of the "proof of concept" stage for installations made in the initial phase of the project and the results and the effect on the contingency, if any. AG is directed to submit an update to its business case economic analysis. The Commission will finalize the test year forecast amounts along with the contingency following the compliance application. .... Paragraph 216

9. Accordingly, retired assets that are not anticipated to be disposed of at approximately the same time that they are retired should be moved to a non-utility account where any ongoing costs associated with the assets would be for the account of the utility shareholder. Given that the Irma agency office has been retired and not disposed of, the Commission directs AG to move the Irma agency office to the applicable non-utility accounts effective January 1, 2011. Operating costs and other costs associated with the facility, to the extent there are any, will be for the account of the AG shareholder from and after January 1, 2011. .... Paragraph 320

10. The Commission directs AG in the compliance filing to this decision to reflect the movement of the Irma agency office to a non-utility account as of January 1, 2011 and to reflect the removal of any operating or related costs associated with the facility as of that date. .... Paragraph 323

11. Should the Okotoks agency office not be disposed of at approximately the same time as it is retired, AG is directed to move the asset to a non-utility account where further operating and capital costs would be for the account of the utility shareholder. .... Paragraph 330

12. Rather than an across the board reduction, the Commission prefers to use an escalation of past costs based on a three-year average of the actual expenditures in 2008, 2009 and 2010. AG has noted it has used a three-year average of past costs in other categories. In this case the three year average applied across-the-board to all the accounts noted above in the table equals \$13.6 million. Allowing for inflation of three per cent, the amount approved for all the above accounts in 2011 is \$14.0 million and in 2012 is \$14.4 million. AG is directed to indicate in its compliance filing how it proposes to allocate the approved total amounts between the different accounts. .... Paragraph 355

13. The Commission acknowledges that expenditures in excess of the approved amounts in Decision 2008-113 could be due in part to the pricing determined in the Evergreen proceeding. The Commission finds that the over-expenditure on SIBS (NGSIS) replacements was not adequately explained in the application or supported in the analysis of variances provided in Tabs 8.1 and 8.2. The Commission directs AG in its compliance filing to revise the SIBS amount to be included in opening rate base to the forecast approved in Decision 2008-113, adjusted for increases in price approved by this Commission. .... Paragraph 359

14. The Commission finds the actual cost of \$15.1 million to be in excess of these three cost estimates. The Commission also recognizes that the estimates undertaken are imprecise and accordingly relies on them as directional guidance. The Commission has reviewed the business cases of ATCO Electric and AG and other evidence on the record and determines that a 10 per cent cost reduction in the actual costs of HRX is warranted. The Commission directs AG in its compliance filing to reduce the actual cost of HRX in its opening rate base by 10 per cent. .... Paragraph 386

15. The Commission considers the HRchitect report which assumes a different platform, is helpful in providing directional guidance. Similarly, the Commission considered the 15 to 25 per cent application cost to total cost ratio as put forward by AG in the HRX business case. This analysis also provided directional guidance for a reduction in forecast costs for TMS. AG had agreed to address in testimony and rebuttal to remove the costs of the three TMS modules that will not be implemented in the test years. The Commission directs AG in its compliance filing to only include the forecast costs of the two modules to be implemented in the test years; performance management and succession planning. For all other costs in the business case, the Commission finds that in consideration of all the evidence before it, the TMS project is approved but that the forecast capital costs should be reduced by 10 per cent. .... Paragraph 410

16. The Commission finds that the proposed update to Oracle E in Business Case 16 is premature. A major argument in support of this business case is that support of the current version of Oracle E will end in 2013. The Commission agrees with Calgary that the need for this project has not been demonstrated as the current software support does not expire until 2013 and the benefits were not quantified. For these reasons the Commission denies the application for this business case and directs that the forecast costs related to this business case should be removed from its revenue requirement in the compliance filing for this application. .... Paragraph 437

17. Business Case 17 for oracle mid-size is proposed based on the fact that support of the current version will end in July 2013. The application states that Oracle will terminate the existing level of support on January 1, 2012. The Commission notes that there is a discrepancy in the dates of termination. According to AG's business case support will not be withdrawn but the level of support may change. The Commission does not consider it has sufficient information to determine if support will be withdrawn, and whether any change in the existing level of support will impact AG's operations. The Commission directs AG in the compliance filing to this application to provide information from the vendor regarding the proposed withdrawal of support, including the level of support which will continue to be available. If the vendor provides the option of continuing support at a lower level, AG is directed to provide an analysis of any impact on its operations. .... Paragraph 438

18. Business Case 19, work enhancements, also proposes a Maximo software upgrade in 2012. The Commission notes that functional benefits are forecast and that withdrawal of support is anticipated for the fourth quarter of 2012. The Maximo software appears to have been installed as part of work management Phase II in October 2009 at a cost of $3.9 million. As Calgary noted the entire work management Phase II project was installed at a cost of $17 million compared to a forecast cost of $13.5 million. Calgary also noted a discrepancy in the cost breakdown between the business case and the schedule provided at page 16 of Tab 4.2 Attachment 1. The argument in support of the business case is premised on the withdrawal of support by the vendor. The Commission notes, as acknowledged by AG, that the vendor has not announced the withdrawal of support for the software. For the preceding reasons, the Commission denies approval of the forecasts costs for the Maximo software proposed in Business Case 19. The Commission directs AG to remove the forecast costs associated with this software package from its revenue requirement in the compliance filing for this application. .... Paragraph 441

19. AG has forecast costs for the general CIS enhancement program of $1 million in 2011 and $0.6 million in 2012. This program and the related benefits are not clearly described. The Commission finds the explanation in paragraph 129 of the application does not justify the requested capital expenditure for this project. Therefore, the Commission denies this proposed enhancement and directs that related costs be removed from the revenue requirement in the compliance filing to this decision. .... Paragraph 443

20. For approved IT capital projects the Commission directs AG in its compliance filing to provide a description of volume metrics and a detailed breakdown of the labour units related to the different classifications with the current rates in support of theforecast labour costs. For any items without units, an explanation should be provided of the reason for inclusion in labour costs. Similarly, AG shall provide an explanation for all projects that have been allocated a volume of processing costs. .... Paragraph 450

21. Accordingly, the Commission finds the preferred share issuance to have been prudent. However, given that preferred shares are subordinate to debt and in certain market conditions, the issuance of preferred shares may demand higher dividend rates than anticipated, alternative debt options should be examined in such circumstances. The Commission directs AG in its next preferred share application to provide a comparative analysis of the alternative of issuing debt. .... Paragraph 469

22. The Commission notes that AG offered to prepare a similar analysis to the one directed from ATCO Electric, concurrent with or prior to AG's next preferred share application. The Commission considers such an analysis is required and directs AG to prepare an updated analysis concurrent with or prior to AG's next preferred share application to assess whether the optimal range of five to 10 per cent for preferred shares as discussed in Decision 2006-100 should be continued thereafter. This analysis should also include a number that represents the most cost effective level of preferred shares for AG and should be submitted to the Commission concurrently with or before AG's next preferred share application to the Commission. Accordingly, approval of the actual preferred share issue is subject to the Commission's approval of the directed analysis. ...... Paragraph 489

23. Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual preferred share rates for preferred shares issued in 2011, if any, for the purposes of calculating capital structure, forecast return on rate base, forecast utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 preferred shares in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 preferred share rate and the rate of any preferred shares issued in 2011. .... Paragraph 494

24. Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual long-term debt rates for long-term debentures issued in 2011, if any, for the purposes of calculating capital structure, forecast return on rate base, forecast utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 long-term debt in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 long-term debt rate and the rate of any long-term debt issued in 2011. .... Paragraph 507

25. The Commission has not been persuaded that the proposed decrease to a six per cent vacancy rate due to an increasing proportion of vacancies caused by retirements is warranted. A six per cent vacancy rate is inconsistent with historical results and unsupported by the evidence filed in this proceeding. AG is therefore directed to increase its forecast vacancy rate for 2011 and 2012 to 8.3 per cent based on a three-year historical average and to revise its forecast FTE levels and revenue requirement in the compliance filing to this decision. .... Paragraph 538

26. Interveners did not oppose this expenditure but the CCA submitted that it should be a one time charge. The Commission agrees with the CCA that this expenditure should be treated as a one-time cost in 2012 revenue requirement. The Commission approves the forecast costs of $0.5 million for an assessment of inspection practices as a one time expense. AG is directed to incorporate these costs as a one time expense in its compliance filing to this decision. .... Paragraph 554

27. The Commission recognizes the necessity to comply with changing standards and accepts AG's proposed cost increases for the test years for the proposed commercial inspection program. However, the Commission does not approve AG's request for an accounting change to capitalize costs related to meter exchanges when a meter is being permanently retired. The cost of the "original installation of house regulators and meters" is capitalized in Account 474. "Expenses incurred in connection with removing, resetting, changing, testing and servicing customer meters and house regulators" are recorded in Account 673. AG's change in policy to use only new meters does not change the accounting requirement. AG has stated that without the approval requested the expenses

in 2011 and 2012 would need to be increased by $4.2 million. However, this amount does not agree with the $3.1 million in 2011 and $2.8 million in 2012 that AG planned to capitalize for the same activity. The Commission directs AG in its compliance filing to deal with this apparent discrepancy. AG is directed to revise its revenue requirement accordingly in the compliance filing to this decision. .... Paragraph 558

28. AG stated that most of the forecast cost increase over 2010 actual costs was driven by inflation and customer growth. However, AG indicated in AUC-AG-65(c) that 1.2 per cent of the total increase in 2011 and an additional 0.5 per cent of the total increase in 2012 related to training in anticipation of higher employee turnover due to aging workforce and a tightening of the market. The Commission previously rejected the justification of forecast cost increases due to an aging workforce and a tightening of the labour market. Accordingly, the Commission directs AG to reduce the forecasted costs in Account 674 by 1.2 per cent in 2011 and 1.7 per cent in 2012 in the compliance filing to this decision. .... Paragraph 561

29. AG provided limited support for the forecast increase to the costs for accounts 678 and 679. Accordingly, in the absence of any other substantive information, the Commission considers that an adjustment of five per cent for inflation and growth is justified for each of the test years. The Commission directs AG in its compliance filing to forecast costs for accounts 678 and 679 by escalating 2010 actual costs by a factor of five per cent per year. .... Paragraph 584

30. AG explained that it spends $50,000 per year on "cross-promotion of safety messages" through the BFK while the forecast for the test period for the BFK is $2 million per year. The Commission considers that BFK provides a disproportionate amount of costs for the safety and gas distribution service communication benefits received. Further, AG is the only Canadian distribution utility that has a facility like the BFK Calgary Learning Centre. The Commission is not persuaded that the Edmonton BFK is required in light of the limited benefit that customers receive through safety and gas distribution communication through the BFK. The Commission finds that the BFK is not a cost effective means of proving public safety communication. Further, AG has other options to meet its responsibility to distribute public safety information. For the preceding reasons, AG is directed to remove all Edmonton BFK costs from 2011 opening rate base and from revenue requirement for the test years, including both capital and O&M related costs. For the same reasons the request to include in revenue requirement costs associated with the Calgary BFK is denied. .... Paragraph 610

31. The Commission does, however, continue to support the expenditure of $50,000 per year on safety messaging that the BFK has provided in the past. AG may add this expenditure to its Customer Relations and Communications forecast for the test years. AG is directed to advise the Commission in the compliance filing to this decision as to the mechanism it will use to promote natural gas safety matters and gas distribution education information to customers. .... Paragraph 611

32. Similar to the Commission's finding with respect to AG's BFK program above, the Commission is of the view that the increase in costs for the purpose of the Centennial Anniversary celebration is not justified as a cost effective means to communicate safety matters and is unnecessary for the provision of safe and reliable delivery of natural gas. Accordingly AG is directed to remove the forecast costs associated with the Centennial

Anniversary from the sales and transportation promotions function for the 2011 and 2012 test years. .... Paragraph 616

33. The Commission denies AG's request to include in revenue requirement for the test years all costs associated with current and proposed DSM activities. The Commission directs that all DSM related costs, both capital and operating, be removed from rate base and revenue requirement for the test years. The Commission further directs that the DSM capital expenditures incurred during the period 2008 to 2010 are to be excluded from opening rate base. .... Paragraph 686

34. The Commission considers that AG has not provided an adequate explanation for the forecast increases in the account. The discussion of governance provides no explanation of which accounts are impacted by the governance amounts. In the absence of a satisfactory explanation for the increase, the Commission directs AG to revise its forecasts for Account 710 to the amount calculated as the actual expenditure for 2010 increased by a five per cent per year, to reflect inflation and growth, for each of 2011 and 2012. The $0.3 million for CC&B benchmarking is also approved in 2012. Paragraph 691

35. The Commission has calculated assuming a mid-year installation in 2012 that 318,000 meters will have been converted to AMR units by the end of 2012. AG stated that the average meter reader will be able to read 4500 meters per year. Theoretically this represents a reduction of approximately 70 meter readers in 2012. AG has forecast an opportunity savings of 12.9 meter readers, which is 57 less than the theoretical reduction based on the number of meters removed. At a fully loaded cost of $76,175 per meter reader an adjustment of approximately $4.3 million would be warranted. The Commission considers the transition factors identified in paragraph 714 and the redeployment of meter readers to other areas or potential severance costs must be considered. Given the lack of detailed information on the record regarding these matters, the Commission recommends a reduction of the estimated $4.3 million by 25 per cent. The Commission directs AG in its compliance filing to reduce the forecast costs for Account 712 by $3.2 million in 2012. .... Paragraph 712

36. AG is directed to revise its 2011 and 2012 forecast for administrative labour, excluding the VPP component, utilizing AG's 2010 actual costs increased by five per cent per year. .... Paragraph 731

37. The Commission finds that the inclusion of net income component within a VPP is reasonable when there is a balance struck between the benefits that customers may receive through reduced costs versus increased earnings for the benefit of shareholders. A net income component greater than 10 per cent for officers and senior managers might result an inherent conflict between shareholder interests and customers. The Commission finds that setting limits to individual performance objectives will ensure that management is not incented to maximize shareholder value at the expense of customers. If AG wishes to include a net income component for specific individuals higher than 10 per cent of their VPP compensation, those costs are to be borne by shareholders. AG is directed to revise its VPP forecast to reflect a maximum individual net income component of VPP of 10 per cent in its compliance filing to this decision with a supporting explanation to its revised VPP forecast. .... Paragraph 751

38. With regard to AG's forecasted increases in 2011 and 2012 for VPP, the Commission concurs with the UCA that AG did not justify an increase to the VPP forecast cost in excess of inflation. In its April 21 update, AG revised its forecast inflation rate for

supervisory labour in 2012 to 4.0 per cent. The Commission finds that AG's four per cent inflationary adjustment for supervisory labour for 2012 is reasonable. The Commission directs AG in its compliance filing to revise its forecast VPP for 2011 by utilizing the 2010 forecast cost (which is consistent with the 2009 actual expense) by three per cent for 2011 and increasing the 2011 amount by four per cent for 2012. .... Paragraph 752

39. AG is directed in the compliance filing to this decision to include in its revenue requirement a rental rate for 2011 of $14.50. For 2012, rent should be forecast based on $14.50 per square foot increased by a three per cent inflation factor. .... Paragraph 769

40. The Commission relies on the approval of the corporate cost allocation methodology in Decision 2010-447 for 2011. The Commission has reviewed the corporate costs in Table 42, Administrative expense and notes that actual costs for 2008, 2009 and 2010 exceeded forecasts. However, for 2008 an explanation of the variance is provided. The Commission accepts AG's explanation and considers that the increase, which was with respect to HRX, would be a recurring cost. A comparison of actual 2008 costs to forecast 2011 costs is an increase of 10.5 per cent over a three-year period. The Commission considers an increase of approximately 3.5 per cent per year to be reasonable. However, the Commission agrees that the $73,000 for 2011 and $75,000 for 2012 of allocated corporate advertising, as noted above by the UCA, should not have been included in the corporate costs and directs that this amount should be removed. .... Paragraph 780

41. The Commission therefore approves mass media and other supplies expenses for 2011 and 2012 calculated as 2010 actual costs increased by five per cent per year for inflation and growth. AG is directed to include this revision in its compliance filing. .... Paragraph 797

42. As noted above, AG has not fully described which accounts, O&M or capital, include corporate governance costs. The Commission directs AG in its compliance filing to indicate the allocation of the governance costs identified above to specific capital and O&M accounts, including the corresponding amounts approved in Decision 2011-228 and the actual amounts incurred in 2010. .... Paragraph 805

43. Calgary brought forward issues with respect to the Evergreen Strategy Report, O&M IT volumes and the lack of comparability due to the differences in structure and terms of the two MSAs. The Commission is satisfied that Exhibit 180 provided sufficient detail of volumes in a standardized format to allow the Commission to assess the reasonability of the forecast volumes. The Commission accepts the O&M forecast volumes as filed. The Commission notes the dollars are placeholders and directs AG to use the amounts provided in Table 42 above for the test years. .... Paragraph 810

44. AG's request for a recovery of $1.8 million related to the settlement and associated legal expenses is denied. The Commission therefore directs AG to remove the settlement and associated legal expenses from AG's forecast for reserve for injuries and damages and revenue requirement in its compliance filing. The $300,000 balance of the proposed $2.1 million recovery in order to maintain a reserve balance of $600,000 is approved. .... Paragraph 842

45. The Commission is satisfied that AG has adequately explained why employee benefits are increasing for the test years. Further the Commission notes that the largest component of employee benefits is the pension funding which is subject to a placeholder. In Decision 2011-391 the Commission made a determination of pension funding for AG to be included in revenue requirement for 2011 and 2012. AG is directed to maintain the

current placeholders for pension funding, pending a decision in relation to the compliance filing for Decision 2011-391 noted above. AG is directed to submit an application to replace the placeholders within a reasonable time following the issuance of the decision in the compliance filing. With the exception of the placeholder for pension funding, the Commission approves the forecast costs for employee benefits. .... Paragraph 852

46. The Commission is satisfied with AG's explanation that credit facility costs and standby fees have increased as a result of the recent economic crisis. Further, the Commission recognizes that ensuring liquidity levels are maintained at levels required by bond rating agencies results in CU Inc. being able to maintain its existing credit rating and allows AG access to lower market rates for financing its operations. The forecast bank charges are consistent in total with the 2009 charges and the Commission finds the amounts to be reasonable. As these costs are allocated using the ATCO Utilities corporate cost allocation methodology approved in Decision 2010-447 the Commission accepts the allocation methodology for 2011. As noted earlier, ATCO Utilities corporate cost allocation methodology is subject to review in 2012. As a result, all costs for 2012 including "bank and short term financing costs" are subject to a placeholder pending the outcome of the aforementioned proceeding. AG is directed to maintain a placeholder for 2012. .... Paragreaph 858

47. The Commission directs AG in its compliance filing to reclassify bank and short-term financing costs as financing costs. .... Paragraph 860

48. AG is directed in the compliance filing to calculate depreciation expense using a 57-R2.5 Iowa curve for Account 47300, Services. .... Paragraph 915

49. AG is directed in the compliance filing to calculate depreciation using an Iowa curve of 51-R3 for Account 47400, Regulator & Meter Installations. .... Paragraph 921

50. AG is directed to calculate depreciation using an Iowa curve for 66-R2.5 for account 47500, mains in the compliance filing to this decision. .... Paragraph 941

51. The Commission considers that the determination of a depreciation rate for this account has been particularly difficult given the size of the account and the mix of non-homogeneous assets of different vintages. The Commission notes the discussion at the hearing about the possibility of introducing accounting mechanisms to segregate the account into multiple accounts of a more homogeneous nature. The lack of detailed historical records was an impediment to further segregation at this time. The Commission directs AG to report in the compliance filing to this application on the feasibility of further segregation of significant accounts on a go-forward basis. .... Paragraph 942

52. AG is directed in the compliance filing to calculate depreciation using the 11-R2 Iowa curve for Account 48400, Transportation Equipment. .... Paragraph 947

53. The Commission will consider Account 48400 separately from the other accounts. With respect to the balance of the "other depreciation accounts" identified above, the Commission notes that the interveners did not file evidence with respect to these accounts and that the aggregate net change in depreciation expense is $1,990,539 in the test period. The Commission has denied a number of programs in other parts of this Decision which may have assets reflected in some of these accounts. Accordingly, the Commission directs that the assets associated with denied programs be removed from these accounts and reflected in the compliance filing to this decision. Subject to the removal of the

denied assets, the Commission approves the depreciation expense for these other depreciation accounts. .... Paragraph 952

54. The Commission agrees with the UCA and the evidence of Mr. Pous that AG has failed to provide sufficient justification for the proposed changes to the net salvage rates. Neither Mr. Kennedy nor AG have provided a reasonable explanation for the large changes in net salvage percentages calculated by Mr. Kennedy in his analysis. The explanation provided by Mr. Kennedy for the proposed modified net salvage rates, based on the calculated percentages, lacks the robustness and precision necessary to support the determination of the proposed net salvage rates. In the absence of probative evidence the Commission is inclined to deny the requested increase in net salvage rates for the test period. However, the Commission is concerned that should the current net salvage rates be insufficient, continuation of existing rates for an extended period of time may result in intergenerational inequity for ratepayers and unfairness to the utility. Accordingly, the Commission would entertain a timely separate application outside of the compliance filing process on net salvage rates for the test period. AG is directed to indicate in the compliance filing to this decision whether it will be submitting a separate application and if proceeding, the anticipated filing date. If AG chooses not to submit a separate application the existing net salvage rates will remain in place for the test years. If AG chooses to file a separate application, the compliance filing will use the existing salvage rates as placeholders pending a decision on the separate application. .... Paragraph 971

55. The collection from customers of a depreciation reserve deficiency or the refund to customers of a depreciation reserve surplus does not amount to retroactive rate making, rather it is a prospective rate setting mechanism designed to ensure that the costs of an asset are recovered over its anticipated service life. The Commission directs AG in its compliance filing to this Decision to update it depreciation reserve deficiency account in accordance with the revised depreciation rates. .... Paragraph 983

56. The Commission directs AG to remove the 2011 and 2012 production abandonment costs of $2.18 and $1.5 million respectively from revenue requirement. .... Paragraph 1005

57. The Commission notes that in the presentation provided during its SPC Forecast Workshop on June 14, 2010, AG made mention that gas price has not been included in the regression models in past GRA's. In its compliance filing AG is directed to provide information on why it has added gas price as a variable into the regression model and the impact the gas price variable has on its revenue forecast. .... Paragraph 1018

58. The Commission notes that 2010 actual revenue was very close to the forecast for 2011. Further the Commission notes that the largest component of other revenue is services provided to AP. The Commission directs AG in its compliance filing to discuss if the recently approved integration of AP with NGTL will have an impact on its other revenue from AP including any change to the basis on which the work will be priced. The Commission accepts the revenue forecast for the rest of the components of other revenue for the test years. .... Paragraph 1021

59. The Commission considers the establishment of the requested deferral account is consistent with the above principle because it establishes a mechanism to monitor and address any shifting of risk between customers and shareholders with respect to the unanticipated differences. Accordingly the Commission approves the establishment of a deferral account in accordance with AG's proposal provided however that the deferral account shall include only unanticipated differences that are within the scope of Rule

Appendix 4 – Rulings on motions during the proceeding

(return to text)

Appendix 4 - Rulings on motions

(consists of 23 pages)

Appendix 5 – AG's responses to Commission directions

AG provided responses in Volume 2-1, Tab 1.0 of the application to Commission directions from prior decisions. The Commission has reviewed the responses and has provided its opinion regarding compliance as follows.

Directions from Decision 2008-021:

1. While not a specific direction the Commission is satisfied with AG's comments on the review of the administration of its prudential requirements and the default supply provider.

Directions from Decision 2008-113:

2. Direction 23 (differences in unit costs between north and south operations): The Commission is satisfied that AG has complied.
3. Direction 36 (timeframe for reviewing corporate cost allocation methodology): The Commission is satisfied that AG has complied.
4. Direction 40 (any costs, legal fees or other payments be maintained in RID pending conclusion of the case in respect of late payment charges) (AG referred to "Other Commission Direction" (page 82) when responding): The Commission is satisfied that AG has complied, however, the final determination in respect of costs of a legal claim related to late payment charges is discussed elsewhere in this decision
5. Direction 41 (include: Financials Appl Host & Storage" item and "Adabas-IMS License" item with the variable items in 2008-2009 Evergreen proceeding): The Commission is satisfied that AG has complied.
6. Direction 43 (review final rate base amount for DFSS): The Commission is satisfied that AG has complied.
7. Direction 44 (file a full depreciation study in next GRA): The Commission is satisfied that AG has complied.
8. Direction 45 with Attachments 1-2 (file alternative methods for depreciating leasehold improvements in next GRA): The Commission is satisfied that AG has complied having presented the study.
9. Direction 46 with Attachment (estimated retirement date for CIS, with assumptions and any available cost of alternatives): The Commission is satisfied that AG has complied.
10. Direction 49 (utilize six weather stations in the next GRA): The Commission is satisfied that AG has complied.
11. Direction 50 with Attachment (conduct a technical meeting prior to next GRA to review regression models and normalization process): The Commission is satisfied that AG has complied.
12. Direction 52 with Attachment (provide a schedule for high use demand customers): The Commission is satisfied that AG has complied.
13. Direction 53 (investigate and report on negative irrigation throughput amounts at next GRA): The Commission is satisfied that AG has complied.

Directions from Decision 2009-093:

14. Direction 1 with Attachments 1-4 (weather deferral account methodology): The Commission is satisfied that AG has complied.

Directions from Decision 2009-109:

15. Direction 1 (calculation of labour steps and increases): The Commission is satisfied that AG has complied for the current GRA, but notes that future reports are required as this direction has an ongoing requirement for future GRAs.
16. Direction 21 with Attachments 1-2 (approval of deferral account for rental rates, reconciliation and closure): The Commission is satisfied that AG has complied, however any approvals will be provided elsewhere in this decision.

Directions from Decision 2009-178:

17. Direction 1 (use of deferral account for final revenue requirement changes): The Commission is satisfied that AG has complied.

Directions from Decision 2009-214:

18. Direction 1 (breakdown of types and amounts of deductions included in Income Tax Deductable Capital Cost Deferral Account): The Commission is satisfied that AG has complied for the current GRA, but notes that compliance is required for future applications as this direction has an ongoing requirement.

Directions from Decision 2010-189:

19. Direction 5 (pension plan COLA effects on revenue requirements): The Commission is satisfied that AG has complied given that it was directed in Decision 2010-553 to file a 2011 Pension Common Matters application by December 15, 2010. Decision 2011-391 was released on September 27, 2011.

Directions from Decision 2010-291:

20. Direction 3 (contribution revenues fom Schedule "C" charges): The Commission is satisfied that AG has complied.
21. Direction 4 (custom customer contribution installations): The Commission is satisfied that AG has complied.
22. Direction 7 with Attachments 1-2 (disposition and status of deferral accounts per 2009 Phase II Settlement): The Commission is satisfied that AG has complied.

Directions from Order U2008-264:

23. Commission Order: As of this application AG is not yet in compliance with the order pending a report on the balance of the transmission deferral account.

Alberta Utilities Commission

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Electronic Notification

April 1, 2011

To: Interested Parties

ATCO Gas
2011-2012 General Rate Application (GRA) Phase I
Application No. 1606822
Proceeding ID No. 969

Re-start of process

1. On March 25, 2011, the Alberta Utilities Commission (the AUC or the Commission) received a motion (motion) from The City of Calgary to compel ATCO Gas to provide full and adequate responses to a number of information requests contained in Attachment A to the motion. Calgary requested that the Commission consider the motion prior to the filing of intervener evidence scheduled for March 30, 2010.

2. On March 25, 2011, the Commission suspended the procedural schedule in this proceeding for all parties pending a ruling on the motion and provided the opportunity for a response by ATCO Gas and a reply by Calgary.

3. ATCO Gas filed their response to the motion on March 29, 2011. In their response, ATCO Gas included certain additional information requested by Calgary. Calgary responded on March 31, 2011, that there were now only three information responses it considered were still deficient, namely CAL-AG-7(c), CAL-AG-53 and CAL-AG-58.

4. The Commission has reviewed the submissions of Calgary and ATCO Gas and provides its initial ruling on the motion. A more detailed ruling will be issued shortly. The Commission finds that ATCO Gas has provided full and adequate responses to CAL-AG-53 and CAL-AG 58. The motion with respect to these information requests is denied.

5. With respect to CAL-AG-7(c), the Commission believes that ATCO Gas has not provided a sufficient response to this information request. ATCO Gas will be directed in the detailed ruling to provide the following information for all assets listed in Exhibit 97.02 with an assessed value in excess of $250,000:

a. The year of acquisition
b. The original cost
c. The operational purpose of the facility

This information will be required to be provided by 3 p.m. April 8, 2011.

6. In light of the above ruling, the Commission sets the following amended process schedule (the original schedule is included for comparison only):

Original Process Schedule	
Intervener evidence	**March 30, 2011**
Information requests to interveners	**April 13, 2011**
Information responses from interveners	**April 27, 2011**
Rebuttal evidence	**May 11, 2011**
Hearing - Edmonton	**May 24-June 3, 2011**

New Process Schedule	
Intervener evidence	**April 7, 2011**
Information requests to interveners	**April 21, 2011**
Information responses from interveners	**May 5, 2011**
Rebuttal evidence	**May 18, 2011**
Hearing - Edmonton	**May 24-June 3, 2011**

All submissions are due by 3 p.m. on the due date.

7. Should Calgary wish to amend its evidence subsequent to the receipt of the additional CAL-AG-7(c) information to be filed by ATCO Gas pursuant to the Commission's ruling, it may do so by 3 p.m. April 15, 2011.

8. If you have any questions or comments regarding this letter, please contact Ben Whyte at 403-592-4450 or ben.whyte@auc.ab.ca.

Yours truly,

(sent by email)

Ben Whyte
Application Officer

AUC
Alberta Utilities Commission

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Electronic Notification

April 8, 2011

To: Interested Parties

ATCO Gas
2011-2012 General Rate Application (GRA) Phase I
Application No. 1606822
Proceeding ID No. 969

Commission ruling on The City of Calgary motion

1. On March 25, 2011, the Alberta Utilities Commission (the AUC or the Commission) received a motion from The City of Calgary (Calgary) to compel ATCO Gas to provide full and adequate responses to a number of information requests (IRs) contained in Attachment A to the motion. Calgary requested that the Commission consider the motion prior to the filing of intervener evidence then scheduled for March 30, 2010.

2. On March 25, 2011, the Commission suspended the procedural schedule in this proceeding for all parties pending a ruling on the motion and provided the opportunity for a response by ATCO Gas and a reply by Calgary.

3. ATCO Gas filed its response to the motion on March 29, 2011. In its response, ATCO Gas included certain additional information requested by Calgary. Calgary responded on March 31, 2011, that there were now only three information responses it considered were still deficient, namely CAL-AG-7(c), CAL-AG-53 and CAL-AG-58.

4. On April 1, 2011 the Commission provided its initial ruling on the motion indicating that a more detailed ruling would be issued. The Commission found that ATCO Gas had provided full and adequate responses to CAL-AG-53 and CAL-AG 58. The motion with respect to these information requests was denied.

5. With respect to CAL-AG-7(c), the Commission found that ATCO Gas had not provided a sufficient response to this information request. ATCO Gas was directed to provide the following information for all assets listed in Exhibit 97.02 with an assessed value in excess of $250,000:

   a. The year of acquisition,
   b. The original cost, and
   c. The operational purpose of the facility.

This information was required to be provided by 3 p.m. April 8, 2011.

6. ATCO Gas filed a letter with the Commission dated April 4, 2011, submitting that a materiality threshold of $250,000 was unreasonable. ATCO Gas estimated that it would take approximately 133 work days for a single individual to obtain the requested information. ATCO Gas instead proposed a materiality threshold of $1,000,000, in which only seven buildings and eight parcels of land would fall.

7. In a letter dated April 6, 2011, Calgary submitted that the ATCO proposal was in effect a Review and Variance (R&V) on the Commission direction. Calgary disputed the amount of work which ATCO Gas indicated would be required to complete the response directed in the initial ruling of the Commission.

8. By letter dated April 6, 2011, the Commission indicated that it was prepared to consider these latter submissions before issuing its final ruling on this matter. Further in the interest of understanding fully the parties' position, the Commission allowed an expedited additional response from ATCO Gas and a final reply by Calgary.

9. ATCO Gas responded by letter dated April 7, 2011, and Calgary replied by letter dated April 8, 2010.

10. The purpose of this letter is to communicate the final ruling of the Commission referenced in its letter of April 1, 2011. The writer has been authorized by the Commission to provide its ruling in respect of the motion.

11. The Commission provided guidance[1] to interested parties to the ATCO Gas 2008-2009 GRA with respect to the form and content required in motions requesting direction from the Commission with respect to allegedly deficient information request responses. The Commission indicated that such motions should clearly include as part of the grounds on which the motion is made:

- the reasons why the information request response does not comply with the provisions of Rule 001, section 30(1)(b) or 31(1);
- the materiality of the requested information, in the context of either the principle involved or the approximate impact to the applied for revenue requirement (or to the subject matter of the application);
- the purpose for which the requested information is required;
- the prejudice to the intervener if the requested information is not provided; and
- how the requested information will assist the Commission in evaluating the application.[2]

12. The Commission considered that this information should be provided with respect of each such allegedly deficient information request response. This information will assist all parties in understanding the rationale for the motion, promote more complete response and reply submissions and assist the Commission in evaluating the merits of a motion of this nature.

13. In considering the Calgary motion the Commission started with the premise that the utility has the onus of proof to demonstrate the reasonableness of the applied for revenue requirement and the fairness of the resulting rates. It therefore must carefully consider the evidence required to substantiate and defend the reasonableness of its application. However, under the Commission's rules, interveners are entitled to a full and adequate response to each relevant information request unless the information necessary to provide an answer is not available or cannot be provided with reasonable effort. This information is required to permit a full testing of the application and the preparation of intervener evidence. With these principles in mind, the Commission has considered the guidance provided by the above ruling in a prior ATCO Gas proceeding, all submissions of the parties, including those filed after the date of the initial ruling, and the provisions of sections 29, 30(1) and 31 and 9 of Rule 001.

[1] Commission Letter, dated March 7, 2008, in respect of motions made by the UCA and the City of Calgary in ATCO Gas Application No. 155302, Proceeding ID. 11, 2008-2009 General Rate Application.

[2] Consistent with the Alberta Utilities Commission letter, dated March 7, 2008, regarding motions related to information responses in AG's 2008-2009 GRA, Application No. 1553052.

14. The Commission has also considered the materiality and potential impacts to parties of either providing or not providing the requested information. In particular, the Commission was concerned with balancing the level of detail requested in some of the IRs, the effort required and cost to produce the material requested; potential prejudice to ATCO Gas if the information is produced over its objections and the potential benefit to interveners and to the Commission of receiving it. Lastly, the Commission has considered the need to maintain an efficient and timely regulatory process.

CAL-AG-53

15. CAL-AG-53 requested ATCO Gas to provide all quantitative and qualitative studies, analyses, reports and any other efforts conducted by ATCO Gas which evaluate or measure the benefits to rate payers of implementing the proposed DSM initiatives. In its March 21, 2011 update to this IR, ATCO Gas indicated that it had "…provided all of the studies and reports that it relied on in the preparation of its proposed DSM initiative and the benefits of those initiatives in its Application and various information responses."

16. The Commission considers that ATCO Gas has provided a full and adequate response to this question.

CAL-AG-58

17. CAL-AG-58 requested ATCO Gas to identify where and when ATCO Gas had satisfied a Commission direction to establish a cost allocation method capable of capturing costs causal to the North and South systems. ATCO Gas has provided three attachments to its supplementary IR responses filed on March 21, 2011. In these attachments further information was provided on ATCO Gas' separate regulatory accounts and its accounting policies for the North and South systems.

18. The Commission considers that ATCO Gas has provided a full and adequate response to this IR.

CAL-AG-07(c)

19. CAL-AG-07(c) requested the following information:

> (c) For each of 2009, 2010, and forecast for 2011 and 2012 for each of AGN and AGS provide:
>
> > (i) A complete listing of all real property including the legal description held by each of AGN and AGS and provide for each
> >
> > (ii) the original cost and the year acquired
> >
> > (iii) the accumulated depreciation or amortization, if any
> >
> > (iv) the operational purpose of each, and
> >
> > (v) the owning and operating costs associated with each property

20. The Commission considers the information request to be relevant and potentially probative to an understanding of the reasonableness of the forecasted rate base and opening account balances for the 2011 and 2012 test years. However, the scope of the request raises significant concerns.

21. The Commission has heard various representations from the parties on the degree of effort and time necessary to produce the information and with respect to the reasonableness of the request. ATCO Gas has also made submissions about the materiality of the threshold of $250,000 set out by the Commission in its initial ruling and the amount of information that could be reasonably produced in the timeframe contemplated without causing a delay in the procedural schedule. In an effort to strike a balance between the effort and cost required to produce the requested information and the potential benefit of the information to Calgary and to the Commission, the Commission has decided to revise its initial directions on the production of information with respect to all assets listed in Exhibit 97.02 with an assessed value in excess of $250,000.

22. The specific information requested by Calgary in CAL-AG-07(c) was in respect of information on "real property". The Commission considers that the information to be provided should focus on property owned in fee simple by the utility. Such property is primarily identified in the "ATCO Gas Site Summary" Tab 3 included in Exhibit 97.02. The Commission continues to consider that a $250,000 threshold remains appropriate in limiting the extent of the effort and information required.

23. The directed information will assist all parties in understanding the nature and use of a sample of real property included in the forecasted rate base and opening account balances of ATCO Gas.

24. Accordingly, the Commission directs ATCO Gas to provide the following information for each of the properties with a assessed value greater than $250,000, as listed in the "ATCO Gas Site Summary" Tab 3, Exhibit 97.02 and identified below:

a. The year of acquisition
b. The original cost
c. The operational purpose of the facility

Municipality	Legal Description	Property Type	$ Assessed Value
CITY OF EDMONTON	PLAN: 1654HW BLOCK: B	Land	251,000
CITY OF CALGARY	2732X;26	Land	251,500
CITY OF EDMONTON	PLAN: 491MC LOT: A	Land	256,900
CITY OF EDMONTON	PLAN: 9721199 BLOCK: B	Land	270,000
CITY OF EDMONTON	PLAN: 414ET BLOCK: A / PLAN: 1654HW BLOCK: B	Land	289,000
CITY OF EDMONTON	PLAN: 7520856 BLOCK: 2 LOT: 7G	Land	289,300
TOWN OF STRATHMORE	129 THIRD AVENUE	Land	358,090
TOWN OF EDSON	BLOCK 2A PLAN 782 3382	Land	398,950
CITY OF EDMONTON	PLAN: 9723789 BLOCK: 7 LOT: 3PUL	Land	648,300
CITY OF EDMONTON	PLAN: 7821552 BLOCK: 6 LOT: 4	Land	668,600
CITY OF CALGARY	A1;76;7	Land	699,000
CITY OF CALGARY	A1;76;8	Land	699,000
CITY OF EDMONTON	19-52-23-4-OT	Land	797,500
CITY OF CALGARY	8208HR 0T	Land	937,500
CITY OF BROOKS	PLAN NUMBER: 0412994; BLOCK: 11; LOT: 3;	Land	980,490
CITY OF CALGARY	A1;76;9,10	Land	1,390,000
CITY OF EDMONTON	PLAN: EDMONTO LOT: 43	Land	1,634,500
CITY OF AIRDRIE	14 -4 -0814088	Land	1,638,700
CITY OF CALGARY	2732X;26;0T	Land	2,110,000
CITY OF EDMONTON	PLAN: 0920803 BLOCK: 5 LOT: 2	Land	3,665,900

CITY OF EDMONTON	PLAN: B4 BLOCK: 12 LOT: A	Land	3,852,500
CITY OF CALGARY	A1;64;1-8	Land	5,870,000
CITY OF EDMONTON	PLAN: 2054MC BLOCK: B LOT: 2 / PLAN: 2054MC LOT: 2	Land	8,382,800
KNEEHILL COUNTY	SE-17-29-22-4	Buildings & Structures	256,090
TOWN OF OLDS	PLAN 472I BLOCK 2 LOT 14615; 5025 52 ST	Buildings & Structures	300,000
TOWN OF EDSON	BLOCK 2A PLAN 782 3382	Buildings & Structures	365,640
CITY OF CAMROSE	PLAN: 7820519 BLOCK: 4 LOT: 32	Buildings & Structures	379,500
KNEEHILL COUNTY	SE-17-29-22-4	Buildings & Structures	439,830
CITY OF WETASKIWIN	PLAN 7821171 LOT 1 BLOCK 55	Buildings & Structures	446,250
TOWN OF TOFIELD	PLAN 8439ET LOT PARCEL A; 4720 46 AVE	Buildings & Structures	504,700
KNEEHILL COUNTY	SE-17-29-22-4	Buildings & Structures	565,310
CITY OF EDMONTON	PLAN: B4 BLOCK: 12 LOT: A	Buildings & Structures	825,500
CITY OF AIRDRIE	9-13 -B -4445K	Buildings & Structures	839,900
KNEEHILL COUNTY	SE-17-29-22-4	Buildings & Structures	1,671,600
CITY OF GRANDE PRAIRIE	7921756;4;21;;7921756;4;22;;7921756;4;23	Buildings & Structures	2,085,000
BEAVER COUNTY	04-13 047-35-NE	Buildings & Structures	2,445,800
RM OF WOOD BUFFALO	7620533 26 1	Buildings & Structures	3,738,010
CITY OF EDMONTON	PLAN: 2054MC BLOCK: B LOT: 2 / PLAN: 2054MC LOT: 2	Buildings & Structures	3,902,700
STRATHCONA COUNTY	W4 23 53 10 NW	Buildings & Structures	8,302,000
CITY OF RED DEER	LOT-1A BK-2 PL-0524610	Buildings & Structures	8,883,200
CITY OF EDMONTON	PLAN: 0920803 BLOCK: 5 LOT: 2	Buildings & Structures	9,154,100

25. The Commission wishes to be clear that using a $250,000 materiality threshold is not indicative of anything other than as a limitation on the degree of effort, cost and time required to produce a sampling of the requested information which may assist in testing the reasonableness of the application and in the preparation of Calgary evidence. Using ATCO's estimate of two hours per piece of property the Commission considers that there are approximately 80 hours of work involved in this request. This being the case, two ATCO Gas employees working a standard 40 hour work week would be able to complete the retrieval of this information in one week.

26. ATCO Gas is directed to file the above information no later than **3 p.m. on April 15, 2011**.

27. Given that the above deadline is after the deadline for filing intervener evidence, Calgary may file supplemental evidence specific to ATCO Gas' response to CAL-AG-7(c) by **3 p.m. on April 20, 2011**.

28. If you have any questions or comments regarding this ruling, please contact Ben Whyte at 403-592-4450 or ben.whyte@auc.ab.ca or alternatively please contact Mark McJannet at 403-592-4412 or mark.mcjannet@auc.ab.ca.

Yours truly,

(sent by email)

Mark McJannet,
On behalf of Ben Whyte
Application Officers

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Electronic Notification

April 29, 2011

To: Interested Parties

ATCO Gas (ATCO)
2011-2012 General Rate Application (GRA), Phase I
Application No. 1606822
Proceeding ID No. 969

Ruling with regard to the April 21, 2011 letter from The City of Calgary (Calgary)

1. On April 21, 2011 ATCO filed with the Alberta Utilities Commission (Commission) an application update (Application Update) rectifying omissions, providing corrections and adding certain information including a business case for the proposed Talent Management System (TMS Business Case).

2. On April 27, 2011 Calgary filed a letter requesting that the Commission reject the filing outright, or delay the start of the hearing to later in 2011.

3. The Calgary letter was dealt with by the Commission by way of a written process:

Process Step	**Date**
ATCO comments to Calgary Letter	Thursday, April 28, 2011 – 1 p.m.
Calgary reply to ATCO	Friday, April 29, 2011 – 1 p.m.

4. Following receipt of the above-noted submissions from parties, the Commission indicated that it would issue a ruling on the letter, and if required, any changes to the schedule.

Views of the parties

5. Calgary submitted that Section 27 of AUC Rule 001: *Rules of Practice* (Rule 001) requires a party to seek leave from the Commission prior to a party filing a document after the time set out for the filing of that document is established. ATCO did not seek leave for its late filing nor did it receive the Commission's leave. Calgary submitted that the filing must be rejected outright, or the hearing start date must be set back to later in 2011 to permit and full, fair and complete testing of the ATCO filing.

6. Specifically, Calgary expressed concern that it cannot properly assess the Application Update. Calgary suggested that its ability to retain an expert to test the materials and the applied for amounts with respect to TMS Business Case is compromised given the fact that the oral hearing is scheduled to begin on May 24, 2011. It was submitted that there is no reason why ATCO Gas could not have filed the TMS Business Case with its GRA application in December, 2010.

7. On April 28, 2011, ATCO responded to Calgary's submission and stated that no delay in the proceeding schedule should be required. ATCO submitted that it is continually being placed in a position of having to provide updated information that interveners attempt to use to alter ATCO's forecast. At the same time, ATCO submitted that it should not be denied the opportunity to make updates of its own to ensure that a balanced record exists.

8. ATCO also asserted that the filing of omissions and updates is entirely distinct from withdrawing evidence that has been placed on the public record of a proceeding which requires the prior consent of the Commission under Section 27 of Rule 001. In this regard, ATCO noted that the Commission has consistently stated that it will rely on the most up-to-date information (as available to the close of the hearing) in the context of rate applications. In Decision 2008-113 (ATCO Gas 2008-2009 GRA), the Commission stated that updates are necessary to ensure that it has the most up-to-date information. At page 16 the Commission stated:

> The Commission … continues to hold that an appropriate balance can be struck which allows for a utility to plan and budget according to its forecasts but that also provides the Commission with sufficient current information to enable it to assess the reasonableness of those forecasts. It is expected that a utility will put forth its best possible case in making an application for its revenue requirement. That best possible case should reflect information available to the utility that may reasonably form part of its Application and <u>any updates thereto</u>.
>
> <u>Given the reality that the Commission expects to receive the most up-to-date information during a proceeding and that AG and other utilities bring evidence of increasing costs during a proceeding as it becomes available</u>, the Commission agrees with CG's submission that prospectivity effectively starts from the close of the proceeding, rather than at the time of the application. This is the practical consequence of having a proceeding that runs into the year for which a rate application is made and ensuring that the Commission has the best possible information before it in order to make a decision on that application.[Emphasis added by ATCO]

9. ATCO Gas also cited Decision 2006-004 (ATCO Gas' 2005-2007 GRA), wherein the Board stated the following at pages 3 and 5 relating to the filing of GRA applications and providing updated forecasts:

> … The timing of a GRA application is within the control and discretion of the applicant. … <u>[A]n applicant should be prepared to provide updated actual information whenever the processing of an application straddles the end of a fiscal year and the actual results become available prior to the close of the evidentiary portion of the proceeding.</u>
>
> <u>. . .</u>
>
> <u>With respect to AG's concern of an asymmetrical result from the consideration of actual results or events that were not known at the time that the filed forecasts were prepared, the Board considers that it is up to the applicant to determine if it would like to update the forecasts it has provided in its application to reflect the updated information. [Emphasis added by ATCO]</u>

10. ATCO disputed Calgary's claim to require a new expert to address the TMS Business Case. ATCO noted that Calgary had retained an information technology witness that had filed approximately thirty pages of evidence on all aspects of ATCO Gas' IT business cases and

expenditures, including the business case related to Oracle HRX which is also a human resources related system. ATCO further submitted, however, that if the inclusion of the TMS Business Case on the record might cause a delay, then ATCO submitted that it is prepared to seek leave to withdraw it and related expenditures from the Omissions and Updates Filing rather than entertain a delay in the proceeding schedule.

11. On April 29, 2011, Calgary replied to ATCO's submission. Calgary disagreed with ATCO that the filing of the TMS Business Case and related expenditures are permitted by the excerpted portions of Decisions 2006-004 and 2008-113 set out in the ATCO submissions. Further, Calgary argued that the TMS Business Case was a new project not originally filed with the GRA, and as such, is not an update to the application. However, Calgary did not object to ATCO's proposal to seek leave to withdraw the TMS Business Case while retaining the balance of the filing on the record and proceeding to the oral hearing as presently scheduled in order to permit the proceeding to continue on the current schedule.

12. The Consumers' Coalition of Alberta filed a letter in support of Calgary's position on April 29, 2011.

Commission ruling

13. The writer has been authorized by the Commission to provide its ruling on the Calgary letter.

14. Section 27 of the Rule 001 is not intended to apply to an omissions and corrections update filing of the nature under review unless the Commission has previously established a timeline for such a filing.

15. Consistent with the decisions referenced by ATCO above, the Commission considers that updates are necessary to ensure that the Commission and interested parties have the most up to date and best information available to assess the application and complete the record of a proceeding. Although updated information would usually take the form of omissions and corrections, there is no reason why the applicant can not also elect to amend its application to seek approval of new cost items provided it could not have reasonably included that information with its original application. The ability to file updated information must be balanced with a requirement to provide parties with sufficient opportunity to review and test the new evidence.

16. The Commission notes that there are approximately three weeks remaining prior to the start of the oral hearing and that a process may be established to permit testing of the Application Update, including the TMS Business Case.

17. The Commission is prepared to accept the Application Update, including the TMS Business Case evidence but considers that it is incumbent on ATCO in future filings of this nature to clearly explain why evidence relating to new expenditures could not have been filed with the original application. The Commission establishes the following process to afford interveners and the Commission to review and test the Application Update via interrogatories prior to the oral hearing. Interveners will also be given the opportunity to file supplemental evidence. Recognizing that the timing of the filing of the Application Update was under the control of ATCO and the limited time available in which to submit interrogatories and prepare

supplemental evidence, the Commission will permit the filing of the supplemental evidence after the commencement of the hearing but prior to the sitting of the Calgary witness panel. As a result, the Commission has established the following schedule:

Process Step	**Date**
Intervener information requests to ATCO on April 21, 2011 update	Thursday, May 12, 2011 – 2 p.m.
ATCO responses to information requests on April 21, 2011 update	Wednesday , May 18, 2011 – 2 p.m.
Supplemental intervener evidence restricted to matters pertaining to April 21, 2011 update	Thursday, May 26, 2011 – 2 p.m.

18. The Commission considers the schedule reasonably balances the interests of parties and is consistent with the objective of achieving an effective and efficient regulatory process.

19. If you have any questions on this matter please contact the undersigned at 403-592-4412 or by e-mail at mark.mcjannet@auc.ab.ca.

Sincerely,

Mark McJannet for Ben Whyte
Application Officer

AUC
Alberta Utilities Commission

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Electronic Notification

May 31, 2011

To: Parties currently registered on Proceeding ID No. 969

ATCO Gas (ATCO)
2011-2012 General Rate Application Phase I
Application No. 1606822
Proceeding ID No. 969

Alberta Utilities Commission (the AUC or the Commission) ruling on ATCO's May 29, 2011 motion (Exhibit 176)

1. On May 29, 2011, ATCO filed a motion that portions of The City of Calgary's (Calgary) human resources evidence with regard to the Oracle Human Resource Management System (HRX)(the impugned evidence) must be struck from the record of this proceeding because it falls outside the permitted scope of the Commission's letter dated April 29, 2011 (ruling). ATCO also argued that allowing the additional evidence would create regulatory inefficiencies.

2. The Commission's ruling dealt with ATCO's April 21, 2011 filing, ATCO Gas Omissions, Corrections and Updates to 2011/2012 Forecasts (Exhibit 118). Specifically, the Commission allowed ATCO to include on the record a business case related to the proposed Talent Management System (TMS) over the objections of Calgary. Calgary was provided an opportunity to ask information requests and to file supplemental evidence following commencement of the oral hearing but before the Calgary panel was to be seated. Supplemental evidence was required to be filed by May 26, 2011, (subsequently extended to May 27, 2011) and was to be "restricted to matters pertaining to [ATCO's] April 21, 2011 update ...."

3. Calgary filed Addendum No. 2 to its written evidence (supplemental evidence) on May 27, 2011. ATCO provided parties and the Commission by e-mail on Sunday, May 29, 2011, with a motion (motion) requesting the Commission to strike those portions of the supplemental evidence that related to the HRX.

4. Calgary argued that there were four reasons to deny ATCO's motion. They were:

1. the connection between the TMS and HRX systems
2. the lack of prejudice to ATCO
3. the best evidence available to the Commission
4. the public interest

5. Calgary argued that because the two systems were fundamentally linked, they could not introduce evidence on the one without commenting on the other. Calgary also argued that ATCO would not be prejudiced as it would have sufficient time to prepare for cross-examination of Calgary's expert. Additionally, Calgary argued that the supplemental evidence would provide the Commission with the best evidence available which would assist the Commission in determining the public interest. Calgary responded to ATCO's assertions of regulatory inefficiency by stating that it was the late filing of the TMS evidence on April 21, 2011, that was the cause of the regulatory inefficiency. Calgary also argued that the supplemental evidence was within the scope of the Commission's ruling, if one interpreted it broadly.

6. The Consumers' Coalition of Alberta (CCA) argued that the TMS and HRX systems were linked and, therefore, the supplemental evidence should be accepted and ATCO's motion should be denied.

7. The Commission has considered the arguments of ATCO, the CCA, and Calgary. In arriving at its decision, the Commission considered two main issues:

- the first is whether or not a plain reading of the ruling could reasonably be interpreted to permit filing additional evidence on the HRX system

- the second issue was, irrespective of the language of the ruling, was whether or not Calgary established that it would be unable to adequately produce evidence regarding the TMS system without also filing evidence on the HRX system

8. The Commission finds that an objective reading of its ruling confines the scope of Calgary's evidence to the TMS system.

9. The Commission understands that Calgary may consider that providing evidence on TMS alone would not address the relevant issues comprehensively. The Commission is also mindful of the procedural integrity it must maintain in its proceedings to ensure procedural fairness for all parties. Calgary could have contacted the Commission prior to its filing of evidence to clarify the scope of the ruling or to request an expansion of the scope, but it did not. In the course of the proceeding, Calgary attempted to link the two systems through evidence obtained from its cross-examination of ATCO's witnesses. During oral argument of the motion, when Calgary was questioned on whether or not it could establish a link between the TMS and HRX systems without reference to what it learned during cross-examination, Calgary admitted that it was relying on the testimony to establish the link.[1]

10. The Commission is willing to grant much leeway in allowing parties to introduce their evidence and ensure fairness to all. In this case, however, the Commission finds that the procedural directions set out in the ruling were clear and that the evidence of a linkage between the TMS and HRX systems, which Calgary sought to rely on to defeat the motion, was obtained through cross-examination of ATCO's witnesses. Further, this cross-examination was conducted without ATCO's witnesses having the benefit of Calgary's evidence and, more importantly, the

[1] Transcript, Volume 5, page 878-881.

knowledge that the additional evidenced was forthcoming.[2] To simply provide ATCO with additional time to review and respond to the supplemental evidence would not address the above concerns. The Commission does not consider that the public interest is best served by allowing the impugned evidence on to the record in these circumstances. As such, the Commission grants ATCO's motion to strike Calgary's evidence. Calgary is directed to re-file its originally filed evidence with the following portions expunged:

Document	**Evidence Relating to HRX (HRMS)**
City of Calgary	Q4 in its entirety
City of Calgary	Q5, Line 15, beginning with "…and that for HRMS…" to the end of Line 19
Hrchitect	Executive Summary, Page 3 to Page 4, Bullets 3, 4, and 5
Hrchitect	Section 5 in its entirety (*A Typical Business Case for an HRMS/Time and Labor Application*), Page 15 to Page 21
Hrchitect	Section 6 in its entirety (*Analysis/Comparison of ATCO HRMS/Time & Labor Business Case*), Page 21 to Page 22

The Alberta Utilities Commission

Moin A. Yahya
Panel Chair

Bill Lyttle
Commission Member

Kay Holgate
Commission Member

[2] Transcript, Volume 5, page 876-877.

On June 1, 2011 Calgary brought a motion requesting, the Commission review and vary its ruling of May 31, 2011, and allow the impugned evidence back onto the record of this proceeding. The below are the relevant sections of hearing transcripts.[1]

01387

Thank you, sir. Again, sir, this is an oral motion brought by the City of Calgary pursuant to Rule 1, sections 9 and 10 with respect to the May 31st ruling of the Commission.

Mr. Chairman, the Commission ruling sets out its written reasons in the letter I'm referring to, sir. The

01388

City of Calgary makes a motion to have the Commission review its decision and reverse its decision and to allow the impugned evidence back onto the record of this proceeding.

The reasons for this, in my respectful submission, Mr. Chairman, is that the Commission, in the course of providing its ruling, failed to consider the entirety of the record of the proceeding with respect to the matters before it. It also, in determining certain procedural fairness matters, failed to consider that record.

I'd like to elaborate on that with you, sir. We have the response to CAL AG 63, which was an information request filed with the City of Calgary with respect to TMS and HRMS. The response, I believe, is Exhibit 160 -- pardon me, 162. And have that handy, sir, in front of you.

One of the reasons that the Commission chose to deny the Calgary motion was set out in section 10, and the reasons say that, amongst other things, the ATCO witnesses did not have the opportunity to determine that additional evidence was forthcoming. And, in my respectful submission, sir, there is documentary evidence on this proceeding that suggested otherwise in the absence of my cross-examination, which I'll get to, that was relied upon by the Commission.

CAL AG 63 contains a lot of questions, three pages of questions as far as I can tell, Mr. Chairman. In fact, three and a half. The preamble to those questions I

01389

will read into the record. Quote: (As read)

> "Within the IT industry, Calgary understands that human capital management is used to describe all HR applications including the HRMS and TMS applications. Calgary would like to better understand the referenced HRMS and TMS, that is, HCM-related business cases and whether AG or an ATCO affiliate has prepared a more detailed business case for talent management since there appears to be statements not supported by the business case."

[1] Volume 7, June 1, 2011.

Mr. Chairman, the preamble, in my respectful submission, makes it very clear to the ATCO witnesses what is coming. This was dated May 12th, this request, filed May 12th, received by the ATCO Group or ATCO Gas on May 12th.

You'll recall my letter of May 12th which received -- the interpretation of which received some discussion during the motion the other day was also dated that day and, indeed, was filed with these IRs.

I'm not going to run you through the three and a half pages of questions, Mr. Chairman, but I do want to confirm for you a couple of questions that, in my respectful submission, was more than satisfactory to get a heads-up.

01416

THE CHAIR: Please be seated.

The Panel has considered the motion for review and variance of our original decision or ruling on ATCO's motion on Monday to strike the evidence that Calgary had filed regarding the HRX system.

Before announcing our ruling we would note that generally speaking the Commission on its own motion notes that interlocutory R&Vs are generally only to be done in extreme circumstances.

Secondly, the Panel notes that the test for an R&V is error of law or error in fact; especially in light of any new evidence that's come since the ruling.

Irrespective of that, nonetheless, the Commission feels that it is important that it gets its decision right. The Commission, or the Panel here, went back, looked over the evidence cited by both sides, looked at IR Cal AG 63, as cited to us by the City of Calgary, we looked over the interrogatory in its totality, and have come to the decision that an objective reading of our letter, or our ruling, would still confine the evidence to the TMS. The linkage that the City of Calgary is trying to establish is not found by this Panel. As such, the motion for review and variance is denied.

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August 12, 2011

To: Parties currently registered on Proceeding ID No. 969

ATCO Gas
2011-2012 General Rate Application
Application No. 1606822
Proceeding ID No. 969

Ruling on July 14, 2011 request of the Office of the Utilities Consumer Advocate

1. On July 14, 2011, the Alberta Utilities Commission (the AUC or the Commission) received a request from the Office of the Utilities Consumer Advocate (UCA) (UCA request) to suspend reply argument which was due on July 18, 2011. The UCA referenced a conditional agreement announced by the ATCO Group on July 7, 2011 for Canadian Utilities Limited to acquire Western Australia Gas Networks (WAGN). Canadian Utilities Limited is the holding company for ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.

2. The UCA suggested that should the acquisition close as anticipated in the third quarter of 2011, that there could be a material impact on the allocation of Head Office costs to ATCO Gas at least in 2012. The UCA stated:

> Accordingly, the new acquisition appears to be similar to ATCO Gas. If this is true, and the Head Office costs are allocated to the new entity in the same manner, the estimated result would be a reduction in the allocation of Head Office costs to ATCO Gas by $1.4 million per year.[1]

3. The UCA also expressed concern about customers paying for business development costs included within the head office function and any costs of ATCO Gas staff seconded to business development activities. The UCA also suggested that there was the potential for increased vacancies or reduced full-time employees (FTEs) from the current ATCO Gas forecast. The UCA argued that given the magnitude of the transaction, an expectation that such impacts are real and material is reasonable.

4. The UCA requested the Commission to create a process, including information requests, responses and potentially intervener evidence and an oral hearing, to explore the impact to the allocation of head office and business development costs as a result of the conditional agreement to acquire WAGN. In the alternative, the UCA requested the Commission to commence separate processes that could lead to the creation of placeholders for costs related to the acquisition and to examine the impact of the acquisition.

[1] UCA request dated July 14, 2011, page 2.

5. By letter dated July 15, 2011, the Commission suspended the date for filing of reply argument in order to seek comment from parties on the UCA request. The following process was established:

Process step	Date
Other interveners may make submissions on the UCA request	Tuesday, July 19, 2011
ATCO Gas response to interveners	Thursday July 21, 2011
UCA reply	Friday, July 22, 2011

Views of the parties

6. The Consumers' Coalition of Alberta (CCA) filed an initial letter on July 15, 2011, in support of the UCA proposal. The City of Calgary filed a letter on July 15, 2011, supporting the UCA proposal and the grounds advanced by the UCA.

7. Climate Change Central (C3) responded on July 18, 2011, stating it took no position in this matter.

8. On July 19, 2011, the CCA filed a second letter supporting the UCA request. The CCA submitted that "ATCO Gas made a choice to remain silent respecting the activities of its corporate head office. Alternatively its corporate head office failed to advise ATCO of probable changes in the costs which would likely be passed down to the operating utility and collected from customers through rates".[2] The CCA noted that ATCO Gas could have amended the application to include placeholder treatment of corporate office charges pending acquisition or alternately a deferral account in respect of corporate costs.

9. In its response dated July 21, 2011, ATCO Gas noted that the Head Office cost allocation methodology had recently been approved in Decision 2010-447.[3] The approved methodology is based on a two-year lag. Accordingly 2011 Head Office cost allocations are based on 2009 financial information and 2012 Head Office costs will be allocated on the basis of 2010 financial information. ATCO stated that the 2009 and 2010 financial information would not reflect the impact of the conditional agreement to acquire WAGN.

10. In response to the CCA, ATCO Gas submitted that it was under no obligation to disclose the prospect of a conditional agreement to acquire WAGN as part of the GRA proceeding "…because there is no impact related to ATCO Gas' GRA. The head office cost forecasts included in ATCO Gas' 2011/2012 revenue requirement forecasts would not change whether the conditional agreement existed today or not." [4] Further, the ATCO Group could not have disclosed the agreement prior to the public announcement on July 7, 2011.

11. In response to the concerns raised by the UCA with respect to ATCO Gas vacancy levels or staff levels, ATCO Gas stated that the "…GRA forecast is based on the staffing complement

[2] CCA letter dated July 19, 2011, paragraph 8.
[3] Decision 2010-447: ATCO Utilities Corporate Cost Allocation Methodology, Application No. 1605473, Proceeding ID. 306, September 20, 2010.
[4] ATCO Gas letter dated July 21, 2011, page 2.

that **ATCO Gas** requires to provide safe, reliable distribution service"[5] and that the conditional agreement does not alter that requirement.

12. ATCO requested that the AUC recommence the proceeding schedule for filing of reply argument as soon as possible and that no placeholders are required.

13. In its July 22, 2011 reply submission the UCA noted the WAGN announcement did not indicate any anticipated hold-ups to a third quarter 2011 closing. The UCA further submitted that if the Commission is particularly concerned about the conditional nature of the acquisition the Commission could establish placeholders for head office costs pending closing of the transaction.

14. The UCA also submitted with respect to the two-year lag methodology previously approved by the Commission that a "…two year lag is reasonable when there are no material changes to the allocation percentages, but cannot be slavishly followed when it will obviously result in unfair rates".[6] The UCA also submitted that because WAGN is a going concern, there should be data available to allow for a 2011 allocation based on the 2009 data. Further, the UCA noted that in Decision 2011-134[7] related to the ATCO Electric 2011-2012 Distribution and Transmission Tariff Application, ATCO Electric stated that it would true-up 2010 forecast allocation percentage to actual numbers.

15. In respect to FTEs, the UCA noted that ATCO Gas did not refute the suggestion that ATCO Gas staff worked on the acquisition project.

16. The UCA confirmed its position that a separate process is warranted, or alternately, a process that would create placeholders for costs of the acquisition and a separate process for the impact of the acquisition.

17. On July 29, 2011, the ATCO Group announced that the acquisition of WAGN had been successfully concluded.

Commission ruling

18. The writer has been authorized by the Commission to provide its ruling on the UCA request.

19. The Commission recognizes that ATCO Gas could not have disclosed the conditional agreement to acquire WAGN prior to the public announcement on July 7, 2011. The Commission considers that material events relevant to the proceeding which occur prior to the closing of the record, and in some cases prior to the release of a decision, which were not known to all parties during the course of the evidentiary portion of the proceeding may provide a sufficient basis to re-open the evidentiary portion of the proceeding. In Decision 2008-113[8] the

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[5] ATCO Gas letter dated July 21, 2011, page 2.

[6] UCA reply dated July 22, 1011, page 2.

[7] Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase 1 Distribution Tariff, 2011-2012 Transmission Facility Owner Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.

[8] Decision 2008-113: ATCO Gas 2008-2009 General Rate Application Phase 1, Application No. 1553052, Proceeding ID. 11, November 13, 2008.

Commission stated the following with respect to receiving the most up-to-date information during a proceeding:

> Given the reality that the Commission expects to receive the most up-to-date information during a proceeding and that AG and other utilities bring evidence of increasing costs during a proceeding as it becomes available, the Commission agrees with CG's submission that prospectivity effectively starts from the close of the proceeding, rather than at the time of the application.[9]

20. The Commission agrees with the UCA that the impact of the WAGN acquisition is a material event that could significantly impact the allocation of head-office costs to ATCO Gas as well as the other ATCO utilities.

21. The currently approved methodology for the allocation of corporate costs uses the second preceding year's audited financial information as the basis of the allocation of head office costs.[10] ATCO referenced Decision 2010-447 in support of its position that the head office cost allocation for 2011 and 2012 would not be affected irrespective of whether or not the acquisition of WAGN proceeds given the recent approval of the corporate allocation methodology. The Commission is not prepared however, to dismiss the UCA request based solely on the operation of existing allocation methodology thereby ignoring the possible significant impact of the WAGN acquisition on how corporate allocations should be made and therefore just and reasonable rates.

22. The UCA has requested that the Commission create a process to explore the impact to the allocation of head office and business development costs as a result of the conditional agreement to acquire WAGN. In the alternative, the UCA requested the Commission to commence separate processes that could lead to the creation of placeholders for costs related to the acquisition and to examine the impact of the acquisition. The Commission is not prepared to create a process or to consider a placeholder with respect to 2011 costs. Given the timing of the acquisition, a reallocation of corporate costs to ATCO Gas in 2011 would relate, at most, to the five months remaining in the year. Full integration of WAGN is likely to take some time and ATCO Group corporate services may not be fully utilized during that period. Further, the corporate cost allocation methodology was recently approved in Decision 2010-447. That allocation methodology was approved "until such time as the Commission may direct otherwise".[11] ATCO Gas and parties have relied on this determination in the preparation of their evidence in respect of 2011 corporate cost allocations. The Commission recognizes that by the time a decision is issued in this proceeding it will be approaching the end of the 2011 calendar year. The stability of the regulatory environment, the certainty of Commission decisions and regulatory efficiency all suggest, that barring exceptional circumstances, that any change to an approved methodology should be made prospectively. The Commission therefore denies the portion of the UCA request

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9 Decision 2008-113, page 16.

10 At page 89 of Decision 2002-069, ATCO Group Affiliate Transactions and Code of Conduct Proceeding Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues, Application No. 1237673, dated July 26, 2002, the Alberta Energy and Utilities Board referred to the allocation methodology for ATCO head office cost allocations using the average of revenue, assets, and capital expenditures based on the average of the second preceding year's audited financial figures. The corporate cost allocation methodology was reviewed and approved in Decision 2010-447.

11 Decision 2010-447, paragraph 55.

requesting a process to review corporate allocations with respect to 2011 or in the alternative to implement a process to create placeholders in respect of these 2011 costs.

23. The Commission would expect that the integration of WAGN will be carried out expeditiously and that the impact of the acquisition on corporate cost allocations would be better understood by the end of 2011. Therefore, the impact of corporate cost allocations to ATCO Gas in 2012 could be significant if carried out on a basis that recognized the acquisition. While the 2012 corporate cost allocations included in the current general rate application were prepared by ATCO Gas based on the methodology approved in Decision 2010-447, the Commissions considers that the potential significance of the WAGN acquisition requires that the approved allocation methodology be reconsidered on a going forward basis, to ensure just and reasonable rates are implemented for the 2012 test year. This suggests to the Commission that a placeholder for allocated 2012 corporate costs should be employed in the present proceeding and that the corporate cost allocation methodology should be revisited with respect to 2012 and future years in an appropriate proceeding involving all of the ATCO Utilities as soon as practicably possible. Accordingly, the Commission will establish a placeholder in respect of the 2012 allocation of corporate costs to ATCO Gas. The placeholder will be set at the amount determined by the Commission in its decision in the current proceeding after having considered the ATCO Gas forecasts and the evidence and argument of the parties in this proceeding.

24. The Commission notes that the corporate cost allocation methodology is subject to period review and that the next periodic review is scheduled for September 30, 2012. In Decision 2010 447 the Commission directed:

> ...that the next periodic review of the Methodology and the Model should be provided on or before September 30, 2012. In the next review application, the ATCO Utilities are directed to specifically include the following, having regard to the guidance provided by this Decision:
>
> (1) A review of the necessity of the Corporate Office services provided to the regulated utilities. The review should include an examination of Corporate Office Costs for possible exclusion on the basis that they should not be included in rates for the ATCO Utilities.
>
> (2) A validation (without conducting an audit) of the quantum of the Corporate Office Costs allocated in the Model for the services provided.
>
> (3) Confirmation, supported by analysis, that the Corporate Office Costs allocated in the Model for the services provided cannot be directly assigned to individual companies (Step 1 of the Methodology) nor can those costs be allocated to individual companies based on cost causation (Step 2 of the Methodology), on a cost efficient basis.
>
> (4) An analysis of the three-factor financial composite formula employed in the Model as compared to alternative formulae, including the Massachusetts Formula. The analysis should provide sample detailed calculations, and assessments as to why the chosen formula is superior to the comparator formulae.[12]

25. The Commission considers that the next corporate cost allocation methodology proceeding is the proceeding best suited to consider the impacts of the WAGN acquisition. In the circumstances, however, the Commission considers that the September 30, 2012 date for the

[12] Decision 2010-447, paragraph 56.

filing of the next ATCO Utilities application should be advanced to April 2, 2012. At that time the impacts of the WAGN transaction on corporate costs and the allocation of those costs would be better understood and 2011 audited financial information would be available.

26. The ATCO Utilities should include within the application a request to set the corporate allocation methodology for 2012 for all ATCO Utilities that have not otherwise had their revenue requirement with respect to 2012 corporate allocations previously finalized. Following the Commission's decision on the ATCO Utilities application, ATCO Gas would apply to the Commission to finalize the 2012 corporate allocation placeholder to be included in the final 2012 revenue requirement.

27. In establishing a placeholder for corporate allocated costs for 2012 and by advancing the dated for the filing of the next corporate cost allocation proceeding to April 2, 2012, the Commission is attempting to meet the public interest requirements of regulatory certainty and efficiency while ensuring rates remain just and reasonable.

28. With respect to the UCA's concerns about business development costs included within the head office function, costs of ATCO Gas staff seconded to business development activities and the potential for increased vacancies or reduced FTEs from the current ATCO Gas forecast, the Commission is not prepared to enter into a process that would review these concerns beyond what it has stated above. In particular, the Commission will not enter into a process tht will review ATCO Gas staffing forecasts for 2011 and 2012 given the closing date of the transaction and in reliance on ATCO's representation that the "…GRA forecast is based on the staffing complement that **ATCO Gas** requires to provide safe, reliable distribution service"[13] and that the conditional agreement does not alter that requirement. In making this determination the Commission is not making a finding that the forecasted amounts are appropriate and should be included in the approved revenue requirement.

29. The Commission directs parties to file their reply argument on or before August 18, 2011 at 4 p.m.

30. If you have any questions on this matter please contact the undersigned at 403-592-4412 or by e-mail at brian.mcnulty@auc.ab.ca

Sincerely yours,

Brian C. McNulty
Commission Counsel

[13] ATCO Gas letter dated July 21, 2011, page 2.

Alberta Utilities Commission

ATCO Gas

2011-2012 General Rate Application
Phase I Compliance Filing

July 20, 2012

The Alberta Utilities Commission
Decision 2012-191: ATCO Gas
2011-2012 General Rate Application Phase I Compliance Filing
Application No. 1608144
Proceeding ID No. 1709

July 20, 2012

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Contents

List of Tables

The Alberta Utilities Commission

Calgary, Alberta

ATCO Gas	**Decision 2012-191**
2011-2012 General Rate Application	**Application No. 1608144**
Phase I Compliance Filing	**Proceeding ID No. 1709**

1 Introduction

1. On December 5, 2011, the Alberta Utilities Commission (AUC or the Commission) issued Decision 2011-450[1] regarding the 2011-2012 General Rate Application (GRA) Phase I for ATCO Gas (AG). In Decision 2011-450, the Commission directed AG to refile its 2011-2012 GRA incorporating the Commission's findings, conclusions and directions (directions) in that decision and provide a detailed reconciliation of the 2011-2012 revenue requirements.

2. On February 9, 2012,[2] AG refiled its 2011-2012 GRA (the compliance filing), reflecting the revisions required to comply with the Commission's directions in Decision 2011-450.

3. On February 13, 2012, the Commission issued notice of application with respect to the compliance filing. Subsequently, statements of intent to participate in the proceeding were received from the Consumers' Coalition of Alberta (CCA), The City of Calgary (Calgary) and the Office of the Utilities Consumer Advocate (UCA).

4. On March 2, 2012, the Commission established a process schedule in order to examine and address any issues with respect to the compliance filing. Information requests to AG were due on March 13, 2012, and information responses from AG were due March 27, 2012. By letter dated March 29, 2012, the Commission set the dates for argument and reply argument as April 12, 2012, and April 26, 2012, respectively.

5. The Commission considers that the record for this proceeding closed on April 26, 2012.

6. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

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[1] Decision 2011-450: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) - 2011-2012 General Rate Application Phase 1, Application No. 1606822, Proceeding ID No. 969, December 5, 2011.

[2] AG GRA Proceeding ID No. 969, Exhibit 221, The Commission extended the deadline for AG to re-file its 2011-2012 GRA Compliance application to February 9, 2012.

2 Background

7. On June 8, 2012, the Commission issued Decision 2012-156,[3] the Phase I review and variance (R&V) of Decision 2011-450. AG requested a review and variance of Decision 2011-450, the AG 2011-2012 GRA decision, for the following matters:

- Demand Side Management (DSM) programs
- The Edmonton Blue Flame Kitchen (BFK)
- Customer Information System (CIS) enhancements
- Head Office Advertising Costs
- Oracle HRX (HRX)
- NOVA Gas Transmission Ltd.(NGTL)/ATCO Pipelines (AP) Integration Matters
- Late Payment Penalty
- Calgary Office Lease
- Production Abandonment

8. The Commission determined that AG had not demonstrated a substantial doubt as to the correctness of Decision 2011-450 regarding the issues of DSM, the Edmonton BFK, head office advertising costs, or a deferral account for NGTL/AP Integration. Further review of these matters was denied. However, the Commission granted a second stage review of the CIS enhancements, HRX, the legal costs associated with the NGTL hearing, the Calgary office lease and late payment penalty. For production abandonment costs, the Commission determined that a substantial doubt as to the correctness of the decision was raised, and this matter would be considered in the Utility Asset Disposition Rate Review Proceeding (Proceeding ID No. 20) or in a generic proceeding on asset disposition and stranded assets.

9. On June 19, 2012, the Commission received a letter from AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Utilities, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. (the Utilities) requesting clarification of Decision 2012-154 and Decision 2012-156. The Utilities requested confirmation whether or not stranded cost risk exists for any of the Utilities for the 2011-2012 test period and how the Commission proposed to address the fact that such risk was not reflected in the Commission's determination of fair return. The Utilities also wanted confirmation that any findings made in future proceedings would only apply prospectively. The Commission determined that the issues raised by the Utilities in the clarification letter would be addressed in Proceeding ID No. 20 or another generic proceeding. If the issue of prospectivity has not been addressed in Proceeding ID No. 20 or the generic proceeding, the Commission would establish a proceeding to determine whether any adjustments to the fair return of the Utilities should be made for 2011 and 2012.

[3] Decision 2012-156: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) – Decision on Request for Review and Variance of AUC Decision 2011-450 2011-2012 General Rate Application Phase I, Application No. 1608121, Proceeding ID No. 1698, June 8, 2012.

3 Particulars of the application

10. AG updated its revenue requirement in the compliance filing application and provided summary tables comparing the applied-for revenue requirements and the approved revenue requirement from Decision 2011-450 for each of 2011 and 2012:

Table 1. ATCO Gas 2011 base rate revenue requirements ($000's)

Line No.		2011 As Filed	2011 GRA Update	2011 AUC 2011-450	2011 Change
1	Rate Base	1,566,115	1,562,650	1,524,391	(38,259)
2	Return on Rate Base	7.200%	7.200%	7.156%	8.942%
3	Utility Income	112,767	112,514	109,093	(3,421)
	Cash Operating Expenses				
4	Other Taxes	335	335	335	0
5	Other Operating Expenses	368,404	365,873	346,586	(19,287)
6	Total Cash Operating Expenses	368,739	366,208	346,921	(19,287)
7	Depreciation	126,386	114,828	100,487	(14,341)
8	Provision for Income Taxes	14,012	9,502	8,003	(1,499)
9	Base Rate Revenue Requirement	621,904	603,052	564,504	(38,548)
10	Less Revenue on Existing Rates	560,436	561,426	585,624	24,198
11	Revenue Shortfall	**61,468**	**41,626**	**(21,120)**	**(62,746)**

Table 2. ATCO Gas 2012 base rate revenue requirement ($000's)

Line No.		2012 As Filed	2012 GRA Update	2012 AUC 2011-450	2012 Change
1	Rate Base	1,760,535	1,758,185	1,673,701	(84,484)
2	Return on Rate Base	7.130%	7.141%	7.071%	8.529%
3	Utility Income	125,530	125,555	118,349	(7,206)
	Cash Operating Expenses				
4	Other Taxes	358	358	358	0
5	Other Operating Expenses	378,844	377,613	360,372	(17,241)
6	Total Cash Operating Expenses	379,202	377,971	360,730	(17,241)
7	Depreciation	137,522	126,165	109,292	(16,873)
8	Provision for Income Taxes	15,807	11,952	9,925	(2,027)
9	Base Rate Revenue Requirement	658,061	641,643	598,296	(43,347)
10	Less Revenue on Existing Rates	571,285	571,952	623,814	51,862
11	Revenue Shortfall	**86,776**	**69,691**	**(25,518)**	**(95,209)**

4 Compliance with directions from Decision 2011-450

11. In Decision 2011-450, the Commission made 59 separate directions to be addressed in its compliance filing.[4] AG further addressed additional directions, number 60 through 65 which were not highlighted in Appendix 3 of the decision. The Commission has regrouped some of the directions by subject matter rather than by numerical order and certain sections of the decision will not follow the numerical order set out in Decision 2011-450 Appendix 3 – Summary of Commission Directions.

12. During the course of this proceeding, interveners argued that there were some Commission directions with which AG had not properly complied in its compliance filing.

[4] Decision 2011-450, Appendix 3.

13. The Commission has reviewed the explanations, detailed calculations and adjustments AG has made for each direction. In the following sections of this decision, the Commission will identify each direction separately, address the items at issue and make a finding on AG's compliance with each direction.

4.1 Commission Direction 1 – opening rate base

14. In Decision 2011-450, the Commission issued the following direction to AG:

> 83. The Commission will review the prudence of some of the 2008 to 2010 capital expenditures in the other sections of this report. The Commission directs AG in its compliance filing to update its 2011 opening rate base in accordance with the findings in other sections of this decision. The 2011 opening property, plant, and equipment accounts are approved subject to the Commission's directions relating to specific assets addressed in subsequent sections of this decision.[5]

15. The Commission also issued the following directions summarized in Appendix 3 of Decision 2011-450, which are relevant to the discussion of the opening rate base adjustments, and the Commission directions on the costs associated with the service initiation and billing system (SIBS), HRX, the BFK and DSM:

> 13. The Commission acknowledges that expenditures in excess of the approved amounts in Decision 2008-113 could be due in part to the pricing determined in the Evergreen proceeding. The Commission finds that the over-expenditure on SIBS (NGSIS) replacements was not adequately explained in the application or supported in the analysis of variances provided in Tabs 8.1 and 8.2. The Commission directs AG in its compliance filing to revise the SIBS amount to be included in opening rate base to the forecast approved in Decision 2008-113, adjusted for increases in price approved by this Commission.
>
> 14. The Commission finds the actual cost of $15.1 million to be in excess of these three cost estimates. The Commission also recognizes that the estimates undertaken are imprecise and accordingly relies on them as directional guidance. The Commission has reviewed the business cases of ATCO Electric and AG and other evidence on the record and determines that a 10 per cent cost reduction in the actual costs of HRX is warranted. The Commission directs AG in its compliance filing to reduce the actual cost of HRX in its opening rate base by 10 per cent.
>
> 30. AG explained that it spends $50,000 per year on "cross-promotion of safety messages" through the BFK while the forecast for the test period for the BFK is $2 million per year. The Commission considers that BFK provides a disproportionate amount of costs for the safety and gas distribution service communication benefits received. Further, AG is the only Canadian distribution utility that has a facility like the BFK Calgary Learning Centre. The Commission is not persuaded that the Edmonton BFK is required in light of the limited benefit that customers receive through safety and gas distribution communication through the BFK. The Commission finds that the BFK is not a cost effective means of proving public safety communication. Further, AG has other options to meet its responsibility to distribute public safety information. For the preceding reasons, AG is directed to remove all Edmonton BFK costs from 2011 opening

5 Decision 2011-450, paragraph 83.

rate base and from revenue requirement for the test years, including both capital and O&M related costs. For the same reasons the request to include in revenue requirement costs associated with the Calgary BFK is denied.

33. The Commission denies AG's request to include in revenue requirement for the test years all costs associated with current and proposed DSM activities. The Commission directs that all DSM related costs, both capital and operating, be removed from rate base and revenue requirement for the test years. The Commission further directs that the DSM capital expenditures incurred during the period 2008 to 2010 are to be excluded from opening rate base.

16. AG summarized the opening rate base reductions and these reductions are reflected in the following table:

Table 3. Opening Rate Base Reductions (000's)

Description	Reference	Original Cost	Accumulated Depreciation	Net Utility Property, Plant and Equipment
SIBS	CD 13	(2,476)	(206)	(2,270)
HRX	CD 14	(1,439)	(130)	(1,309)
Blue Flame Kitchen	CD 30	(2,044)	(228)	(1,816)
DSM	CD 33	(335)	(58)	(277)
Total Adjustments		**(6,294)**	**(622)**	**(5,672)**

17. AG noted that these assets would not be fully depreciated for 30 years, and that it would have to keep track of the differences between property, plant and equipment (PP&E), undepreciated capital costs for income tax purposes, depreciation expense, and capital cost allowance for accounting purposes and income tax purposes in two sets of books. AG proposed to make a present value payment of $6,376,000 to customers to allow AG to retain its existing opening rate base. AG stated "The present value payment provides the financial impact to customers of adjusting rate base while avoiding the unnecessary administrative burden involved in tracking these adjustments over an extended period of time."[6] AG also noted that keeping two sets of books rather than using the present value payment would increase the administrative burden. Present value payments were approved by the Commission in the ATCO Utilities 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-up Proceeding[7] and the 2008-2009 Evergreen Application Compliance Filing to Decision 2011-228.[8]

18. The UCA stated that it did not favour the use of one-time adjustments and the decisions noted by AG were related to adjustments to ATCO I-Tek costs as a result of a benchmarking report.[9] The asset cost adjustments, reflected as a one-time payment in Decision 2010-102, did not reflect adjustments for disallowed assets, but rather reflected the amounts for ATCO I-Tek costs that were determined to be too high. Further, in that decision, there was no mention of imprudent costs or disallowed assets unlike the asset costs that were disallowed in Decision 2011-450. The approach of removing assets from rate base is not a new process and

6 Application, page 1, Opening Rate Base Adjustments.

7 Decision 2010-102: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) - 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up, Application No. 1562012, Proceeding ID No. 32, March 8, 2010.

8 Decision 2011-485: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) 2008-2009 Evergreen Application Compliance Filing to Decision 2011-228, Application No. 1607460, Proceeding ID No. 1321, December 12, 2011, paragraphs 24 and 25.

9 Exhibit 40.02, UCA argument, paragraph 3.

AG's methodology was more the exception than the rule.[10] In prior proceedings the removal of costs was shown as a separate line item of disallowed or as non-utility assets.

19. The UCA considered that future changes to income tax rates, depreciation rates, return on equity and capital structures virtually guarantee that the assumptions used in the net present value calculations will become inaccurate over time. The UCA submitted that "Leaving the assets as disallowed or non-utility assets will allow for the most appropriate treatment of these costs and ensure future changes to the above components of revenue requirement are properly reflected in customer rates."[11]

20. The UCA also argued that an appropriate discount rate had not been determined or argued in the 2011-2012 GRA, and as a result, it recommended that the Commission reject AG's proposal to use a present value method to determine the refund to customers. However, should the Commission be persuaded by the AG proposal, the UCA recommended that the Commission adopt a deferral account approach to take into account future income tax, depreciation rates, rates of return, and capital structure changes that can and likely will occur over the next 10 years and into the future. Further, the appropriate discount rate would be the same discount rate used in carrying cost calculations in deferral account applications.[12]

21. Calgary was opposed to AG's net present value (NPV) approach and considered that the benefit customers receive from removing these items from rate base may be different than AG's calculated revenue impact adjustments.[13]

22. Calgary asserted that allowing these items to remain in rate base was contrary to the findings from the Supreme Court of Canada in the Stores Block decision[14] and the Alberta Court of Appeal in the Carbon decision[15] that only assets providing utility service should be included in rate base. AG's treatment allows non-utility items to remain in rate base. Further, under performance based regulation, AG's going-in revenue requirement would be higher than it should be and AG would receive adjustments based upon that higher revenue requirement.[16]

23. Calgary noted AG's position that it could not provide details of the disallowed capital expenditures by asset account. Calgary questioned how proper depreciation rates were determined and a net present value of the revenue requirement for the account was calculated if AG cannot provide details of the fixed asset accounts related to the disallowed assets. If the assets were removed from rate base they would likely be impaired and at some point be removed from the utility assets of AG for financial accounting purposes. The need for two sets of books would be eliminated.[17]

24. Calgary submitted that the Commission should reject AG's NPV approach and require the assets to be removed from rate base.[18]

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10 Exhibit 40.02, UCA argument, paragraph 5.
11 Exhibit 40.02, UCA argument, paragraph 6.
12 Exhibit 40.02, UCA argument, paragraph 7.
13 Exhibit 41.01, Calgary argument, page 3.
14 ATCO Gas & Pipeline Ltd. v. Alberta (Energy & Utilities Board) 2006 SCC 4.
15 ATCO Gas & Pipeline Ltd. v. Alberta (Energy & Utilities Board) [2008] ABCA 200.
16 Exhibit 41.01, Calgary argument, page 3.
17 Exhibit 41.01, Calgary argument pages 3 and 4.
18 Exhibit 41.01, Calgary argument, page 4.

25. CCA noted AG's response to CCA-AG-02[19] that customers are not harmed by holding smaller assets such as the BFK assets in the legal entity. CCA disagreed that customers are not harmed. Interest rates were currently low and would likely increase over the next 30 years. Changes in income rates, capital cost allowance rates and methodologies are likely to occur in the future. These changes cause risk for customers, for which they should not be responsible. Further, there will be increased regulatory activity as the disallowed assets must continue to be reviewed and keeping non-regulated or disallowed assets in rate base was not good regulatory practice.[20]

26. CCA was concerned about the cumulative risk and magnitude as disallowed assets continue to be placed into rate base over time.[21] The appropriate regulatory practice is to remove disallowed assets from rate base, as noted in Decision 2005-128:[22]

> …the Board finds it preferable that, within a corporate group, assets which are not engaged in rate regulated service should be held by a separate legal entity from the one holding rate regulated assets ... With respect to existing material assets already owned by a utility that have never been included in rate base like the MRP, or assets which at some point in time are removed from rate base, the preference of the Board would be that these assets also be moved into a separate legal entity.[23]

27. AG agreed that it is common to see a "Disallowed Asset" or "Non-Utility Asset" category in utility revenue requirement summaries and that the present value approach is more the exception than the rule. These adjustments are unique in that, for the most part, they do not refer to whole assets being removed from utility service. The majority of the disallowed costs relate to SIBS and HRX which are software applications that are clearly still in utility service. This is the exact same situation that arose from actual I-Tek costs being charged to PP&E being determined to be too high in which the Commission ruled that something less than the total dollars in PP&E were to be included in rates.[24]

28. Similar to the I-Tek costs, AG is attempting to avoid a situation where the same asset or assets have a portion of their costs included in utility operations and a portion in non-utility operations. AG argued, "In this situation depreciation expense must be split between utility and non-utility, capital cost allowance must be split between utility and non-utility and the ultimate retirement of the asset must be split between utility and non-utility."[25]

29. While the Blue Flame Kitchen is an entire program and not a disallowance of partial costs there would be a significant amount of administrative burden to isolate what is a small portion of AG's overall leasehold improvement costs. This is similar to SIBS and HRX, where costs for leasehold improvement depreciation and capital cost allowance need to be split and an amount is assigned to non-utility.[26]

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19 Exhibit 37.01 CCA-AG-02(a) page 2 of 3, page 4 PDF.
20 Exhibit 42.01, CCA argument, paragraph 8.
21 Exhibit 42.01, CCA argument, paragraph 8.
22 Exhibit 42.01, CCA argument, paragraph 9.
23 Decision 2005-128: ATCO Pipelines - Muskeg River Pipeline Application, Application No, 1393613, November 29, 2005, page 6 (page 10 in PDF).
24 Exhibit 45.01, ATCO Gas reply argument, paragraph 7.
25 Exhibit 45.01, ATCO Gas reply argument, paragraph 8.
26 Exhibit 45.01, ATCO Gas reply argument, paragraph 9.

30. AG did not agree with CCA's argument that further regulatory activity will be increased as a result of the NPV proposal. Under AG's proposal, these assets will remain in rate base to be depreciated for both accounting purposes and income tax purposes in their normal course until they reach the end of their useful lives, when they will be retired. This will not create any incremental regulatory activity unlike isolating the costs as non-utility. Isolating these costs as non-utility would create additional administrative burden in splitting the depreciation expense and capital cost allowance every year between utility and non-utility, and maintaining a life to date continuity of the accumulated amounts.[27]

31. In response to the UCA, AG considered that these assets are unique and warrant different treatment as they are not disallowances of whole assets, but rather partial disallowances of assets that, for the most part, remain in utility service. The UCA's suggested use of the standard approach to disallowed assets is not appropriate.[28]

32. Noting the UCA and CCA's concerns with respect to changing interest rates, tax rates, capital cost allowance rates and methodologies, and UCA's recommendation to adopt a deferral account approach regarding potential changes in these rates, AG noted that the 2011 revenue requirement related to these assets is $850,000, which represents less than two tenths of one per cent of the 2011 revenue requirement of $564.5 million and these amounts are not material.[29]

33. AG also considered the materiality on the impact in the one time payment if the weighted average cost of capital (WACC), income tax rates, and depreciation expense were increased by 10 per cent and capital cost allowance claims reduced by 10 per cent. Assuming these changes would occur at the earliest possible time, the magnitude of the one-time payment changed by $218,000 from $6,376,000 to $6,594,000, or $0.22 per customer based on 1,000,000 customers. AG submitted that those amounts are not material and any risk that customers are exposed to is insignificant regardless of the standard applied. The immateriality of the amounts demonstrates that there is no need for a deferral account.[30]

34. AG agrees with the UCA that the appropriate discount rate would be the same discount rate used in carrying cost calculations for deferral accounts. Both the recently established weather deferral account and load balancing deferral account have carrying charges applied to the average monthly balances, and, in both cases, apply the WACC rate approved by the Commission for accrual of carrying costs.[31]

35. While Calgary argued that the NPV methodology was a zero sum game in which ATCO suffers no loss, AG argued that this was incorrect. AG submitted that "When items are removed from rate base there is no recovery of depreciation expense, income taxes or return provided for in customer rates/revenue. Under the AG proposal, the one-time payment along with a financing accretion amount is amortized and offsets the higher revenue AG receives by these assets

[27] Exhibit 45.01, ATCO Gas reply argument, paragraph 11.
[28] Exhibit 45.01, ATCO Gas reply argument, paragraph 12.
[29] Exhibit 45.01, ATCO Gas reply argument, paragraph 15.
[30] Exhibit 45.01, ATCO Gas reply argument, paragraph 16.
[31] Exhibit 45.01, ATCO Gas reply argument, paragraph 19.

remaining in rate base."[32] The financial result for AG is identical whether the NPV methodology is used or the amounts are removed from rate base.[33]

36. In response to Calgary's argument that allowing items to remain in rate base was inconsistent with the Stores Block and Carbon decisions, AG indicated that these assets have not been removed from utility service but rather a portion of their costs have been disallowed. The remaining minority of these assets, for the BFK and DSM, are immaterial amounts.[34]

37. AG also acknowledged Calgary's position that under a performance-based regulation (PBR) regime, its going in revenue would be higher than it otherwise would be, but AG could remove the revenue requirement impact for the insignificant amounts from the indexing mechanism in its PBR formula and treat these amounts as a Y Factor flow through adjustments.[35]

38. With respect to asset accounts, AG is aware of what asset accounts the disallowed assets are in, which allows AG to properly determine the depreciation expense and calculate a net present value. Under International Financial Reporting Standards (IFRS), these assets are not impaired and will not be removed from the financial assets of AG for accounting purposes, which gives rise to the issue of keeping two sets of books.[36]

39. AG submitted that its proposal for a present value payment was reasonable. The present value payment provides the financial impact to customers of adjusting rate base while avoiding the significant and unnecessary administrative burden involved in tracking these adjustments over an extended period of time.[37]

40. Both the UCA and CCA argued that future changes in income tax rates, depreciation rates, rates of return on equity, and capital structures would impact the current NPV calculation and place customers at risk for bearing costs that should have been removed from ratebase.

41. When determining the merits of using a net present value approach to address rate base adjustments, an assessment of the benefits and concerns of using a net present value approach, including the reasonableness of the approach to the utility, present ratepayers, and future ratepayers, must be made based on the circumstances of the particular situation. The Commission agrees with both the UCA and CCA that future changes may occur. However, the calculations done by AG indicated that dramatic changes to WACC, income tax rates, depreciation and capital cost allowance claims, should they occur, should not have a material impact on the NPV amount to be refunded to customers.

42. While it would be preferable to remove costs from rate base for assets that are not required for utility service, the Commission realizes that this may not be practical in every situation. As indicated by AG, the majority of disallowed costs are related to SIBS and HRX programs, which are currently in utility service. Given the current use of these programs, the Commission considers that it would not be efficient to require AG to track differences for income tax and accounting purposes until these assets are retired as the costs for these projects have been reduced, but the programs have not been disallowed.

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32 Exhibit 45.01, ATCO Gas reply argument, paragraph 21.
33 Exhibit 45.01, ATCO Gas reply argument, paragraph 21.
34 Exhibit 45.01, ATCO Gas reply argument, paragraph 22.
35 Exhibit 45.01, ATCO Gas reply argument, paragraph 23.
36 Exhibit 45.01, ATCO Gas reply argument, paragraph 25.
37 Exhibit 45.01, ATCO Gas reply argument, paragraph 28.

43. Given the small reduction in the NPV amount that would be refunded to customers should WACC, income tax rates, depreciation and capital cost allowance assumptions change, and the fact that a portion of the assets in question are still in utility service, the Commission considers the proposal advanced by AG is an effective way to balance the amounts owing to customers with regulatory efficiency. On this basis, the Commission approves the NPV methodology recommended by AG for the SIBS and HRX amounts.

44. With respect to the BFK and DSM, the Commission finds that these costs are related to entire programs which have been disallowed by the Commission, and costs associated with these programs are not required for utility service, unlike SIBS and HRX costs which were split between utility and non-utility service. On this basis the Commission directs AG to remove the BFK and DSM reductions accounted in for its opening rate base in its second compliance filing to Decision 2011-450.

45. For HRX, AG has reflected the 10 per cent cost reduction in the actual costs in this compliance filing. This issue of the 10 per cent cost reduction for HRX is currently before the Commission in Proceeding ID No. 1698, the ATCO Gas 2011-2012 Phase II Review and Variance (Phase II R&V). In Decision 2012-156, the Phase I R&V decision, the review panel stated that AG did not have a reasonable opportunity to place its HRX business case in context as the business case was filed after the cross examination of the AG panel was completed.[38] Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount for 90 per cent of the actual costs of HRX in its second compliance filing to Decision 2011-450.

4.2 Commission Direction 2 - Tier 2 and Tier 3 meters

46. The Commission issued the following direction to AG:

> 163. The Commission directs AG in the compliance filing to this decision to provide the Commission with the actual number of Tier 2 meters replaced in 2010 and the actual capital costs incurred. AG is directed to indicate the number of Tier 2 meters and Tier 3 meters with a medium risk factor left to be replaced in 2011 and 2012 and to provide the forecast capital costs in each year using the forecast capital costs calculated from Tables 2.1.1.2(c) and (d) in the application.[39]

47. In the application AG identified the actual number of Tier 2 and Tier 3 meters which were replaced in 2012 and the capital costs, not including removal costs.[40] A summary table was provided showing the breakdown between Tier 2 and Tier 3 medium risk and Tier 3 low risk. In 2010, AG performed a total of 3,356 above ground moves for the total capital cost of $8,819,000. The Commission is satisfied that AG has complied with this request.

4.3 Commission Direction 3 – Tier 2 and Tier 3 meters

48. The Commission issued the following direction to AG:

> 164. The Commission further directs AG to plan the replacement of the Tier 2 and the portion of the Tier 3 meters with a medium risk factor in a manner that achieves efficiencies and distributes the costs evenly over the period 2011 to 2014.[41]

[38] Decision 2012-156, page 17, paragraph 65.
[39] Decision 2011-450, paragraph 163.
[40] Application, Commission Direction 2.
[41] Decision 2011-450, paragraph 164.

49. AG adjusted the 2011 to 2014 forecast expenditures for meter relocation and replacement program (MRRP), and provided a summary of the changes in Commission Direction 3 attachment.[42]

50. In reviewing the MRRP forecast expenditure changes, the UCA raised concerns regarding the addition of 1,240 meters into the project, the apparent shifting of 1,200 meter replacements from 2014 to 2011 and 2012, and the addition of 16.5 per cent cost premium. UCA noted that 1,240 meters that were previously scheduled to be replaced as part of the urban mains replacement (UMR) program were added into the total number of meters to be moved or replaced in 2014 as part of MRRP. Further a 16.5 per cent cost premium was added to the average unit cost for above ground meters.

51. With respect to the additional 1,240 meters added to MRRP, UCA pointed out that it appeared 1,200 meters were removed from 2014 and redistributed primarily to 2011 and 2012. UCA considered that the need for these moves was not previously identified, discussed or tested in the GRA. UCA argued that assuming that the 1,240 additional meters need to be replaced at some point as part of the program, it would be reasonable to schedule those meter replacements in 2014 without "redistributing" them into the test years.

52. UCA noted the 16.5 per cent cost premium was approved in AUC Decision 2008-113[43] because work was to be performed on sites spread out across the province. Having reviewed the reference to the cost premium in Decision 2008-113, UCA considered that there was no reason to believe that the circumstances that led to the approval of a cost premium in 2008 currently existed and should be applied in this case. There is no reasonable evidentiary basis for adding the 16.5 per cent premium and the premium should be removed.

53. AG stated that with the proposed acceleration of the UMR program 1,240 meters were removed from the MRRP. However, with the Commission's reductions to UMR, the 1,240 meters were returned to MRRP, as the meters in these locations would now not be moved as part of the reduced UMR program.

54. With the addition of these meters to the MRRP, the costs were distributed evenly over the period 2011 to 2014, as ordered in Commission Direction 3. The 1,200 "redistributed" units noted by the UCA as shown in 2011 and 2012 were only coincidentally close to the same number of units that were removed from 2014. AG stated that scheduling these meter replacements in 2014, as argued by UCA, was contrary to the Commission direction to distribute the costs evenly over the period 2011 to 2014.

55. While AG did not dispute UCA's argument that the circumstances surrounding the 16.5 per cent cost premium approved in Decision 2008-113 may be different than the circumstances in the 2011-2012 GRA, the resulting inefficiencies are similar. The loss of efficiencies due to the work being more spread out as a result of the exclusion of the Tier 3 low risk meter replacements from the approved program relates to approximately 28 per cent of the requested work being excluded from the revenue requirement forecasts.

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42 Application, Exhibit 1, pages 122 of 238 PDF.

43 Decision 2008-113: ATCO Gas – 2008-2009 General Rate Application Phase I, Application No. 1553052, Proceeding ID No. 11, November 13, 2008.

56. Rather than completing the work as planned, AG is now required to skip over both the Tier 3 low risk meters as well as the Tier 4 meters, resulting in increased inefficiencies. The costs to set up in a neighbourhood, pack up for a relocation and travel costs will now be spread over 28 per cent less units which will have a significant impact on unit cost rates. AG submitted that while the circumstances may be different, the resulting impact of lost efficiencies on unit cost rates is very much the same.

57. The Commission notes that due to the overlap of the UMR program with the MRRP, AG removed the installation of 1,240 meters from the MRRP, as these meters would be replaced under the UMR program. Given the Commission directions and resulting reductions to the UMR program, the Commission agrees with AG that the previously removed 1,240 meters should be restored to the MRRP is consistent with the findings in the GRA decision.

58. The Commission also agrees with the shifting of 1,200 meters from the 2014 forecast to the 2011 and 2012 forecasts. The Commission finds that this shifting of meters was done in response to the Commission's direction to distribute the costs evenly over the 2011 to 2014 period and the forecasts in 2011 and 2012 are reflective of the Commission's direction.

59. With respect to the 16.5 per cent premium added to the MRRP costs for work being spread out over 2011 to 2014, while the average installation cost per meter may change as noted by AG, there was no evidence presented by AG to suggest that there will be additional set-up, pack-up and travel costs as a result of the reduction in meters being replaced. Decision 2008-113 allowed for the 16.5 per cent premium based on the midrange of three per cent and 30 per cent of subsequent contractor premiums quoted to AG. The Commission in that decision recognized labour constraints in allowing the premium but also indicated that it expected AG to make its best efforts to utilize in house labour in carrying out the MRRP.

60. The Commission finds that there was limited evidence provided by AG in the compliance filing with regard to increased labour requirements or travel costs to support a premium in the 2011 and 2012 test years. However, the Commission recognizes that potential inefficiencies may have resulted due to AG's required exclusion of Tier 3 low risk meter replacements as per Commission Direction 2. As a result, the Commission directs AG in its second compliance filing to provide a detailed justification of any premium that should be applied to AG's forecast due to the above noted inefficiencies.

4.4 Commission Direction 4, 5 and 6 – plastic pipe

61. The Commission issued the following directions to AG:

> 4. With respect to the second UCA recommendation the Commission acknowledges that pre-1973 plastic pipe and 1973 to1975 plastic pipe were subject to different certification practices and approved for different operating pressures. However, the Commission notes that neither vintage group was required to meet the CSA standard which became mandatory in 1975. Accordingly, the Commission considers it in the public interest to remove all pipe manufactured prior to 1973. With respect to pipe manufactured from 1973 to 1975, the Commission notes AG's comment that it is acting with an "abundance of caution." With regard to the UCA's first recommendation, the issue for the Commission to address is the extent to which inventory practices may have resulted in the installation in 1976 or 1977 of interim certified pipe from the 1973 to1975 period. AG's records are inadequate. AG is neither able to identify whether pipe purchased during the interim 1973 to1975 period was certified nor has it the ability to determine how long pipe remained in inventory and therefore, what portion, if any of the pipe was

> installed in 1976 and 1977. These facts have made the consideration of this program difficult. Nonetheless, the Commission considers the risk of brittle failure associated with plastic pipe and PVC pipe when subjected to stress to be a serious safety and reliability issue, and therefore, the Commission approves the entire program. However, the Commission directs that the program be implemented over a 20-year period considered in alternative three in the business case rather than the 17-year proposed in alternative two. Given the fact that the pipe manufactured during the 1973 to1975 period was of a higher quality than the pre-1973 pipe and some of the 1973 to 1975 pipe may have met the then voluntary CSA standard and noting that this vintage of pipe was proposed to be removed last, the Commission considers the extended installation period to be warranted. Lengthening the time period over which replacement occurs will reduce the magnitude of the impact on rates to customers but does put in place a comprehensive plan to replace PVC and early generation PE.[44]
>
> 5. As additional leak history data on pipe installed from the 1973 to1977 period becomes available it may be appropriate to reconsider the program scope and timelines. The Commission directs AG to continue to provide plastic pipe leak history in future capital program applications.[45]
>
> 6. The Commission directs AG in the compliance filing required by this decision to indicate what the 2011 and 2012 plastic pipe replacement program revenue requirement would be based on a 20-year program, without considering the actual 2011 expenditures.[46]

62. In its application, AG reduced its forecast for the PE/PVC Pipe replacement by 15 per cent in the test years to reflect the extension of the program from 17 years to 20 years.[47] The 15 per cent reductions result in an impact of $2.9 million and $3.5 million in 2011 and 2012 respectively. AG will continue to identify leak information for pipe installed in the 1973 to 1977 period as a subgroup in order to comply with Direction 5. In its response to Direction 6, AG provided the 2011 and 2012 revenue requirements of the plastic pipe replacement program based on the compliance filing capital expenditures included in the response to Commission Direction 4. The forecast revenue requirements are $1 million for 2011 and $3.1 million for 2012.

63. The Commission has reviewed the calculation of the plastic pipe program extension revenue requirement and the Summary of Capital Expenditures spreadsheet[48] and is satisfied that AG has complied with these directions.

4.5 Commission Direction 7 – line heaters

64. The Commission issued the following direction to AG:

> 200. The Commission relies on AG's statement that OH&S regulations require AG to update its line heaters. A three-year program has been proposed to complete the work to bring the non-compliant line heaters into compliance and to do reliability work at the same time. The plan by AG to complete the compliance work in three years seems reasonable and the Commission approves this portion of the program for inclusion in

[44] Decision 2011-450, paragraph 191.
[45] Decision 2011-450, paragraph 192.
[46] Decision 2011-450, paragraph 193.
[47] Application, Commission Direction 4.
[48] Application, Exhibit 7.

> revenue requirement. The Commission finds that when reliability improvements are to be made on heaters for which compliance work is to be done, it is practical to do both at the same time over the three year period. However, the Commission does not consider that justification has been made for a three-year period to complete work on line heaters that do not have a compliance component. Therefore the Commission directs AG to exclude from its program, line heaters that are in compliance with OH&S regulations. The Commission directs AG in the compliance filing to this decision to reflect two years of the three-year replacement and upgrading of the non-compliant line-heaters.[49]

65. AG revised the line heater program to exclude work on line heaters that do not have a compliance component and to only reflect sites which require improvements to bring non-compliant line heaters into compliance with Occupational Health and Safety (OH&S) regulations. The revised program results in expenditures of $6 million in each of 2011 and 2012, resulting in a reduction of $1 million for each test year. The Commission has reviewed the Summary of Capital Expenditures spreadsheet[50] and is satisfied that AG has reflected the change to the Line Heater program in its revenue requirement for the test years.

4.6 Commission Direction 8 – AMR contingency

66. The Commission issued the following direction to AG:

> 216. The UCA's primary concern with the AMR program was the magnitude of the contingency included in the forecast estimates. The Commission agrees that the contingency may be too high, but notes that AG was expected to complete a "proof of concept" by the end of June 2011. The Commission directs AG to report in the compliance application to this decision on the results and effects of the "proof of concept" stage for installations made in the initial phase of the project and the results and the effect on the contingency, if any. AG is directed to submit an update to its business case economic analysis. The Commission will finalize the test year forecast amounts along with the contingency following the compliance application.[51]

67. AG completed a proof of installation concept review in October 2011. The forecast automated meter reading (AMR) capital expenditure and removal costs are $18.5 million for 2011 and $39.5 million for 2012, respectively. AG explained that the 20 per cent contingency forecast of 3.1 million for 2011 and $6.6 million for 2012 included in the AMR project continues to be reasonable based on the requirements identified in the proof of installation concept. AG confirmed that no change to the contingency was required.[52] Additional costs were identified in the proof of concept as follows:[53]

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49 Decision 2011-450, paragraph 200.
50 Application, Exhibit 7.
51 Decision 2011-450, paragraph 216.
52 Exhibit 36, AG information response to UCA-AG-06(a).
53 Application, Exhibit 1, page 129 of 238 PDF.

Table 4. Contingency requirements

Contingency requirements ($ millions)	2011	2012
Finalization of Contract with Intron	0.8	1.7
Additional Project Management Requirements	0.5	0.7
Additional costs related to Installation Quality Assurance & Materials	0.8	1.2
Additional costs to retrofit ERT's	0.4	0.4
Additional Costs to address return to utility work	0.8	2
Increase in remote mount installation & cabling costs	0.2	0.5
Total Additional Costs identified	3.5	6.5

68. The Commission is satisfied that the additional costs identified by AG in the proof of concept for 2011 and 2012 of $3.5 million and $6.5 million are consistent with the 20 per cent contingency applied to the AMR project capital expenditures and the removal cost forecast of $18.5 million in 2011 and $39.5 million in 2012. Further, the Commission has reviewed the explanations provided by AG for the additional costs and is satisfied that AG's 20 per cent contingency amount of $3.1 million in 2011 and $6.6 million in 2012 as forecast in its general rate application continues to be reasonable. The Commission approves these forecast amounts for inclusion in AG's revenue requirement.

4.7 Commission Direction 9, 10 and 11 – Irma and Okotoks agency offices

69. The Commission issued the following direction to AG:

> 9. Accordingly, retired assets that are not anticipated to be disposed of at approximately the same time that they are retired should be moved to a non-utility account where any ongoing costs associated with the assets would be for the account of the utility shareholder. Given that the Irma agency office has been retired and not disposed of, the Commission directs AG to move the Irma agency office to the applicable non-utility accounts effective January 1, 2011. Operating costs and other costs associated with the facility, to the extent there are any, will be for the account of the AG shareholder from and after January 1, 2011.[54]
>
> 10. The Commission directs AG in the compliance filing to this decision to reflect the movement of the Irma agency office to a non-utility account as of January 1, 2011 and to reflect the removal of any operating or related costs associated with the facility as of that date.[55]
>
> 11. Should the Okotoks agency office not be disposed of at approximately the same time as it is retired, AG is directed to move the asset to a non-utility account where further operating and capital costs would be for the account of the utility shareholder.[56]

70. In its compliance filing, AG confirmed that no Irma agency costs were included in the 2011/2012 revenue requirement forecast and that the assets associated with the Irma agency office were retired in accordance with the Uniform Classification of Accounts for Gas Utilities.[57] As a result, AG stated that no associated changes were required to the 2011-2012 forecast revenue requirements for the Irma agency office. AG has also removed $8,000 in operating costs

54 Decision 2011-450, paragraph 320.
55 Decision 2011-450, paragraph 323.
56 Decision 2011-450, paragraph 330.
57 AR 546/63.

related to the Okotoks facility from its 2012 revenue requirement. The Commission is satisfied with these adjustments and considers that AG has complied with these directions.

4.8 Commission Direction 12 - moveable equipment

71. The Commission issued the following direction to AG:

> 355. Rather than an across the board reduction, the Commission prefers to use an escalation of past costs based on a three-year average of the actual expenditures in 2008, 2009 and 2010. AG has noted it has used a three-year average of past costs in other categories. In this case the three year average applied across-the-board to all the accounts noted above in the table equals $13.6 million. Allowing for inflation of three per cent, the amount approved for all the above accounts in 2011 is $14.0 million and in 2012 is $14.4 million. AG is directed to indicate in its compliance filing how it proposes to allocate the approved total amounts between the different accounts.[58]

72. AG provided a table in its response to Direction 12 showing the weightings of each category making up the other moveable equipment category.[59] The original forecast for the moveable equipment category was $17.4 million and $19.4 million. The total impact on revenue requirement using the approved amounts in Direction 12 is a reduction of $3.4 million and $5 million, which has been reflected in the table and the Summary of Capital Expenditures spreadsheet[60] attached to AG's application. The Commission has reviewed the reductions in the other moveable equipment category and is satisfied that AG has complied with this direction.

4.9 Commission Direction 13 - SIBS

73. The Commission issued the following direction to AG:

> The Commission acknowledges that expenditures in excess of the approved amounts in Decision 2008-113 could be due in part to the pricing determined in the Evergreen proceeding. The Commission finds that the over-expenditure on SIBS (NGSIS) replacements was not adequately explained in the application or supported in the analysis of variances provided in Tabs 8.1 and 8.2. The Commission directs AG in its compliance filing to revise the SIBS amount to be included in opening rate base to the forecast approved in Decision 2008-113, adjusted for increases in price approved by this Commission.[61]

74. For SIBS, AG has reflected the 10 per cent cost reduction in the actual costs in its compliance filing. The inclusion of the SIBS replacement program in opening rate base was addressed in paragraph 43 of Direction 1 above. The Commission finds that AG has complied with this direction. The Commission also notes that the ongoing Evergreen 2 proceeding[62] will determine the final pricing amount for inclusion in 2011 and 2012 revenue requirements.

58 Decision 2011-450, paragraph 355.
59 Application, Exhibit 1, page 136 of 238 PDF.
60 Application, Exhibit 7.
61 Decision 2011-450, paragraph 359.
62 Proceeding ID No. 240, Application No. 1605538.

4.10 Commission Directions 14 and 15- HRX and TMS

75. The Commission issued the following direction regarding HRX:

> 14. The Commission finds the actual cost of $15.1 million to be in excess of these three cost estimates. The Commission also recognizes that the estimates undertaken are imprecise and accordingly relies on them as directional guidance. The Commission has reviewed the business cases of ATCO Electric and AG and other evidence on the record and determines that a 10 per cent cost reduction in the actual costs of HRX is warranted. The Commission directs AG in its compliance filing to reduce the actual cost of HRX in its opening rate base by 10 per cent.[63]

76. For HRX, AG has reflected the 10 per cent cost reduction in the actual costs in its compliance filing. The inclusion of the remaining costs of HRX in opening rate base was addressed in paragraph 43 of Direction 1 above. As stated in Direction 1, the issue of Oracle HRX is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V and pending the outcome of the Phase II R&V and any appeals on this issue, AG is directed to include a placeholder amount for Oracle HRX of 90 per cent of the actual cost in its second compliance filing to Decision 2011-450.

77. The Commission issued the following direction regarding AG's talent management system (TMS):

> 15. The Commission considers the HRchitect report which assumes a different platform, is helpful in providing directional guidance. Similarly, the Commission considered the 15 to 25 per cent application cost to total cost ratio as put forward by AG in the HRX business case. This analysis also provided directional guidance for a reduction in forecast costs for TMS. AG had agreed to address in testimony and rebuttal to remove the costs of the three TMS modules that will not be implemented in the test years. The Commission directs AG in its compliance filing to only include the forecast costs of the two modules to be implemented in the test years; performance management and succession planning. For all other costs in the business case, the Commission finds that in consideration of all the evidence before it, the TMS project is approved but that the forecast capital costs should be reduced by 10 per cent.[64]

78. AG noted in its application that the three modules of TMS which are not in use results in a reduction of $0.234 million.[65] AG is proposing to assign this amount to Plant Held for Future Use.[66] The 10 per cent reduction for all other costs in the business case results in an additional removal of $0.162 million. The Commission has reviewed AG's calculations for the TMS reductions and confirms they have been accurately reflected in the GRA schedules and the Capital Adjustments sheet.[67]

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[63] Decision 2011-450, paragraph 386.
[64] Decision 2011-450, paragraph 410.
[65] Application, Exhibit 1, page 139 of 238 PDF.
[66] Application, Exhibit 2, Schedule 2.5-A.
[67] Application, Exhibit 7.

4.11 Commission Direction 16 – Oracle E

79. The Commission issued the following direction to AG:

> The Commission finds that the proposed update to Oracle E in Business Case 16 is premature. A major argument in support of this business case is that support of the current version of Oracle E will end in 2013. The Commission agrees with Calgary that the need for this project has not been demonstrated as the current software support does not expire until 2013 and the benefits were not quantified. For these reasons the Commission denies the application for this business case and directs that the forecast costs related to this business case should be removed from its revenue requirement in the compliance filing for this application.[68]

80. In its application, AG has removed the Oracle E forecast capital expenditure amount of $2.748 million for 2011 in determining its revised revenue requirement and no capital expenditures were included for Oracle E in 2012. The Commission has confirmed that the forecast costs have been removed and the reduction has been reflected in the Capital Adjustments sheet.[69] The Commission concludes that AG has complied with this direction.

4.12 Commission Direction 17 – Oracle mid-size

81. The Commission issued the following direction to AG:

> Business Case 17 for oracle mid-size is proposed based on the fact that support of the current version will end in July 2013. The application states that Oracle will terminate the existing level of support on January 1, 2012. The Commission notes that there is a discrepancy in the dates of termination. According to AG's business case support will not be withdrawn but the level of support may change. The Commission does not consider it has sufficient information to determine if support will be withdrawn, and whether any change in the existing level of support will impact AG's operations. The Commission directs AG in the compliance filing to this application to provide information from the vendor regarding the proposed withdrawal of support, including the level of support which will continue to be available. If the vendor provides the option of continuing support at a lower level, AG is directed to provide an analysis of any impact on its operations.[70]

82. AG provided further information on Oracle product technical support levels. Premier product support is available from the product version availability date and extended support adds an additional three years. Sustained support is available as long as the technical support is maintained. The three different levels of support involve different service levels. Extended support for the current version, Oracle database 10g, will end in July 2013. AG stated there is risk associated with sustained support as problems with the database management system would most likely impact multiple applications.[71]

83. The Commission has reviewed the additional information provided by AG in support of the upgrade to Oracle database management system version 11g. AG stated it has 13 mid-size applications which currently use the Oracle 10g databases[72] and that that operation of the Daily

68 Decision 2011-450, paragraph 437.
69 Application, Exhibit 7.
70 Decision 2011-450, paragraph 438.
71 Application, Exhibit 1, page 114 of 238 PDF.
72 Application, Commission Direction 17, page 5 of 9, paragraph 15.

Forecasting and Settlement System (DFSS) and Imbalance Reporting Information System (IRIS) are dependent on the Oracle databases. Given the additional information provided regarding the limitations of support, the integration with other programs, and risks of continuing with the current version of Oracle, the Commission approves the costs to upgrade to Oracle 11g for inclusion in the 2011-2012 revenue requirement.

4.13 Commission Direction 18 - Maximo

84. The Commission issued the following direction to AG:

> Business Case 19, work enhancements, also proposes a Maximo software upgrade in 2012. The Commission notes that functional benefits are forecast and that withdrawal of support anticipated for the fourth quarter of 2012. The Maximo software appears to have been installed as part of work management Phase II in October 2009 at a cost of $3.9 million. As Calgary noted the entire work management Phase II project was installed at a cost of $17 million compared to a forecast cost of $13.5 million. Calgary also noted a discrepancy in the cost breakdown between the business case and the schedule provided at page 16 of Tab 4.2 Attachment 1. The argument in support of the business case is premised on the withdrawal of support by the vendor. The Commission notes, as acknowledged by AG, that the vendor has not announced the withdrawal of support for the software. For the preceding reasons, the Commission denies approval of the forecasts costs for the Maximo software proposed in Business Case 19. The Commission directs AG to remove the forecast costs associated with this software package from its revenue requirement in the compliance filing for this application.[73]

85. AG removed the Maximo software upgrade forecast amount of $0.4 million, from its 2012 revenue requirement.[74] The Commission has confirmed that removal of this amount has been reflected in the capital adjustment sheet[75] and considers that AG has complied with this direction.

4.14 Commission Direction 19 - CIS

86. The Commission issued the following direction to AG:

> AG has forecast costs for the general CIS enhancement program of $1 million in 2011 and $0.6 million in 2012. This program and the related benefits are not clearly described. The Commission finds the explanation in paragraph 129 of the application does not justify the requested capital expenditure for this project. Therefore, the Commission denies this proposed enhancement and directs that related costs be removed from the revenue requirement in the compliance filing to this decision.[76]

87. AG has removed the CIS enhancement program, forecast amounts of $1 million and $0.6 million, in 2011 and 2012, respectively, determining its revised revenue requirement [MH1]. The Commission has confirmed that this amount has been reflected in the capital adjustment sheet.[77] The issue of the CIS enhancement program forecast costs is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V of Decision 2011-450. In the Phase I R&V, the review panel found that it was unclear whether the hearing panel considered

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73 Decision 2011-450, paragraph 441.
74 Application, Exhibit 1, page 150 of 238 PDF.
75 Application, Exhibit 7.
76 Decision 2011-450, paragraph 443.
77 Application, Exhibit 7.

AG's response to the business case in AUC-AG-43(b).[78] Pending the outcome of the Phase II R&V, AG is directed to include a placeholder amount for CIS of zero in its second compliance filing to Decision 2011-450.

4.15 Commission Direction 20 – IT capital projects

88. The Commission issued the following direction to AG:

> For approved IT capital projects the Commission directs AG in its compliance filing to provide a description of volume metrics and a detailed breakdown of the labour units related to the different classifications with the current rates in support of the forecast labour costs. For any items without units, an explanation should be provided of the reason for inclusion in labour costs. Similarly, AG shall provide an explanation for all projects that have been allocated a volume of processing costs.[79]

89. The Commission has reviewed the tables provided in Attachment 1-4[80] and finds that AG has provided the volume metrics and breakdown of the labour units and costs related to the different classifications as requested. AG has complied with Direction 20.

4.16 Commission Direction 21 and 22 – preferred shares

90. The Commission issued the following directions to AG:

> 21. Accordingly, the Commission finds the preferred share issuance to have been prudent. However, given that preferred shares are subordinate to debt and in certain market conditions, the issuance of preferred shares may demand higher dividend rates than anticipated, alternative debt options should be examined in such circumstances. The Commission directs AG in its next preferred share application to provide a comparative analysis of the alternative of issuing debt.[81]
>
> 22. The Commission notes that AG offered to prepare a similar analysis to the one directed from ATCO Electric, concurrent with or prior to AG's next preferred share application. The Commission considers such an analysis is required and directs AG to prepare an updated analysis concurrent with or prior to AG's next preferred share application to assess whether the optimal range of five to 10 per cent for preferred shares as discussed in Decision 2006-100 should be continued thereafter. This analysis should also include a number that represents the most cost effective level of preferred shares for AG and should be submitted to the Commission concurrently with or before AG's next preferred share application to the Commission. Accordingly, approval of the actual preferred share issue is subject to the Commission's approval of the directed analysis.[82]

91. AG stated in its application that it will provide a comparative analysis of the alternative of issuing debt in its next preferred share application and prepare an updated analysis of whether the optimal range of AG's capital structure should include five to ten per cent of preferred shares concurrent with or prior to AG's next preferred share application.[83] For the purposes of this application, the Commission finds that Directions 21 and 22 have been complied with. AG is

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78 Decision 2012-156, paragraph 48, pages 12 and 13.
79 Decision 2011-450, paragraph 450.
80 Application, Commission Direction 20, Attachment 1-4.
81 Decision 2011-450, paragraph 469.
82 Decision 2011-450, paragraph 489.
83 Application, Exhibit 1, pages 157 and 158 of 238 PDF.

directed to include the alternatives and analysis as directed in Decision 2011-450 in its next preferred share application.

4.17 Commission Direction 23 – preferred shares

92. The Commission issued the following direction to AG:

> Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual preferred share rates for preferred shares issued in 2011, if any, for the purposes of calculating capital structure, forecast return on rate base, forecast utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 preferred shares in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 preferred share rate and the rate of any preferred shares issued in 2011.[84]

93. AG stated in its application that it did not issue any preferred shares in 2011. AG also provided a revised forecast preferred share rate for 2012 of 4.25 per cent.[85] AG requested that the forecast rate be used as a placeholder pending the outcome of its leaves to appeal and review and variance of Decision 2011-450 and Decision 2011-474[86] as the forecast may be directly and materially affected by these decisions. The Commission has reviewed the information provided in the response to this direction, including the market forecast information from three Canadian Banks.[87] The Commission accepts the revised forecast preferred share rate of 4.25 per cent for 2012. In relation to the leaves to appeal and R&V applications of Decisions 2011-450 and Decision 2011-474, the Commission recently issued a June 28, 2012, clarification letter addressing stranded cost risk and any adjustments to the fair return:

> The Commission has reviewed the Utilities' letter and considers that the issues raised by the Utilities will be determined as part of either Proceeding ID No. 20 or another generic proceeding. In that proceeding, the Commission will consider whether its findings should apply to 2011 and 2012 or prospectively. Following the completion of either Proceeding ID No. 20 or another generic proceeding, and if the matter has not already been addressed, the Commission will establish a proceeding to determine whether any adjustments to the fair return of the Utilities should be made for 2011 and 2012.

94. The Commission accepts that it is possible that the proceeding mentioned above, whether under Proceeding ID No. 20 or another generic proceeding, may have a potential effect on the 2012 preferred share forecast depending the outcome of the issue of stranded cost risk and any adjustments to the fair return. AG's request that the forecast 2012 preferred share rate be used as a placeholder is granted.

4.18 Commission Direction 24 - debt

95. The Commission issued the following direction to AG:

> Accordingly, the Commission directs AG in the compliance filing to this decision to include the actual long-term debt rates for long-term debentures issued in 2011, if any, for the purposes of calculating capital structure, forecast return on rate base, forecast

[84] Decision 2011-450, paragraph 494.
[85] Application, Exhibit 1, page 159.
[86] Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011.
[87] Application, Commission Direction 23 Attachment 1-3.

> utility income and revenue requirement in 2011. AG shall also provide an updated forecast for 2012 long-term debt in the compliance filing, and shall include an analysis of any rate differential between the recommended forecast 2012 long-term debt rate and the rate of any long-term debt issued in 2011.[88]

96. On October 24, 2011, AG issued two tranches of debt: a 30 year debenture at 4.543 per cent and a 50 year debenture at 4.593 per cent.[89]

97. AG also provided a forecast long-term debt rate for 2012 of 4.75 per cent. AG requested that the forecast rate be used as a placeholder pending the outcome of its leaves to appeal and R&V of Decision 2011-450 and Decision 2011-474, as the forecast may be directly and materially affected by these decisions. The Commission has reviewed the information provided in the response to this direction, including the market forecast information from three Canadian Banks.[90] The Commission accepts the revised forecast long-term debt rate of 4.75 per cent for 2012. In relation to the leaves to appeal and R&V applications of Decision 2011-450 and Decision 2011-474, the Commission recently issued a June 28, 2012, clarification letter addressing stranded cost risk and any adjustments to the fair return:

> The Commission has reviewed the Utilities' letter and considers that the issues raised by the Utilities will be determined as part of either Proceeding ID No. 20 or another generic proceeding. In that proceeding, the Commission will consider whether its findings should apply to 2011 and 2012 or prospectively. Following the completion of either Proceeding ID No. 20 or another generic proceeding, and if the matter has not already been addressed, the Commission will establish a proceeding to determine whether any adjustments to the fair return of the Utilities should be made for 2011 and 2012.

98. The Commission accepts that it is possible that the proceeding, mentioned above, whether under Proceeding ID No. 20 or another generic proceeding, may have a potential effect on AG's long-term debt forecast depending the outcome of the issue of stranded cost risk and any adjustments to the fair return. AG's request that the forecast 2012 long-term debt rate be used as a placeholder is granted.

4.19 Commission Direction 25 – vacancy rate

99. The Commission issued the following direction to AG:

> The Commission has not been persuaded that the proposed decrease to a six per cent vacancy rate due to an increasing proportion of vacancies caused by retirements is warranted. A six per cent vacancy rate is inconsistent with historical results and unsupported by the evidence filed in this proceeding. AG is therefore directed to increase its forecast vacancy rate for 2011 and 2012 to 8.3 per cent based on a three-year historical average and to revise its forecast FTE levels and revenue requirement in the compliance filing to this decision.[91]

88 Decision 2011-450, paragraph 507.
89 Application, Commission Direction 24, page 1 of 2.
90 Application, Commission Direction 23, Attachment 1-3.
91 Decision 2011-450, paragraph 538.

100. As part of its application, AG calculated the 8.3 per cent adjustment to the vacancy rate, subject to exclusions,[92] and reduced its operation and maintenance (O&M) forecasts by $123,000 for 2011 and $131,000 for 2012.[93] This amount was included in the summary of O&M adjustments.[94]

101. The UCA submitted that Direction 25 requires AG to revise its forecast capital component, rather than only its O&M forecasts, to reflect a higher vacancy rate. The UCA argued that this would seem to imply that the Commission expects the company to adjust both O&M and capital components of its revenue requirement.[95] The UCA submitted that the Commission should adjust AG's capital program to reflect a reduction in the vacancy rate, based on AG's estimates of full time equivalents (FTE) labour allocated to capital.[96]

102. With respect to O&M expenses, the UCA stated that AG did not adjust forecast O&M labour costs to account for a higher vacancy rate in any account for which the original forecast was either specifically approved by the Commission or for which the forecast was adjusted on some other basis. The net result is that the 2011 vacancy rate adjustment is applied to only $5.3 million of labour expense out of a total O&M labour expense of $101.4 million and the resulting adjustment is only $123,000.[97]

103. The UCA submitted that Direction 2011-450, as a whole "is most reasonably understood as requiring AG to implement both a general or over-arching reduction in O&M labour expense pursuant to Direction 25 and various other account-specific reductions as discussed in subsequent sections of the Decision."[98] Direction 25 is not qualified in any way nor is there any discussion of the issue of vacancy rates in subsequent sections of the decision.

104. The UCA therefore, argued that a 2.3 per cent reduction should be applied to all, or at least most, of AG's O&M labour expenses to reflect a higher vacancy rate[99] and UCA disputed exclusions from the vacancy rate adjustment.[100] However, it is necessary to properly align the O&M reduction under Direction 25 with the Commission's other directions to ensure that AG is not subjected to a double reduction (i.e. for costs that were disallowed by the Commission but were used to reduce O&M adjustments for those cost categories).[101] The UCA recommended that this concern could be addressed by applying the 2.3 per cent vacancy adjustment to overall O&M labour expenses calculated after application of the various other account-specific O&M adjustments that were directed by the Commission.[102]

105. AG disagreed with the UCA's assertion that Commission Direction 25 was a general and over-arching reduction to both capital expenditures and O&M as a result of applying an increase in the vacancy rate to 8.3 per cent.[103] If the Commission wanted a general and overarching

92 Exclusions are listed in the Application, Exhibit 1, page 184 and 185 of 238, and include BFK and DSM full program costs, general overall labour reductions, line heater inspections, overall meter reading labour.
93 Application, Exhibit 1, page 183 of 238 PDF.
94 Application, Exhibit 8.
95 Exhibit 40.02, UCA argument, paragraph 12.
96 Exhibit 40.02, UCA argument, paragraph 14.
97 Exhibit 1, Response to Commission Direction 25, table at page 183.
98 Exhibit 40.02, UCA argument, paragraph 17.
99 Exhibit 40.02, UCA argument, paragraph 33.
100 Exhibit 40.02, UCA argument, paragraphs 20 to 32.
101 Exhibit 40.02, UCA argument, paragraph 34.
102 Exhibit 40.02, UCA argument, paragraph 35.
103 Exhibit 45.01, AG argument, paragraph 33.

reduction in addition to specific adjustments for capital expenditures and O&M functions, it would have made a specific directive.[104] By applying a general and overarching reduction under Direction 25, the result would be in effect a doubling up of reductions.[105]

106. Regarding capital expenditures, AG stated that they are forecast and approved for each of the various types of capital expenditure projects applied for including all necessary resources to complete capital projects, including internal labour, contractors and the required supply costs. Capital forecasts are calculated using a three year average of historical costs which would already incorporate the actual vacancies in those years.[106] AG submitted that no further reduction to capital forecasts related to vacancy rates is required.

107. The Commission has reviewed AG's adjustment to O&M as per Direction 25 and is satisfied that AG's revised forecast labour costs and associated FTEs complies with Decision 2011-450. AG's adjustment to the vacancy rate, subject to exclusions, and reduced O&M forecasts is consistent with Direction 25 since the intent of this direction was that any reduction to labour with respect to fractional vacancies was specific to O&M related labour expenses, with matters pertaining to capital expenditures or projects being addressed on a project by project basis in the capital section of Decision 2011-450.

4.20 Commission Direction 26 - inspection

108. The Commission issued the following direction to AG:

> Interveners did not oppose this expenditure but the CCA submitted that it should be a one time charge. The Commission agrees with the CCA that this expenditure should be treated as a one-time cost in 2012 revenue requirement. The Commission approves the forecast costs of $0.5 million for an assessment of inspection practices as a one time expense. AG is directed to incorporate these costs as a one time expense in its compliance filing to this decision.[107]

109. AG has included the cost of the $0.5 million for the assessment of inspection practices as a one-time adjustment in 2012 in its compliance filing. The Commission has reviewed the corresponding Summary of Revenue Shortfalls[108] spreadsheet and is satisfied that AG has complied with this direction.

4.21 Commission Direction 27 – capitalization of meter exchange costs

110. The Commission issued the following direction to AG:

> The Commission recognizes the necessity to comply with changing standards and accepts AG's proposed cost increases for the test years for the proposed commercial inspection program. However, the Commission does not approve AG's request for an accounting change to capitalize costs related to meter exchanges when a meter is being permanently retired. The cost of the "original installation of house regulators and meters" is capitalized in Account 474. "Expenses incurred in connection with removing, resetting, changing, testing and servicing customer meters and house regulators" are recorded in Account 673. AG's change in policy to use only new meters does not change the

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104 Exhibit 45.01, AG argument, paragraph 35.
105 Exhibit 45.01, AG argument, paragraph 35.
106 Exhibit 45, AG reply argument, paragraph 36.
107 Decision 2011-450, paragraph 554.
108 Application, Exhibit 3.

> accounting requirement. AG has stated that without the approval requested the expenses in 2011 and 2012 would need to be increased by $4.2 million. However, this amount does not agree with the $3.1 million in 2011 and $2.8 million in 2012 that AG planned to capitalize for the same activity. The Commission directs AG in its compliance filing to deal with this apparent discrepancy. AG is directed to revise its revenue requirement accordingly in the compliance filing to this decision.[109]

111. The Commission has reviewed AG's response to Direction 27 that the difference between the additional $3.1 million in 2011 and $2.8 million in 2012 is due to capitalization of removal costs. AG clarified in its application that the $4.2 million adjustment to O&M also does not include meter exchange costs associated with the AMR program.[110] AG argued that AMR meter exchange costs should continue to be capitalized as they relate to meters that may be damaged or otherwise cannot be retrofitted with the AMR device. The Commission agrees with this approach and directs AG to continue to capitalize meter exchange costs associated with the AMR program. The Commission considers that AG has explained the discrepancy in metering costs and that the additional $4.2 million in O&M for 2011 and 2012 is consistent with Commission direction. AG has complied with this direction.

4.22 Other O&M Commission Directions – Directions 28, 29, 34 to 41, and 61

112. The Commission issued a number of other directions to AG to adjust their O&M forecasts for the test years and AG provided an O&M summary spreadsheet for each year in its application.[111] The O&M adjustments made in compliance with the directions for the test years can be found in appendices 3 and 4 of this decision. The O&M adjustments in these directions are of a simple nature and were not objected to by interveners. Accordingly the Commission will group the relevant directions together and the attached appendices show specific dollar amounts which have been adjusted.

4.22.1 Commission Direction 28 –aging workforce – Account 674

113. The Commission issued the following direction to AG:

> AG stated that most of the forecast cost increase over 2010 actual costs was driven by inflation and customer growth. However, AG indicated in AUC-AG-65(c) that 1.2 per cent of the total increase in 2011 and an additional 0.5 per cent of the total increase in 2012 related to training in anticipation of higher employee turnover due to aging workforce and a tightening of the market. The Commission previously rejected the justification of forecast cost increases due to an aging workforce and a tightening of the labour market. Accordingly, the Commission directs AG to reduce the forecasted costs in Account 674 by 1.2 per cent in 2011 and 1.7 per cent in 2012 in the compliance filing to this decision.[112]

114. In its application, AG has changed the forecasted costs in Account 674 by 1.2 per cent in 2011 and 1.7 per cent in 2012 as reflected in its labor and supplies forecast in appendices 3 and 4, respectively. The Commission has reviewed the adjustments and is satisfied that AG has complied with Direction 28.

[109] Decision 2011-450, paragraph 558.
[110] Application, Exhibit 1, Commission Direction 27, page 2 of 2.
[111] Application, Exhibit 8.
[112] Decision 2011-450, paragraph 561.

4.22.2 Commission Direction 29 – five per cent inflation factor – Accounts 678 and 679

115. The Commission issued the following direction to AG:

> AG provided limited support for the forecast increase to the costs for accounts 678 and 679. Accordingly, in the absence of any other substantive information, the Commission considers that an adjustment of five per cent for inflation and growth is justified for each of the test years. The Commission directs AG in its compliance filing to forecast costs for accounts 678 and 679 by escalating 2010 actual costs by a factor of five per cent per year.[113]

116. AG has removed the five per cent for inflation and growth for 2011 and 2012 required amounts from its labor and supplies forecast for Accounts 678 and 679, as reflected in appendices 3 and 4. The Commission has reviewed the adjustments in the application and is satisfied that AG has complied with Direction 29.

4.22.3 Commission Direction 34 – governance costs – Account 710

117. The Commission issued the following direction to AG:

> The Commission considers that AG has not provided an adequate explanation for the forecast increases in the account. The discussion of governance provides no explanation of which accounts are impacted by the governance amounts. In the absence of a satisfactory explanation for the increase, the Commission directs AG to revise its forecasts for Account 710 to the amount calculated as the actual expenditure for 2010 increased by a five per cent per year, to reflect inflation and growth, for each of 2011 and 2012. The $0.3 million for CC&B benchmarking is also approved in 2012.[114]

118. AG has removed the required amounts from its labor and supplies forecast for the test years, as shown in appendices 3 and 4. AG used the actual expenditures for 2010 and added the five per cent per year to reflect inflation and growth. The Commission has reviewed the adjustments in the application and is satisfied that AG has complied with Direction 34.

4.22.4 Commission Direction 35 – meter reader adjustment – Account 712

119. The Commission issued the following direction to AG:

> The Commission has calculated assuming a mid-year installation in 2012 that 318,000 meters will have been converted to AMR units by the end of 2012. AG stated that the average meter reader will be able to read 4500 meters per year. Theoretically this represents a reduction of approximately 70 meter readers in 2012. AG has forecast an opportunity savings of 12.9 meter readers, which is 57 less than the theoretical reduction based on the number of meters removed. At a fully loaded cost of $76,175 per meter reader an adjustment of approximately $4.3 million would be warranted. The Commission considers the transition factors identified in paragraph 714 and the redeployment of meter readers to other areas or potential severance costs must be considered. Given the lack of detailed information on the record regarding these matters, the Commission recommends a reduction of the estimated $4.3 million by 25 per cent. The Commission directs AG in its compliance filing to reduce the forecast costs for Account 712 by $3.2 million in 2012.[115]

113 Decision 2011-450, paragraph 584.
114 Decision 2011-450, paragraph 691.
115 Decision 2011-450, paragraph 712.

120. In its compliance filing, AG has reduced costs included in Account 712 by $3.2 million from its labor forecast for 2012, as shown in Appendix 4. The Commission has reviewed this adjustment and is satisfied that AG has complied with Direction 35.

4.22.5 Commission Directions 36, 37 and 38 – VPP – Account 721

121. The Commission issued the following direction to AG:

> 36. AG is directed to revise its 2011 and 2012 forecast for administrative labour, excluding the VPP component, utilizing AG's 2010 actual costs increased by five per cent per year.[116]

122. The Commission has reviewed the tables provided in the application[117] as well the adjustments made to the O&M spreadsheet.[118] The Commission is satisfied that AG has adjusted its 2011 and 2012 forecast for administrative labour, excluding the variable pay program (VPP) component, as directed. In respect to Directions 37 and 38, the Commission stated:

> 37. The Commission finds that the inclusion of net income component within a VPP is reasonable when there is a balance struck between the benefits that customers may receive through reduced costs versus increased earnings for the benefit of shareholders. A net income component greater than 10 per cent for officers and senior managers might result in an inherent conflict between shareholder interests and customers. The Commission finds that setting limits to individual performance objectives will ensure that management is not incented to maximize shareholder value at the expense of customers. If AG wishes to include a net income component for specific individuals higher than 10 per cent of their VPP compensation, those costs are to be borne by shareholders. AG is directed to revise its VPP forecast to reflect a maximum individual net income component of VPP of 10 per cent in its compliance filing to this decision with a supporting explanation to its revised VPP forecast.[119]

> 38. With regard to AG's forecasted increases in 2011 and 2012 for VPP, the Commission concurs with the UCA that AG did not justify an increase to the VPP forecast cost in excess of inflation. In its April 21 update, AG revised its forecast inflation rate for supervisory labour in 2012 to 4.0 per cent. The Commission finds that AG's four per cent inflationary adjustment for supervisory labour for 2012 is reasonable. The Commission directs AG in its compliance filing to revise its forecast VPP for 2011 by utilizing the 2010 forecast cost (which is consistent with the 2009 actual expense) by three per cent for 2011 and increasing the 2011 amount by four per cent for 2012.[120]

123. In accordance with Direction 37, AG has revised the maximum individual net income component of VPP to 10 per cent in its labor forecast for the test years in appendices 3 and 4. AG has changed the 2011 and 2012 forecast costs to reflect the inflation adjustment in Direction 38.

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[116] Decision 2011-450, paragraph 731.
[117] Application, Commission Direction 36, page 1 of 1.
[118] Application, Exhibit 8.
[119] Decision 2011-450, paragraph 751.
[120] Decision 2011-450, paragraph 752.

124. The Commission has reviewed the adjustments to the VPP forecast and finds that the adjustments arising from Directions 37 and 38 have been accurately reflected in appendices 3 and 4. AG has complied with these directions.

4.22.6 Commission Direction 39 – Calgary office lease

125. The Commission issued the following direction to AG:

> AG is directed in the compliance filing to this decision to include in its revenue requirement a rental rate for 2011 of $14.50. For 2012, rent should be forecast based on $14.50 per square foot increased by a three per cent inflation factor.[121]

126. In terms of the rental rate, AG has confirmed that the 2011 revenue requirement has a placeholder amount of $14.50 per square foot and no adjustment was required for 2011 forecast revenue requirement. AG included the $14.50 per square foot rental rate and the three per cent inflation factor in its supplies forecast, as shown in the 2012 summary of O&M Adjustments at Appendix 4.

127. The issue of the Calgary office lease is currently before the Commission in Proceeding ID No. 1698, the Phase II of AG's R&V of Decision 2011-450. In granting a review of the findings, the review panel stated that it is unclear whether the hearing panel rate was aware that AG's existing rental rate was $16 per square foot in reaching the determination that the existing lease rate should be used.[122] Pending the outcome of the Phase II R&V proceeding, AG is directed to maintain a placeholder amount for the Calgary lease rate of $14.50 per square foot for 2011, and a placeholder amount of $14.50 per square foot increased by a three per cent inflation factor for 2012, in its second compliance filing to Decision 2011-450.

4.22.7 Commission Direction 40 – corporate costs – Account 721

128. The Commission issued the following direction to AG:

> The Commission relies on the approval of the corporate cost allocation methodology in Decision 2010-447 for 2011. The Commission has reviewed the corporate costs in Table 42, Administrative expense and notes that actual costs for 2008, 2009 and 2010 exceeded forecasts. However, for 2008 an explanation of the variance is provided. The Commission accepts AG's explanation and considers that the increase, which was with respect to HRX, would be a recurring cost. A comparison of actual 2008 costs to forecast 2011 costs is an increase of 10.5 per cent over a three-year period. The Commission considers an increase of approximately 3.5 per cent per year to be reasonable. However, the Commission agrees that the $73,000 for 2011 and $75,000 for 2012 of allocated corporate advertising, as noted above by the UCA, should not have been included in the corporate costs and directs that this amount should be removed.[123]

129. In its application, AG has removed the corporate adverting costs of $73,000 for 2011 and $75,000 for 2012 from its supplies forecast for the test years, as shown in appendices 3 and 4.

130. The Commission is satisfied that this adjustment has been accurately reflected in the appendices and considers that AG has complied with Direction 40.

[121] Decision 2011-450, paragraph 769.
[122] Decision 2012-156, page 24, paragraph 99.
[123] Decision 2011-450, paragraph 780.

4.22.8 Commission Direction 41 – mass media and other supplies – Account 721

131. The Commission issued the following direction to AG:

> The Commission therefore approves mass media and other supplies expenses for 2011 and 2012 calculated as 2010 actual costs increased by five per cent per year for inflation and growth. AG is directed to include this revision in its compliance filing.[124]

132. AG provided the five per cent per year adjustment for inflation and growth using the 2010 actual costs. Supporting calculations were included in AG's application and reflected in the supplies forecast for the test years at appendices 3 and 4.

133. The Commission has reviewed AG's adjustments to mass media and other supplies. The Commission is satisfied that AG has complied with Direction 41.

4.22.9 Commission Direction 61 – distribution supervision – Account 670

> 552. For Account 670, distribution supervision, the Commission accepts cost increases of \$0.5 million for inflation and \$0.3 million for the increased work provided to ATCO Pipelines. As discussed earlier in this decision, the Commission does not accept AG's arguments with respect to cost increases being driven by an aging workforce and retirements. Accordingly, the forecast cost increases of \$0.6 million for training, mentoring and coaching related to forecast retirement activity, \$0.5 million for safety initiatives related to changes to the workforce and retirements, and \$0.2 million in 2012 for the costs of two new occupational health nurses to proactively implement preventative programs to address potential injuries in the aging workforce are denied.[125]

134. AG has removed the distribution supervision adjustments, as directed, from its labor and supplies forecast for the test years. These adjustments have been described and accounted for in the summaries of O&M adjustments in appendices 3 and 4, as separate line items for the years to which the reductions apply, as:

- remove forecast costs related to training, mentoring and coaching
- safety initiatives related to changes in workforce
- remove occupational health nurses

135. The Commission has reviewed the amounts in these line items and concludes that the compliance filing amounts are consistent with the reductions directed in Decision 2011-450 for Account 670 - Distribution Supervision. The Commission is satisfied that AG has complied with this direction.

4.23 Commission Direction 62 – line heater inspections - Account 677

> 578. The evidence submitted by AG with respect to the line heater inspection program has not persuaded the Commission that these inspections are required during the test period. The Commission notes that AG stated that line heaters on well sites have a legal requirement for inspection every five years but AG is not legally bound to abide by this same inspection requirement. Further AG has not inspected its line heaters in the past and AG has not supplied any evidence to suggest that it should begin inspecting line heaters during the test period. Given the above, the Commission denies the line heater inspection

[124] Decision 2011-450, paragraph 797.
[125] Decision 2011-450, paragraph 552.

costs of $0.9 million per year. The Commission also observes that it has approved the forecast costs associated with AG's line heater improvements program to meet OH&S standards and improved reliability enhancements on noncompliant meters during the test years. [126]

136. AG has removed line heater inspection costs for each of the test years from its labor and supplies forecast in appendices 3 and 4. The Commission is satisfied that AG has complied with this direction.

4.24 Commission Directions 30, 31 and 32 – the BFK and Centennial Anniversary

137. The Commission issued the following directions to AG:

> 30. AG explained that it spends $50,000 per year on "cross-promotion of safety messages" through the BFK while the forecast for the test period for the BFK is $2 million per year. The Commission considers that BFK provides a disproportionate amount of costs for the safety and gas distribution service communication benefits received. Further, AG is the only Canadian distribution utility that has a facility like the BFK Calgary Learning Centre. The Commission is not persuaded that the Edmonton BFK is required in light of the limited benefit that customers receive through safety and gas distribution communication through the BFK. The Commission finds that the BFK is not a cost effective means of proving public safety communication. Further, AG has other options to meet its responsibility to distribute public safety information. For the preceding reasons, AG is directed to remove all Edmonton BFK costs from 2011 opening rate base and from revenue requirement for the test years, including both capital and O&M related costs. For the same reasons the request to include in revenue requirement costs associated with the Calgary BFK is denied.[127]
>
> 31. The Commission does, however, continue to support the expenditure of $50,000 per year on safety messaging that the BFK has provided in the past. AG may add this expenditure to its Customer Relations and Communications forecast for the test years. AG is directed to advise the Commission in the compliance filing to this decision as to the mechanism it will use to promote natural gas safety matters and gas distribution education information to customers.[128]
>
> 32. Similar to the Commission's finding with respect to AG's BFK program above, the Commission is of the view that the increase in costs for the purpose of the Centennial Anniversary celebration is not justified as a cost effective means to communicate safety matters and is unnecessary for the provision of safe and reliable delivery of natural gas. Accordingly AG is directed to remove the forecast costs associated with the Centennial Anniversary from the sales and transportation promotions function for the 2011 and 2012 test years.[129]

138. The proposed treatment of the BFK in opening rate base is addressed within the findings of Commission Direction 1 above. In relation to the removal of the BFK costs in Direction 30, AG has removed the costs for the BFK in each of the test years, $1.9 million for 2011, and $2.1 million for 2012.[130] The Commission has reviewed the tables provided in AG's compliance

126 Decision 2011-450, paragraph 578.
127 Decision 2011-450, paragraph 610.
128 Decision 2011-450, paragraph 611.
129 Decision 2011-450, paragraph 616.
130 Application, Exhibit 1, page 191 of 238 PDF.

application and the O&M summary of adjustments included as appendices 3 and 4 of this decision. AG also reduced other utility revenue relating to the BFK by $0.6 million on 2011, and $0.7 million in 2012.[131] The Commission is satisfied that AG has complied with the direction to remove the BFK costs from its revenue requirement.

139. For safety messaging, AG stated in its application that it has added $50,000 for each test year to the Customer Relations and Communications forecast expenditures from the BFK operating expenditures. AG stated that it will use media, such as television, print, and radio to promote safety matters and gas distribution education.[132] The Centennial Anniversary forecast costs have been similarity removed from the sales and transportation promotions function for the test years.[133] The Commission considers that AG has complied with directions 31 and 32. These adjustments have been reflected in the summary of O&M adjustments in appendices 3 and 4, and therefore, AG has complied with these directions.

4.25 Commission Direction 33 - DSM

140. The Commission issued the following direction to AG:

> 680. The Commission denies AG's request to include in revenue requirement for the test years all costs associated with current and proposed DSM activities. The Commission directs that all DSM related costs, both capital and operating, be removed from rate base and revenue requirement for the test years. The Commission further directs that the DSM capital expenditures incurred during the period 2008 to 2010 are to be excluded from opening rate base.[134]

141. The proposed treatment of the DSM in opening rate base was addressed within the findings under Commission Direction 1 above.

142. AG noted in its application that a correction was required regarding the inclusion of expenditures related to natural gas load building activities and it adjusted the DSM O&M amounts to reflect the correction of this error.[135] The Commission has reviewed the revisions reflected in the tables in the application as well as the capital and O&M adjustment spreadsheets.[136] Also in relation to DSM, AG stated that it has reduced other utility revenue by $1.2 million in 2011, and $1.4 million in 2012.[137] The Commission confirms that AG has complied with the direction to remove the DSM related capital expenditures and O&M costs for the test years from its rate base and revenue requirement.

4.26 Commission Direction 42 – corporate governance

143. The Commission issued the following direction to AG:

> As noted above, AG has not fully described which accounts, O&M or capital, include corporate governance costs. The Commission directs AG in its compliance filing to indicate the allocation of the governance costs identified above to specific capital and

131 Application, Exhibit 1, page 192 of 238 PDF.
132 Application, Exhibit 1, page 193 of 238 PDF.
133 Application, Exhibit 1, page 194 of 238 PDF.
134 Decision 2011-450, paragraph 686.
135 Application, Exhibit 1, page 195 of 238 PDF.
136 Application, Exhibits 7 and 8.
137 Application, Exhibit 1, page 196 of 238 PDF.

> O&M accounts, including the corresponding amounts approved in Decision 2011-228 and the actual amounts incurred in 2010.[138]

144. In its response to this direction AG clarified that IT Governance and Office of the Chief Information Officer (CIO) costs are allocated to Account 721 – Administrative Expenses, and CC&B is allocated to governance to Account 710 – Supervision. AG also provided the amounts for CC&B and IT costs for 2008 and 2009 that were approved in Decision 2011-228.[139] AG also provided the 2010 actual amounts for CC&B, IT and CIO costs. The Commission has reviewed the allocation of these governance costs and finds that AG has sufficiently explained the allocation of these costs. AG has complied with this direction.

4.27 Commission Direction 43 – IT placeholders

145. The Commission issued the following direction to AG:

> 810. Calgary brought forward issues with respect to the Evergreen Strategy Report, O&M IT volumes and the lack of comparability due to the differences in structure and terms of the two MSAs. The Commission is satisfied that Exhibit 180 provided sufficient detail of volumes in a standardized format to allow the Commission to assess the reasonability of the forecast volumes. The Commission accepts the O&M forecast volumes as filed. The Commission notes the dollars are placeholders and directs AG to use the amounts provided in Table 42 above for the test years.[140]

146. AG noted in the application that final forecast costs will be determined by applying the approved O&M volumes to rates approved in the Evergreen 2010 proceeding.[141] The Commission agrees with AG that the forecast O&M volumes are placeholders and considers that AG has complied with this direction.

4.28 Commission Direction 44 – late payment settlement costs

147. The Commission issued the following direction to AG:

> 842. AG's request for a recovery of $1.8 million related to the settlement and associated legal expenses is denied. The Commission therefore directs AG to remove the settlement and associated legal expenses from AG's forecast for reserve for injuries and damages and revenue requirement in its compliance filing. The $300,000 balance of the proposed $2.1 million recovery in order to maintain a reserve balance of $600,000 is approved.[142]

148. AG confirmed in its application that it had removed the late payment settlement costs and legal expenses in the amount of $1.8 million from the forecast for reserve for injuries and damages.[143]

149. The Commission granted a review and variance of late payment settlement costs in Decision 2012-156.[144] The issue of late payment settlement costs is therefore, currently before the

138 Decision 2011-450, paragraph 805.
139 Decision 2011-228: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) - 2008-2009 Evergreen Application, Application No. 1577426, Proceeding ID No. 77, May 26, 2011.
140 Decision 2011-450, paragraph 810.
141 Application, Commission Direction 43, page 1 of 1.
142 Decision 2011-450, paragraph 842.
143 Application, Exhibit 1, page 209 of 238 PDF.
144 Decision 2012-156, paragraphs 87 to 89.

Commission in Proceeding ID No. 1698, the Phase II R&V proceeding of Decision 2011-450. Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount of zero for late payment penalty settlement costs in its second compliance filing to Decision 2011-450.

4.29 Commission Direction 45 – pension funding placeholders

150. The Commission issued the following direction to AG:

> 852. The Commission is satisfied that AG has adequately explained why employee benefits are increasing for the test years. Further the Commission notes that the largest component of employee benefits is the pension funding which is subject to a placeholder. In Decision 2011-391 the Commission made a determination of pension funding for AG to be included in revenue requirement for 2011 and 2012. AG is directed to maintain the current placeholders for pension funding, pending a decision in relation to the compliance filing for Decision 2011-391 noted above. AG is directed to submit an application to replace the placeholders within a reasonable time following the issuance of the decision in the compliance filing. With the exception of the placeholder for pension funding, the Commission approves the forecast costs for employee benefits.[145]

151. AG has stated it will file an application to replace the placeholders for pension funding following the Commission issuing its decision in the compliance filing of Decision 2011-391.[146] The Commission notes that the pension compliance filing Decision 2012-166[147] was released on June 14, 2012. In Decision 2012-166, the Commission directed AG to file a second compliance filing with respect to revised placeholder amounts for 2011 and 2012.[148] The Commission is satisfied that AG has maintained the current placeholders for pension funding and has complied with this direction.

4.30 Commission Direction 46 – credit facility and standby fees placeholder

152. The Commission issued the following direction to AG:

> The Commission is satisfied with AG's explanation that credit facility costs and standby fees have increased as a result of the recent economic crisis. Further, the Commission recognizes that ensuring liquidity levels are maintained at levels required by bond rating agencies results in CU Inc. being able to maintain its existing credit rating and allows AG access to lower market rates for financing its operations. The forecast bank charges are consistent in total with the 2009 charges and the Commission finds the amounts to be reasonable. As these costs are allocated using the ATCO Utilities corporate cost allocation methodology approved in Decision 2010-447 the Commission accepts the allocation methodology for 2011. As noted earlier, ATCO Utilities corporate cost allocation methodology is subject to review in 2012. As a result, all costs for 2012 including "bank and short term financing costs" are subject to a placeholder pending the outcome of the aforementioned proceeding. AG is directed to maintain a placeholder for 2012.[149]

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145 Decision 2011-450, paragraph 852.

146 Decision 2011-391: ATCO Utilities (ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd.) - 2011 Pension Common Matters, Application No. 1606850, Proceeding ID No. 999, September 27, 2011.

147 Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) - 2011 Pension Common matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.

148 Decision 2012-166, page 14, paragraphs 70 and 71.

149 Decision 2011-450, paragraph 858.

153. AG stated that it will maintain placeholders for credit facility and standby fees pending the outcome of the review of ATCO Utilities corporate cost allocation methodology in 2012.[150] The Commission is satisfied that AG has complied with this direction.

4.31 Commission Direction 47 – financing costs

154. The Commission issued the following direction to AG:

> The Commission directs AG in its compliance filing to reclassify bank and short-term financing costs as financing costs.[151]

155. AG indicated in its application that it has removed bank and short term financing costs of $1 million in 2011, and $0.9 million in 2012, from operating expenses and has included them in financing costs. The Commission has reviewed Schedule 3.2-C which adjusts 2011 and 2012 forecast GRA updates[152] to reflect the Commission's direction on financing costs, and is satisfied that AG has complied with this request.

4.32 Commission Directions 48, 49, 50 and 52 – depreciation adjustments

156. The Commission issued the following directions to AG:

> 48. AG is directed in the compliance filing to calculate depreciation expense using a 57-R2.5 Iowa curve for Account 47300, Services.[153]
>
> 49. AG is directed in the compliance filing to calculate depreciation using an Iowa curve of 51-R3 for Account 47400, Regulator & Meter Installations.[154]
>
> 50. AG is directed to calculate depreciation using an Iowa curve for 66-R2.5 for account 47500, mains in the compliance filing to this decision.[155]
>
> 52. AG is directed in the compliance filing to calculate depreciation using the 11-R2 Iowa curve for Account 48400, Transportation Equipment.[156]

157. AG provided the depreciation adjustments in its compliance application regarding the above referenced accounts. The UCA indicated in argument that after review of AG's responses to information requests that it was satisfied that the depreciation adjustments were reasonable and correct.[157]

158. The Commission has reviewed the tables in the application as well as the depreciation expense adjustments spreadsheet[158] and the depreciation expense sheets are attached as appendices 5 and 6, respectively. The Commission is satisfied that AG has complied with these directions.

150 Application, Commission Direction 46, page 1 of 1.
151 Decision 2011-450, paragraph 860.
152 Application, Exhibit 2.
153 Decision 2011-450, paragraph 915.
154 Decision 2011-450, paragraph 921.
155 Decision 2011-450, paragraph 941.
156 Decision 2011-450, paragraph 947.
157 Exhibit 40.02, UCA argument, page 13.
158 Application, Exhibit 10.

4.33 Commission Direction 51 – segregation of depreciation accounts

159. The Commission issued the following direction to AG:

> 942. The Commission considers that the determination of a depreciation rate for this account has been particularly difficult given the size of the account and the mix of non-homogeneous assets of different vintages. The Commission notes the discussion at the hearing about the possibility of introducing accounting mechanisms to segregate the account into multiple accounts of a more homogeneous nature. The lack of detailed historical records was an impediment to further segregation at this time. The Commission directs AG to report in the compliance filing to this application on the feasibility of further segregation of significant accounts on a go-forward basis.[159]

160. AG confirmed in its application that it will complete a study looking into the further segregation of significant depreciation accounts on a go-forward basis. The study will then be brought to the Commission in a future application.[160] For the purposes of this application, AG has complied with this direction, as a further study will be conducted and provided to the Commission in a future application.

4.34 Commission Direction 53 – removal of non-utility assets from depreciation calculation

161. The Commission issued the following direction to AG:

> 952. The Commission will consider Account 48400 separately from the other accounts. With respect to the balance of the "other depreciation accounts" identified above, the Commission notes that the interveners did not file evidence with respect to these accounts and that the aggregate net change in depreciation expense is $1,990,539 in the test period. The Commission has denied a number of programs in other parts of this Decision which may have assets reflected in some of these accounts. Accordingly, the Commission directs that the assets associated with denied programs be removed from these accounts and reflected in the compliance filing to this decision. Subject to the removal of the denied assets, the Commission approves the depreciation expense for these other depreciation accounts.[161]

162. The Commission has reviewed the table in the application as well as the depreciation expense adjustments spreadsheet.[162] Given the findings in Direction 1 of this decision, the Commission directs AG to provide a schedule detailing the removal of the DSM and the Calgary BFK assets from opening rate base, and any accompanying impact on depreciation in its second compliance filing.

4.35 Commission Direction 54 – net salvage rates

163. The Commission issued the following direction to AG:

> 971. The Commission agrees with the UCA and the evidence of Mr. Pous that AG has failed to provide sufficient justification for the proposed changes to the net salvage rates. Neither Mr. Kennedy nor AG have provided a reasonable explanation for the large changes in net salvage percentages calculated by Mr. Kennedy in his analysis. The

159 Decision 2011-450, paragraph 942.
160 Application, Commission Direction 51, page 1 of 1.
161 Decision 2011-450, paragraph 952.
162 Application, Exhibit 10.

> explanation provided by Mr. Kennedy for the proposed modified net salvage rates, based on the calculated percentages, lacks the robustness and precision necessary to support the determination of the proposed net salvage rates. In the absence of probative evidence the Commission is inclined to deny the requested increase in net salvage rates for the test period. However, the Commission is concerned that should the current net salvage rates be insufficient, continuation of existing rates for an extended period of time may result in intergenerational inequity for ratepayers and unfairness to the utility. Accordingly, the Commission would entertain a timely separate application outside of the compliance filing process on net salvage rates for the test period. AG is directed to indicate in the compliance filing to this decision whether it will be submitting a separate application and if proceeding, the anticipated filing date. If AG chooses not to submit a separate application the existing net salvage rates will remain in place for the test years. If AG chooses to file a separate application, the compliance filing will use the existing salvage rates as placeholders pending a decision on the separate application.[163]

164. AG has advised that it will not be filing a separate application to deal with net salvage rates in the test years.[164] AG explained that a study cannot be completed in time to allow for a separate application for the test years. Consistent with Direction 54 in Decision 2011-450, the Commission therefore directs AG to use the existing net salvage rates for the test years and to reflect the corresponding change in the compliance filing.

4.36 Commission Direction 55 – depreciation reserve deficiency account update

165. The Commission issued the following direction to AG:

> 983. The collection from customers of a depreciation reserve deficiency or the refund to customers of a depreciation reserve surplus does not amount to retroactive rate making, rather it is a prospective rate setting mechanism designed to ensure that the costs of an asset are recovered over its anticipated service life. The Commission directs AG in its compliance filing to this Decision to update it depreciation reserve deficiency account in accordance with the revised depreciation rates.[165]

166. AG indicated that it has updated its depreciation reserve deficiency account in its compliance filing, and in accordance with the revised depreciation rates[166] as a result of Decision 2011-450. The Commission has reviewed the depreciation expense adjustments spreadsheet[167] and is satisfied that AG has complied with this direction.

4.37 Commission Direction 56 – production abandonment costs

167. In Decision 2011-450, the Commission addressed the issue of production abandonment costs as follows:

> [A]ssets which no longer have an operational purpose are no longer used or required to be used to provide utility service as required by Section 37 of the *Gas Utilities Act* should be retired and removed from rate base. Further, if the asset is not disposed of at the time of retirement, it should be moved to a non-utility account whether or not the asset has been fully consumed in providing utility service or whether it had residual value at the time it was retired. Accordingly, all ongoing costs of any nature, including operational

163 Decision 2011-450, paragraph 971.
164 Application, Commission Direction 54, page 1 of 2.
165 Decision 2011-450, paragraph 983.
166 Application, Exhibit 1, page 221 of 238 PDF.
167 Application, Exhibit 10.

and remediation costs (except to the extent that remediation costs are notionally offset by the net salvage component of depreciation expense previously included in rates an collected from ratepayers) associated with the asset after it creases to have an operational purpose should be removed from revenue requirement and be for the account of the utility shareholder.[168]

168. The Commission issued the following direction to AG:

> 10004. Given the above determination, all production abandonment costs applied for during the test period are disallowed and shall be removed from forecast revenue requirement in the compliance filing to this decision. Similarly, the deferral account in respect of these costs will be discontinued as of January 1, 2011. The closing deferral account balances in the north and south for 2010 are \$0.76 million and \$0.24 million respectively. Given that these balances relate to prior periods and the decisions that relate to those periods, AG will be permitted to include a one time recovery of those balances in 2011 revenue requirement.[169]
>
> The Commission directs AG to remove the 2011 and 2012 production abandonment costs of \$2.18 and \$1.5 million respectively from revenue requirement.[170]

169. In respect to production abandonment costs, AG noted in its application that the 2011 amount of \$2.18 million included a one time adjustment of \$0.68 million, which was approved in paragraph 1004 of Decision 2011-450.[171] AG removed the 2011 and 2012 annual expense amounts for production abandonment costs from its revenue requirement. The adjustments have been reflected in the depreciation expense adjustments spreadsheet.[172]

170. The issue of production abandonment costs was included in Decision 2012-156. In granting the Phase I R&V on the issue of production abandonment costs, the review panel granted a further review of production abandonment and AG's settlement agreements and stated that this issue would be better suited for the Utility Asset Disposition Rate Review Proceeding (Proceeding ID No. 20) or the generic proceeding on asset disposition and stranded assets following Proceeding ID No. 556.[173] The review panel determined:

> In the interim, the Commission directs AG to maintain a placeholder of zero with respect to these costs, to be adjusted upon completion of either Proceeding ID No. 20 or the generic proceeding.[174]

171. As the issue of production abandonment costs will be subject to a further proceeding and given the direction of the Commission in Decision 2012-156 that a placeholder is warranted for production abandonment costs, the Commission directs AG in its second compliance filing to use a placeholder of zero for production abandonment costs for the 2011 and 2012 test years.

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168 Decision 2011-450, page 207, paragraph 1000.
169 Decision 2011-450, page 208, paragraph 1004.
170 Decision 2011-450, paragraph 1005.
171 Application, Commission Direction 56, page 1 of 1.
172 Application, Exhibit 10.
173 Decision 2012-156, paragraphs 110 and 113.
174 Decision 2012-156, paragraph 110.

4.38 Commission Direction 57 – gas price regression model variable

172. The Commission issued the following direction to AG:

> 1018. The Commission notes that in the presentation provided during its SPC Forecast Workshop on June 14, 2010, AG made mention that gas price has not been included in the regression models in past GRA's. In its compliance filing AG is directed to provide information on why it has added gas price as a variable into the regression model and the impact the gas price variable has on its revenue forecast.[175]

173. AG stated in its application that:

> Prior to the 2011/2012 GRA, the gas price variable has never resulted in a statistically significant variable, and for that reason, it was never previously used. For the 2011-12 GRA, the 12 month lagged gas cost recovery rate was found to be statistically significant for one model – the South High Use Industrial Model. The inclusion of gas price in the South High Use Industrial model has no impact on the revenue forecast for the test years because the High Use GJPC model forecasts are not used in the calculation of the revenue forecast. The High Use rate group is applied a fixed charge and a demand charge and not a variable charge.[176]

174. The Commission finds that AG has sufficiently explained why the gas price variable has not been used for regression analysis in the test years. The Commission concludes that AG has complied with this direction.

4.39 Commission Direction 58 – other revenue

175. The Commission issued the following direction to AG:

> 1021. The Commission notes that 2010 actual revenue was very close to the forecast for 2011. Further the Commission notes that the largest component of other revenue is services provided to AP. The Commission directs AG in its compliance filing to discuss if the recently approved integration of AP with NGTL will have an impact on its other revenue from AP including any change to the basis on which the work will be priced. The Commission accepts the revenue forecast for the rest of the components of other revenue for the test years.[177]

176. In its response to Direction 58, AG requested in the compliance filing that the Commission approve the use of a deferral account related to the impacts of the NGTL/AP Integration. The deferral account would have included the effect of changes to services between AG and AP as a result of integration. Any integration impact related to 2011 revenues and expenses from AP has been addressed in AG's response to Direction 64. For 2012, AG stated that it "does not anticipate any significant changes to its 2012 other revenue as a result of NGTL/AP Integration, however that was the reason why a deferral account was requested, because ATCO Gas is unable to control or properly forecast the effect of Integration on its costs and revenues. However, any change in service agreement revenues would also be accompanied by a change in operating costs so it would be inappropriate to only address the revenue aspect."[178]

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175 Decision 2011-450, paragraph 1018.
176 Application, Exhibit 1, page 223 of 238 PDF.
177 Decision 2011-450, paragraph 1021.
178 Application, Exhibit 1, page 224 of 238 PDF.

177. The Commission notes that in AG's 2011-2012 GRA, AG provided an "Other Revenue Forecast"[179]. AG forecast $18.9 million for 2011 and $19.8 for 2012. In the compliance application, AG stated that it did not anticipate any significant changes to its 2012 other revenue forecast.

178. The Commission considers that AG has not provided any new information in the compliance filing to support an impact on other revenue that would change the basis on which the work will be priced. The Commission has previously denied a deferral account to capture the potential impacts related to integration in Decision 2011-450 and Decision 2012-156. In this application, AG reiterated the need for the deferral account to address the impacts and indicated that at the current time, it did not anticipate any significant changes to its 2012 other revenue as a result of integration of AP with NGTL. Accordingly, the Commission considers that since no new information has been provided on the effect of integration on other revenue and given that AG does not expect any significant changes to its 2012 other revenue, that no changes to other revenue is required. The Commission finds that AG has complied with this direction and that the original forecast amounts for other revenue approved in Decision 2011-450 remain unchanged.

4.40 Commission Direction 59 – IFRS deferral account

179. The Commission issued the following direction to AG:

> 1037. The Commission considers the establishment of the requested deferral account is consistent with the above principle because it establishes a mechanism to monitor and address any shifting of risk between customers and shareholders with respect to the unanticipated differences. Accordingly the Commission approves the establishment of a deferral account in accordance with AG's proposal provided however that the deferral account shall include only unanticipated differences that are within the scope of Rule 026. The Commission directs that this deferral account be closed and an application filed along with AG's proposal for the method for settling each deferral account adjustment within three months of the public release of the 2011 annual financial statements for Canadian Utilities Limited.[180]

180. In its application, AG stated it will close the IFRS deferral account and file an application to address settlement of each deferral account adjustment within three months of the public release of 2011 Canadian Utilities Limited financial statements.[181] The Commission notes that no application regarding this deferral account has been filed to date. The Commission directs AG to provide an update in its second compliance filing regarding the status of its application for the closure and settlement of the IFRS deferral account.

4.41 Commission Direction 60 – UMR adjustment

181. The Commission issued the following direction to AG:

> Given all the above the Commission approves a capital expenditure based on a status quo urban mains replacement program during the test years based on the actual expenditures in 2010 increased each year by an inflation factor of three per cent. The amounts approved for inclusion in revenue requirement are $12.0 million and $12.4 million in 2011 and 2012, respectively.[182]

179 Decision 2011-450, Table 54, page 211, paragraph 1019.
180 Decision 2011-450, paragraph 1037.
181 Application, Commission Direction 59, page 1 of 1.
182 Decision 2011-450, paragraph 135.

182. AG has adjusted its forecast for the Urban Mains Replacement program to reflect the approved amounts of $12 million in 2011 and $12.4 million in 2012. The Commission has reviewed the capital adjustments spreadsheet[183] and is satisfied that AG has complied with this direction.

4.42 Commission Direction 63 – NEB costs

183. The Commission issued the following direction regarding forecast costs for AG's participation in National Energy Board (NEB) hearings:

> The Commission has not been persuaded that the $150,000 forecast costs in each of the test years for potential involvement in hearings before the NEB relating to integration are justified because no supporting rationale was provided. The Commission is satisfied that the balance of AG's forecast costs for its audit, legal and consulting fees is reasonable based on AG's explanation that it is an average of its previous three-year costs. AG's forecast with regard to legal and consulting expenses is approved, subject to the above reduction.[184]

184. In its application, AG provided an update to its 2011 costs with respect to NEB hearings including legal and consulting expenses, to $128,000 for 2011. The 2012 forecast costs of $150,000 were not amended.[185] AG provided further rationale for the inclusion of these costs as AG considered it important for it to act in the best interests of its customers and take the position in the TransCanada (TCPL) Business and Services Restructuring Proposal NEB proceeding (RH-003-2011) that its customers should not be allocated costs for which they bear no cost responsibility and from which they receive no benefit.

185. The UCA stated that it is prepared to accept that AG has or will incur the additional costs and that AG's participation in the RH-003-2011 proceeding is appropriate.[186] However, the UCA questioned whether the inclusion of these costs in AG's revenue requirement was appropriate. In the UCA's opinion,

> The procedure adopted by the Commission in relation to these issues is unusual, in the sense that AG is effectively being allowed to request increases in its allowed expenses after the hearing and without the normal scrutiny provided by the hearing process.[187]

186. The UCA also stated that it was not clear if the costs associated with AG's participation in the NEB proceeding were genuinely integration costs because they were not associated with implementing integration. However, the UCA stated that if AG is allowed to recover these costs, then it should be allowed to do so only as a one-time for those years and not as an on-going expense embedded in base rates.

[183] Application, Exhibit 7.
[184] Decision 2011-450, paragraph 813.
[185] Application, Commission Direction 64, Response to UCA-AG-131.
[186] Exhibit 40.02, UCA argument, pages 11 to 13.
[187] Ibid, page 12, paragraph 50.

187. The CCA stated that given the potential harm to customers as a result of the possible outcomes of the TCPL mainline hearing, it was not opposed to including some of the hearing costs into AG's hearing cost reserve account if AG can demonstrate a benefit to customers and not to the utility or its parent company.[188]

188. In Proceeding ID No. 1698, 2012 General Rate Application R&V application, AG submitted that the hearing panel's determination in Decision 2011-450 to deny AG's ability to recover legal and consulting expenses related to the NEB proceeding on the basis that AG provided no supporting rationale should be reviewed. AG stated that it did in fact support its claim in its response to information request AUC-AG-83.[189] In that response, AG stated that it was not familiar with NGTL's rate design and cost allocation methodologies, and there are also cost risks associated with export deliveries and TransCanada mainline costs that may have an effect on Alberta customers. AG made similar arguments in its compliance filing application.[190]

189. The Commission has reviewed the O&M adjustments spreadsheet and is satisfied that AG has removed $150,000 in forecast costs related to participating in NEB proceedings for each of 2011 and 2012, in compliance with the Commission's direction. However, the Commission notes that in Decision 2012-156, the review panel has granted a review of the decision to deny AG's request to recover $300,000 in forecast costs for participation in the NEB NGTL hearings.[191] The issue of the recovery of 2011 and 2012 forecast costs related to AG's participation in NEB hearings related to integration is properly before the Commission in Proceeding ID No. 1698. Pending the outcome of the Phase II R&V proceeding in Proceeding ID No. 1698, AG is directed to use a placeholder amount of zero for forecast hearing costs related to integration hearings for 2011 and 2012. The Commission directs AG to reflect the zero placeholder for these costs in its second compliance filing to Decision 2011-450.

4.43 Commission Direction 64 – integration deferral account

190. The Commission issued the following direction regarding forecast costs for integration between AP and NGTL:

> 1040. The Commission does not consider that the proposed deferral account satisfies the materiality factor criterion for the establishment of a new deferral account and accordingly denies AG's request. However, the Commission is sensitive to the concerns raised by AG with respect to possible unknown costs of integration and the difficulty of forecasting these costs prior to integration occurring. Contract integration between ATCO Pipelines and NGTL occurred October 1, 2011. While the Commission denies the requested deferral account, the Commission will permit AG in the compliance filing to this decision to identify any additional specific costs that AG has incurred due to integration and to include a request for approval of such costs in revenue requirement.[192]

[188] Exhibit 42.01, CCA argument, page 5.
[189] Exhibit 84.01.
[190] Application, Exhibit 1, footnote 4 on pages 236 and 237 PDF.
[191] Decision 2012-156: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) - Decision on Request for Review and Variance of AUC Decision 2011-450 2011-2012 General Rate Application Phase I, page 19, paragraph 74.
[192] Decision 2011-450, paragraph 1040.

191. In the 2011-2012 AG GRA filing, AG proposed to use a deferral account to address the impact of any changes on its revenues, capital and operating costs directly related to integration. The table below provides these costs,[193] with the removal of legal costs as discussed in Direction 63:

Table 5. AG Costs for Integration Deferral from AG 2011-2012 GRA

O&M	2011 (000s)	2012 (000s)
New Contract Analyst (50% of salary allocated to O&M)	$14	$14
New Admin. Coordinator (50% of salary allocated to O&M)	$20	$20
Increased meter maintenance for meters transferred to AG. Two additional FTEs in 2011, one additional FTE in 2012	$90	$170
Total	$124	$204
Capital	**2011 (000s)**	**2012 (000s)**
CNG Tube Trailers	$40	$80
Enhancements to Imbalance Reporting Information System	$55	$0
New Contract Analyst (50% of salary allocated to Capital)	$14	$14
New admin. Coordinator (50% of salary allocated to Capital)	$20	$20
Purchase of non SCADA equipment from AP	$0	$6,500
Total	$489	$6,568

192. AG stated that it expected it would be required to manage approximately 60 contracts for FT-D3 service.[194] In its compliance application, AG commented that NGTL required it to hold contracts at approximately 1,150 summary points, significantly increasing staff requirements. The original estimate of $170,000 for technologists to visit non SCADA meter sites was increased to $235,000 based on better information. The survey costs are unforeseen post integration rights-of-way costs. AG assets within rights-of-way assumed by NGTL require new rights-of-way agreements. The following table identifies updated costs provided by AG:

Table 6. Costs for integration from compliance filing update

O&M	2011 (000s)	2012 (000s)
New Analyst, Contract Demand Quantity (75% allocated to O&M)	$13	$56
New Supervisor, Contract Demand Quantity (75% allocated to O&M)	$45	$93
Contract Management System Maintenance and Support	$0	$4
New contract mgmt. system to manage FT-D3 Service Contracts	$0	$18
Increased meter maintenance/reading for meters transferred to AG. Two additional FTEs in 2012 plus travel costs.	$0	$235
Survey Costs	$120	$180
Total	$178	$586

Capital	2011 (000s)	2012 (000s)
CNG Tube Trailers	$47	$0
Enhancements to Imbalance Reporting Information System	$110	$4
New Analyst, Contract Demand Quantity (25% allocated to Capital)	$4	$19
New Supervisor, Contract Demand Quantity (25% allocated to Capital)	$15	$31
Purchase of non SCADA metering equipment from AP	$0	$7,600
Total	$176	$7,654

[193] Proceeding ID No. 969 AG 2011-2012 GRA, Exhibit 83.01, UCA-AG-131(a)(b).
[194] Application, Commission Direction 64, page 6.

193. In the opinion of the UCA,

> there is a difference between identifying "additional specific costs" in the sense of discovering new and previously unforeseen types or categories of costs, on the one hand, and identifying such costs in the sense of discovering that the company's original forecast was simply wrong. The UCA is unclear about whether the Commission intended in paragraph 1040 to simply give ATCO Gas an opportunity to identify new types or categories of integration related costs (of which the survey costs might be an example), or whether it intended to go further and give ATCO Gas something like a short-run deferral account to protect it against bad forecasting of costs it had already identified.[195]

194. In the UCA's view, if the Commission meant it will allow AG to correct its forecasts for integration related activities by saying it will permit AG to identify any additional specific costs that AG has incurred due to integration broad brush opportunity, then AG's forecast must be accepted. If a narrower definition of additional costs was intended by the Commission, UCA submits that there is a question of what should be approved.[196]

195. Calgary stated that AG should not be allowed to revise the number of positions for staff administering the NGTL contracts as AG has not met its onus as to why a Supervisor is required as compared to a Contract Analyst and an Administrative Coordinator. Increased complexity does not require a Supervisor and AG has provided no evidence of the abilities required for the different positions.[197]

196. The Commission agrees with Calgary that the need for increased manpower in addition to the requested enhancements to the Imbalance Reporting System has not been supported in this compliance filing. The reporting system should increase efficiency in imbalance reporting and AG has not made a case for personnel additions in this area.

197. As the Commission stated in Decision 2011-450, unknown costs associated with integration were identified as an issue for the test years, and AG was given the opportunity to request approval for these unknown costs. The UCA points out that AG's integration costs submitted in this application could be reviewed for an approval on a more limited or narrow basis. However, upon review of the information provided in the compliance filing, the Commission considers that integration with NGTL has changed AG's requirements with respect to the number of FT-D3 contracts AG is required to manage. This is an unexpected consequence of integration that has lead to additional specific costs for AG. The Commission approves AG's request for increases to O&M and capital costs related to contracts for FT-D3 service outside of the personnel additions identified in the paragraphs below.

198. The Commission finds that AG has not justified why a Supervisor and a Contract Analyst are required rather than a Contract Analyst and an Administrative Coordinator. Increasing complexity does not necessarily require a Supervisory position be established. AG stated in response to AUC-AG-4(c),[198]

> …by the time commercial integration took place in October 2011, NGTL determined that ATCO Gas would be required to contract for service by Summary Point instead of sub-group. ATCO Gas has approximately 1,150 Summary Points of service off the NGTL

[195] Exhibit 41.02, UCA argument, page 12, paragraph 51.
[196] Exhibit 41.02, UCA argument page 12, paragraph 52.
[197] Exhibit 41.01, City of Calgary argument, page 3.
[198] Exhibit 34.01.

> system. Additionally, any additional changes due to growth or shifts in forecast demand between points will require a new contract resulting in multiple contracts being held at a single summary point. It is expected that the number of contracts will increase to over 1,500 in 2012 and will continue to increase in the future. This twenty five fold increase in the number of contracts to be managed obviously increases the level of complexity and the capability of staff to ensure due diligence is maintained with the respect to the cost of transmission service and equally importantly ensuring that NGTL has adequate transmission capacity to meet the ATCO Gas peak requirements.

199. The Commission is aware that contracting for firm delivery service on the NGTL system is done on a yearly basis. NGTL offers variable pricing dependent on the length of term with a longer term contract resulting in a lower toll. While the choice of which product meets AG system requirements may require some analysis, the Commission considers that this will most likely be an annual occurrence. AG has not presented any evidence that the day-to-day management of its NGTL business is any more difficult or onerous to require additional staff. The Commission considers that the original organizational plan of having the Contract Analyst and Administrative Coordinator under the supervision of the existing Distribution Planning, Supervising Engineer[199] is a much more reasonable utilization of resources. The Commission denies the request for the Supervisor, Contract Demand Quantity position. AG is directed in its second compliance filing to only include in revenue requirement the capital and labor components for the Contract Analyst and Administrative Coordinator which were filed as part the GRA application for the test years.

4.44 Commission Direction 65 – MRRP costs

200. The Commission issued the following direction to AG:

> 160. The Commission approves the relocation of meters classified as Tier 3 with low risk factors in conjunction with other work such as meter recalls.[200]

201. AG stated in its application:

> In compliance with Commission Direction 3, AG removed the relocation of meters classified as Tier 3 with low risk from its MRRP program, which is scheduled to be completed by 2014. ATCO Gas has reviewed its meter recall program and notes that 316 of its 2011 meter recalls and 900 of its 2012 meter recalls involve locations identified as Tier 3 with low risk factors.

202. The total capital costs associated with these meter relocations is $690,000 and $1,985,000 respectively for 2011 and 2012.[201] The Commission approves these additional meter relocations and the capital costs for the test years as a result of AG's removal Tier 3 meters with low risk from its MRRP consistent with Direction 3 of this decision.

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199 Ibid, AUC-AG-4(c).
200 Decision 2011-450, paragraph 160.
201 Application, Exhibit 1, page 238 of 238.

5 Order

203. It is hereby ordered that:

(1) AG shall re-file its 2011-2012 General Rate Compliance Application including its placeholder summary to reflect the findings, conclusions and directions in this decision.

(2) AG shall re-file its 2011-2012 General Rate Compliance Application by September 10, 2012.

Dated on July 20, 2012.

The Alberta Utilities Commission

(original signed by)

Moin A. Yahya
Commission Member

Appendix 1 – Proceeding participants

Name of Organization (Abbreviation) Counsel or Representative (APPLICANTS)
ATCO Gas (AG) D. Cook L. Fink
Office of the Utilities Consumer Advocate (UCA) M. Stauft R. Daw T. Marriot K. Kellgren
Consumers' Coalition of Alberta (CCA) J. Wachowich J. Jodoin
The City of Calgary D. Evanchuk H. Johnson M. Rowe

Alberta Utilities Commission Commission Panel M. Yahya, Commission Member Commission Staff A. Sabo (Commission Counsel) B. Whyte C. Burt M. McJannet C. Taylor

Appendix 2 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. With respect to the BFK and DSM, the Commission finds that these costs are related to entire programs which have been disallowed by the Commission, and costs associated with these programs are not required for utility service, unlike SIBS and HRX costs which were split between utility and non-utility service. On this basis the Commission directs AG to remove the BFK and DSM reductions accounted in for its opening rate base in its second compliance filing to Decision 2011-450............................ Paragraph 44

2. Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount for 90 per cent of the actual costs of HRX in its second compliance filing to Decision 2011-450..Paragraph 45

3. The Commission finds that there was limited evidence provided by AG in the compliance filing with regard to increased labour requirements or travel costs to support a premium in the 2011 and 2012 test years. However, the Commission recognizes that potential inefficiencies may have resulted due to AG's required exclusion of Tier 3 low risk meter replacements as per Commission Direction 2. As a result, the Commission directs AG in its second compliance filing to provide a detailed justification of any premium that should be applied to AG's forecast due to the above noted inefficiencies.. ..... Paragraph 60

4. For HRX, AG has reflected the 10 per cent cost reduction in the actual costs in its compliance filing. The inclusion of the remaining costs of HRX in opening rate base was addressed in paragraph 43 of Direction 1 above. As stated in Direction 1, the issue of Oracle HRX is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V and pending the outcome of the Phase II R&V and any appeals on this issue, AG is directed to include a placeholder amount for Oracle HRX of 90 per cent of the actual cost in its second compliance filing to Decision 2011-450……………………….Paragraph 76

5. AG has removed the CIS enhancement program, forecast amounts of $1 million and $0.6 million, in 2011 and 2012, respectively, determining its revised revenue requirement [MH1]. The Commission has confirmed that this amount has been reflected in the capital adjustment sheet.[202] The issue of the CIS enhancement program forecast costs is currently before the Commission in Proceeding ID No. 1698, the Phase II R&V of Decision 2011-450. In the Phase I R&V, the review panel found that it was unclear whether the hearing panel considered AG's response to the business case in AUC-AG-43(b).[203] Pending the outcome of the Phase II R&V, AG is directed to include a placeholder amount for CIS of zero in its second compliance filing to Decision 2011-450………………..Paragraph 87

[202] Application, Exhibit 7.
[203] Decision 2012-156, paragraph 48, pages 12 and 13.

6. AG stated in its application that it will provide a comparative analysis of the alternative of issuing debt in its next preferred share application and prepare an updated analysis of whether the optimal range of AG's capital structure should include five to ten per cent of preferred shares concurrent with or prior to AG's next preferred share application.[204] For the purposes of this application, the Commission finds that Directions 21 and 22 have been complied with. AG is directed to include the alternatives and analysis as directed in Decision 2011-450 in its next preferred share application………………………………………………………..……….Paragraph 91

7. AG argued that AMR meter exchange costs should continue to be capitalized as they relate to meters that may be damaged or otherwise cannot be retrofitted with the AMR device. The Commission agrees with this approach and directs AG to continue to capitalize meter exchange costs associated with the AMR program. The Commission considers that AG has explained the discrepancy in metering costs and that the additional $4.2 million in O&M for 2011 and 2012 is consistent with Commission direction. AG has complied with this direction……………………………………..………...Paragraph 111

8. The issue of the Calgary office lease is currently before the Commission in Proceeding ID No. 1698, the Phase II of AG's R&V of Decision 2011-450. In granting a review of the findings, the review panel stated that it is unclear whether the hearing panel rate was aware that AG's existing rental rate was $16 per square foot in reaching the determination that the existing lease rate should be used.[205] Pending the outcome of the Phase II R&V proceeding, AG is directed to maintain a placeholder amount for the Calgary lease rate of $14.50 per square foot for 2011, and a placeholder amount of $14.50 per square foot increased by a three per cent inflation factor for 2012, in its second compliance filing to Decision 2011-450.………………….....……......Paragraph 127

9. Pending the outcome of the Phase II R&V proceeding, AG is directed to use a placeholder amount of zero for late payment penalty settlement costs in its second compliance filing to Decision 2011-450.……………………………….....….Paragraph 149

10. The Commission has reviewed the table in the application as well as the depreciation expense adjustments spreadsheet.[206] Given the findings in Direction 1 of this decision, the Commission directs AG to provide a schedule detailing the removal of the DSM and the Calgary BFK assets from opening rate base, and any accompanying impact on depreciation in its second compliance filing. .... Paragraph 162

11. AG has advised that it will not be filing a separate application to deal with net salvage rates in the test years.[207] AG explained that a study cannot be completed in time to allow for a separate application for the test years. Consistent with Direction 54 in Decision 2011-450, the Commission therefore directs AG to use the existing net salvage rates for the test years and to reflect the corresponding change in the compliance filing.…………………………………………………………………....Paragraph 164

204 Application, Exhibit 1, pages 157 and 158 of 238 PDF.
205 Decision 2012-156, page 24, paragraph 99.
206 Application, Exhibit 10.
207 Application, Commission Direction 54, page 1 of 2.

12. As the issue of production abandonment costs will be subject to a further proceeding and given the direction of the Commission in Decision 2012-156 that a placeholder is warranted for production abandonment costs, the Commission directs AG in its second compliance filing to use a placeholder of zero for production abandonment costs for the 2011 and 2012 test years. .... Paragraph 171

13. In its application, AG stated it will close the IFRS deferral account and file an application to address settlement of each deferral account adjustment within three months of the public release of 2011 Canadian Utilities Limited financial statements.[208] The Commission notes that no application regarding this deferral account has been filed to date. The Commission directs AG to provide an update in its second compliance filing regarding the status of its application for the closure and settlement of the IFRS deferral account…………………………………………………………………....Paragraph 180

14. The Commission has reviewed the O&M adjustments spreadsheet and is satisfied that AG has removed $150,000 in forecast costs related to participating in NEB proceedings for each of 2011 and 2012, in compliance with the Commission's direction. However, the Commission notes that in Decision 2012-156, the review panel has granted a review of the decision to deny AG's request to recover $300,000 in forecast costs for participation in the NEB NGTL hearings.[209] The issue of the recovery of 2011 and 2012 forecast costs related to AG's participation in NEB hearings related to integration is properly before the Commission in Proceeding ID No. 1698. Pending the outcome of the Phase II R&V proceeding in Proceeding ID No. 1698, AG is directed to use a placeholder amount of zero for forecast hearing costs related to integration hearings for 2011 and 2012. The Commission directs AG to reflect the zero placeholder for these costs in its second compliance filing to Decision 2011-450.………………………………….Paragraph 189

15. The Commission considers that the original organizational plan of having the Contract Analyst and Administrative Coordinator under the supervision of the existing Distribution Planning, Supervising Engineer[210] is a much more reasonable utilization of resources. The Commission denies the request for the Supervisor, Contract Demand Quantity position. AG is directed in its second compliance filing to only include in revenue requirement the capital and labor components for the Contract Analyst and Administrative Coordinator which were filed as part the GRA application for the test years. ……………………………………………………………………..Paragraph 199

208 Application, Commission Direction 59, page 1 of 1.
209 Decision 2012-156: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) - Decision on Request for Review and Variance of AUC Decision 2011-450 2011-2012 General Rate Application Phase I, page 19, paragraph 74.
210 Ibid, AUC-AG-4(c).

Appendix 3 – Summary of 2011 O&M adjustments

SUMMARY OF 2011 O&M ADJUSTMENTS

Description	Reference	Gas Management	Transmission	Distribution	General	Sales & Transportation Promotion	Customer Accounting	Administrative	Total
O&M Labour as Filed	4.2	593	-	57,791	1,905	3,927	20,317	17,245	101,778
Updated for April 21 Adjustments		-	-	(100)	-	-	(300)	-	(400)
VPP Net Income reduction to 10% - Transcript Response - D Wilson - Volume 2, page 344		-	-	-	-	-	-	(531)	(531)
VPP Net Income adjustment to 10% max per participant	CD37	-	-	-	-	-	-	(119)	(119)
Vacancy Allowance Increase to 8.3%	CD25	(13)	-	-	(42)	(30)	(38)	-	(123)
Meter Recalls recorded as O&M	CD27	-	-	1,725	-	-	-	-	1,725
Reduce forecasted costs in Account 674 by 1.2%	CD28	-	-	(166)	-	-	-	-	(166)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(140)	-	-	-	-	(140)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(1,375)	-	-	(1,375)
Remove DSM costs	CD33	-	-	-	-	(1,205)	-	-	(1,205)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(281)	-	(281)
Adjust foreasted costs for admin labour excluding VPP to 2010 actuals increased by 5% per year	CD36	-	-	-	-	-	-	(2,146)	(2,146)
Remove forecasted costs related to training, mentoring, and coaching	CD61	-	-	(600)	-	-	-	-	(600)
Line heater inspection costs	CD62	-	-	(200)	-	-	-	-	(200)
NEB Integration labour for additional supervisor and analyst	CD64	-	-	(66)	-	-	-	-	(66)
Labour adjustments		(13)	-	553	(42)	(2,610)	(319)	(2,265)	(4,696)
Adjusted O&M Forecast - Labour		**580**	**-**	**58,244**	**1,863**	**1,317**	**19,699**	**14,449**	**96,152**
O&M Supplies as Filed	4.2	19	107,898	24,870	5,474	4,624	31,423	92,316	266,624
Updated for April 21 Adjustments		-	-	400	(400)	(600)	(300)	(700)	(1,600)
Meter Recalls recorded as O&M	CD27	-	-	2,475	-	-	-	-	2,475
Reduce forecasted costs in Account 674 by 1.2%	CD28	-	-	(24)	-	-	-	-	(24)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(128)	-	-	-	-	(128)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(574)	-	-	(574)
BFK safety messaging moved to Customer Relations & Communications	CD31	-	-	-	-	50	-	-	50
Remove Centennial Anniversary costs	CD32	-	-	-	-	(250)	-	-	(250)
Remove DSM costs	CD33	-	-	-	-	(1,927)	-	-	(1,927)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(92)	-	(92)
Allocated corporate advertising	CD40	-	-	-	-	-	-	(73)	(73)
Adjust foreasted costs for mass media & other supplies to 2010 actuals increased by 5% per year	CD41	-	-	-	-	-	-	(1,045)	(1,045)
Reclassify bank and short-term financing as financing costs	CD47	-	-	-	-	-	-	(1,000)	(1,000)
Safety initiatives related to changes in workforce	CD61	-	-	(500)	-	-	-	-	(500)
Line heater inspection costs	CD62	-	-	(700)	-	-	-	-	(700)
NEB Integration legal costs	CD63	-	-	-	-	-	-	(150)	(150)
NEB Integration legal costs	CD64	-	-	-	-	-	-	128	128
Transmission Approved Rate		-	(9,755)	-	-	-	-	-	(9,755)
ATCO I-Tek Placeholder Update to 2010 Utilities Evergreen Proceeding		-	-	-	-	-	(1,025)	-	(1,025)
Supplies adjustments		-	(9,755)	1,123	-	(2,701)	(1,117)	(2,140)	(14,590)
Adjusted O&M Forecast - Supplies		**19**	**98,143**	**26,393**	**5,074**	**1,323**	**30,006**	**89,476**	**250,434**
Total Adjustments - April 21 Update		-	-	300	(400)	(600)	(600)	(700)	(2,000)
Total Adjustments - Hearing Update		-	-	-	-	-	-	(531)	(531)
Total Adjustments - Decision 2011-450		(13)	(9,755)	1,676	(42)	(5,311)	(1,436)	(4,405)	(19,286)
Total Adjustments		(13)	(9,755)	1,976	(442)	(5,911)	(2,036)	(5,105)	(21,286)
Adjusted O&M Forecast - Total		**599**	**98,143**	**84,637**	**6,937**	**2,640**	**49,705**	**103,925**	**346,586**

Appendix 4 – Summary of 2012 O&M adjustments

SUMMARY OF 2012 O&M ADJUSTMENTS

Description	Reference	Gas Management	Transmission	Distribution	General	Sales & Transportation Promotion	Customer Accounting	Administrative	Total
O&M Labour as Filed	4.2	611	-	61,232	2,024	4,432	21,301	17,804	107,404
Updated for April 21 Adjustments		-	-	100	-	-	(300)	100	(100)
VPP Net Income reduction to 10% - Transcript Response - D Wilson - Volume 2, page 344		-	-	-	-	-	-	(531)	(531)
VPP Net Income adjustment to 10% max per participant	CD37	-	-	-	-	-	-	(119)	(119)
Vacancy Allowance Increase to 8.3%	CD25	(13)	-	-	(45)	(32)	(41)	-	(131)
Meter Recalls recorded as O&M	CD27	-	-	1,700	-	-	-	-	1,700
Reduce forecasted costs in Account 674 by 1.7%	CD28	-	-	(250)	-	-	-	-	(250)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(223)	-	-	-	-	(223)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(1,492)	-	-	(1,492)
Remove DSM costs	CD33	-	-	-	-	(1,505)	-	-	(1,505)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(358)	-	(358)
Reduce Meter Reading costs	CD35	-	-	-	-	-	(3,200)	-	(3,200)
Adjust foreasted costs for admin labour excluding VPP to 2010 actuals increased by 5% per year	CD36	-	-	-	-	-	-	(2,019)	(2,019)
Remove forecasted costs related to training, mentoring, and coaching	CD61	-	-	(800)	-	-	-	-	(800)
Remove occupational health nurses	CD61	-	-	(200)	-	-	-	-	(200)
Line heater inspection costs	CD62	-	-	(200)	-	-	-	-	(200)
NEB Integration labour for additional supervisor and analyst	CD64	-	-	115	-	-	-	-	115
Labour adjustments		(13)	-	142	(45)	(3,029)	(3,599)	(2,138)	(8,682)
Adjusted O&M Forecast - Labour		**598**	**-**	**61,474**	**1,979**	**1,403**	**17,402**	**15,235**	**98,091**
O&M Supplies as Filed	4.2	19	109,349	26,898	5,741	5,073	32,433	91,926	271,439
Updated for April 21 Adjustments		-	-	400	(400)	-	(300)	(300)	(600)
Okotoks Operating Costs	CD11				(8)	-	-	-	(8)
Consultant costs moved to one-time adjustment	CD26	-	-	(500)	-	-	-	-	(500)
Meter Recalls recorded as O&M	CD27	-	-	2,500					2,500
Reduce forecasted costs in Account 674 by 1.7%	CD28	-	-	(35)	-	-	-	-	(35)
Adjust forecasted costs in Account 678 & 679 to 2010 actuals increased by 5% per year	CD29	-	-	(202)	-	-	-	-	(202)
Remove BFK Costs for Edmonton and Calgary	CD30	-	-	-	-	(636)	-	-	(636)
BFK safety messaging moved to Customer Relations & Communications	CD31	-	-	-	-	50	-	-	50
Remove Centennial Anniversary costs	CD32	-	-	-	-	(1,100)	-	-	(1,100)
Remove DSM costs	CD33	-	-	-	-	(2,018)	-	-	(2,018)
Adjust forecasted costs in Account 710 to 2010 actuals increased by 5% per year	CD34	-	-	-	-	-	(338)	-	(338)
CC&B Benchmarking	CD34	-	-	-	-	-	300	-	300
Office rent based on $14.50 inflated by 3%	CD39	-	-	-	-	-	-	24	24
Allocated corporate advertising	CD40	-	-	-	-	-	-	(75)	(75)
Adjust foreasted costs for mass media & other supplies to 2010 actuals increased by 5% per year	CD41	-	-	-	-	-	-	(1,182)	(1,182)
Reclassify bank and short-term financing as financing costs	CD47	-	-	-	-	-	-	(900)	(900)
Line heater inspection costs	CD62	-	-	(700)	-	-	-	-	(700)
NEB Integration legal costs	CD63	-	-	-	-	-	-	(150)	(150)
NEB Integration legal costs	CD64	-	-	-	-	-	-	150	150
NEB Integration for meter maintenance/reading	CD64	-	-	65	-	-	-	-	65
NEB Integration for system maintenance & support	CD64	-	-		-	-	-	22	22
Transmission Approved Rate		-	(2,769)	-	-	-	-	-	(2,769)
ATCO I-Tek Placeholder Update to 2010 Utilities Evergreen Proceeding		-	-	-	-	-	(1,056)	-	(1,056)
Supplies adjustments		-	(2,769)	1,128	(8)	(3,704)	(1,094)	(2,111)	(8,558)
Adjusted O&M Forecast - Supplies		**19**	**106,580**	**28,426**	**5,333**	**1,369**	**31,039**	**89,515**	**262,281**
Total Adjustments - April 21 Update		-	-	500	(400)	-	(600)	(200)	(700)
Total Adjustments - Hearing Update		-	-	-	-	-	-	(531)	(531)
Total Adjustments - Decision 2011-450		(13)	(2,769)	1,270	(53)	(6,733)	(4,693)	(4,249)	(17,240)
Total Adjustments		(13)	(2,769)	1,770	(453)	(6,733)	(5,293)	(4,980)	(18,471)
Adjusted O&M Forecast - Total		**617**	**106,580**	**89,900**	**7,312**	**2,772**	**48,441**	**104,750**	**360,372**

Appendix 5 – Summary of 2011 depreciation adjustments

SUMMARY OF 2011 UTILITY DEPRECIATION EXPENSE ADJUSTMENTS

Description	Reference	Distribution	General Plant	Gross Depreciation	Amortization of Contributions	Capitalized Depreciation	Net Depreciation	Production Abandonments	Total Depreciation Expense
North									
Depreciation Expense as Filed	5.1-9 & 10	**53.3**	**16.8**	**70.1**	**(5.5)**	**(2.7)**	**61.9**	**0.5**	**62.4**
Account 473 - Services	CD 48	0.2	-	0.2	(0.1)	-	0.1	-	0.1
Account 474 - Regulator and Meter Installations	CD 49	(1.8)	-	(1.8)	0.1	-	(1.8)	-	(1.8)
Account 475 - Mains	CD 50	(3.2)		(3.2)	0.2	-	(3.0)	-	(3.0)
Account 484 - Transportation Equipment	CD 52	-	(2.0)	(2.0)	-	0.9	(1.1)	-	(1.1)
Other Depreciation Accounts	CD 53	(0.1)	(0.8)	(0.9)	0.6	(0.4)	(0.7)	-	(0.7)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(0.5)	(0.5)
Total Adjustments		(4.9)	(2.8)	(7.7)	0.7	0.5	(6.5)	(0.5)	(7.0)
Adjusted Depreciation Expense Forecast		**48.4**	**14.0**	**62.4**	**(4.8)**	**(2.2)**	**55.4**	**-**	**55.4**
South									
Depreciation Expense as Filed	5.1-9 & 10	**45.9**	**13.4**	**59.3**	**(5.0)**	**(2.0)**	**52.3**	**1.0**	**53.3**
Account 473 - Services	CD 48	0.3	-	0.3	(0.1)	-	0.2	-	0.2
Account 474 - Regulator and Meter Installations	CD 49	(1.3)	-	(1.3)	0.0	-	(1.3)	-	(1.3)
Account 475 - Mains	CD 50	(3.3)	-	(3.3)	0.2	-	(3.1)	-	(3.1)
Account 484 - Transportation Equipment	CD 52	-	(1.7)	(1.7)	-	0.8	(0.9)	-	(0.9)
Other Depreciation Accounts	CD 53	(0.5)	(0.5)	(1.0)	(0.6)	(0.2)	(1.8)	-	(1.8)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.0)	(1.0)
Total Adjustments		(4.8)	(2.2)	(7.0)	(0.4)	0.6	(6.8)	(1.0)	(7.8)
Adjusted Depreciation Expense Forecast		**41.1**	**11.2**	**52.3**	**(5.4)**	**(1.4)**	**45.5**	**-**	**45.5**
Total									
Depreciation Expense as Filed	5.1-9 & 10	**99.2**	**30.2**	**129.4**	**(10.5)**	**(4.7)**	**114.2**	**1.5**	**115.7**
Account 473 - Services	CD 48	0.5	-	0.5	(0.2)	-	0.3	-	0.3
Account 474 - Regulator and Meter Installations	CD 49	(3.1)	-	(3.1)	0.1	-	(3.0)	-	(3.0)
Account 475 - Mains	CD 50	(6.5)	-	(6.5)	0.4	-	(6.1)	-	(6.1)
Account 484 - Transportation Equipment	CD 52	-	(3.7)	(3.7)	-	1.7	(2.0)	-	(2.0)
Other Depreciation Accounts	CD 53	(0.6)	(1.3)	(1.9)	-	(0.6)	(2.5)	-	(2.5)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.5)	(1.5)
Total Adjustments		(9.6)	(5.0)	(14.6)	0.3	1.1	(13.3)	(1.5)	(14.8)
Adjusted Depreciation Expense Forecast		**89.6**	**25.2**	**114.8**	**(10.2)**	**(3.6)**	**100.9**	**-**	**100.9**

Appendix 6 – Summary of 2012 depreciation adjustments

SUMMARY OF 2012 UTILITY DEPRECIATION EXPENSE ADJUSTMENTS

Description	Reference	Distribution	General Plant	Gross Depreciation	Amortization of Contributions	Capitalized Depreciation	Net Depreciation	Production Abandonments	Total Depreciation Expense
North									
Depreciation Expense as Filed	5.1-9 & 10	**58.9**	**18.0**	**76.9**	**(5.9)**	**(2.9)**	**68.1**	**0.6**	**68.7**
Account 473 - Services	CD 48	(0.1)	-	(0.1)	(0.1)	-	(0.2)	-	(0.2)
Account 474 - Regulator and Meter Installations	CD 49	(2.1)	-	(2.1)	0.1	-	(2.0)	-	(2.0)
Account 475 - Mains	CD 50	(3.9)	-	(3.9)	0.2	-	(3.7)	-	(3.7)
Account 484 - Transportation Equipment	CD 52	-	(2.2)	(2.2)	-	1.0	(1.2)	-	(1.2)
Other Depreciation Accounts	CD 53	(0.2)	(0.8)	(1.0)	0.7	(0.4)	(0.7)	-	(0.7)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(0.6)	(0.6)
Total Adjustments		(6.2)	(3.0)	(9.2)	0.8	0.6	(7.8)	(0.6)	(8.4)
Adjusted Depreciation Expense Forecast		**52.7**	**15.0**	**67.7**	**(5.1)**	**(2.3)**	**60.3**	**-**	**60.3**
South									
Depreciation Expense as Filed	5.1-9 & 10	**50.4**	**14.4**	**64.8**	**(5.4)**	**(2.1)**	**57.3**	**1.0**	**58.3**
Account 473 - Services	CD 48	0.3	-	0.3	(0.1)	-	0.2	-	0.2
Account 474 - Regulator and Meter Installations	CD 49	(1.4)	-	(1.4)	0.0	-	(1.4)	-	(1.4)
Account 475 - Mains	CD 50	(3.9)	-	(3.9)	0.2	-	(3.7)	-	(3.7)
Account 484 - Transportation Equipment	CD 52	-	(1.8)	(1.8)	-	0.8	(1.0)	-	(1.0)
Other Depreciation Accounts	CD 53	(0.5)	(0.7)	(1.2)	(0.6)	(0.1)	(1.9)	-	(1.9)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.0)	(1.0)
Total Adjustments		(5.6)	(2.5)	(8.1)	(0.4)	0.7	(7.8)	(1.0)	(8.8)
Adjusted Depreciation Expense Forecast		**44.8**	**11.9**	**56.7**	**(5.8)**	**(1.4)**	**49.5**	**-**	**49.5**
Total									
Depreciation Expense as Filed	5.1-9 & 10	**109.3**	**32.4**	**141.7**	**(11.3)**	**(5.0)**	**125.4**	**1.6**	**127.0**
Account 473 - Services	CD 48	0.2	-	0.2	(0.2)	-	(0.0)	-	(0.0)
Account 474 - Regulator and Meter Installations	CD 49	(3.5)	-	(3.5)	0.1	-	(3.4)	-	(3.4)
Account 475 - Mains	CD 50	(7.8)	-	(7.8)	0.4	-	(7.4)	-	(7.4)
Account 484 - Transportation Equipment	CD 52	-	(4.0)	(4.0)	-	1.8	(2.2)	-	(2.2)
Other Depreciation Accounts	CD 53	(0.7)	(1.5)	(2.2)	0.1	(0.5)	(2.6)	-	(2.6)
Production Abandonment Costs	CD 56	-	-	-	-	-	-	(1.6)	(1.6)
Total Adjustments		(11.8)	(5.5)	(17.3)	0.4	1.3	(15.6)	(1.6)	(17.2)
Adjusted Depreciation Expense Forecast		**97.5**	**26.9**	**124.4**	**(10.9)**	**(3.7)**	**109.8**	**-**	**109.8**

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2018 SUSTAINABILITY REPORT

ENERGY STEWARDSHIP

Secure, reliable and affordable energy underpins the economic vitality of our communities. It is our responsibility to understand the evolving needs of our customers and develop solutions that support the transition to a lower-emitting energy system.

Page 4

ENVIRONMENTAL STEWARDSHIP

As a critical infrastructure provider, a collaborative and long-term approach to minimizing our environmental footprint is vital. As part of this, we continue to explore new and more efficient ways to generate, transport and conserve energy.

Page 12

VISION

Our core vision is to make lives easier for our customers by providing sustainable, innovative and comprehensive solutions globally.

SAFETY

Safety is the first consideration in everything we do. Providing a safe work environment for our people is ingrained in our culture: a shared belief that directs our day-to-day priorities and decisions.

Page 18

COMMUNITY & INDIGENOUS RELATIONS

Building respectful and mutually beneficial relationships has long defined how we do business. Along with our Indigenous and community partners, we are continually exploring new ways to collaborate.

Page 24

Today's global community is experiencing a pace and scale of change that is unprecedented, and it is incumbent upon business to adapt and lead the way. At ATCO, we have continued to forge ahead with a team of more than 6,000 committed people who bring their best to build communities, energize industry and deliver customer-focused infrastructure solutions around the world. Sustainability is more than an ideal; it is inter-woven into our decisions, our products and services, and our culture. We know you expect nothing less.

This report highlights our sustainability performance through four, forward-looking lenses that help drive our multi-faceted business:

- ENERGY STEWARDSHIP
- ENVIRONMENTAL STEWARDSHIP
- COMMUNITY AND INDIGENOUS RELATIONS
- SAFETY

For ATCO, energy stewardship means energy access that is secure, reliable and affordable. We have fostered world-class innovation with a keen eye for integration of emerging technology, including initiatives in renewable energy, energy efficiency, low-carbon transportation, and overall energy systems—for homes and businesses both down the road, and in remote communities. But innovation for innovation's sake isn't enough: we listen closely to our customers to identify the right mix of technologies, tailored to their specific needs. One stellar example of this is the integration of renewable energy and battery storage in remote Indigenous communities to reduce their reliance on diesel-fueled electricity generation.

Our customers are our partners in everything we do and maintaining our connections with them has never been more important. Within our Alberta electricity and natural gas businesses, over 90 per cent of our customers agree we have a strong reputation in their community. Our reputation is an intangible collection of thousands of positive actions taken by our people, but it has very tangible benefits for the resiliency and strength of our company.

We utilize a similar approach to environmental stewardship, recognizing that strong environmental practices are intrinsic to sound business practices. We continue to innovate and lead the transition to a lower-emitting energy future through renewables, focus on operational efficiency and fuel switching; in particular, converting our coal-fired electricity generation to operate on lower-emitting natural gas enables us to utilize existing infrastructure, while achieving immediate and significant reductions in emissions. It is through initiatives such as this that we have been able to reduce our greenhouse gas emissions by 37 per cent since 2008.

Community and Indigenous relations are a key to our success and integral to how we grow as a company through understanding the needs of our customers and working collaboratively to develop the strongest solutions possible. We have a history of meaningful collaboration with Indigenous communities, but most importantly, we understand that we have a future together made possible through meaningful engagement, economic participation, training and employment opportunities. When our partners do well, ATCO does well.

Safety is critical; and it is the cornerstone in ensuring that our most important assets—our people and our customers—are poised for success. While we mobilize to help people around the globe by providing disaster and emergency management services, we put equal focus on the health and safety of our employees, our customers and contractors. In 2018, our total recordable incident frequency rate and lost time incident frequency rate saw a respective 35 and 36 per cent improvement from 2017. I am proud to say we are working cleaner, safer, and more reliably than ever before, and at a lower cost for our customers.

Underpinning our accomplishments are the herculean efforts of our people. I would like to thank them for their commitment to connecting the practical to the sustainable; the immediate response to the long-term vision; and to let them know they have the full support of myself and our board of directors.

Nancy

Nancy Southern
Chair & Chief Executive Officer

INTEGRATED SOLUTIONS

From reliable, sustainable energy for homes and businesses to innovative temporary and permanent structures and everything in between, we build communities, energize industries, and deliver customer-focused infrastructure solutions.

Sustainability disclosures reflect our global business unit operations including:

STRUCTURES & LOGISTICS

- Relocatable Structures
- Permanent Structures
- Emergency Response
- Site Services

ELECTRICITY

- Electricity Generation
- Electricity Transmission
- Electricity Distribution

PIPELINES & LIQUIDS

- Natural Gas Distribution
- Natural Gas Transmission
- Energy Storage
- Industrial Water

RETAIL

- Retail Electricity and Natural Gas (Home & Business)

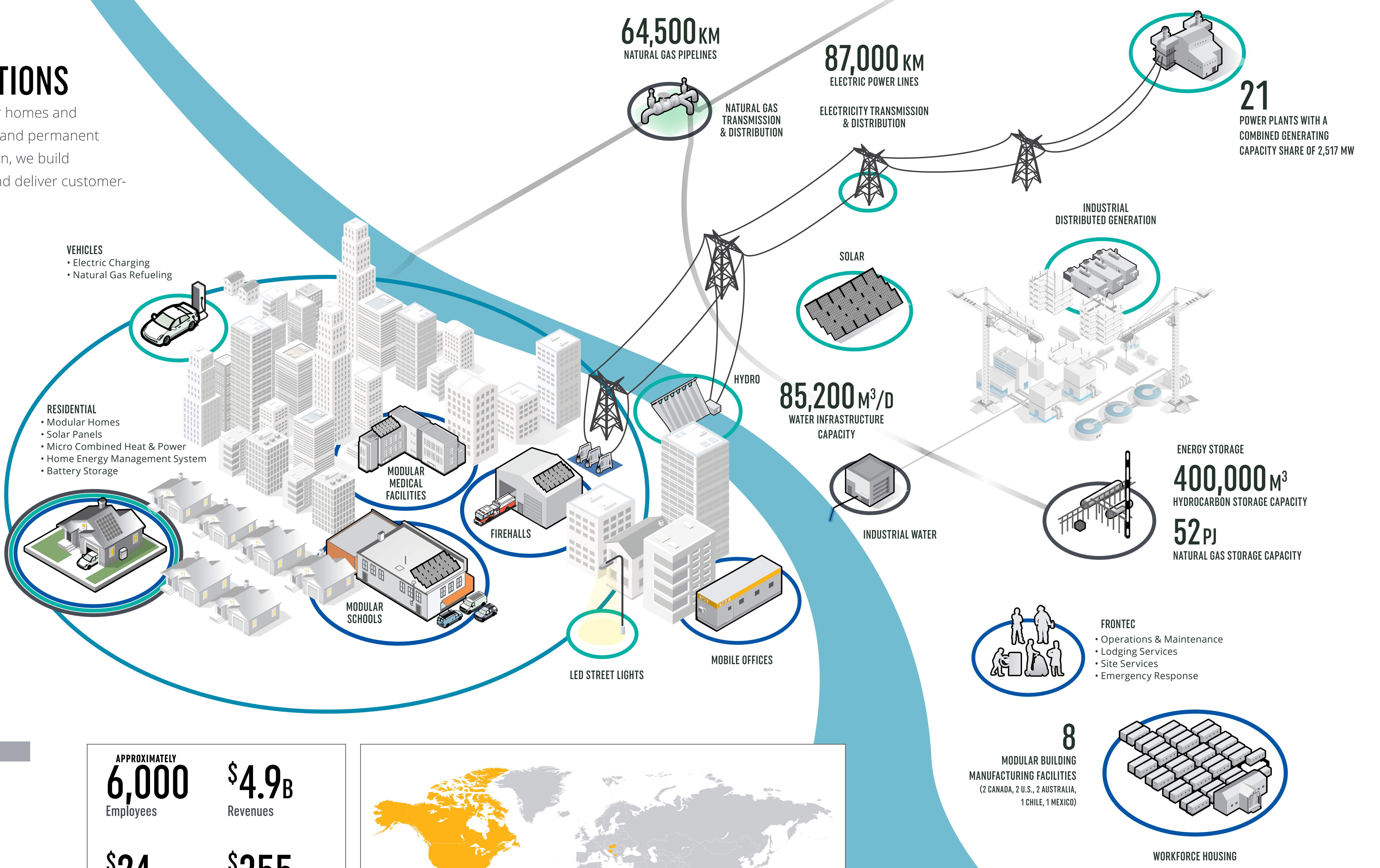
ATCO also has investments in:

PORTS & TRANSPORTATION

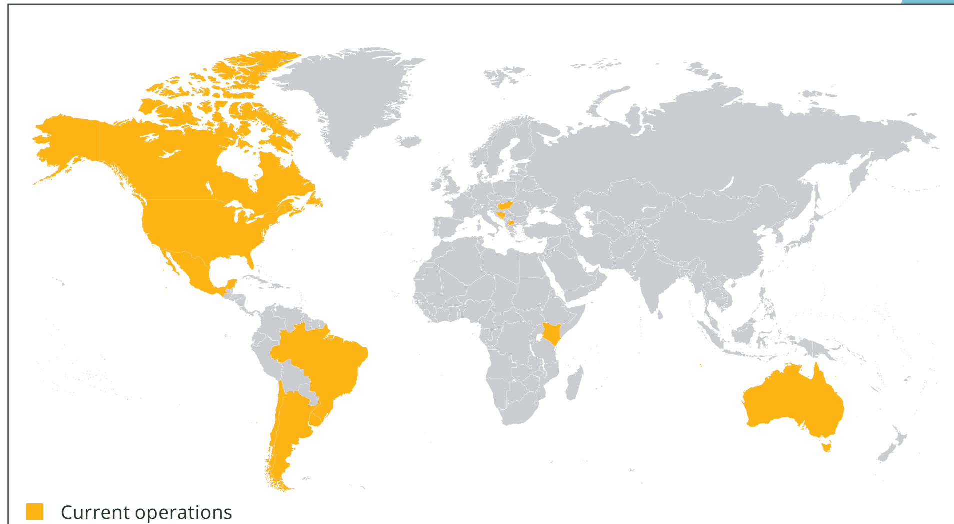
- Port Facilities
- Port Operations Services

ATCO INVESTMENTS

- Commercial Real Estate



APPROXIMATELY 6,000 Employees	$4.9B Revenues
$24B Assets	$355M Adjusted Earnings
2M+ Global Customers	$2.5B Capital Investment



ENERGY STEWARDSHIP

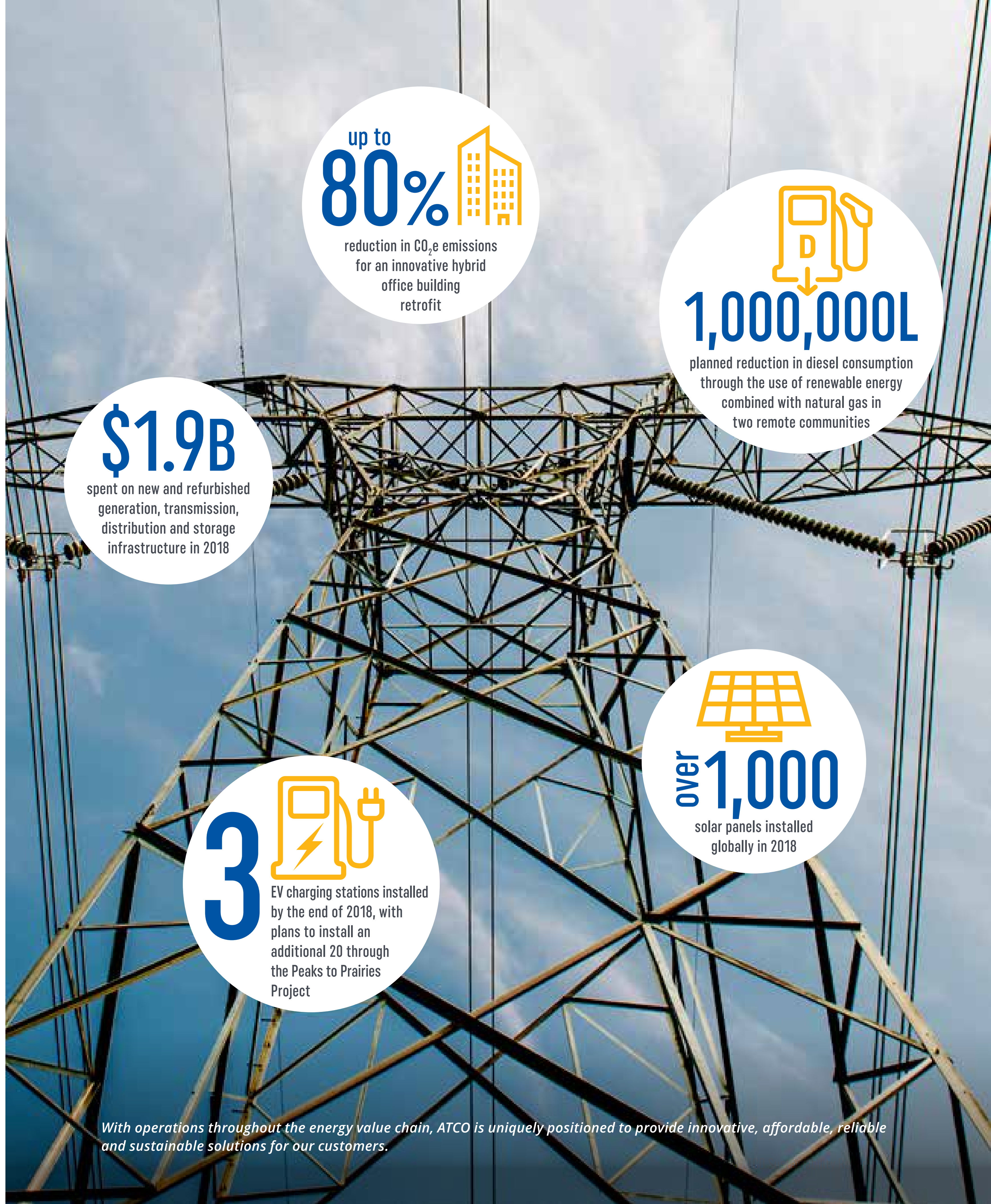
Secure, reliable and affordable energy underpins the economic vitality of our communities. It is our responsibility to understand the evolving needs of our customers and develop solutions that support the transition to a lower-emitting energy system.

CUSTOMER SATISFACTION

SECURITY & RELIABILITY

ACCESS TO ENERGY

AFFORDABILITY



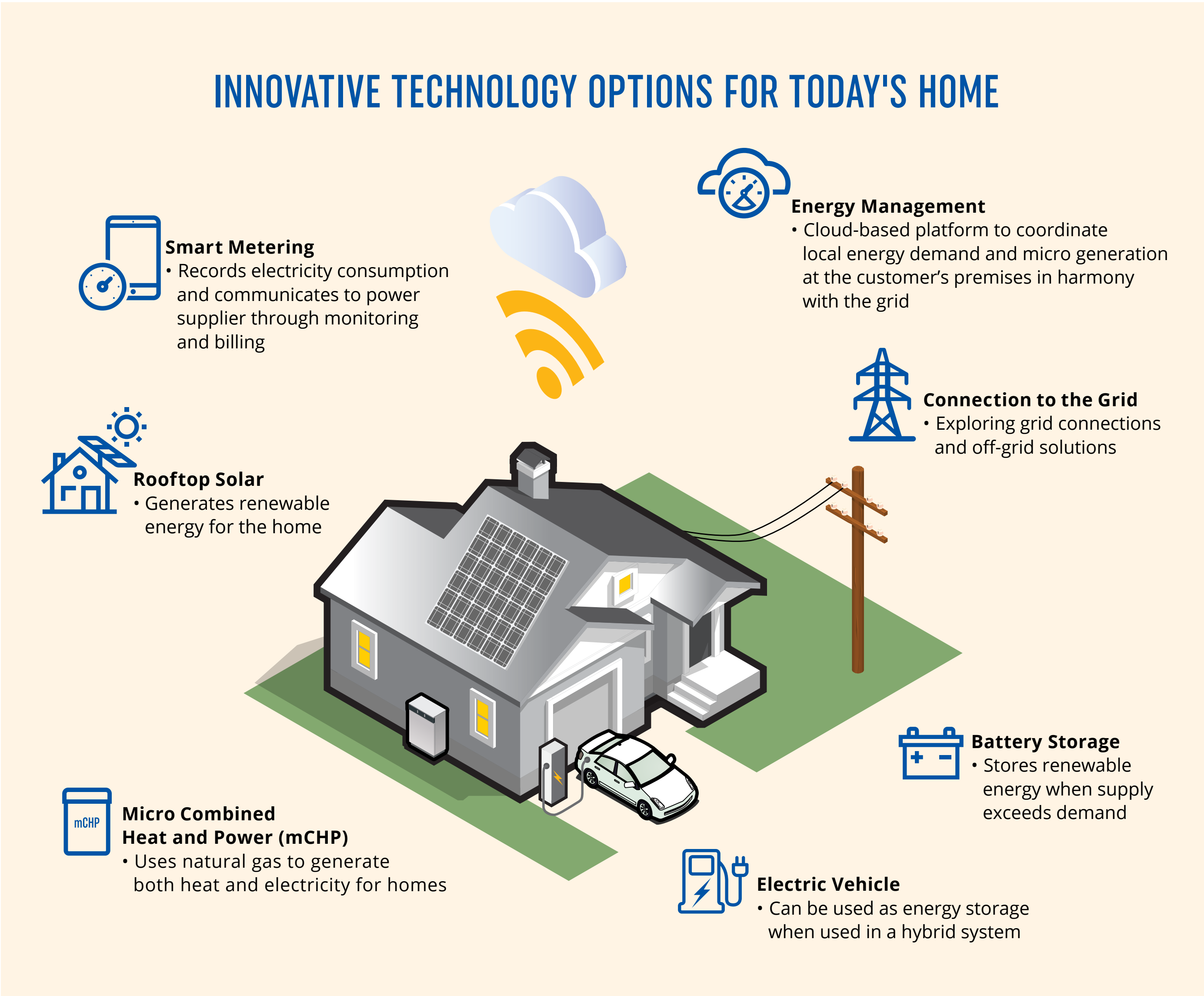
With operations throughout the energy value chain, ATCO is uniquely positioned to provide innovative, affordable, reliable and sustainable solutions for our customers.

At ATCO, our success depends on providing innovative solutions that are affordable, reliable and sustainable. As we continue to look ahead to our global energy future, we see tremendous change—from generation to transmission and distribution to end-user consumption. Many of these changes are driven by innovation, consumer choices and are reflected in public policy. The intersection of these drivers can occur quickly, such as when customers become 'prosumers' who take a more active role in generating electricity and selling it back to the grid, reversing the traditional producer to consumer model.

With operations throughout the energy value chain, ATCO is uniquely positioned to help facilitate this global transformation and to empower our customers to play a role. The transition requires near and long-term thinking and collaboration to get to the best solutions. We advocate for a holistic perspective on energy policy—one that considers both immediate impacts but accounts for the future, including competitiveness, consumer affordability and preference, and balance between the economy and environment.

In the near-term, finding new ways to reuse existing infrastructure can provide significant and immediate results, such as fuel switching from coal or diesel to reliable combinations of renewables and natural gas. In the long-term, we must keep challenging ourselves to integrate the best solutions for each project, customer and region.

We are actively and constructively engaging with industry, governments, regulators and experts on core issues. These include changing policy to enable integration of innovative solutions and renewables, carbon pricing, sector-specific output-based standards, maintaining industry competitiveness and plans for lower-emissions fuels for the transportation sector.



An example of different technologies that can be implemented—either by themselves or in combination with others—in a home, depending on the customer's unique needs.

CUSTOMER SOLUTIONS

Every person, neighbourhood and region is unique, so their lower-emitting energy systems must fit their situation.

We work with customers to select the right balance of technologies to meet their energy needs, affordably and reliably. Solutions are tailored to the specific situation to optimize results, requiring innovation and collaboration and exciting new partnerships.

Single Building Innovation

At ATCO, we have been evaluating how to integrate technology options effectively, including solar panels, battery storage, advanced building envelopes and Micro Combined Heat and Power (mCHP) units. mCHP units use natural gas to produce electricity in homes while capturing energy that would otherwise be lost for home heating and hot water.

Adding to the suite of energy technologies, we are evaluating smart metering and energy management systems that work to ensure multiple components of the system work efficiently together to manage and meet energy demand.

We have several projects in progress that combine different technology applications including retrofits versus new builds and off-grid versus grid connections. Our 18 hybrid house pilot projects have successfully demonstrated over 42 per cent reduction of a typical household's greenhouse gas (GHG) emissions, with one of our homes demonstrating up to 75 per cent reduction in GHGs.

In addition, through our project with the Southern Alberta Institute of Technology (SAIT) and Brookfield Residential, we will be installing an innovative mix of energy solutions in a new Low Carbon Discovery Show Home in Edmonton, Alberta. The project, made possible with funding support from Western Economic Development, has the potential to save $1,400 in utility costs and nine tonnes of CO_2e per year.

It's not just homes that can benefit from these solutions. Effect Home Builders' hybrid office building in Edmonton will be the first in the city to disconnect from the electrical grid. The project will reduce GHGs from the original structure by approximately 20 tonnes of CO_2e per year, or a reduction of 80 per cent.

We've recently taken another exciting step in providing customers with more energy efficient options with our acquisition of Source Energy Co. in Australia. Source Energy Co. is an expert at managing energy needs for high-density apartment buildings, using a mix of rooftop solar panels and energy from the grid, matched with smart metering technology. This provides customers with a clear view of their energy options, presented with tailored advice on how to save energy and money. Smart metering technology also provides valuable insights into customers' energy consumption, guiding decisions in residential solar power, battery storage and natural gas solutions.

Our Low Carbon Discovery Show Home will demonstrate how mCHP, solar, an advanced building envelope and performance technology can be used in a new home to sustainably and affordably meet energy requirements.

Community Building Solutions

On a larger integrated-systems scale, we installed a Combined Heat and Power (CHP) unit at the Mount Royal University Campus in Calgary, Alberta, with funding from Emissions Reduction Alberta. Providing up to 26 per cent of the university's electricity, the unit is expected to decrease their GHG emissions by almost 2,000 tonnes per year and result in a significant decrease in annual operational costs.

We are also partnering with Siemens, the University of Alberta and the Northern Alberta Institute of Technology (NAIT) to construct a collaborative microgrid research facility in NAIT's new Productivity and Innovation Centre. This initiative, known as DEMI (Distributed Energy Management Initiative), is the first approved project to receive funds through the Alberta Climate Change Innovation and Technology Framework, and will help speed up decarbonization though the development of a technology implementation road map.

Renewable Energy in Remote Communities

We serve many communities located hundreds of kilometres from the main electrical grid over a vast geographic area in northern Alberta and Yukon. These regions have relied on isolated diesel-powered generation for decades. In 2017, we initiated a program to connect these communities to the grid, where possible. In communities where we were not able to connect to the grid, we developed unique options for each community to reduce diesel consumption.

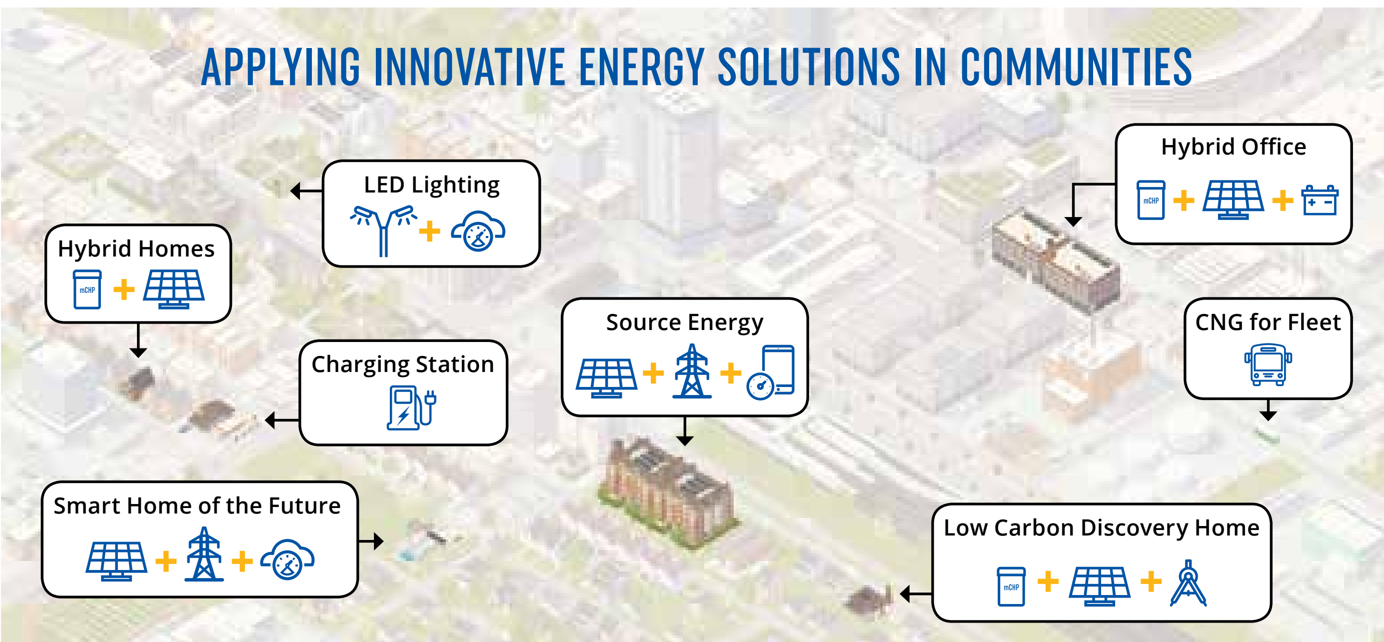
18

hybrid residential home projects demonstrating over **42%** reduction in CO_2e emissions when compared to a typical home

Through partnerships with Indigenous communities, we are installing renewable microgrids in six isolated communities that will integrate solar or wind power with existing diesel-generation systems to reduce GHG emissions.

In 2018, we began construction on an initial 400 kilowatt (kW) solar farm installation in the northern Alberta community of Fort Chipewyan. We continue to prepare for a second phase that includes an Indigenous-owned 2 megawatt (MW) solar farm, battery energy storage system and microgrid control system. These two projects together will achieve a reduction in diesel consumption of 800,000 litres (L) a year or about a quarter of the annual fuel consumption.

We are also working on solar power projects in Old Crow, Yukon, with the signing of an Electricity Purchase Agreement (EPA) with the Vuntut Gwitchin First Nation, which will enable a 200,000 L reduction in diesel consumption per year, or about a quarter of the annual fuel consumption.



Renewables | LED Lighting | Connection to the Grid | Integrated Control System | Compressed Natural Gas (CNG) for Fleet
Battery Storage | Micro Combined Heat and Power | Charging Stations | Smart Metering | Building Envelope Design

ATCO enabled a key customer in Canmore, Alberta, to use natural gas in place of propane—a safer, cleaner, and more affordable energy source.

Beyond reducing annual GHG emissions for our customers by an estimated 3,100 tonnes, or more than 27 per cent, these projects will reduce the risks associated with transporting diesel to remote areas.

For more information on these and other partnerships with Indigenous communities, see the Community & Indigenous Relations section of this report.

Industrial Customers

We also continue to look for opportunities to improve operational efficiencies and reduce emissions for our industrial customers.

In 2018, we announced a partnership with RANMAN Energy to build the 26 MW La Laguna Cogeneration Facility on the site of a Chemours Company chemical facility in Mexico. The project will use excess gas and reuse steam generated by the host facility to provide secure, low-emitting and cost-effective electricity and heat to a strategic industrial partner.

In 2018, we launched our construction heat and energy service, which provides builders with temporary natural gas access during construction as opposed to propane. In addition to reducing cost for the customer, this solution reduces GHG emissions by approximately 15 per cent, and enhances site safety by eliminating the need for propane tanks on site during the build cycle.

Our modular structures solutions provide industrial customers with high-efficiency structures aligned with evolving building codes, in addition to reducing environmental impacts through the construction of units in factories rather than building on site.

Energy Efficiency

Energy efficiency is a cost-effective way to achieve emissions reductions and it remains a critical focus as we continually improve our operations and enhance our customer solutions. For every dollar invested in energy efficiency, three or more are typically saved. There are different approaches to achieve energy efficiency, so we tailor solutions to the specific needs of customers, finding the right mix of technologies.

Our Intelligent Street Light Project, in Lloydminster, Alberta, uses wireless motion sensors and a control system for Light Emitting Diode (LED) street lights to deliver light on demand: street lights dim during off-peak hours and automatically brighten when the presence of vehicles, cyclists or pedestrians is detected. This lighting design can result in up to 80 per cent energy reduction and reduces light pollution. In 2018, ATCO was recognized by the Illuminating Engineering Society with an Illumination Award of Excellence for Energy & Environmental Lighting Design.

At ATCO, we continue to look for opportunities to improve operational efficiencies and reduce emissions for our industrial customers.

Shared Infrastructure Solutions

Hybrid Energy Solutions

The Clean Energy Innovation Hub, supported by funding from the Australian Renewable Energy Agency (ARENA), will be a test facility for microgrid solutions that integrate hydrogen production, natural gas, solar and battery storage. What truly sets this project apart is our research and development into the use of renewable energy to produce, store and ultimately use hydrogen as a fuel source. This project includes over 1,000 solar panels and 500 kWh battery storage and will demonstrate how hydrogen can potentially be blended with natural gas at rates up to 10 per cent, transported in current infrastructure and used in homes with existing domestic appliances.

Low-Carbon Transportation

To promote a higher adoption of electric vehicles (EVs), a robust infrastructure is required to entice the switch. In the past two years we installed three EV charging stations, including the fast-charging corridor from Sherwood Park to Red Deer to Calgary. We also received funding to install and own an additional 20 EV charging stations through the Peaks To Prairies Project, aimed at expanding EV charging infrastructure in southern Alberta. We've also secured contracts to power all EV charging stations with 100 per cent renewable energy for the next ten years.

95%

of our regulated natural gas and electricity distribution customers in Canada agree we provide good service

Moving from traditional transportation fuels such as diesel and gasoline to natural gas also delivers substantial and cost-effective emission reductions. We provided the cities of Red Deer and Calgary with distribution infrastructure to enable the transition from diesel to cleaner, compressed natural gas (CNG) transit. Fuel switching of transit buses typically reduces operating costs while also reducing GHG emissions by almost 20 per cent, in addition to reducing air emissions.

Renewable Natural Gas

Renewable Natural Gas (RNG) is natural gas produced from existing waste streams and biomass sources, such as landfills, farms, wastewater treatment plants and forestry by-products. RNG has the potential to significantly reduce emissions from the heating, electricity generation and transportation sectors in Canada and other markets.

Through a partnership with G4 Insights and the Canadian Gas Association Natural Gas Innovation Fund, we plan to host a 1 gigajoule (GJ) per day pilot plant in Edmonton. The plant will test a new process allowing for steadier production flow of RNG from forestry by-products, and then injection of the RNG produced into our existing natural gas distribution system.

CUSTOMER SATISFACTION

Our performance is measured by the people we serve: our customers. Within the Alberta electricity and natural gas distribution industries, more than 95 per cent of customers surveyed agree we provide good service, and more than 93 per cent of our customers agree we have a strong reputation in the community. These are metrics we are particularly proud of and are committed to maintaining.

Beyond the day-to-day calls, we seek to understand our customer experience. We engage our customers through surveys and focus groups to measure service quality. This approach, applied first in our electricity distribution business, has been implemented through our gas distribution and energy retail operations. We anticipate results will be available across all three business lines in 2019.

Innovating the customer experience often leads to both operational efficiency and improved customer satisfaction.

93%

of our regulated natural gas and electricity distribution customers in Canada agree we have a strong reputation in the community

Examples from 2018 include:

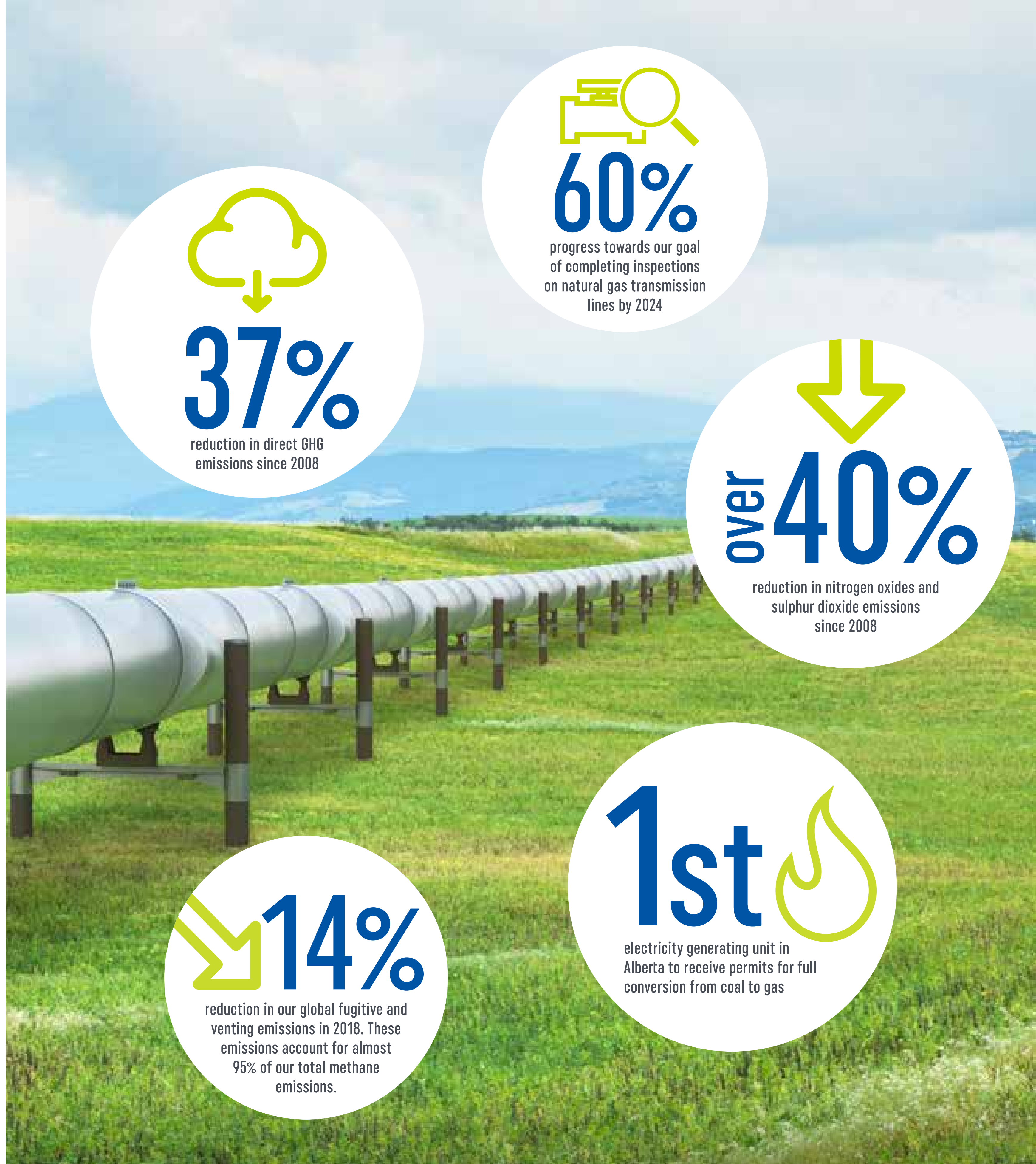
- Testing an automated system that restores electricity after unplanned outages. The system has significantly improved response and event resolution time; for example, for one remote Alberta community our new system was able to improve average resolution time from 3 hours to 13 seconds.
- Introducing a new Customer Connection Model that takes new or expanding distribution electricity service from initial customer request to energization much more efficiently. In 2018, we reduced associated project costs by 15 per cent and time by 40 per cent. That's time and money that benefit our customers and build our reputation as an efficient service provider.
- Transforming our process to connect customers who sign up to receive natural gas services. Instead of customers booking a four-hour stand-by window, our customer service technicians now provide service from a central location so that customers do not need to be home. The service improvement has resulted in about 21,000 fewer calls into our call centre, which also translates into reduced operating costs.

ENVIRONMENTAL STEWARDSHIP

As a critical infrastructure provider, a collaborative and long-term approach to minimizing our environmental footprint is vital. As part of this, we continue to explore new and more efficient ways to generate, transport and conserve energy.

CLIMATE CHANGE & ENERGY USE

ENVIRONMENTAL MANAGEMENT



We believe that environmental protection is critical, and minimizing environmental impacts associated with our operations is the responsibility of all our people.

Solar panels, such as these test panels installed at our Old Crow Project site with our Vuntut Gwitchin First Nation partners, help remote communities in Canada's North reduce diesel consumption.

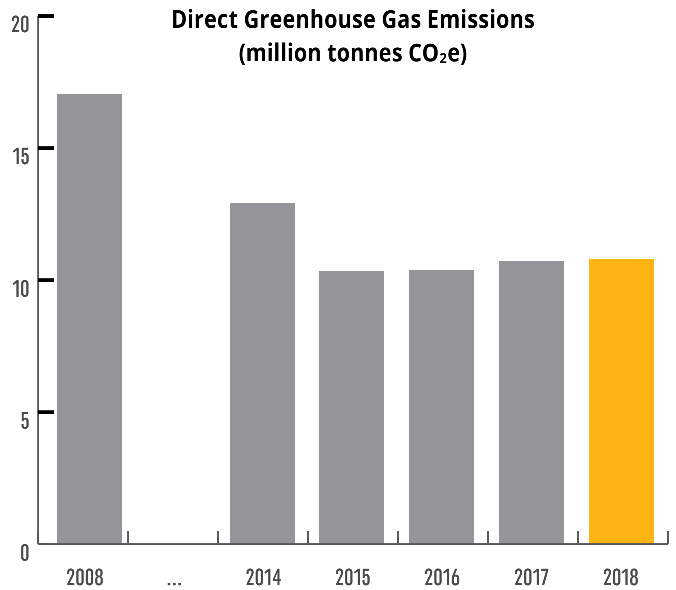
CLIMATE CHANGE & ENERGY USE

Across ATCO, we focus on actively reducing our GHG and air emissions by driving operational efficiencies, lowering fuel consumption, phasing in renewables, installing new technology and transitioning to lower-emitting fuels.

In 2014, we committed to reduce GHG emissions from our electricity generation to 30 per cent below 2005 levels, by 2030. Despite having slightly grown our generation capacity since 2005, our associated GHG emissions have been reduced by almost 40 per cent, surpassing this goal. With this milestone met, we plan to find new opportunities to drive continuous improvement in our performance.

We are actively engaged with industry, governments, regulators and other experts on core issues, including regulations and strategies to reduce greenhouse gases, air pollutants and methane emissions.

Reducing Our Environmental Impacts



Approximately 95 per cent of our direct GHG emissions are due to our power generation operations. Our power generation increased by approximately eight per cent in 2018, but our GHG emissions increased by only one per cent due to a reduction in our GHG intensity, largely a result of co-firing of natural gas with coal at one of our units. Since 2008, we have reduced our direct GHG emissions by 37 per cent, and our nitrogen oxides and sulphur dioxide emissions by more than 40 per cent.

Coal-to-Gas Conversion

ATCO continues to lead the transition to a lower-emitting energy future through fuel switching initiatives such as electricity generation coal-to-gas conversions. Coal-to-gas conversion allows significant and immediate reductions to GHG and other air emissions, while maintaining energy reliability and affordability by using existing infrastructure and skilled labour force.

In 2018, we enabled one of our units to co-fire with natural gas for up to 50 per cent of its generating capacity. In late 2019, we expect to complete the next phase to allow 100 per cent natural gas co-firing capability on a second unit. Our portfolio will be off coal no later than 2022, earlier than the proposed 2030 set out in regulations. We will be the first coal-fired generator in Alberta to convert its coal-fired power generation fleet to burn lower-emitting natural gas.

Phasing in Renewables

In addition to our Oldman River hydroelectric facility, in 2018, we acquired a 35 MW hydroelectric generation asset in Veracruz, Mexico. This facility is providing green energy credits for commercial and industrial customers, who are required to purchase a minimum percentage of clean energy to comply with new government regulations.

Further diversifying our electricity generation portfolio, ATCO actively looks for opportunities in solar-powered generation. In addition to the solar projects with Indigenous communities in Fort Chipewyan and Old Crow, we have 75 MW of potential solar projects located near Three Hills and Drumheller, Alberta, which could generate more than 135,000 MW hours per year of renewable electricity. Along with our project partner Samsung, we have obtained a permit to build and operate a 25 MW solar power generation facility. We continue to look for opportunities to advance these and other solar projects.

Reducing Methane Emissions

Methane represents a small fraction of our GHG emissions and is predominantly related to venting and fugitive emissions from our natural gas pipeline operations. We continue to proactively manage and reduce methane emissions through routine maintenance supplemented by targeted leak detection and repair programs. In addition, we have identified potential equipment upgrades for future continuous improvement. We also monitor regulatory developments and are well positioned in Canada to meet or exceed future regulations and reduction targets.

Operational Efficiency

In 2018, our gas distribution division successfully implemented the largest known aerial meter reading application in North America. We're taking meter reading from the sidewalk to the skies using

A new initiative which commenced June 1, 2018, sees small aircraft outfitted with a device called an Encoder, Receiver and Transmitter (ERT) to collect natural gas readings from roughly 1,300 metres above our customers' homes, ensuring our delivery charges remain among the lowest in Canada.

electronic transmitters to gather data roughly 1,300 metres above our customers' homes. Much like the vehicles that preceded them, the planes use a device called an Encoder, Receiver and Transmitter (ERT) that sends data to the mobile collector using radio signals. Not only will this project reduce the distance employees drive by over 600,000 kilometres (km), it will also eliminate the associated travel safety risks, reduces operating costs by over $300,000 annually and significantly reduces vehicle and equipment maintenance costs, helping to ensure our delivery charges remain among the lowest in Canada.

In our electricity distribution division, we established a new Work Aggregation Office that centralizes trip planning and finds efficiencies for our fleet of vehicles that transport our employees and equipment to worksites. This initiative reduced truck trips by approximately 7,300 hours a year, reducing our fleet's fuel consumption and emissions. Combined with aerial meter reading, we anticipate employees will drive 1,000,000 fewer kilometres each year.

ATCO Park, our global headquarters located in Calgary, Alberta, opened in 2018. The campus has been constructed to the highest standards of energy efficiency and environmental stewardship. It features EV charging stalls with 14 high-amperage EV plug-ins, an outdoor fruit and vegetable garden and an urban beehive that will be used by ATCO Blue Flame Kitchen for cooking and training. LED lighting is used throughout the entire building, with a control system that turns off lights when there are no occupants.

At one of our operations centres we partnered with CleanO2 Carbon Capture Technologies to test their commercial carbon capture device, known as CARBiNX. The outcome was lower energy demand through heat recovery, reducing total emissions by approximately five per cent annually. We continue to work with CleanO2 on commercial applications and the potential for expansion.

Climate Change Resiliency

ATCO continues to manage climate change-related risks, including preparing for and responding to extreme weather events to ensure the reliable delivery of essential services such as natural gas and electrical utilities. Our approach covers activities such as proactive site and route selection, storm-proofing assets, regular maintenance and appropriate insurance.

The majority of our natural gas pipeline network is underground, making it less susceptible to extreme weather events; however, we continue to increase resiliency through asset improvement projects. In electricity transmission and distribution operations, we focus on improving grid resiliency through activities such as retrofitting and vegetation management to reduce incidents that result in outages. In our modular structures and logistics activities, we look to leverage our expertise to produce high-efficiency structures in response to evolving building codes.

ENVIRONMENTAL MANAGEMENT

We believe environmental protection is critical, and minimizing environmental impacts associated with our operations is the responsibility of all of our people. We work diligently to minimize our footprint and protect the environment in the unique settings where we operate. We incorporate environmental considerations into the full lifecycle of every project and regularly monitor, assess and report our performance.

One example is Alberta PowerLine's comprehensive Caribou Protection Program that sets a new standard for construction in Alberta. The approach minimizes impacts to caribou with practices such as identifying routes that follow existing linear disturbances, focusing on vegetation retention and management, and limiting fragmentation of the land to reduce the effects of predation.

Also, for our Jasper Interconnection Project, we used innovative construction that allowed us to narrow the power line right of way from the standard width of 18 metres to 10 metres, allowing more vegetation to remain.

As we continue to expand our diverse lines of business in areas such as storage and water management services, we identify and manage unique environmental risks and opportunities while delivering creative solutions.

Incident & Risk Management

We mitigate our environmental impacts through the systematic and responsible management of our operations. We are committed to continually improving our environmental and operational integrity programs by regularly sharing best practices through industry associations and our internal Environment Network.

Natural Gas Pipeline Integrity

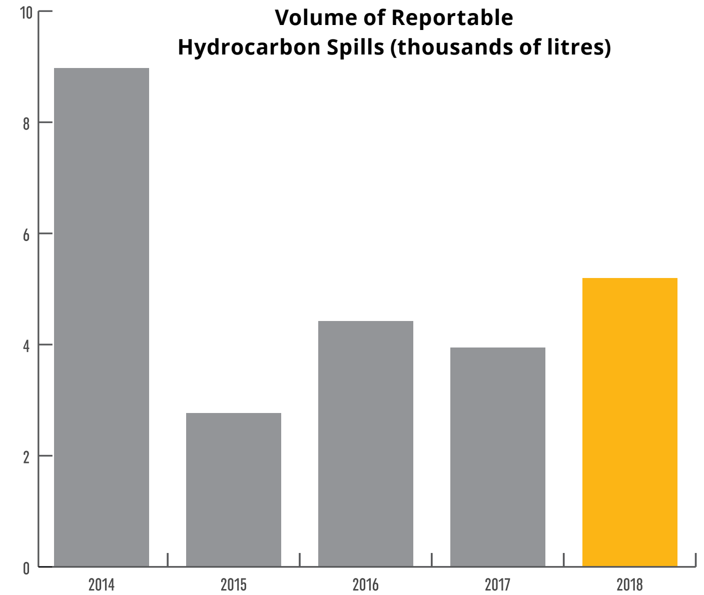
We own and operate more than 9,000 km of natural gas transmission and 55,000 km of natural gas distribution pipelines, so the safe management of this infrastructure is integral to our business. In 2018, we brought the total length of in-line inspected transmission pipeline to over 2,500 km, as part of a continuing program. Our target is to inspect all transmission lines of more than eight inches in diameter and five kilometres in length by 2024. We have also mapped water crossings and continue to regularly inspect environmentally sensitive areas.

Our smaller diameter natural gas distribution pipelines require a different approach. In 2018, we partnered with Picarro to pilot new leak detection technology, improving operational efficiency and survey coverage up to four times.

Environmental Incident Management

One aspect of our environmental management is spill prevention; we prevent, manage and mitigate spills through a variety of measures including equipment design, training, and operating and maintenance procedures. When spills do occur, we assess the unique circumstances to ensure all appropriate steps are taken to minimize environmental impacts and that similar incidents do not happen in the future.

As 99 per cent of our pipelines transport natural gas, most of the hydrocarbon liquids we manage are related to fuel management solutions in northern and remote communities, hydrocarbon storage solutions in Alberta's Industrial Heartland, and small volumes in operating equipment in electrical transmission and distribution. However, the majority of reportable hydrocarbon-related spills in 2018 were related to equipment in electrical transmission and distribution systems, predominantly caused by third-party incidents such as damage to electrical transformers from automobile accidents and vandalism.



Although our hydrocarbon spill volume has been reduced by over 40 per cent in the last five years, it increased over the past year. The majority of hydrocarbon spills are related to our electrical business, and include third party caused incidents such as damage to electrical transformers due to automobile accidents and vandalism.

Non-hydrocarbon liquids, such as waste water, are part of our workforce housing services and in 2017, the spill volume of this treated waste water increased. Our 2018 performance has returned to previous levels. In addition, our innovative, industrial water service provides a multi-user system that allows customers to tap into common infrastructure, eliminating the need for duplicative river intakes, transportation pipelines or water storage and clarification facilities, and thus reducing regional potential for spills.

	2018 REPORTABLE SPILLS	
	REPORTABLE SPILLS (NUMBER)	VOLUME OF REPORTABLE SPILLS (THOUSANDS OF LITRES)
Hydrocarbon	13	5.2
Non-hydrocarbon	6	45.7

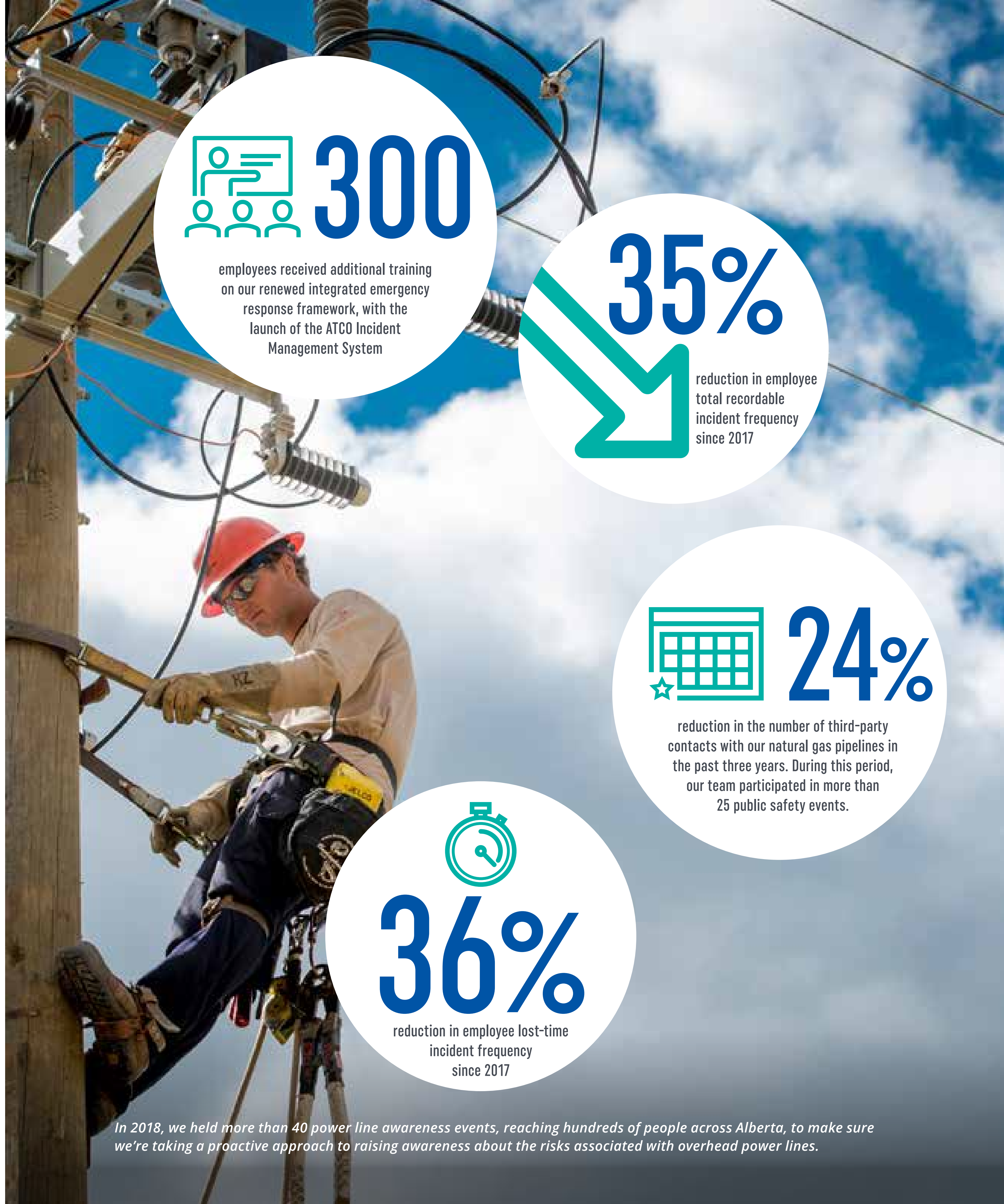
Non-hydrocarbon spills are often comprised of high volumes of saline water or water containing small quantities of other substances. After the large 2017 non-hydrocarbon spill volume, we returned closer to our historical average, and continue to focus on reducing these types of spills. Of the 2018 non-hydrocarbon spill volume, 99 per cent was related to a single incident involving the early release of treated water that otherwise met all regulatory release requirements.

SAFETY AT ATCO

Safety is the first consideration in everything we do. Providing a safe work environment for our people is ingrained in our culture: a shared belief that directs our day-to-day priorities and decisions. We actively engage with first responders, regulators, government and the communities we serve to promote the importance of safety and provide emergency response. We are also committed to the highest safety standards across all our products and services.

EMERGENCY PREPAREDNESS & PUBLIC SAFETY

EMPLOYEE AND CONTRACTOR HEALTH & SAFETY



In 2018, we held more than 40 power line awareness events, reaching hundreds of people across Alberta, to make sure we're taking a proactive approach to raising awareness about the risks associated with overhead power lines.

Our crews are prepared to respond whenever and wherever they are needed, even in the most extreme weather conditions. In Alberta, when ice and snow disable power lines, our power line technicians work round-the-clock to ensure that service is restored to customers as soon as possible.

EMERGENCY PREPAREDNESS & RESPONSE

Public safety and emergency preparedness are vital to ATCO's operations as a provider of housing, site services, and energy and infrastructure solutions. We respond to emergencies and disasters, wherever and whenever they occur, and leverage our comprehensive safety programs and global footprint to educate communities on the importance of energy safety.

As providers of essential services, emergency response and incident management is a key aspect of our business. We take a proactive approach to potential incidents, tracking risks such as extreme weather and readying our response. When incidents occur that impact our natural gas and electrical utilities, minutes matter. We work quickly to restore services and support first responders. After incidents, we debrief to learn how we can improve.

For decades, ATCO has had emergency coordination and incident management plans that are overseen by Crisis Management Teams within our business units and escalated to our enterprise-wide Crisis Management Committee when required.

As part of our commitment to continual improvement, we conducted a comprehensive review of our response to the Fort McMurray wildfire. The updated ATCO Crisis and Incident Management System provides a framework for an integrated 'One ATCO' response that enables us to quickly leverage our full organizational capabilities, coordinating efforts and resources across business units and, in some cases, regions.

With millions of people relying on our natural gas and electrical utilities, it is critical that our emergency response and incident management is effective and efficient. We demonstrated these capabilities when we responded to a storm in central Alberta that caused significant infrastructure damage. Our teams worked around the clock to repair power lines in difficult conditions and restored power to nearly 5,000 homes and businesses within three days, without any safety incidents.

Our teams responded quickly and safely to a forest fire around Lower Post in northern British Columbia that brought power down for 13 days. When the community returned home, the power system was once again fully operational with all fire-damaged trees removed from around our power lines. Our employees met people at their homes to ensure power was properly and safely restored.

To further support both our residential and commercial customers, we launched ATCO's online outage notification system in 2017. With further refinements in 2018, the system provides information about all outages, planned and unplanned. Updates to status and estimated restoration time occur every 15 minutes, based on real-time information provided by our people.

DISASTER & EMERGENCY MANAGEMENT SERVICES

ATCO's Frontec division provides disaster and emergency management services around the globe. A valued partner in countless responses, from the 2005 earthquake in Pakistan to British Columbia's 2017 wildfires, we have supported the Canadian Armed Forces, NATO and various non-government organizations in areas of humanitarian need.

As extreme weather events—floods, wildfires, hurricanes, earthquakes—become more frequent, our consulting and training services are a growing dimension of Frontec's operations, as we share our expertise from preparedness planning to disaster recovery efforts.

PUBLIC SAFETY

We take a proactive approach to safety across all our operations, including public safety. Through our safety campaigns, we raise awareness on the importance of safe digging near natural gas pipelines and the risks associated with overhead power lines and carbon monoxide in homes.

For example, the goal of ATCO's Pipelines & Liquids Damage Prevention Team is to eliminate damages to our natural gas distribution and transmission infrastructure while promoting safety and industry best practices. We have a team of dedicated individuals who work with utility members, municipalities, design firms, excavation companies, government, homeowners and a variety of vendors to promote awareness regarding ground disturbances. In 2018 alone, we participated in more than 25 public safety events, contributing to a 24 per cent reduction in the number of third-party contacts with our natural gas pipelines in the past three years.

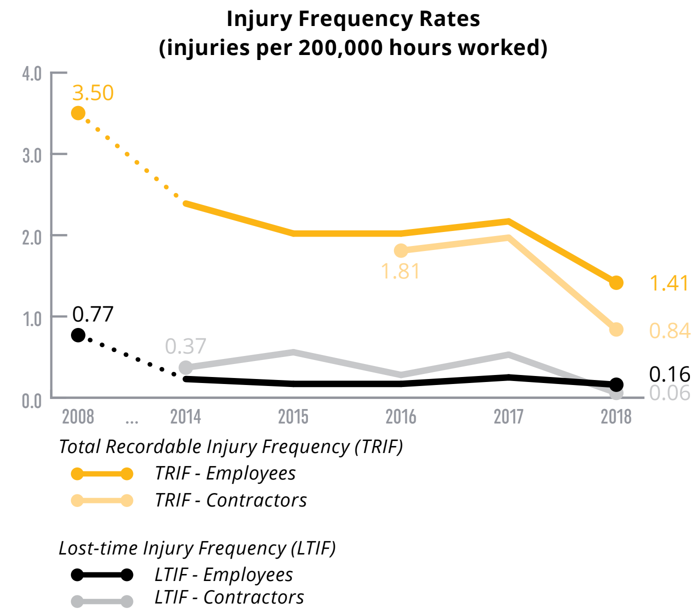
We also continue to participate in and promote the "Where's the Line" campaign, formed to collectively address the safety issue of power line contacts in Alberta. We held more than 40 power line awareness events in 2018, reaching hundreds of people around the province.

EMPLOYEE AND CONTRACTOR HEALTH & SAFETY

All our employees and contractors have the right to a safe and healthy workplace. As we continue to expand our global footprint, we remain committed to ensuring our operations are safe and our people are appropriately trained to deliver integrated solutions safely. We seek to incrementally improve safety performance year-over-year through a number of initiatives.

Employees

ATCO measures safety performance with multiple metrics including lost-time employee incident frequency and total recordable incident frequency. We successfully improved both rates in 2018, achieving a 36 per cent reduction in the lost time incident frequency and a 35 per cent reduction in the total recordable incident frequency.



Through a focus on awareness and incident prevention campaigns, we saw a decrease in both employee and contractor incident rates. Changes to contractor incident rates year-over-year vary depending on the type of significant capital projects which occur during that year.

Although our successful performance was achieved across ATCO, we are made up of several distinct business units, each facing unique safety risks. Each business unit aligns with, and contributes to, developing industry best practice. They also select and track leading indicators that will drive performance improvements in their sector. We have an internal Safety Network comprised of experts from across the company who meet to share learnings and best practices.

One way we achieved our safety results was to focus on awareness and incident prevention campaigns that addressed specific types of incidents; for example, after an assessment of operational risks, our electricity business undertook a focused initiative and was successful in reducing targeted injuries by almost 50 per cent. We also make policy changes where appropriate; for example, in 2018 our Pipelines & Liquids Global Business Unit increased the personal protective footwear allowance to ensure employees would have boot traction control in all seasons, minimizing slips, trips and falls.

More broadly, we continue to raise employee risk awareness about how injuries occur and can be prevented through open discussion and information sharing, including company-wide events and conferences focused solely on safety. Our Pipelines & Liquids Global Business Unit worked with DuPont Sustainable Solutions, an industry leader in safety processes, to further enhance our safety culture.

All our employees and contractors have the right to a safe and healthy workplace; we remain committed to ensuring our operations are safe and our people are appropriately trained to deliver integrated solutions safely.

Contractors

ATCO oversees contractor safety throughout the contract relationship, starting from hiring and onboarding through ongoing monitoring on the job.

Enhancing our screening processes before making a hiring decision, we implemented new software to make our processes more efficient. Our onboarding approach for new contractors, tailored to the needs of each ATCO business line, is often a key driver of safety success. 2018 strategies included computer-based training, particularly for remote locations, and a full-day contractor safety summit facilitated by our electricity transmission and distribution businesses and attended by multiple external agencies and contractors.

Implementing safety programs in new facilities can be challenging, especially when expanding to a different country. In 2016, we partnered with Mexican counterpart RANMAN Energy to supply an innovative electricity generation solution in the rapidly developing World Trade Centre Industrial Park in San Luis Potosí, Mexico. Since then, contractors have operated the facility, which has expanded generating capacity by 300 per cent, while maintaining a health and safety record of zero recordable incidents. We are proud of the safety training we've provided to contractor personnel and the facility's record of safety excellence.

Mental Health

ATCO recognizes the importance of health and wellness for our people. In 2018, we continued our Not Myself Today campaign and trained 100 more volunteers to share monthly modules focused on these topics. These "Mental Health Champions" provide various educational opportunities to employees to engage on topics such as mindfulness, occupational wellness and most recently the science of happiness. 200 employees participated in the program in 2018, and we have a target to engage 500 employees in 2019.

COMMUNITY & INDIGENOUS RELATIONS

Building respectful and mutually beneficial relationships has long defined how we do business. Along with our Indigenous and community partners, we are continually exploring new ways to collaborate.

As we diversify our business operations, we also recognize the need to continue to work to understand unique perspectives of neighbouring communities and Indigenous Peoples, and take a long-term approach to building relationships based on trust.

ENGAGEMENT | PARTNERSHIPS | EMPLOYMENT | EDUCATION

ATCO is committed to providing Indigenous education and training programs that allow us to contribute to vibrant communities, build stronger workforces and create opportunities to share experiences and learn from local expertise.

COMMUNITY ENGAGEMENT

We build upon open and transparent dialogue, engaging with communities near existing and new projects throughout their lifecycles. In 2018, significant projects included Alberta PowerLine and Jasper Interconnection.

Alberta PowerLine, a partnership with Quanta Services, remained commited to excellence in building the Fort McMurray West 500 kilovolt (kV) Transmission Project from west of Edmonton to Fort McMurray. We engaged extensively with landowners, counties, municipalities and 20 First Nations along the route. We listened carefully to their feedback and appropriately adjusted our approach in response.

We are committed to engaging with people throughout the life of our projects; for example, Alberta PowerLine maintained close contact with people in the area and connected over 1,600 times to provide construction details and updates.

The Jasper Interconnection Project will join Jasper National Park to Alberta's electrical grid, eliminating the use of diesel and natural gas to generate power in the community and lowering air emissions. After five years of successful and committed consultation, construction began in 2018.

These two examples are in addition to ongoing engagement and consultation on many of our projects.

COMMUNITY INVESTMENT

We develop partnerships with non-profit organizations and community groups to offer a range of support, including employee volunteer efforts, expertise and financial support.

Our ATCO EPIC (Employees Participating in Communities) program combines fundraising events, volunteerism and individual donations to support more than 800 non-profit organizations around the world. ATCO matches employee donations made to human health and wellness charities. As well, we support our employees' volunteer efforts through our Time to Give Program, with a financial contribution to the charity of their choice. In 2018, ATCO and its employees donated $2.7 million and more than 8,600 hours to make communities better places to live and work.

ATCO is also proud to be a Building Partner of the Homes for Heroes Foundation. The foundation assists homeless Canadian Armed Forces veterans by providing housing and support systems. Utilizing our expertise in modular housing, our employee teams built two homes in 2018, with the community ultimately to include up to 20 tiny homes.

At ATCO, we believe sports can have a tremendous impact on communities and youth as a tool to build leadership, confidence and a sense of unity. We continued our sponsorships of the 2018 Arctic Winter Games in the Northwest Territories, Alberta Winter Games in Fort McMurray and 2018 Alberta Summer Games in Grande Prairie, Alberta.

We also remain a supporter of Spirit North—a program aimed at helping communities move from introductory cross-country ski days to community-led, sustainable programs that promote lifelong well-being. The Spirit North program visited 30 communities, involving approximately 3,200 students and over 30 schools during the 2017/18 ski season.

more than

$41M

raised for charities through our ATCO EPIC campaign since it's inception in 2006

INDIGENOUS RELATIONS & COMMUNITY DEVELOPMENT

There are many evolving factors shaping how Indigenous communities, businesses and governments navigate their relationships across Canada and globally. We have a long history of working in collaboration with Indigenous communities, businesses and Peoples. With this foundation, we remain steadfast in our commitment to build long-lasting relationships with Indigenous communities, now in the context of Truth & Reconciliation. As we continue along this path, our comprehensive strategy—and the metrics to measure it—are based on the four pillars of meaningful engagement, economic participation, training and employment and awareness education.

Meaningful Engagement

ATCO recognizes there are different ways to engage. First and foremost, we listen and seek to understand the needs and interests of the communities we serve through proactive, transparent engagement. Together, we identify optimal solutions, resolve concerns and work through different relationship and partnership models that can include regular meetings, investment in community initiatives, joint business ventures, employment and training, or ways to jointly connect with other partners or government participation. We take this approach across our lines of business and around the world.

At ATCO, we believe sports can have a tremendous impact on communities and youth as a tool to build leadership, confidence and a sense of unity. During the 2017/18 ski season, the Spirit North program visited 30 communities, involving approximately 3,200 students and over 30 schools.

Sometimes meaningful engagement means resolving specific concerns of communities near our operations, such as with the 14 Indigenous communities near our hydro plant in Mexico. We visit regularly and work collaboratively to foster mutually beneficial relationships.

Other times our engagement strategy includes Relationship Agreements that formalize long-term commitments with communities. These agreements require regular, strategic discussions about how we can work together, now and in the future, and become the foundation for project-specific memoranda of understanding (MOUs) and joint venture partnerships. We signed eight Relationship Agreements in 2018, bringing our total to ten across the company, and continue to work on new opportunities in 2019.

13

engagement commitments signed with Indigenous communities in 2018, including eight long-term relationship agreements

Our engagement has resulted in a range of opportunities for collaboration, including incorporating renewables into remote communities' energy mix, connecting communities to the electrical grid, and focusing on energy efficiency, sustainable water solutions and performing clean energy efficiency audits.

In 2018, we signed five MOUs with Indigenous communities. In particular, MOUs between ATCO and communities in northern Alberta and Yukon paved the way to offset diesel-powered generation with off-the-grid renewable energy that reduces localized air emissions and energy costs, while increasing energy reliability.

Economic Participation

We actively pursue partnerships with Indigenous groups on business opportunities that deliver shared social and economic benefits. We maintained or launched 47 business arrangements in 2018 that generated over $250 million dollars of revenue for our Indigenous partners in 2018, with some partnerships in place for over 35 years.

As highlighted on page 8, new partnerships in 2018 include a solar project with Three Nations Energy in Fort Chipewyan. Three Nations Energy will co-own the project, allowing the communities to directly participate in the development of their energy future and earn revenue from the project, while reducing environmental effects of diesel consumption.

We are also working on solar power in Old Crow, Yukon. This partnership includes a 25-year energy agreement where ATCO will buy the solar energy, feed it into the power grid and redistribute it to the community.

ATCO is working with our joint venture partners from the Haisla Nation on the largest accommodation facility ever built in Canada to support the LNG Canada energy project. As well, we are working together to provide workforce homes and operational support services for three residences in the Haisla territory that will support construction of the Coastal GasLink pipeline.

Our employees shared their expertise and experience with over 100 high school students from Indigenous communities across Alberta in 2018, as part of an important pilot project aimed at showcasing career opportunities to Indigenous youth.

For our Alberta PowerLine project, we have been meeting with Indigenous communities to forge an equity ownership model that will afford the opportunity to acquire a stake in the project following energization. This model enables Indigenous communities to become direct owners in Alberta's energy sector and supports community development opportunities.

Economic participation is also woven into our procurement approach. We look for opportunities to implement Indigenous contracting strategies to help create jobs, opportunities for skills training and local economic development; for example, our work in Fort McMurray, Alberta, and Jasper National Park has included community development and contracting arrangements with 27 Indigenous communities.

In Australia, we supported a new Indigenous-owned travel agency by committing to engage their services for all ATCO's Australian travel needs, providing them with a foundation to grow their business.

Training & Employment

An important aspect of our Indigenous Relations approach is providing training, scholarships and employment opportunities, including providing summer student placements for Indigenous youth.

2018 highlights include:

- ATCO piloted a program inspired by the Governor General's Canadian Leadership Conference to showcase career opportunities to Indigenous youth. In 2018, 119 Grade 9 students from eight Indigenous communities across Alberta participated in one-day trips to local businesses to show perspectives on opportunities available to high school graduates. Building on this foundation, 17 students participated in a multi-day program where they met with leaders across many sectors about future opportunities. We will build on the success of this pilot program to inspire the next generation of leaders.
- We continued the Canada-wide expansion of the Indigenous Education Awards program to provide opportunities for Indigenous students in high school and post-secondary institutions, providing 50 awards totaling $65,500.
- Our Blue Flame Kitchen hosted two Kitchen Skills Training programs for Indigenous students focused on food safety and cooking nutritious meals, including a school program that reached seven Alberta communities and engaged 539 students. In addition, we partnered with BC Hydro to provide a five-day pre-employment training program to Treaty 8 Nation and British Columbia Indigenous candidates.
- We offered an eight-day program for Tsuut'ina Nation youth to teach skills in gas utility operations. The pilot program offered a combination of health and safety courses along with basic hands-on gas utility equipment training. Courses were designed to be transferable not only to other industries and companies, but to students' everyday lives.
- In Mexico, we work with the non-profit organization Peraj Mexico and the Instituto Tecnológico Superior de Zongolica to reduce school dropout rates of children from disadvantaged families. During 2018, ATCO Mexico supported this program by providing 18 Indigenous university students with scholarships as they each mentored one Indigenous elementary school student. In addition, we are currently working with a local non-profit to develop a job training program in carpentry skills for Indigenous youth who live close to our hydroelectric power station in Veracruz.

Awareness Education

Educating our people on the unique cultural and historical status of Indigenous Peoples and communities through our Indigenous relations training is a core part of employee development.

over $75,000 awarded globally in Indigenous scholarships

In Canada, almost 500 employees completed online Indigenous awareness course work, and more than 180 have taken a further step with intensive training sessions at our operating locations, in addition to over 175 employees engaged in lunch and learn sessions. We have also partnered with the University of Calgary's Indigenous Relations program to certify 30 ATCO employees in an intensive week-long course. As we work to broaden our awareness and outreach, we also started Métis history training in partnership with the Métis Nation of Alberta.

Our commitment to building and maintaining respectful connections with Indigenous communities has grown with ATCO's global investments. In Australia, we have collaborated to create an inaugural Reconciliation Action Plan that translates the idea of reconciliation into actionable steps, committed to building and maintaining respectful connections with Aboriginal and Torres Strait Islander Peoples. After working closely with local Aboriginal Elders and community representatives, one of our first projects was developing a community garden as an educational tool about the local culture for staff and visitors.

As a business, we continue to work hard to integrate this approach into our core operations and ensure that respect for Aboriginal and Torres Straight Islander Peoples is embedded in the way we conduct our business every day. To support this goal, online awareness training was completed by almost 400 employees in our Australian team.

SUSTAINABILITY DEVELOPMENT GOALS

ATCO supports the United Nations' Sustainable Development Goals (SDGs) and associated efforts towards building an inclusive, sustainable and resilient future.

The Park Avenue building in Churchlands, Western Australia, utilizes rooftop solar panels and other energy-efficient design to provide building residents with a sustainable source of energy.

While ATCO contributes to all 17 of the SDGs, as a provider of energy and other essential services, we have the ability to make significant contributions to four SDGs in particular (Goals 7, 8, 11 and 13).

7 AFFORDABLE AND CLEAN ENERGY

We aim to provide access to secure, reliable and affordable energy to support the vitality of our communities.

- INNOVATIVE ENERGY
  - We continue to work with customers to provide access to clean and affordable energy by identifying the right balance of innovative technologies. Examples include hybrid residential homes and solutions integrating mCHP, rooftop solar panels and energy storage, as well as larger integrated-systems scale solutions such as the CHP unit at Mount Royal University.
  - At our Clean Energy Innovation Hub we are looking at microgrid solutions that integrate hydrogen production, natural gas, solar and battery storage.

  2018 Performance Examples:
  • Hybrid houses demonstrated 42 per cent reduction in GHG emissions when compared to conventional homes
  • 1,003 solar panels installed at our Clean Energy Innovation Hub

- REMOTE COMMUNITIES
  - We signed an agreement to develop a solar array to be operated by the Vuntut Gwitchin Nation in Old Crow, Yukon, and began installing a solar farm in Fort Chipewyan, Alberta.

  2018 Performance Examples:
  • 1,000,000 L of diesel displaced by enabling fuel switching in remote communities

We seek to understand the evolving energy needs of our customers, and develop efficient and effective energy solutions that support the transition to a lower-emitting energy system.

- ENERGY EFFICIENCY
  - We collaborate with customers and partners to enable more energy efficient solutions such as using natural gas to generate heat and power at construction sites, building an on-site cogeneration facility for a chemical facility in Mexico, and working with communities served by our utilities in Alberta to install intelligent LED streetlight systems.

  2018 Performance Examples:
  • 80 per cent average energy reduction from intelligent LED streetlight system, when compared to conventional streetlights

11 SUSTAINABLE CITIES AND COMMUNITIES

We engage openly, transparently and honestly and create long-lasting relationships. Our services contribute to sustainable communities and economic development.

- HOUSING / SERVICES
  - With the Homes for Heroes Foundation, we showcased the first of our permanent modular 'tiny homes' designed and constructed to meet the needs of Canadian military veterans and help them transition from homelessness.
  - We were awarded four government-sponsored, affordable housing projects in British Columbia. These projects showcase our ability to rapidly deliver residential solutions using energy efficient modular construction techniques to address the growing demand for affordable housing.

  2018 Performance Examples:
  • 2 Homes for Heroes built by the end of 2018

- LOW-CARBON TRANSPORTATION INFRASTRUCTURE
  - We enabled low-carbon transportation solutions such as compressed natural gas (CNG) buses in Red Deer and Calgary, and expanded electric vehicle (EV) charging infrastructure in Alberta.

  2018 Performance Examples:
  • 38 CNG buses in operation
  • 3 EV charging stations installed

- DISASTER RELIEF
  - We continued to support the Canadian Armed Forces, NATO, and various non-government organizations in disaster and emergency response services.

8 DECENT WORK AND ECONOMIC GROWTH

We keep our people safe. We seek and respect diverse thoughts and perspectives.

- SAFETY
  - Our safety programs include all employees and contractors in all locations. We actively share best practices when we move into a new region, demonstrated by our power generation facility in Mexico that has zero recordable incidents since we entered the joint partnership in 2016.

  2018 Performance Examples:
  • 35 per cent reduction in employee total recordable incident frequency since 2017

- DIVERSITY / INCLUSION
  - The strength of our workforce comes from diversity. Our policies ensure we hire people based on their experience and expertise.

  2018 Performance Examples:
  • 31 per cent women in total workforce
  • 19 per cent women in senior management

- EMPLOYABILITY
  - We provided skills training, including utility equipment skills for youth at Tsuut'ina Nation and kitchen skills for Indigenous students across seven communities.

  2018 Performance Examples:
  • Hosted a Blue Flame Kitchen skills program enagaging with 539 Indigenous students

- INDIGENOUS PARTNERSHIPS
  - We created opportunities for economic participation including the Three Nations Energy partnership, a joint venture with the Haisla Nation, and are working on an equity ownership model for Alberta PowerLine.

  2018 Performance Examples:
  • $250 million in revenue generated for our Indigenous partners in 2018

13 CLIMATE ACTION

We reduce both the direct and indirect GHG emissions associated with our operations by exploring new and more efficient ways to generate, transport and conserve energy.

- GHG EMISSIONS
  - To achieve immediate GHG emission reductions, we enabled a 50 per cent conversion from coal to natural gas at one of our power generation units with full conversion of a second unit underway.

  2018 Performance Examples:
  • Absolute GHG emissions reduced 37 per cent since 2008

  - We continued to phase in renewables, and in 2018 we acquired a 35 MW hydro facility in Mexico. In addition, we have 75 MW of potential solar projects in Alberta.

  2018 Performance Examples:
  • GHG intensity from power generation reduced 6 per cent since 2017

  - We created efficiencies in fleet management through centralized planning and roll out of our aerial meter reading program—reducing fuel and emissions. We also added EVs to our vehicle fleet.

  2018 Performance Examples:
  • Reduction of over 1,000,000 km driven
  • 2 EVs added to our vehicle fleet in 2018, representing a reduction of 1,108 kg of CO_2e

SUSTAINABILITY AT ATCO

As a global provider of modular housing, disaster response, logistical support, and energy infrastructure products and services, we play a central role in delivering long-term, sustainable solutions. Innovation is key: from integrated energy systems to partnerships with Indigenous communities, we are solving customer challenges in a way that balances responsible development with safety and environmental stewardship and the interests of communities and landowners.

Uqsuq Corporation is a joint venture company between Nunavut Petroleum Corporation and ATCO's Frontec business. Uqsuq operates under a Government of Nunavut contract to lease and operate the bulk fuel storage facility and pipeline distribution system in Iqaluit, Nunavut.

We have a long and successful history of building effective partnerships with Indigenous communities across Canada. The NorthwesTel project—operated by our 50/50 joint venture with the Northern Aboriginal Services Company (NASCo)—sees 157 NorthwesTel microwave sites across 96 different communities in the Northwest Territories, Yukon, Nunavut and northern British Columbia maintained at the highest standards.

CORE VALUES

INTEGRITY
We are honest, ethical and treat others with fairness, dignity and respect.

TRANSPARENCY
We are clear about our intentions and communicate openly.

ENTREPRENEURSHIP
We are creative, innovative and take a measured approach to opportunities, balanced with a long-term perspective.

ACCOUNTABILITY
We make good decisions, take personal ownership of tasks, are responsible for our actions and deliver our commitments.

COLLABORATION
We work together, share ideas and recognize the contribution of others.

PERSEVERANCE
We persevere in the face of adversity with courage, a positive attitude and a fierce determination to succeed.

CARING
We care about our customers, our employees, their families, our communities and the environment.

It is ATCO's Heart and Mind that drives the company's approach to service reliability and product quality; employee, contractor and public safety; and environmental stewardship. Our pursuit of excellence governs the way we act and make decisions. At ATCO we strive to live by these core values.

OUR APPROACH

The foundations of a sustainable company include strong governance, a dedicated leadership team and a rigorous management approach. These cornerstones, along with ATCO's core values—integrity, transparency, entrepreneurship, accountability, collaboration, perseverance, and caring—help us deliver on our commitment to sustainability. Our strategy on sustainability is woven into all aspects of the business and can be found throughout this report.

GOVERNANCE

Key elements of our corporate governance system include the oversight and diligence provided by the Board, the lead director, the Audit & Risk Committee and our Corporate Governance, Nomination, Compensation and Succession Committee (GOCOM).

The Audit & Risk Committee, comprised of independent directors, has the greatest oversight of our sustainability practices. The committee reviews risks that could materially affect our ability to achieve our strategic objectives, and is responsible for ensuring that management addresses those risks by implementing appropriate mitigation measures.

We have an established enterprise risk management process that allows us to identify and evaluate risks and opportunities by both severity of impact and probability of occurrence. This evaluation also includes non-financial risks and opportunities such as regulatory, transitional, physical and reputational risks.

The senior executive of each operating division reports on operating results and risks to a designated audit director, who in turn reports to the Audit & Risk Committee. In addition, each division prepares a Stewardship Report, which is presented to the Audit & Risk Committee on a bi-annual basis, and includes topics such as safety, environment and Code of Ethics compliance.

The sustainability function at ATCO is overseen by the Vice President of Indigenous and Government Relations & Sustainability who reports directly to the President & Chief Strategy Officer and is managed collaboratively across numerous groups, including Human Resources, Indigenous Relations, Health & Safety, Environment, Marketing & Communications, Business Development, Internal Audit and Risk Management, among others. These groups monitor best practices, develop and implement policies and standards and support our various divisions.

The daily management of sustainability commitments and implementation of programs is guided by divisional leadership. More specific descriptions of our management approach to material topics are included on our website. The programs include topic-specific policies, responsibilities, training, monitoring and other management considerations.

For more detailed information on our corporate governance and management approach, please refer to the Governance section of the Management Proxy Circulars for ATCO Ltd. and Canadian Utilities Limited.

Our Intelligent Street Light Project, in Lloydminster, Alberta, uses wireless motion sensors and a control system for LED street lights to deliver light on demand.

REPORTING ON OUR MATERIAL TOPICS

Our sustainability reporting is focused on Energy Stewardship, Environmental Stewardship, Safety, and Indigenous & Community Relations. These topics were identified during our 2016 materiality assessment process as being highly relevant to both the company and parties most commonly interested in our sustainability performance, including Indigenous leaders, customers, community members, non-governmental organizations, suppliers, investors, our employees and regulators; and the topics continue to be relevant today.

Our Sustainability Report provides both qualitative and quantitative performance updates for 2018 on these four material topics. This report references the internationally recognized Global Reporting Initiative (GRI) Standards. Our reporting is also guided by frameworks such as the Sustainability Accounting Standards Board (SASB) and the Financial Stability Board's Task Force on Climate-related Financial Disclosures (TCFD) recommendations.

For more on our approach to our key material topics, please visit ATCO.com/en-ca/our-commitment/sustainability.html

For more information on our key policies, please visit our website at ATCO.com/en-ca/about-us/governance/code-ethics.html

For more information on other disclosures, including the Sustainability Framework Index, Annual Reports, and Management Proxy Circulars, please visit our website at ATCO.com/en-ca/about-us/investors/documents-filings.html

REPORTING SCOPE AND BOUNDARIES

- The terms ATCO, ATCO Group, the ATCO Group of Companies, our, we, the company and the corporation, refer to ATCO Ltd. as a whole, including its subsidiary company Canadian Utilities Limited.
- Our most recent previous Sustainability Report was released in June 2018, and reflects operations as of December 31, 2017.
- This report communicates our sustainability performance in 2018, and reflects operations as of December 31, 2018.
- Our Performance Summary includes data for the three years ending December 31, 2018, unless otherwise noted, for ATCO, our subsidiaries and joint ventures. Exceptions are explicitly noted with the relevant information. For brevity, data from 2009 through 2015 is not included in the performance summary, however this historical data is available on our website. Performance data specific to Canadian Utilities Limited only is available on the website.
- Data for 2008, our baseline year for many reporting indicators, is included where available. Certain indicators that have been included in our sustainability reporting more recently may not have data available for 2008; however, graphs will show available trending.
- Financial data is in Canadian dollars and environmental data is in metric units.
- Environmental performance metrics reported include 100 per cent for facilities where ATCO, or one of its subsidiaries has operational control, regardless of percentage of financial ownership. Operational control is defined in alignment with the GHG Protocol.
- There was no material change to the scope of our power generating plant assets in 2018. We include full environmental data for power plants that operated under power purchase arrangements (PPA) during all or part of 2018 including Sheerness and Battle River.
- The following facilities are not included when considering operational control: Primrose, McMahon, Muskeg, Rainbow 4, Scotford, ATCO Espaciomovil and ATCO Sabinco S.A.
- For select sustainability performance indicators, we also provide reporting on an ownership basis in our Sustainability Framework Index, available on our website. Data reported on an ownership basis is prorated to the percentage we own of ATCO subsidiaries, joint operations and joint ventures. In line with standard sustainability reporting practice, all sustainability performance data excludes non-controlling equity investments, such as Neltume Ports. The treatment of joint ventures may be addressed differently in ATCO's 2018 Annual Report with respect to financial performance.
- In 2018, ATCO acquired a 40 per cent interest in Neltume Ports, a leading port operator and developer in South America. ATCO does not have operational control of Neltume Ports. Neltume Ports is a subsidiary of Ultramar, already a strategic partner with ATCO, and operates primarily in Chile and Uruguay along with operations in Brazil and Argentina. As with any investment, a review of health and safety risks, including anti-bribery and corruption, was undertaken to confirm alignment of values.

ATCO LTD. PERFORMANCE SUMMARY

Indicator[1, 2, 3, 4, 5]	Units	2018	2017	2016	…	2008
ENVIRONMENT						
Air Emissions[6]						
Direct greenhouse gases[7]	kilotonnes CO_2e	**10,808**	10,713	10,378		17,049
Indirect greenhouse gases[8]	kilotonnes CO_2e	**43**	189	174		-
Sulphur dioxide	tonnes	**35,242**	40,150	42,111		63,182
Nitrogen oxides	tonnes	**15,938**	16,051	17,019		26,566
Particulate matter (PM2.5)	tonnes	**458**	439	438		510
Carbon monoxide	tonnes	**2,131**	2,523	2,205		3,768
Volatile organic compounds	tonnes	**270**	216	274		168
Mercury	kilograms	**27**	31	37		157
Ozone depleting substances	kilograms	**0**	74	101		77
Water Use[9]	million m^3	**21.2**	22.4	18.5		22.1
Spills[10, 11]						
Hydrocarbon - number	number	**13**	14	14		-
Hydrocarbon - volume	thousand litres	**5.2**	3.9	4.4		-
Non-hydrocarbon - number	number	**6**	7	7		-
Non-hydrocarbon - volume	thousand litres	**45.7**	2,059.4	34.4		-
Hazardous Waste[12]	tonnes	**3,947**	1,651	857		-
Environmental Fines and Penalties	$ thousand	**0**	0	0		0
SOCIAL						
Health & Safety						
Lost-time injury rate (employees)	cases/200,000 hours worked	**0.16**	0.25	0.17		0.77
Lost-time injury rate (contractors)[13]	cases/200,000 hours worked	**0.06**	0.53	0.28		-
Recordable injury rate (employees)	cases/200,000 hours worked	**1.41**	2.17	2.02		3.50
Recordable injury rate (contractors)[13]	cases/200,000 hours worked	**0.84**	1.97	1.81		-
Fatalities (employees)	number	**0**	0	0		0
Fatalities (contractors)	number	**0**	0	0		0
Employees[14]	number	**6,241**	6,752	6,751		7,781
Voluntary Turnover Rate	per cent	**6.1**	7.2	8.3		12.8
Employees in Employee Unions or Associations	per cent	**48**	50	51		54
Diversity						
Women in workforce	per cent	**31**	31	32		29
Women in senior management	per cent	**19**	17	17		14
Women on Board of Directors	per cent	**30**	30	30		9
Human Rights and Ethics Incidents[15]						
Discrimination incidents	number	**0**	0	0		-
Indigenous rights incidents	number	**0**	0	0		-
Corruption Incidents	number	**0**	0	0		-
Customer Privacy Breaches	number	**6**	1	0		40
Number of Regulatory Non-compliance Incidents[16]	number	**2**	4	3		-
Fines and Penalties for Regulatory Non-compliance	$ thousand	**15.3**	10.8	0.9		-
ECONOMIC[17]						
Economic Value Generated[18]	$ million	**4,888**	4,600	4,045		3,266
Economic Value Distributed						
Suppliers	$ million	**2,084**	1,870	1,263		1,127
Employees [19]	$ million	**599**	514	581		466
Lenders	$ million	**485**	414	394		239
Shareholders	$ million	**387**	348	318		166
Governments [20]	$ million	**448**	433	369		365
Communities [21]	$ million	**8**	8	7		5
Economic Value Retained [22]	$ million	**877**	1,013	1,113		897
Financial Assistance Received from Governments [23]	$ million	**1.51**	2.07	0.73		-
Coverage of Defined Benefit Pension Plan Obligations	per cent	**91**	92	93		99

We strive to continually improve our tracking and measurement systems, and may adjust indicator definitions and performance data to reflect current best practice. In most cases, we use standard industry and regulatory calculation methodologies and definitions that may be updated periodically to improve accuracy.

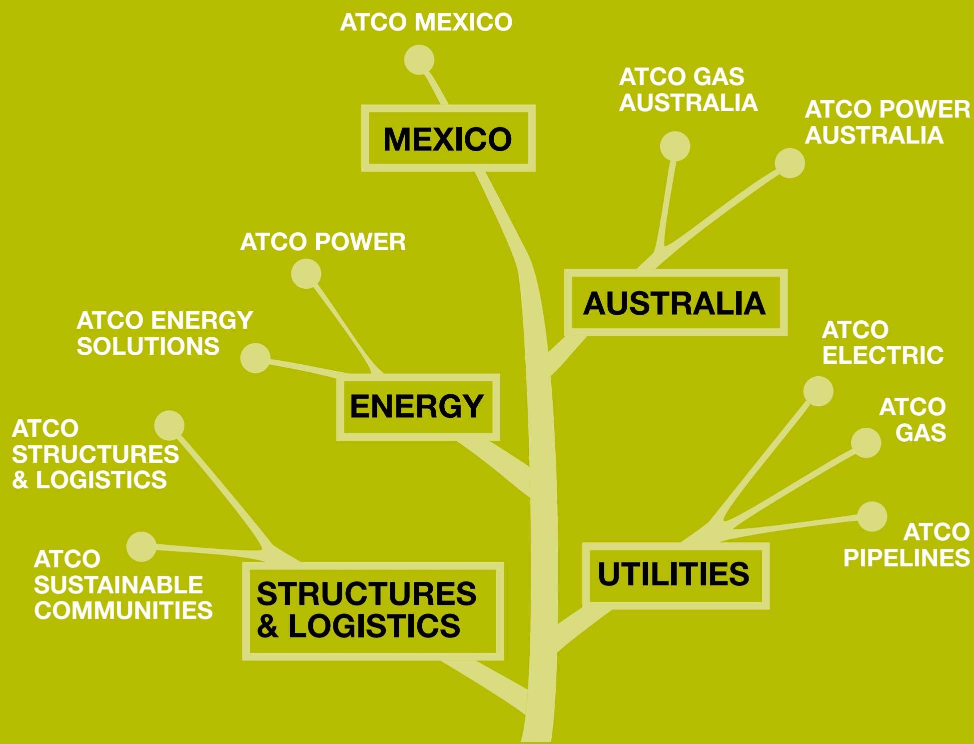
1. This performance summary consolidates data for ATCO Ltd. (ACO.X, ACO.Y). Although we have historically reported metrics for the whole ATCO Group of Companies, in 2018 we aligned our reporting with the traded entities to help shareholders and other stakeholders to make informed decisions. A performance summary for Canadian Utilities Limited (CU, CU.X) can be found online.
2. Data is reported on an operatorship basis, which does not align with financial reporting. Operatorship basis means that environmental performance metrics reported include 100 per cent from operations over which ATCO, or one of its subsidiaries, has operational control, regardless of percentage of financial ownership.
3. We have also provided a limited number of environmental performance metrics on an asset ownership basis in our Sustainability Framework Index.
4. This report includes performance data on indicators that were not included in all previous reports. Data for the new indicators is not provided for previous years, and is denoted with a "-" symbol.
5. Due to differences in government reporting systems, some of the environmental data from our Australian operations is based on a July to June reporting period. Although this does not align with the conventional January to December time period, data reported reflects their annual environmental performance.
6. Emissions figures include amounts that are required to be reported under federal, provincial, regional or other regulations, or under facility permits. We use standard industry calculation methodologies and emission factors, which sometimes change to improve accuracy. In a few instances, we have estimated the environmental impacts of certain facilities.
7. Our direct emissions for 2018 exclude any carbon offsets that we have generated or purchased to meet our regulatory obligations. Although historically we have deducted these amounts from our direct emissions, they represent less than 1 per cent of our total scope 1 emissions, and we will continue to exclude them on a go-forward basis.
8. The reduction in indirect emissions for 2018 is predominantly due to improved calculation methodology and reporting scope. As indirect emissions account for only a small portion of our total emissions, historical figures have not been restated.
9. Water use = water diverted minus water returned.
10. Includes spills that meet the size thresholds for regulatory reporting in the jurisdiction in which they occurred. Volume spilled is often estimated due to variables such as duration, location and when the spill was identified.
11. Non-hydrocarbon spills are often comprised of high volumes of saline water or water containing small quantities of other substances.
12. Increase in hazardous waste volumes is mainly attributable to the decommissioning of our generating station in Garden River, Alberta and construction of the Alberta PowerLine project.
13. Our contractor safety rates do not cover all our contractors since some of our business units only track safety statistics for contractors conducting certain work scopes or greater than a threshold contract size. Changes to contractor incident rates year over year vary depending on significant capital projects which occur during that year.
14. Includes our temporary workforce but does not include joint venture employees.
15. We track and address concerns through several channels, including our internationally accessible ATCO Integrity Line. Only incidents that have been substantiated by an external authority have been included.
16. Non-environmental regulatory non-compliance incidents include one incident regarding power generation response time requirements, and one incident related to the operation of our natural gas transmission system.
17. Figures for 2017 have been restated to account for the impact of IFRS 15.
18. Economic value generated includes revenues, gains on asset dispositions, and interest income.
19. Payments to employees include the expensed cost of wages and benefits.
20. Payments to governments substantially increased and include income, property, and franchise taxes.
21. Distributions to communities include donations, in-kind contributions, and sponsorships.
22. Economic value retained is economic value generated minus economic value distributed. This is not a financial reporting indicator and should not be confused with retained earnings.
23. Financial assistance received from governments includes tax relief/credits, investment grants, R&D grants, financial awards, and favourable financing terms from domestic and foreign governments.

2014

SUSTAINABILITY
REPORT

When energy is shared,
great things happen.

ATCO | ALWAYS THERE. ANYWHERE.



ATCO Group is a diversified, Canadian-based, international group of companies focused on profitable sustainable growth and achievement with approximately $18 billion in assets and more than 9,000 people actively engaged in Structures & Logistics, Utilities and Energy.

2014 Worldwide Operations

ATCO ALWAYS THERE. ANYWHERE.

ATCO Structures & Logistics

ATCO Structures & Logistics offers modular buildings, site and lodging services, and industrial noise and emissions control solutions worldwide. With manufacturing facilities in North America and Australia, a global supply chain, and operations on five continents, the company has the expertise to rapidly deliver a turnkey solution anywhere it is needed.

ATCO Sustainable Communities

ATCO Sustainable Communities provides a full range of pre-fabricated, culturally sensitive building solutions for Indigenous and remote communities.

ATCO Energy Solutions

ATCO Energy Solutions builds, owns and operates non-regulated energy and water-related infrastructure. The company focuses on offering industrial water infrastructure solutions; natural gas gathering, processing, storage and liquids extraction; transportation and services to the energy industry.

ATCO Power

ATCO Power leverages its decades of experience and industry-leading expertise developing, building and operating independent power generation facilities to provide customers with cost-effective power solutions including commercial and industrial power sales and distributed power generation.

ATCO Electric

ATCO Electric builds, owns and operates electrical transmission and distribution facilities in east-central and northern Alberta. It delivers safe, reliable electricity to more than 224,000 farm, business and residential customers in 245 communities. By supplying power to large industrial and oilfield customers, ATCO Electric supports the development of Alberta's energy-rich industrial sector.

ATCO Gas

ATCO Gas has been heating homes and warming communities across Alberta for more than a century. Today, ATCO Gas provides safe, reliable and cost-effective natural gas delivery to more than 1.1 million customers in nearly 300 Alberta communities.

ATCO Pipelines

ATCO Pipelines plays an integral role in delivering natural gas in the Alberta marketplace, serving producers throughout Alberta, as well as distribution companies and major industrial customers.

ATCO AUSTRALIA

ATCO Australia, based in the Western Australia capital, Perth, develops, builds, owns and operates energy infrastructure assets across Australia.

ATCO MEXICO

ATCO Mexico is focused on building, owning and operating natural gas infrastructure, power generation, electricity transmission and distribution, and providing workforce accommodation and site services.

2014 SUSTAINABILITY REPORT

President's Message

When energy is shared, great things happen.

Great things happen at ATCO every day—made possible by the corporation's 9,000 people who, through innovation and imagination, deliver solutions to our customers and improvements across all aspects of our business.

Within our diverse, geographically dispersed businesses, we believe in pursuing improved operational performance — whether it is our relationship with the environment, the health and safety of our employees and the communities where we operate, or as the preferred supplier of choice for our customers.

The current economic volatility in the markets where we operate can put pressure on companies in the area of operational performance. Successfully facing adversity has been a hallmark of our corporation in the past and will continue to serve us into the future. We have always embraced a method of operating that stresses customer-driven innovative solutions, transparency in communication, the intense pursuit of efficiencies and truly knowing and understanding our customers. This 'back-to-basics' philosophy has served us well and many examples are highlighted in this report.

We have always taken our responsibilities very seriously. Minimizing our environmental footprint is integral to our pursuit of operational excellence. But responsible stewardship of the environment is a complex issue with no one silver bullet solution. It takes the thoughtful, strategic identification of multiple solutions in all parts of our business—from internal operational efficiencies such as building energy efficient operations centres, to educating our customers about how to be more energy efficient in their homes with our Demand Side Management programs, to partnering with multiple agencies to deliver innovative solutions such as the natural gas Combined Heat and Power technology.

One of the most critical issues facing Alberta and our company is how to sustainably deliver our province's future power supply. As we decommission coal-fired power generating facilities, we must carefully consider how to replace them. ATCO continues to take a leadership role in advocating for future low emitting and renewable technologies, such as the development of hydroelectricity, as the best and most sustainable option for both emissions reduction and for affordable electricity in the future. Hydro generation is emissions-free and offers unmatched opportunity for Alberta to achieve its reduced emission targets.

ATCO also continues to invest in and evaluate a range of technologies such as geothermal, solar, distributed generation and wind to determine their viability as part of a mix that would provide sustainable, cost-effective and environmentally responsible solutions.

To succeed, we must garner government and public policy support, regulatory certainty and a viable commercial framework for capital-intensive financing. It will require Indigenous participation, consultation and true partnerships that provide for economic growth and job opportunities.

Our valued partnerships with Indigenous communities are a core strength and are central to the principled way we do — and have always done — business. Partnerships that stand the test of time involve respect, trust, understanding and transparency.

Like with our Indigenous partnerships, our companies have had long-standing relationships with the communities we have served for decades. The strength of these relationships is based on our employees who not only volunteer their time, but actively direct their charitable donations to the communities where they live and work. I am most proud of our employee-led ATCO EPIC – Employees Participating in Communities—fundraising program where our employees identify charities important to them and their communities.

The determination our employees bring to all aspects of our business is our greatest strength. Our employees are also our greatest resource and it is critically important that they return home safely at the end of each day. The safety of our communities and our employees was tested in 2014 during a record-breaking windstorm in one part of Alberta and, later that year, a frost storm in another part of our service area in the province. In every instance, our employees went above and beyond to assist communities and restore essential electricity and natural gas services with no major safety incidents. As a provider of essential services, it is our responsibility to remain relentless in our efforts to continuously improve our safety programs with our employees, contractors and the public.

Our past successes have been derived from the efforts of our people and they will continue to be our greatest strength and asset as we tackle what I believe to be a promising future that is safe and sustainable for our customers, our employees, our partners and the environment.

N. C. Southern

Nancy C. Southern
Chair, President & Chief Executive Officer

Approach to Sustainability

ATCO is privileged to serve communities around the world and our success depends on our ability to operate in a responsible and sustainable manner. In pursuit of sustainability, we not only improve social and environmental conditions, we also achieve cost savings, efficiencies and other intangible benefits.

It is our responsibility to conduct business in a manner that reflects ATCO's values: integrity, transparency, entrepreneurship, accountability, collaboration, perseverance and caring. ATCO's businesses are part of the everyday life of many of the communities in which we operate, delivering essential services such as electricity and natural gas.

Long-term sustainability requires practical, integrated solutions that balance responsible development with environmental stewardship and the interests of communities and landowners.

Our stability and commitment to social wellbeing enables us to attract and retain a talented, motivated workforce that shares our values. The actions of our people today, and in the future, earn our company the privilege to operate in existing and new communities.

Management approach

ATCO takes the strategic management of sustainability seriously. The sustainability function reports directly to a member of the Office of the Chair and is managed collaboratively across numerous groups in the enterprise, including Human Resources, Indigenous Relations, Health & Safety, Environment, Communications, Business Development, Internal Audit and Risk Management, among others. These groups monitor best practices, develop and implement policies and standards and support ATCO's operating companies.

The daily management of sustainability commitments and implementation of programs is guided by ATCO operating company leaders. More specific descriptions of our management approach to employee practices, community engagement, environment and safety are included in this report and on our website. The programs include topic-specific policies, responsibilities, training, monitoring and other management considerations.

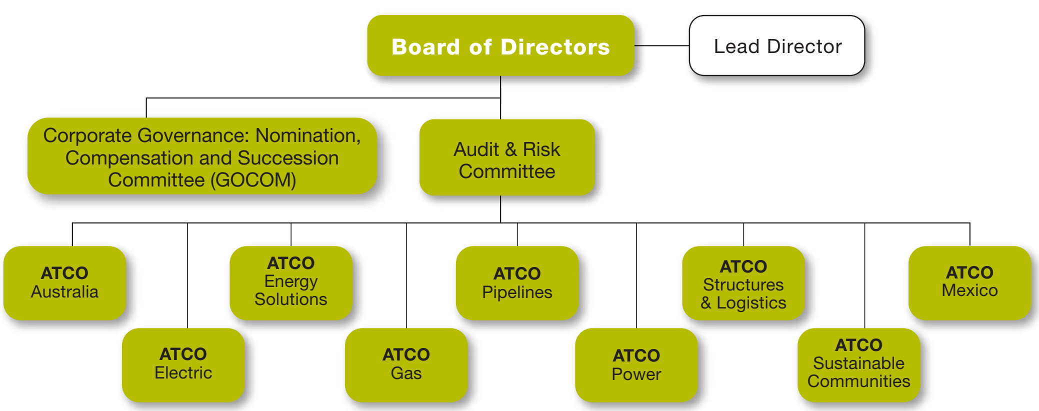
Corporate governance

Effective corporate governance is an essential element for the ongoing sustainability of ATCO - we regularly evaluate our corporate governance practices to support our business needs.

ATCO does not believe in a one-size-fits-all approach to governance. We have a unique and effective system, recognizing the need to provide autonomy and flexibility to our ATCO operating companies, while accommodating the needs of our regulated and non-regulated companies.

ATCO is a diversified group of companies principally held by Sentgraf, a Southern family holding company, and the ATCO share registry has both non-voting and voting common shares. We firmly believe that the existence of a long-standing controlling share owner is fundamental to achieving sustainable, top quartile results. Our stable, long-term position in the marketplace drives our long-term vision on sustainability.

ATCO's Chair is not independent, but we were one of the first public companies in Canada to appoint a Lead Director to ensure independent oversight of management. The independent status of each board member is reviewed annually and the majority of our board members are independent.



Integrated decision-making

The two main committees of the ATCO Board of Directors are the Corporate Governance: Nomination, Compensation and Succession Committee (GOCOM) and the Audit & Risk Committee.

The Audit & Risk Committee has the most impact on the company's sustainability practices. The committee reviews risks that could materially affect the company's ability to achieve strategic and operating objectives. It is responsible for ensuring that management addresses significant risks and that appropriate mitigation measures are implemented.

The President of each Principal Operating Subsidiary chairs a Risk Management Committee that reports to the Audit & Risk Committee. In addition, each subsidiary prepares a Stewardship Report on a bi-annual basis, which covers areas such as Health and Safety, Environment and Code of Ethics compliance.

Ethical behaviour every day

We believe that ethical conduct goes beyond staying in compliance with regulations. The ATCO Code of Ethics affirms our commitment to uphold high moral and ethical standards and specifies the basic norms of behaviour.

All of ATCO's directors, officers and employees annually review and formally acknowledge their understanding of the ATCO Code of Ethics. This formal process reminds us of the importance of ethics and affirms our commitment to making ethical decisions every day. As ATCO's businesses grow and broaden their global reach, we maintain the same high standards of ethical behaviour in every country in which we operate.

ATCO's internationally accessible Integrity Phone Line ensures that our employees and business partners can confidentially and anonymously report any suspected inappropriate business conduct.

Since our last report, ATCO has strengthened anti-bribery and anti-corruption policies and programs, ensuring compliance with Canadian and international laws. This includes training, internal controls and due diligence procedures. We did not record a corruption incident in the reporting period, nor were any such actions brought against ATCO.

We were not involved in any legal actions for anti-competitive behaviour, anti-trust or monopoly practices during the reporting period.

Compliance

In 2013 and 2014, ATCO did not incur any environmental fines or penalties. Over these two years we did have two regulatory non-compliance incidents for power generation reliability requirements and two regulatory non-compliance incidents for power market rule compliance. Total fines for these incidents were $15,000. In all cases, procedures have been implemented to minimize the risk of similar incidents in the future.

We are committed to protecting the privacy of the personal information of people with whom we interact, including customers, suppliers, employees and contractors. Customer privacy breaches totaled two in 2013 and 15 in 2014. All incidents were related to our electricity distribution operations and were resolved successfully.

Public policy

Effective policy decisions require contributions from all interested parties. ATCO operating companies take the time to be a resource for policy makers at the municipal, provincial/state and federal levels of government. Our role is to explain the practicalities of our businesses and collaborate on effective improvements wherever possible. In return, we gain a better understanding of the broader goals and objectives of these governments.

ATCO is in compliance with all laws regarding lobbyist registration and political contributions.

We discuss a number of topics with governments either directly or through industry associations and multi-stakeholder groups. ATCO's approach is principle-based with a focus on open dialogue and fair, effective, efficient solutions.

Examples of topics on which we have participated in public policy discussion include:

- Greenhouse gas emissions and air pollutant reduction initiatives;
- Effective transition to a lower carbon future, including new natural gas turbine standards, the promotion of natural gas vehicles and renewable energy strategies;
- Land Use Framework consultations; and
- Long-term transmission planning to strengthen the electricity grid.

Our Core Values

Our pursuit of excellence governs the way we act and make decisions. At ATCO we strive to live by the following values:

Integrity
We are honest, ethical and treat others with fairness, dignity and respect.

Transparency
We are clear about our intentions and communicate openly.

Entrepreneurship
We are creative, innovative and take a measured approach to opportunities, balanced with a long-term perspective.

Accountability
We make good decisions, take personal ownership of tasks, are responsible for our actions and deliver on our commitments.

Collaboration
We work together, share ideas and recognize the contribution of others.

Perseverance
We persevere in the face of adversity with courage, a positive attitude and a fierce determination to succeed.

Caring
We care about our customers, our employees, their families, our communities and the environment.

About this Report

The ATCO Group publishes a comprehensive sustainability report with complete data and commentary every two years and a concise performance update in alternate years. This is ATCO's fourth biennial report.

- This report includes data for the seven years ended December 31, 2014, unless otherwise noted, for ATCO, our subsidiaries and joint ventures. Any exceptions are explicitly noted with the relevant information. Qualitative information about programs and initiatives is generally confined to 2013-2014 activities.
- We used the Global Reporting Initiative's (GRI) Sustainability Reporting Guidelines to help determine report content. The GRI Content Index on page 34 indicates where you can find specific disclosures.
- An internal materiality assessment was completed to determine which topics and indicators would be of most relevance to interested parties and the success of our business. This internal assessment was reviewed by the project team, including representatives from each operating company as well as subject matter experts from Investor Relations, Communications, Community Investment, Indigenous Relations, Environment and Health and Safety.
- Performance data for assets we divest is reported for the portion of the year until they were divested. Performance data for assets we acquire is included for the year following acquisition to allow for integration of new data systems. Data for ATCO Mexico, which commenced operations in the second half of 2014, is not included in this report.
- Environmental data reported includes 100 per cent of the emissions and water use for the facilities which ATCO owns and operates, and facilities with partnership ownership where ATCO is identified as the operating entity in the contract, regardless of percentage of financial ownership. The treatment of joint ventures may be addressed differently in ATCO's 2014 Annual Report with respect to financial performance.
- We report full environmental data for power plants operating under power purchase arrangements (PPA) – Sheerness and Battle River. The PPA holder may also report performance for the facility in its sustainability report.
- Unless noted, indicators do not cover contractors or temporary employees.
- Measurement and calculation techniques, if not self-explanatory, are stated with the data.
- Financial data is in Canadian dollars and environmental data is in metric units.
- The terms ATCO, ATCO Group, the ATCO Group of Companies, our, we, the company and the corporation, refer to ATCO Ltd. as a whole, including its subsidiary company Canadian Utilities Limited. Company names such as ATCO Gas and ATCO Power are used to refer to our Principal Operating Subsidiaries, as noted on page 3.

Environment

Our Commitment

We believe that reducing our impact on the environment is integral to the pursuit of operational excellence. Our environmental commitments include:

- minimizing our environmental impacts throughout our global operations;
- incorporating efficiency and environmental considerations in the planning and implementation of all our projects;
- developing alternative technologies including co-generation, hydro, geothermal, wind and solar energy;
- monitoring and assessing our performance; and
- educating the public and employees on energy reduction opportunities.

Our Approach

ATCO incorporates environmental considerations into the full lifespan of every project, from planning to implementation and eventual decommissioning of our operations. This long-term, collaborative perspective on environmental issues is especially important because many of our facilities can operate for several decades.

Minimizing environmental impacts of ATCO Electric's operations remains at the core of how each project is approached. Environmental Advisor, Joel VanderMey, drives stakes into the ground to remind workers of sensitive environmental features located near construction areas.

HIGHLIGHTS

- Energy efficiency and air emissions reduction initiatives with partners and internally on operations, buildings and vehicles
- Employee innovations that led to decreased physical footprints of certain projects
- Upgrades and preventive maintenance that reduce environmental incidents

CHALLENGES

- Transitioning to low-emitting power solutions that are economically viable
- Continued effective environmental management of large capital projects and energy transport systems

MOVING FORWARD

- Reduce direct greenhouse gas emissions of our current generating capacity by 30 per cent below 2005 levels by 2030*
- Build on our plans for the replacement of coal and advance low and zero-emission generation options, including large-scale hydro
- Improve our ability to quantify greenhouse gas reduction initiatives

** This would be primarily acheived by replacing power generation, as it retires, with less greenhouse gas intensive alternatives.*

Due to our diverse operations, each ATCO company has its own environmental management system, which includes setting internal targets, developing and implementing procedures, training, monitoring, measuring, reporting and corrective action.

In addition, the enterprise-wide Environment Network encourages continuous improvement and sharing of best practices and promotes consistency throughout the ATCO companies. Environmental performance is also reported in a consistent manner to the Audit & Risk Committee of the company's Board of Directors.

ATCO Power's 580 MW natural gas-fired, combined-cycle Brighton Beach power station is an example of efficient power generation. The combined-cycle process uses waste heat from the gas turbines to power steam turbines and generate more power without additional fuel.

The complexity of the issue of climate change and reducing air emissions means there is no one silver bullet and many alternate solutions need to be considered.

AIR

Managing Emissions

Our greenhouse gas (GHG) emissions management strategy balances environmental benefits and the need for cost-effective customer solutions, and includes:

- Finding new ways to increase the efficiency of our operations, leading to sustainable economic and environmental benefits;
- Investing in the development of new low emission generation projects; and
- Promoting efficiency at the consumer level.

The complexity of the issue of climate change and reducing air emissions means there is no one silver bullet and many alternate solutions need to be considered. We will continue to drive efficiency and innovation in our existing operations, while working with our partners and customers to develop innovative solutions that address environmental and business priorities.

Although we have implemented numerous innovations and energy-efficiency improvements in our operations over the years, addressing climate change is an ongoing, long-term commitment.

In 2014, ATCO operated 17 major power generation plants in Australia, Canada and the United Kingdom.

ATCO has built low-emitting and alternative energy facilities - primarily environmentally progressive natural gas-fired facilities - for the past 25 years. We operate two coal-fired generation facilities with a focus on operational excellence, minimizing environmental impact and ensuring long-term base-load power during the remaining life of these facilities. By 2030, 60 per cent of the coal-fired units which ATCO currently operates will be retired.

The diagram on page 11 illustrates our air emissions reduction strategy and activities.

OUR AIR EMISSIONS REDUCTION STRATEGY AND ACTIVITIES

INTERNAL INNOVATIONS

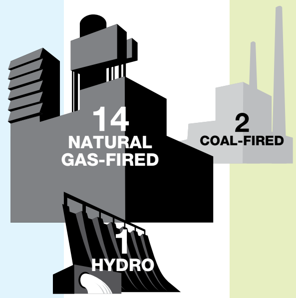
Operational Excellence and Efficiency

↓**Greenhouse gases** Improvements to pipeline compression and air-fuel ratio controls reduce CO_2 emissions by over 45,000 tonnes per year.

↓**NOx** Combustion optimization projects reduced nitrous oxide without affecting performance.

↓**Mercury** Improved the mercury capture rate by injecting activated carbon into the flue gas.

↓**SO_2** Successfuly tested new process to remove sulphur dioxide emissions from the flue gas.



PARTNERING TO REDUCE EMISSIONS

Demand Side Management

2,700 rebates

ATCO Electric Yukon worked with another utility to introduce rebates for customers who install energy efficient LED lights and automotive block heater timers.

4 communities

Northland Utilities completed the conversion of four communities in the Northwest Territories to LED street lighting.

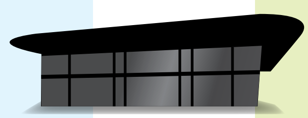
ATCO EnergySense educates and informs Albertans regarding energy efficiency and wise energy use through an interactive website, school program and commercial energy audits.

Efficient Buildings

4 new buildings

New energy-efficient operations centres opened across ATCO in the past two years. Our most recent is in Jandakot, Western Australia.

In 2014, we made the decision to move forward with construction of the ATCO commercial centre in Calgary to be built to Leadership in Energy & Environmental Design (LEED) Gold standards.



Combined Heat and Power (CHP)

3,500 CO_2e tonnes/year expected reduction across Alberta upon program completion

CHP reduces costs and emissions by replacing offsite electricity generation with onsite natural gas electricity generation and waste heat recovery. To date, ATCO Gas has worked with commercial customers in Red Deer and Calgary to install this technology.

Fleet Vehicles

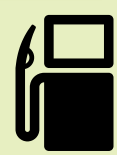
↓5% ATCO Gas 2015 reduction target in fleet fuel consumption, reducing overall emissions.

180 natural gas vehicles

ATCO Gas has the largest natural gas vehicle fleet in Alberta.

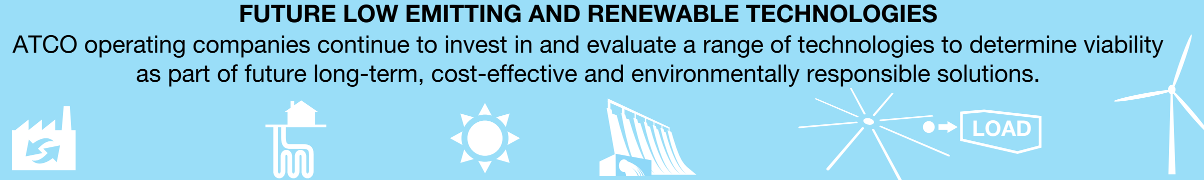
Natural Gas Fueling Stations

We opened a new fleet compressed natural gas station in Fort McMurray in 2013, and plan to add or upgrade three stations in 2015. Municipalities are using ATCO stations to test natural gas-fuelled fleet vehicles, which can lower their greenhouse gas emissions by up to 25 per cent.



FUTURE LOW EMITTING AND RENEWABLE TECHNOLOGIES

ATCO operating companies continue to invest in and evaluate a range of technologies to determine viability as part of future long-term, cost-effective and environmentally responsible solutions.



COGENERATION GEOTHERMAL SOLAR HYDRO DISTRIBUTED GENERATION WIND

Top: ATCO Gas Australia's new business and operations centre in Jandakot, Western Australia, was one of four new energy-efficient operations centres opened by ATCO in the past two years. Using energy efficiency, water usage conservation, waste management and indoor environmental quality data, the building is expected to achieve a 4.5 out of 6 rating using the National Australian Built Environment Rating System.

Bottom: The Collicutt Centre, a 260,000 sq. ft. recreation facility in Red Deer, Alberta, was one of the first customers to sign up for ATCO Gas's Combined Heat and Power program. The program incorporates technology that increases energy efficiency and reduces energy costs and greenhouse gas emissions.

LAND

Reducing impact and minimizing disturbance

ATCO's commitment to operating in a sustainable manner guides how we interact with and manage the land resources that are entrusted to us. This includes minimizing the disruption our operations have on the land and the biodiversity of species, as well as reclamation efforts to restore ecosystems to equivalent land capacity.

In 2013-14, ATCO companies built or replaced utility infrastructure, which included projects such as the Eastern Alberta Transmission Line and the Urban Pipeline Replacement Program. Care is taken to create comprehensive environmental protection plans that outline risks and mitigation procedures for use during construction, reclamation and operation. Similarly, archaeological and historical resources are also protected through programs such as ATCO Electric's Historical and Archaeological Protection Program, which won an award from the Alberta Professional Planners Institute in 2013.

ATCO Energy Solutions is now into the third year of an innovative sustainability initiative at its compression station near Fort Saskatchewan that uses salt-resistant grasses and shrubs to clean up historic soil contamination.

Repairing pipelines after the flood

ATCO Pipelines assessed the integrity of pipeline water crossings that were exposed as a result of the 2013 southern Alberta flooding and developed low-impact remediation and replacement strategies. In Weaselhead Flats Park in Calgary, high river flows eroded the banks of the Elbow River exposing a high-pressure pipeline. In conjunction with government agencies, we developed a comprehensive plan to protect the existing pipeline and minimize disturbance to a sensitive environment. Mitigation techniques included adding woody debris to improve fish habitat, installing bank erosion and sediment control measures, implementing a water quality monitoring program and planting vegetation to assist with bank preservation. The project received the 2014 Alberta Roadbuilders & Heavy Construction Association's Environment Award.

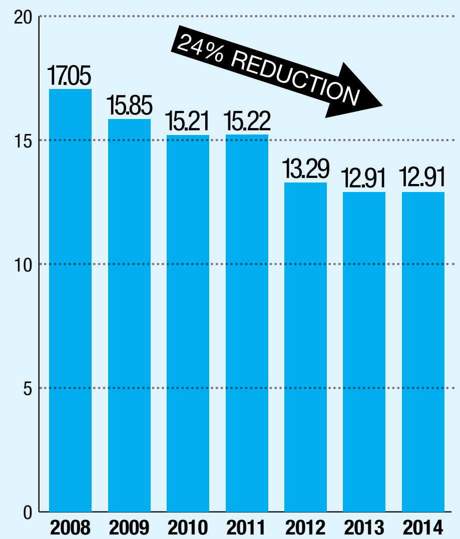
Upgrading a power line in a national park

In 2014, ATCO Electric engineers and construction crews completed an environmentally innovative power line construction project in Jasper National Park. The project involved upgrading a section of power line crossing rocky terrain and three mountain rivers in addition to serving a number of popular tourist attractions.

We used special cable to ensure the right-of-way remained narrow to minimize visibility of the line. For sections of the line inaccessible by bucket truck, crews brought in

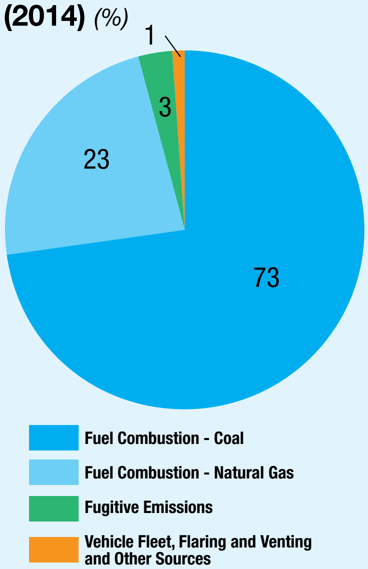
DIRECT GREENHOUSE GAS EMISSIONS

(millions tonnes CO_2e)



We have reduced our greenhouse gas emissions by 24 per cent since 2008. This is largely related to decreased energy output from our power assets.

GREENHOUSE GAS EMISSION SOURCES (2014) *(%)*



The proportion of emissions from the different sources varies from year-to-year depending on the operating hours of our various electricity generating units.

OTHER AIR EMISSIONS

	2008	2014	Change (%) 2014 vs 2008	Notes
Sulphur Dioxide *(tonnes)*	63,182	54,273	**-14**	*Change due to variability in sulphur content of the coal burned*
Nitrogen Oxides *(tonnes)*	26,566	23,806	**-10**	*Decrease predominantly due to changing operating mix from our power assets*
Carbon Monoxide* *(tonnes)*	3,768	3,207	**-15**	*Decrease predominantly due to changing operating mix from our power assets*
Particulate Matter* *(tonnes)*	510	606	**19**	*Increase predominantly due to changing operating mix from our power assets*
Volatile Organic Compounds* *(tonnes)*	168	335	**100**	*Changes predominantly due to expanded natural gas and energy product pipeline operations in Australia and Canada*
Mercury *(kilograms)*	157	44	**-72**	*Decrease due to installation of equipment to meet Alberta mercury control regulations*
Ozone Depleting *(kilograms)*	77	18	**-76**	*Emissions due to accidental releases*

** The 2008 figures have been re-stated since the publication of our last report due to a change in emission factors*

TRANSITION TO A LOWER CARBON FUTURE

ATCO has the opportunity to develop innovative, cost-effective, long-term, environmentally responsible solutions that support progress on climate change.

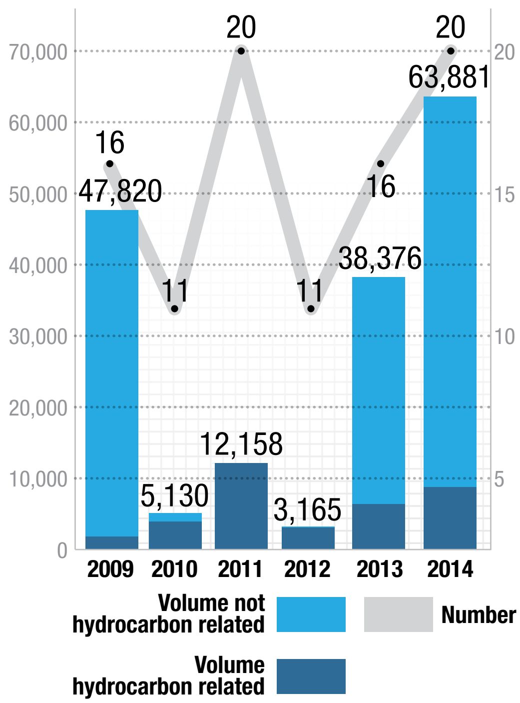
In Alberta and other jurisdictions around the world, coal-fired electricity is being replaced with lower emission sources of generation to meet greenhouse gas (GHG) emission reduction targets. The challenge is to reduce emissions in a way that meets environmental goals, while meeting growing energy demand and keeping the cost of electricity at a reasonable rate.

A large, complex and interconnected system delivers the energy that businesses and families rely on every day. Safe and reliable delivery of these critical services requires long-term planning and careful budgeting as well as effective execution in advance of actual need.

There are a variety of alternative energy sources - each one comes with its own pros and cons. It's important to carefully evaluate the options and create a base load generation mix that ensures jurisdictions are not dependent on a single solution. For example, natural gas-fired generation plants are faster and less expensive to build, but if all new plants in a jurisdiction use natural gas as a fuel source, it will be vulnerable to price increases in natural gas.

ATCO is actively pursuing replacement power through a combination of natural gas combined-cycle, cogeneration and renewables, including hydro. For example, hydro generation is more capital-intensive and requires government and regulatory policy support, but this essentially emissions-free alternative is a fuel source that is not at the financial mercy of commodity markets. As with all potential innovative solutions, collaboration, transparency and partnership guide the way forward to determine optimal ways to fulfill environmental and business priorities while lessening impacts on people, land use and the environment.

REPORTABLE SPILLS
(volume & number)



The increase in volume in 2013 can be attributed to a single incident regarding release of a mud/water mix. Similarly in 2014, the increase in volume can mainly be attributed to a single incident regarding the release of cement onto the ground. Other non-hydrocarbon spills often comprise high volumes of water containing small quantities of other substances.

We strive to minimize the number and size of spills to the environment through rigorous operational procedures and asset integrity with a goal of zero spills. Number of spills refers to all spills which require reporting to regulators. Spill volumes are sometimes estimated.

boatswain chairs that allowed workers to perform aerial work while suspended from a structure.

Reducing risk of environmental incidents

Protecting the environment and reducing the risk of environmental incidents are the result of operational excellence. It involves solid planning, processes, experience and training, and includes clear procedures to prevent operational environmental incidents or spills, regular inspections, risk assessments, building secondary containment where appropriate, and emergency response training.

For example, Northland Utilities completed upgrades to five power plant fuel systems in the Northwest Territories to further reduce risk of environmental incidents. This included proactive measures such as installing additional containment and alarm systems in addition to annual third-party inspections and equipment testing.

ATCO Pipelines has a comprehensive preventive maintenance and integrity program in place. Methods used to test facilities incorporate a cross-section of practices applied on a rotating basis to portions of pipelines. They include leak surveys, corrosion assessments, in-line inspections, aerial inspections and capital improvements. The ATCO Pipelines Urban Pipeline Replacement Program also reduces the risk of future incidents by relocating hundreds of kilometres of high-pressure natural gas pipelines, which exist under densely populated neighborhoods in Calgary and Edmonton, to Transportation Utility Corridors.

Putting waste to good use

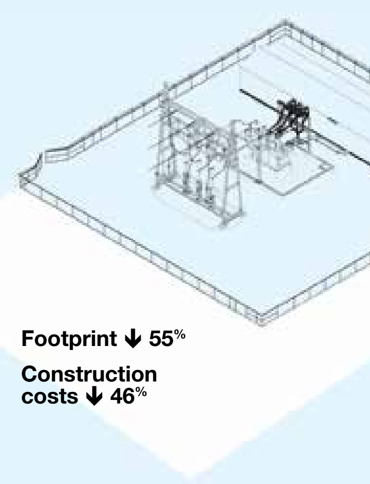
ATCO founded ASHCOR Technologies 17 years ago to use the coal by-product, fly ash, for construction and oil well cementing projects instead of sending it to landfills. In this way, ASHCOR customers reduce their greenhouse gas emissions by displacing cement powder, which has high greenhouse gas emissions intensity.

In addition, ATCO Power's Sheerness generating station is the only coal-fired facility in Alberta that uses a unique process of ensuring any remaining ash is not only responsibly stored and continuously monitored, but also through the reclamation process, successfully seeded with a native prairie mix seed and returned to productive land. This is possible through a 20-year partnership with a leading environmental management company.

EXPANDING ON INNOVATION CULTURE

By tapping into the knowledge, experience and innovative ideas of our people, we enable continual improvement and significant step changes in our environmental performance. Programs like Project Innovate in ATCO Electric's Transmission Division and IdeaWorks 2.0 in ATCO Gas encourage employees to generate value-creating ideas.

Ideas for design modifications to ATCO Electric substations resulted in either a 27 per cent reduction in the physical footprint by using air-insulated switchgear, or a 55 per cent footprint reduction by using indoor gas-insulated switchgear. Further innovation included narrowing access road width to our facilities and reducing roadway material requirements. These are



WATER

ATCO understands that water is a precious resource. More than 98 per cent of water withdrawn for cooling at our coal-fired power facilities is returned. Before this occurs, extensive testing is done to ensure the water meets all regulatory requirements for temperature and quality.

ATCO is also committed to working with regulators, other businesses and the public to effectively steward this resource, improve efficiencies and reduce consumption where possible.

For example, ATCO Power's Battle River generating station is located on the banks of the Battle River. ATCO Power participates in the Battle River Watershed Alliance, an inclusive, collaborative and consensus-based community partnership. As part of the Stakeholder Advisory Group, ATCO Power recommends options and strategies that strike a balance between a healthy aquatic ecosystem, a vibrant economy and sustainable communities. ATCO is also a member of the Alberta Water Council, a multi-interest partnership with members from governments, industry and non-government organizations.

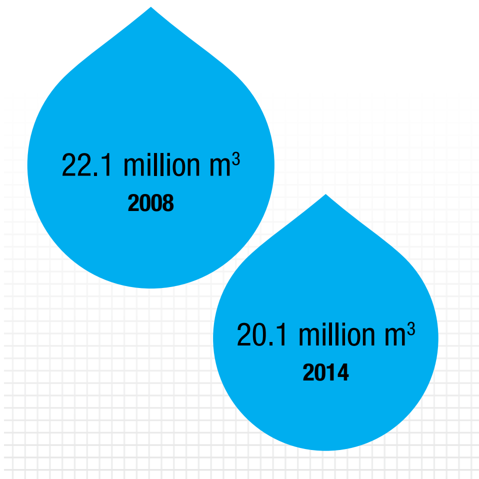
ATCO Power participates in the Battle River Watershed Alliance, an inclusive, collaborative and consensus-based community partnership.

At our Sheerness generating station, existing infrastructure is used to provide water to dozens of nearby communities for irrigation and domestic water use.

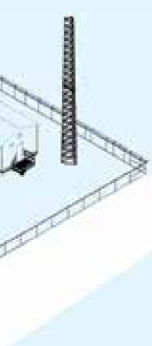
In areas where there are existing water intakes and infrastructure, ATCO looks for opportunities to improve efficiencies. For example, ATCO Energy Solutions offers industrial customers essential water transportation services and industrial water solutions, which mitigates the need for those customers to build water infrastructure to source water from the river.

WATER CONSUMPTION

(millions m^3)



The amount of water ATCO consumes overall has decreased 9 per cent from 2008.



important considerations in more remote parts of northern Alberta as roadway materials are not only difficult to find, but involve long transportation distances which have an environmental impact.

Innovative ideas in ATCO Gas include new tubing tools used to stop the flow of gas for repair and construction purposes. These tools limit the amount of gas released to the atmosphere, reduce environmental impact associated with methane releases and provide a safe work environment for employees.

ATCO Energy Solutions' new pumphouse along the North Saskatchewan River is ecologically sensitive containing a state-of-the-art fish return system.

Health & Safety

Firefighter Rick Herbel works at the North Atlantic Treaty Organization (NATO), at 15 Wing Moose Jaw, where ATCO provides fire protection services.

Our Commitment

We strive to provide a healthy and safe work environment, and continually improve our safety and operational integrity programs to protect our employees, contractors and the public. We are committed to the safety of employees and to promoting safe practices with our customers.

Our Approach

Safety is the first consideration in everything we do. We strive to continually improve our safety programs with the objective of providing the awareness, training, procedures, equipment and follow-up to drive our zero injury culture.

HIGHLIGHTS

- Restoring natural gas and electricity service with no major safety incidents during our response to Alberta weather-related emergencies
- Employee lost-time injury rate has declined by 70 per cent since 2008, and recordable injury rate has declined by 30 per cent in the same period
- Approval to proceed with the Urban Pipeline Replacement (UPR) Program, moving high pressure pipelines out of major urban centres, increasing public safety

CHALLENGES

- Ensuring ATCO's safety culture is adopted in our expanded operations in new markets
- Continued monitoring and maintenance of current safety promotion programs that combat routine and complacency

MOVING FORWARD

- Tailor safety programs and training to each new operating jurisdiction
- Find new channels to promote innovation and best practice sharing between ATCO companies and industry peers
- Following the UPR Program model, advocate for similar initiatives to improve public safety and efficient operations

At ATCO, every task and all decisions must be evaluated for potential safety hazards, and the job only gets done when it can be performed safely. Our employees and contractors are trained to know their responsibilities from day one on the job and this includes taking all precautions necessary to ensure their safety and the safety of others.

Our focus on safety includes the customers who use our products and services, as well as the general public who live and work near our operations. ATCO employees in the field are involved in a vast array of activities – from construction, to maintenance of natural gas and electrical facilities, to running power generation plants.

> A robust safety culture supports innovation and drives positive change in operating practices - including continuously adapting how we think and act, on and off the job.

Due to our diverse operations, each ATCO company translates core values into tailored, industry-specific safety policies and management systems that set expectations, provide comprehensive goals and measure performance. Audits and inspections are an integral part of continually improving safety performance. Safety performance is also reported in a consistent manner to the Audit & Risk Committee of ATCO's Board of Directors.

EMPLOYEE SAFETY
Everyone Has a Role

Continual improvement in our safety performance is achieved through visible commitment and active participation by management and employees. We ensure our staff and contractors can easily access the information and tools required to stay safe on the job every day.

Beyond having the right processes, procedures and training in place, it is equally important to promote a positive safety culture throughout ATCO. A robust safety culture supports innovation and drives positive change in operating practices - including continuously adapting how we think and act, on and off the job.

We regularly reinforce with our workers the need to pay attention to the decisions and actions they take every single day because distraction, complacency and routine are the enemies of safety. Taking the time to complete a task safely is paramount because we know that rushing and distraction are contributing factors in many incidents.

We also involve representatives from different areas of the organization on steering committees. Those who work on the front lines or in the field every day know where process improvement or additional communication are needed, where the potential for human error exists, or where pinch-points are likely to appear.

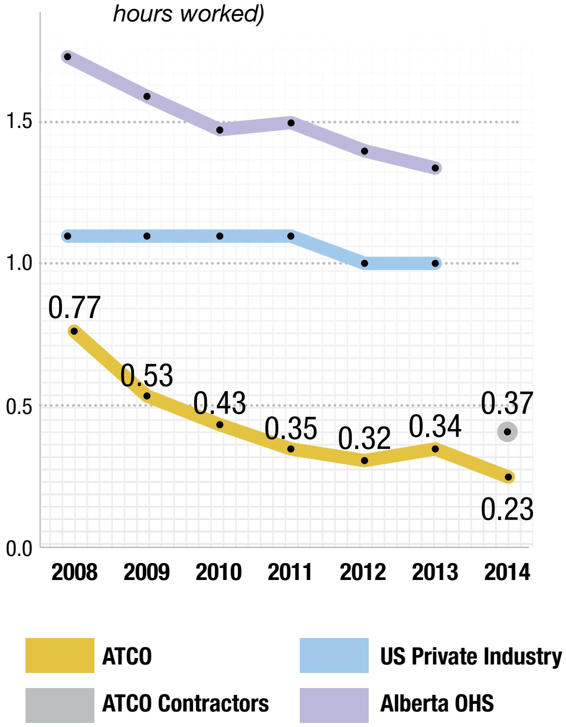
For example:

- The Safety Environment and Quality Steering Committee at ATCO Gas includes frontline employees in direction-setting;
- ATCO Power has a cross-company Health & Safety Advisory Team that includes managers, supervisors and operators who share safety information and review policies and initiatives before they are finalized;
- ATCO Electric Transmission established two Safety Improvement Steering Committees to develop comprehensive action plans to address top opportunities for improvement that were identified in a health and safety perception survey; and

Brendan Walton, Pressure B Welder, ATCO Gas, uses an emergency trench rescue device while welding a stopper fitting onto a steel main. The device is used when employees are working in confined or restricted spaces enabling them to be quickly lifted to safety should the need arise.

LOST TIME INJURY RATES

(cases per 200,000 hours worked)



Our employee lost-time injury rate has declined by more than 70 per cent since 2008. ATCO compares favourably with the general lost-time injury rate for Alberta Occupational Health and Safety as well as US Private Industry. We compare against these general benchmarks due to the diverse nature of the operations of our companies.

In cases where we direct the work of joint-venture employees, we include their data in employee safety statistics.

- ATCO Energy Solutions uses a monthly Operations Forum to discuss trends, review incidents and gain business unit support in the advancement of health, safety, security and environmental initiatives and concerns.

Managing and Reducing Safety Risk

As part of our efforts to manage and reduce risk, ATCO companies are proactively identifying ways to employ technology and partner with industry peers to develop and implement best practices. Examples include:

- In 2014, ATCO Gas completed a three-year automated meter reading project that saw the company replace or retrofit 1.1 million natural gas meters with devices that wirelessly transmit usage data to mobile collectors. This allows employees to read gas meters without entering customers' homes, yards or businesses, which improves billing accuracy and customer convenience. It also improves employee safety by reducing risks of falls and slips in the winter when going house-to-house.
- ATCO Electric partnered with industry peers and forestry companies to develop best management practices and guidelines for forestry activities near power lines. The goal was to create safe work practices by preventing forestry companies from leaving trees standing on the edges of 'cut blocks' during harvest operations. These trees are highly susceptible to toppling during heavy winds and storms and are estimated to cause 40 per cent of tree-related wildfires on power lines. To reduce the risk of future wildfires, an inventory and action plan for tree removal was completed.
- ATCO Gas commenced a pilot initiative to provide electronic tablets to field employees, which enables them to quickly access up-to-date detailed work instructions and safety information rather than referring to paper copies that could be out of date.
- In 2014, ATCO Structures & Logistics implemented new safety incident management software that provides a high level of transparency and in-depth analysis of the company's safety and environment data.

Sharing Best Practices

Sharing information, knowledge and industry best practices with partners, communities, key industry and interest groups, service providers and regulatory agencies is a vital part of our efforts to raise the bar on safety performance.

When choosing to work with external partners, we use safety pre-qualification processes to ensure that only those who share our safety values are selected to work on ATCO projects.

Inside our organization, ATCO's enterprise-wide Safety Network brings together safety managers from each ATCO company to discuss performance, learn from experiences and share industry best practices. The goal is to improve consistency and align practices to ensure all of our companies achieve excellence and continual improvement in health and safety performance.

In a similar manner, the 2014 ATCO Australia Safety Summit brought together employees from all three ATCO operating divisions in Australia to share knowledge and best practices.

PUBLIC SAFETY

Promoting Public Safety and Reducing Safety Risks

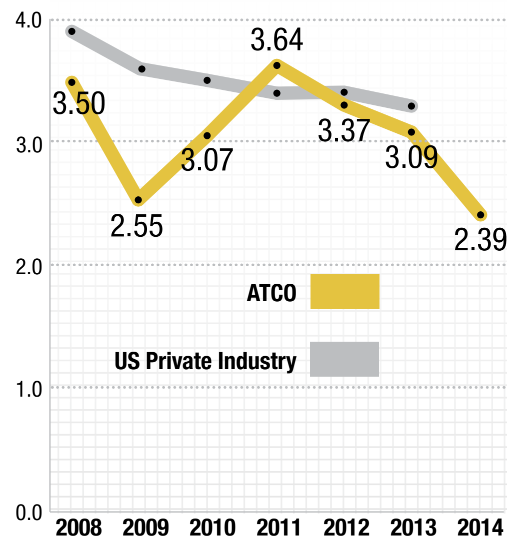
Our utility companies are responsible for the safe delivery of natural gas and electricity to our customers and they play a central role in promoting the safe use of natural gas and electricity to the public. Targeted programs have been developed for workers, homeowners and school children. The programs go beyond providing brochures and pamphlets to engaging, training and providing valuable services to these groups that will help them to stay safe.

For example:

- ATCO Pipelines and ATCO Gas are proactively undertaking the Urban Pipeline Replacement Program, which will see vintage high-pressure natural gas pipelines relocated into the Transportation Utility Corridors that surround Calgary and Edmonton. This initiative will improve gas supply into major cities and increase safety by minimizing the risk of any serious incidents.
- To support safety on the farm, ATCO Electric will help determine the best route for moving tall farming equipment to reduce the risk of contact with a power line.
- ATCO supports the Click Before You Dig program - a free service that identifies the location of underground utilities for homeowners or workers to prevent hits to natural gas lines.
- The Where's the Line safety campaign is co-sponsored by ATCO Electric and other members of Alberta's Joint Utility Safety Team. New television ads remind heavy equipment operators of the serious dangers of being complacent when conducting hazard assessments on the job site.
- In 2014, the Alberta Fire Commissioner and ATCO Gas took aim at carbon monoxide (CO) by showing Albertans how to keep their families safe with the first ever Carbon Monoxide Awareness Week held in Alberta. In 2014 alone, ATCO Gas responded to more than 3,200 service and emergency calls related to CO. The company received a Safety Leadership Award in Public Safety from the Canadian Gas Association for this initiative.
- ATCO has a number of kids' programs such as ATCO Energy Theatre, ATCO Blue Flame Kitchen's Kids Can Cook and the ATCO Energy Education Mobile that teach kids about natural gas and electricity safety, and about Alberta's energy resources and using energy wisely.

RECORDABLE INJURY RATES

(cases per 200,000 hours worked, employees only)



Our total recordable injury rate has declined by over 30 per cent since 2008. The decrease is mainly due to improvements in our manufacturing division with the implementation of behaviour-based safety training and increased sharing of lessons learned.

Elementary school audience → College/university audience → Adult audience

ATCO delivers public safety messages across broad demographic audiences. Scratch and sniff cards educate younger citizens to identify the smell associated with natural gas leaks. ATCO also engages with young adults leaving home for the first time with our Student Survival Guide. Included in this guide are safety messages primarily designed to eliminate fires. Adults are engaged through media campaigns for construction workers.

EMERGENCY RESPONSE AND DISASTER RECOVERY

ALWAYS THERE. ANYWHERE.

ATCO companies have unique expertise in emergency response – skills that have led them to a trusted role as first responders to an emergency.

ATCO is often a critical member of the emergency response planning team at the time of a crisis and provides input on the structure and approach of civic and provincial emergency management as it relates to our services.

ATCO Electric provides free power line safety training to emergency first responders in its service area including fire, ambulance, police and environment personnel. The half-day training program provides first responders with the information and tools they need to respond safely to electrical emergencies.

Similarly, ATCO Gas works with and provides safety training to local fire departments and first responders for emergency situations involving natural gas.

ATCO Electric and ATCO Gas also work with local officials to develop customized emergency preparedness guides for residents and businesses within their operating areas. These guides are part of Alberta's Emergency Preparedness Week in early May.

ATCO Structures & Logistics' rapid response capabilities and global presence have led the company to a role in providing emergency shelters for people who have been displaced from their homes due to emergencies. These structures are often up and ready to use in as little as two weeks and provide essential support to communities that are coping with the aftermath of a natural disaster.

Alberta has seen its share of weather-related emergencies in the past two years – including the floods of 2013 and severe wind and ice storms in 2014. ATCO Gas employees completed service restoration work during the 2013 floods under extreme conditions with zero injuries. As a result, the company and its people were recognized as Heroes of the Flood by the Government of Alberta.

ATCO Electric responded to two widespread weather-related outages in 2014. In spite of weather and electrical system challenges, the company continued to provide safe and reliable service to customers.

Employees

Our Commitment

ATCO is committed to:

- upholding the highest standard of ethical behaviour and maintaining a respectful work environment with an emphasis on teamwork;
- growing our talent through professional, leadership and occupational skills development as well as providing opportunities for career growth;
- ensuring competitiveness from a total compensation perspective;
- clearly communicating performance expectations and recognizing milestones and achievements; and
- enhancing the company's technical infrastructure to manage our large, diverse and geographically dispersed labour force in an efficient, effective manner.

Our Approach

ATCO started as a family business more than 65 years ago. Our enduring ethos is rooted in solid family values: work as a team, be responsible for your actions, always give your very best effort and make a difference in your community.

Senior ATCO Gas Draftsperson, Jean Bradley (right), collaborates with Draftsperson, Tatyana Minuyukova, and Junior Draftsperson, Sophearith Lay, to provide development opportunities for the two employees.

HIGHLIGHTS

- Improved development and collaboration opportunities for employees through increased cross-company transfers
- Enhanced leadership training and development programs
- Broadened online recruitment through the use of ATCO Careers, LinkedIn and Twitter

CHALLENGES

- Adopting communications methods that reach a younger workforce
- Ensuring employees have training and resources available in cases where integrated solutions with other ATCO companies can provide benefit to customers

MOVING FORWARD

- Match training and development required to career interests and goals
- Conduct an internal communications survey for all employees
- Increased focus on women in operational and leadership roles

Highly trained operators in our ATCO Pipelines Control Centre, such as Landon Kelly, use data from remote monitoring technology to safely manage the movement of natural gas in our pipelines 24/7.

Success in our companies depends upon the talent, commitment and expertise of our people. Our workforce of more than 9,000 represents a balance of seasoned professionals and those who are just starting their careers. We strive to offer benefits and programs that attract and retain individuals in all stages of their career – right from the early days through to retirement.

GETTING STARTED

Social media tools, such as LinkedIn, Facebook and Twitter, have become a vital part of our effort to reach and engage people who are our customers and our prospective employees. We continue to reach out directly to prospective employees through career fairs and some of our companies tap into employees' networks through referral programs.

Once the right candidate is found, orientation and onboarding can begin. The onboarding process can last from three months to upwards of one year, depending on the position. Our goal is to ensure new employees are welcomed and provided the right information to have the best start possible with the company.

Encouraging diversity

The diversity of operations at ATCO's worldwide companies demands a diverse, inclusive workforce. It is part of the ATCO Code of Ethics to provide a work environment free of discrimination and harassment, where employment opportunities are based upon merit and ability.

ATCO's overall recruitment goal is to hire the best candidate, so our companies do not generally ask prospective employees to self-identify into specific diversity categories nor do we set diversity quotas.

However, one ATCO company, ATCO Structures & Logistics, implemented an employment equity program in 2012 consistent with the Federal Contractors Program.

This program's goal is to achieve workplace equity for designated groups experiencing disproportionately low representation in the Canadian labour market, namely women, Indigenous people, those with a disability and members of visible minorities. This program encourages potential new hires to voluntarily identify themselves as belonging to one of these four groups that have historically experienced barriers to employment.

YOUR CAREER WITHIN ATCO

ATCO's strong performance is fuelled by the diversity of nine operating companies that span the manufacturing, utility and energy industries. This diversity allows us to create an organization that can not only withstand downturns in cyclic industries, but also stay the course and even seize opportunities during challenging economic times.

Many ATCO employees have grown and developed their careers as well as their knowledge of different industries by transferring from one ATCO company to another. Employees experience new challenges and opportunities by working at several different ATCO companies over the course of their career. In 2014, more than 170 employees saw career growth by transferring from one ATCO company to another.

Supporting learning and development

We strongly support our employees' desire to learn, develop and grow throughout their careers. Employees and their supervisors work together to create a development plan that meets the employee's and their team's goals for growth.

Employees have access to a variety of technical and non-technical training as well as career development opportunities.

In 2013 and 2014 combined, more than 1,700 employees participated in leadership training with more than $850,000 spent on these courses. In addition, in 2014, 40 employees participated in the Aboriginal Leadership Program offered through the University of Calgary.

ATCO's comprehensive leadership development programs build and enhance professional skills. We offer classroom and experiential learning opportunities through Mount Royal University in Calgary and the Ivey School of Business in London, Ontario.

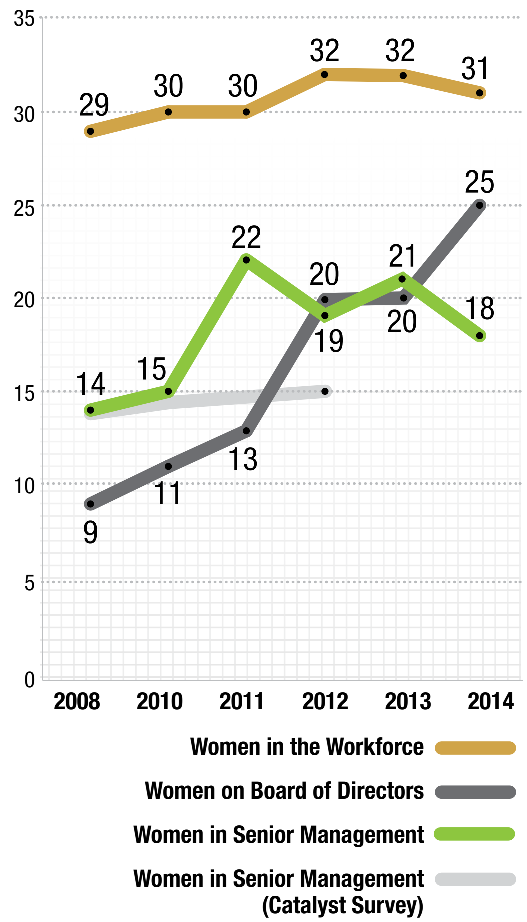
In 2014, all leadership development programs were integrated into the organization's Learning Management System providing employees the ability to view enterprise-wide leadership development courses, as well as schedule and track their training and career development activities.

We also reimburse employees up to 100 per cent for the cost of their post-secondary learning that can be applied to a career growth plan with the company, with the level of reimbursement depending on the applicability to their current role.

Our learning programs extend to the children of our employees who receive scholarship and bursary funds to help defray the costs of post-secondary education. In 2013 and 2014, ATCO bursary funds were $956,500 and $882,600 respectively.

It is part of the ATCO Code of Ethics to provide a work environment free of discrimination and harassment, where employment opportunities are based upon merit and ability.

WOMEN IN THE ATCO WORKFORCE *(%)*

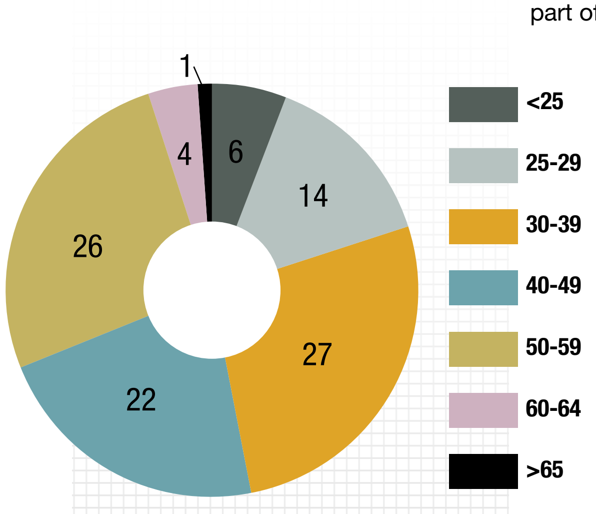


ATCO has increased women in senior management by 29 per cent since 2008.

In 2014, women represented 25 per cent of the ATCO Board. This is more than 40 per cent higher than the average female board member representation of Canada's Financial Post 500 companies of 17 per cent.

ATCO's Chair, President & Chief Executive Officer, Nancy Southern, is a member of the Canadian Advisory Council for Promoting Women on Boards.

WORKFORCE BY AGE *(%)*



We strive to create a workplace that appeals to all age groups. ATCO works to continuously improve and implement succession planning strategies to assist those employees in early career stages to effectively backfill long service employees and upcoming retirements.

Engaging employees through ATCO EPIC

ATCO employees are at the heart of the company's ATCO EPIC (Employees Participating In Communities) community engagement program. As part of the annual fall campaign, the employees of each ATCO company select charities that receive the funds raised through fundraising events. These feature charities work closely with each employee-led organizing committee to identify ways to educate and inspire ATCO employees about the cause they selected to support.

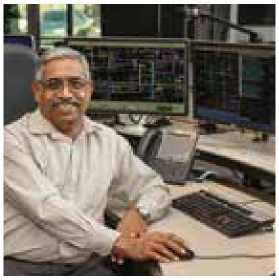
Another key component of the ATCO EPIC program is volunteerism. Employees who volunteer 50 hours or more with a charitable organization are eligible to apply for a donation to a registered charity of their choice.

In 2014, employees volunteered more than 28,000 hours to the communities where they work and live. During the ATCO EPIC campaigns, employees also participate in Days of Caring, a program that allows them to tackle projects in the community during work hours. Projects include refurbishing facilities, stocking food bank shelves and selling items to fundraise for charity. (See page 28 for more about ATCO EPIC.)

ATCO Employee Share Purchase Plan

The ATCO Employee Share Purchase Plan (ESPP) enables employees to become owners of ATCO and Canadian Utilities non-voting shares through regular payroll contributions. Employees choose the percentage of their gross earnings to contribute and ATCO matches a portion of their contributions.

In 2013, the employer contribution increased from 15 per cent to either 25 or 35 per cent, depending on how long the employee had been contributing to the plan. More than 58 per cent of



eligible employees participate in the ESPP. Employees also now have the option to transfer their unrestricted shares to Tax-Free Savings Accounts or Registered Retirement Savings Plan accounts.

MOVING ON

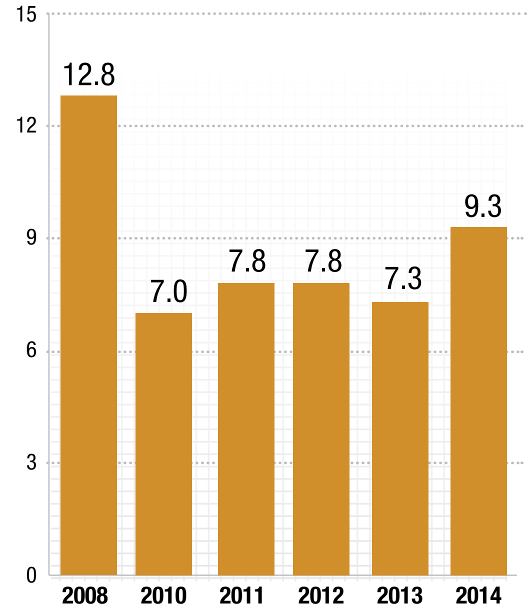
With North America's aging baby boomer workforce currently retired or on the verge of retirement, ATCO works to continuously improve and implement succession planning strategies to ensure the institutional knowledge of our older workers is passed down to the next generations.

ATCO offers eligible employees the opportunity to scale back on their work commitments over time with a graduated transition to retirement. This benefits ATCO and the employee while facilitating knowledge transfer and ensuring business continuity.

We also recognize that personal retirement planning is an essential element of overall benefit planning and retirement readiness. We provide people with training and tools to help them take an active role in achieving their financial goals.

ATCO companies are not immune to changes in commodity prices and other economic cycles. We make every effort to re-deploy people when one of our companies experiences layoffs.

VOLUNTARY TURNOVER RATES *(%)*



The voluntary turnover rate increased in 2014, predominantly as a result of some operating companies repositioning their business and employees realigning their career paths.

Communities

ATCO and Denendeh Investments Incorporated (DII), a First Nations-owned corporation, have been partners in Northland Utilities for nearly 30 years. Ceremonial drummers open an event in Yellowknife, N.W.T., to celebrate the signing of a Memorandum of Understanding that will see DII become equal owners with ATCO in Northland Utilities.

Our Commitment

ATCO is committed to contributing to the quality of life in the communities where we do business and where our people work and live.

We are committed to:

- seeking to understand and meet the needs and interests of the communities we serve;
- developing meaningful partnerships with non-profit organizations and supporting these partnerships through volunteer efforts as well as providing expertise and financial support;
- facilitating engagement with governing authorities, regulatory bodies, landowners, Indigenous and community groups that may be affected by our project proposals and operations worldwide; and
- building mutually beneficial commercial relationships with local suppliers.

Our Approach

Effective community engagement demands a long-term approach that is based on respect, trust and genuine openness to the needs and interests of our customers and the communities where we work and live.

HIGHLIGHTS

- Employees Participating In Communities (EPIC) program wins international award; expanding EPIC to Australia
- Successful public engagement on numerous projects
- Partnering with Indigenous and remote communities to build essential infrastructure

CHALLENGES

- Enabling flexible grassroots approaches to community relations while ensuring consistent standards
- Deferring the roll out of online Indigenous relations training for all employees to 2015

MOVING FORWARD

- Develop long-term relationships to create positive impact in new jurisdictions (e.g., Mexico)
- Find effective ways of quantifying community impact
- Roll out online Indigenous relations training

Our workforce includes more than 9,000 people who live and work in hundreds of communities around the world. We are thoughtful and respectful when engaging people who may be affected by our operations or when we are investing in community organizations.

We have an unwavering commitment to our customers' needs and strive to integrate our employees' first-hand knowledge of their communities into decision-making throughout the organization.

For new projects, we take a proactive grassroots approach and consult with communities early in the planning process and seek to understand and respond to their needs and concerns in an open, respectful manner. Best practices for consultation are shared across the ATCO companies.

We also have a long history of building and maintaining mutually beneficial relationships with Indigenous communities.

Our employees take the lead in their communities when it comes to community investment. Through the ATCO Employees Participating in Communities (EPIC) program, we ensure our investments reflect the needs of our communities and the interests of those who shape our company.

PUBLIC ENGAGEMENT

Given the broad and diverse nature of our businesses, our operations touch the lives of people around the world. We work to ensure our public engagement activities are accessible, transparent, receptive, responsive and accountable. As a provider of essential services, we have a key, long-term role to play in the communities that we serve.

The groups we engage may include, but are not limited to:

- community residents and landowners;
- customers and potential customers;
- Indigenous communities;
- governments and regulators;
- special interest groups and non-government organizations;
- investors and potential investors; and
- employees and potential employees.

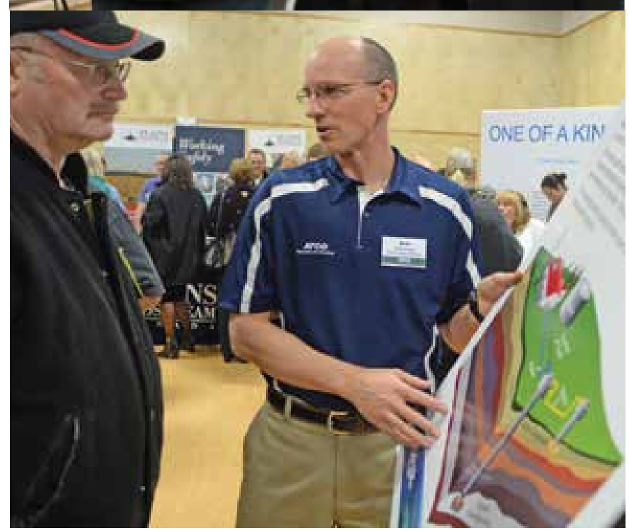
We engage to not only achieve our sustainability commitments and regulatory obligations, but also to earn the social license to operate that comes from positive, transparent, long-term relationships.

Our core stakeholder engagement plans are further supplemented by activities such as cross-functional advisory panels, landowner group meetings, information sessions, early engagement focus groups, surveys and questionnaires. There is no single right approach to the level or type of engagement and we continue to improve how we reach out and incorporate feedback.

Infrastructure

ATCO has been a trusted steward of utility infrastructure in Alberta for many years. This speaks to the quality and transparency of our community engagement and consultation processes as well as to our ability to build and manage safe, reliable and efficient utility infrastructure projects. The following examples from 2013-2014 illustrate the breadth of our engagement activities:

- ATCO Pipelines and ATCO Gas are working together on the Urban Pipeline Replacement (UPR) Program. After public consultation, ATCO Pipelines received approval to proceed with the UPR Program in January 2014. ATCO Gas is constructing new lower pressure distribution pipelines and is transferring some existing high-pressure pipelines to the ATCO Gas



Top: ATCO Pipelines employees from left, Vice President, Engineering & Construction, Jason Sharpe; Team Leader, Construction, Bill Martin; and Director, Field Operations & Pipeline System Control, Jim Yaremko, speak with community members at an Urban Pipeline Replacement Program open house. These open houses provide residents with an opportunity to learn more and provide feedback on the project.

Bottom: Bob Armstrong, Senior Manager, Project Execution, ATCO Energy Solutions, discusses the company's salt cavern storage facility, located in Alberta's Industrial Heartland, with a resident at a Community Information Evening in Gibbons.

distribution system to be operated at lower pressures. Additional public consultation activities for specific segments of the pipeline will be ongoing for both ATCO Pipelines and ATCO Gas over the duration of the program, which is expected to take five years to complete.

Employees celebrated the record-breaking $4.3 million raised by employees and the company for charitable causes during the 2014 ATCO EPIC campaign.

- In 2014, ATCO Electric piloted an early engagement program to explore a more proactive approach to building positive relationships and identifying transmission line route constraints. Questionnaires about routing priorities and a mapping exercise helped identify community priorities and valued land features for consideration for right-of-way planners in route option development. An overwhelming majority of survey participants - 97 per cent - indicated they "felt heard", while 88 per cent indicated they would be interested in participating again.
- Our long history in Alberta includes not only providing electricity and natural gas services to customers, but also providing industrial water solutions, hydrocarbon storage and power cogeneration for commercial customers in the province's Industrial Heartland, northeast of Edmonton. ATCO Energy Solutions, ATCO Pipelines and ATCO Power participated in open houses in 2014 to continue informing businesses, governments and communities of their projects that support growth in the region.

COMMUNITY COMMITMENT

ATCO is committed to helping create healthy, vibrant communities through initiatives that involve developing meaningful partnerships with non-profit organizations. We support these initiatives through volunteer efforts and by providing expertise and financial support.

ATCO also offers more than 90 scholarships and bursaries at post-secondary and trade institutions around the world, while supporting programs and events that encourage healthy, active lifestyles and help to build stronger communities.

ATCO EPIC

The ATCO EPIC (Employees Participating in Communities) fundraising program was launched in 2006 as a way to unite all of the ATCO companies' fundraising efforts and to make a more meaningful impact in communities. Since that time, the award-winning program has raised more than $28 million for more than 500 charities around the world, while also facilitating hundreds of thousands of employee volunteer hours.

The employee-led program involves fundraising events, volunteer activities and financial donations that employees direct to the charitable causes that matter most to them. ATCO enhances its people's generosity by matching donations to human health and wellness organizations. ATCO also covers all administration costs for the program, ensuring that the charities benefit from 100 per cent of the financial donations.

ATCO expanded its employee giving program in 2014 to include the employees working for ATCO Australia.

In 2014, ATCO was recognized as the year's Outstanding Corporation by the Association of Fundraising Professionals (AFP) for the company's many extraordinary contributions to philanthropy and to the charitable sector. In particular, the award recognized the ATCO EPIC program. The AFP represents more than 32,000 charities and charitable fundraisers around the world.

Economic impact

ATCO's broad network of operations and facilities has a significant economic impact in hundreds of communities around the world – we have operations in 350 communities in Alberta alone. We contribute to the economic vitality of the communities in which we operate through the taxes we pay, the jobs we create and the goods and services we purchase and supply.

INDIGENOUS RELATIONS

Building and sustaining mutually beneficial Indigenous relationships help to form the foundation of our global business activities.

The diversity of ATCO's businesses encourages a variety of relationships with Indigenous communities. These communities are our business partners, customers, employees, contractors and neighbours who are consulted and engaged.

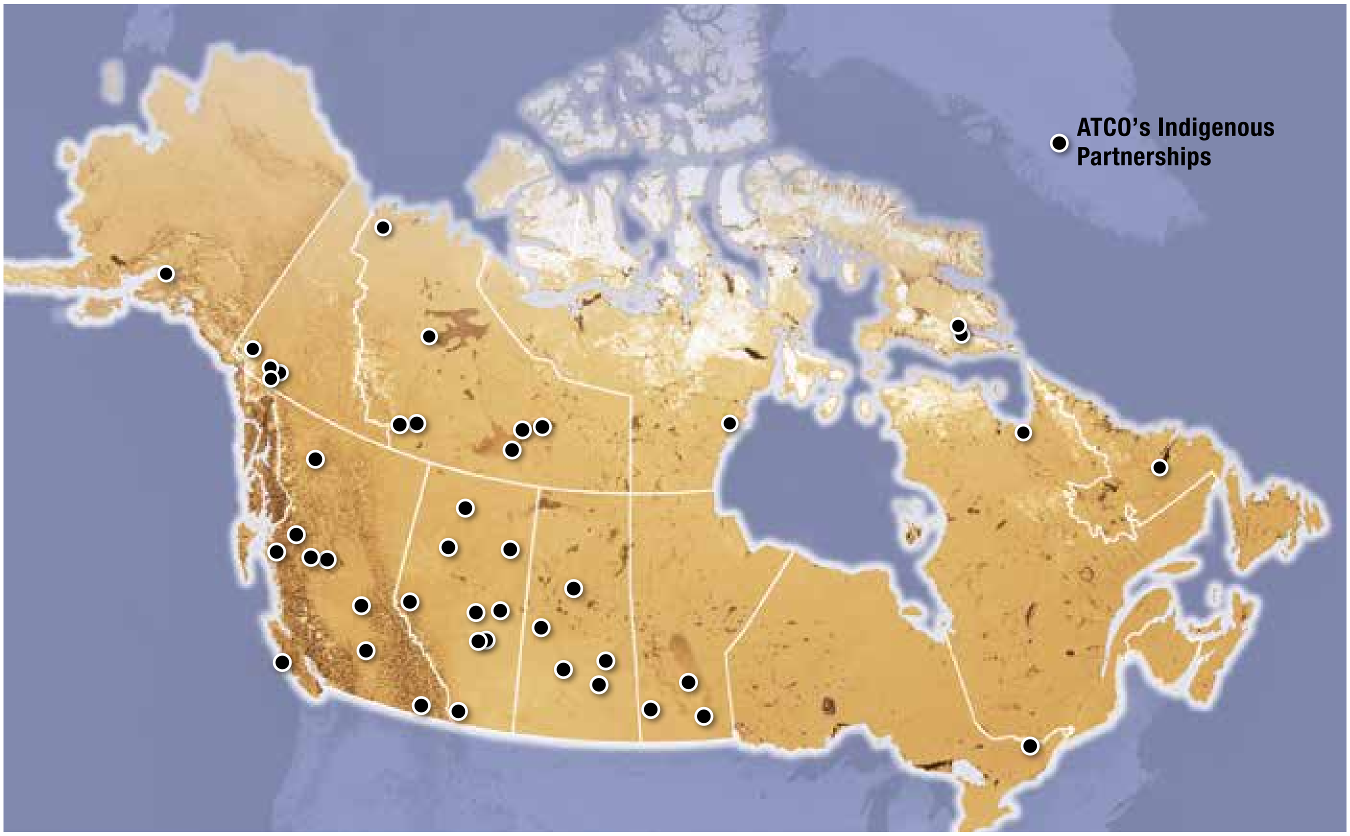
Partnerships that stand the test of time involve respect, trust, understanding and transparency. Each party commits to bringing value to the partnership and continues to negotiate in good faith as the relationship evolves over time. We conduct all of our business in this spirit, striving to maintain positive relationships that contribute to sustainable economic and social development in the communities where we do business.

Building stronger relationships

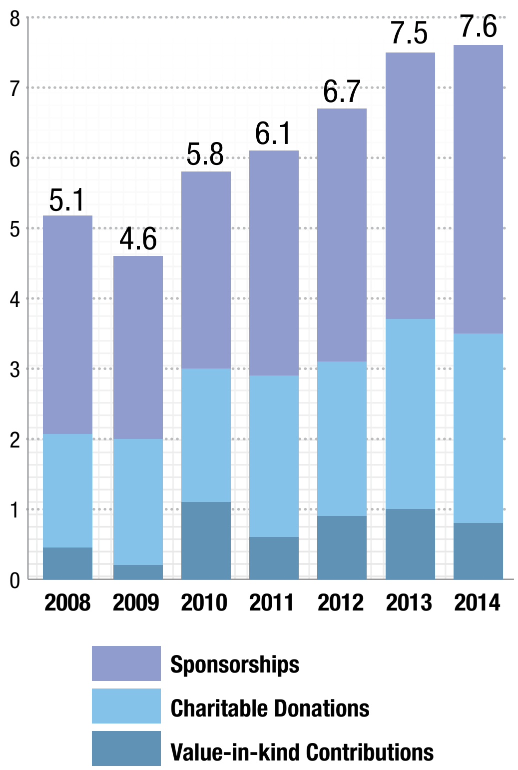
We have more than 40 joint-venture partnerships, Memorandums of Understanding and other relationships with Indigenous communities. Some of our Indigenous partnerships are celebrating more than 25 years of working together. (See map below.)

- Denendeh Investments Incorporated (DII), a First Nations-owned corporation, and ATCO have been partners in Northland Utilities for nearly 30 years. In early 2015, DII, which represents 27 Dene Nations in the North, became equal partners with ATCO in the company, increasing its ownership from 14 to 50 per cent. Northland Utilities provides retail, distribution, transmission and generation services to more than 11,000 customers in nine Northwest Territories communities. More than 25 per cent of Northland Utilities employees are Indigenous and the company has a number of programs in place to build capacity with Indigenous people, such as job shadowing, apprenticeship training and a variety of roles in the engineering field.

Nancy Southern, Chair, President & Chief Executive Officer, with Darrell Beaulieu, President, Denendeh Investments Incorporated (DII), at signing ceremony in Yellowknife, N.W.T.



COMMUNITY INVESTMENT
($ millions)



ATCO's total sponsorship, donation and value-in-kind contributions, excluding employee donations. Charitable Donations includes the ATCO portion of the EPIC donation, as well as other donations.

- In 2014, ARCTEC Alaska, a longstanding joint-venture partnership between ATCO Structures & Logistics and ASRC Federal Primus, won a 10-year contract to provide operations and maintenance services to 15 strategic radar sites that form the Alaska Radar System. ARCTEC is responsible for maintaining the geographically isolated radar sites (accessible only by air or seasonal barge). ASRC Federal Primus is a wholly owned subsidiary of Arctic Slope Regional Corporation, an Alaska Native Corporation owned by approximately 11,000 Iñupiat shareholders.
- ATCO Structures & Logistics operates the Bluesky Lodge through its joint venture with the Woodland Cree First Nation. The lodge provides living quarters for workers at the nearby Shell Carmon Creek heavy oil project near Peace River, Alberta. The lodge's workforce includes Indigenous employees who have roles in camp management and other services. In 2014, the relationship with the Woodland Cree was expanded to include on-the-job apprentice and kitchen skills training.

We also established new partnerships in 2014:

- ATCO Energy Solutions signed a Relationship Agreement with the Simpcw First Nation in BC that will see the two parties jointly pursue a number of sustainable business opportunities related to energy infrastructure development.
- ATCO Power signed a joint-venture agreement with the Sahtu Dene Council to focus on developing renewable energy projects in the Sahtu region of the Northwest Territories.
- ATCO Structures & Logistics signed a joint-venture partnership with the Alexander First Nation in Alberta to pursue business opportunities and began another joint venture with the Naha Dehe (Nahanni Butte Dene Band) in the Northwest Territories.

In 2014, the Canadian Council for Aboriginal Business recognized ATCO Structures & Logistics for its work in engaging Indigenous communities with a silver-level certification from the Progressive Aboriginal Relations program. The program independently certifies and evaluates all aspects of a company's Indigenous relations, including strategy, policies, employment, community engagement and investment, while providing valuable feedback for continued improvement.

Education, mentorship and employment

ATCO supports recruitment, education and training initiatives for Indigenous Peoples as part of an overall workforce strategy to meet our labour force needs. We make every reasonable effort to address internal, cultural and community barriers that impede the employment of Indigenous Peoples in our companies. Joint-venture partnerships often provide Indigenous communities with valuable work placement opportunities and on-the-job training. In turn, ATCO benefits through diversity and much-needed skilled labour for its projects.

We also provide Indigenous awareness training for our employees. ATCO sponsors a four-day Aboriginal Relations Leadership Certificate program at the University of Calgary. Since the program began in 2012, more than 450 University of Calgary students and 100 ATCO employees have participated.

ATCO also maintains ongoing educational awards and scholarship programs that provide valuable financial assistance to Indigenous students pursuing post-secondary education.

ATCO SUSTAINABLE COMMUNITIES

ATCO Sustainable Communities is in its third year of operation providing a full range of prefabricated, culturally-sensitive building solutions for Indigenous and remote communities.

Understanding our customers' specific cultural and physical requirements allows ATCO Sustainable Communities to identify solutions that best meet their customers' needs. Our engagement process welcomes and encourages community-owned businesses and members to participate through the life cycle of a project. Identifying and incorporating local resources strengthens the partnership and helps ensure project success.

Following project completion, we offer specific training and education programs to ensure qualified resources exist in the community to manage the infrastructure over the long term.

In 2014, seven projects were either completed or nearing completion across Canada including:

- **a gas station at Dene Tha' First Nation near Meander River, Alberta;**
- **fire halls at Peerless Trout First Nation near Slave Lake, Alberta, and Attawapiskat First Nation in Attawapiskat, Ontario;**
- **a school expansion for the Blood Tribe in southern Alberta; and**
- **community centres in Nain, Newfoundland and Labrador, and at Swan River First Nation in Kinuso, Alberta.**

Councillor Fabian North Peigan (left) from the Piikani Nation and Dean Seiz, ATCO Sustainable Communities, at a land blessing ceremony for the Piikani Nation's new Multipurpose Centre to be constructed by ATCO Sustainable Communities. The facility is scheduled for completion in early 2016 and will provide a new space for the community to gather and participate in hockey and other recreational activities year-round.

2014 recipients Danielle Lightning (left) and Danika Lightning (right) celebrate after receiving scholarships through the ATCO Pipelines Indigenous Education Awards Program. The program recognizes students from Indigenous communities who demonstrate leadership capabilities and strive to be role models in their schools and communities.

Performance Summary

Indicator[1]	Units	2008	2009	2010
ENVIRONMENT				
Air Emissions[2]				
Direct GHGs	kilotonnes CO_2e	17,049	15,847	15,205
Indirect GHGs[3]	kilotonnes CO_2e	-	-	-
Sulphur dioxide	tonnes	63,182	53,825	56,244
Nitrogen oxides	tonnes	26,566	24,626	24,523
Particulate matter (PM2.5)	tonnes	510	501	523
Carbon monoxide	tonnes	3,768	3,552	3,297
Volatile organic compounds	tonnes	168	162	148
Mercury	kilograms	157	181	189
Ozone depleting substances	kilograms	77	6	0
Water Use[4]	million m^3	22.1	21.6	19.1
Spills[5]				
Number		-	16	11
Volume	litres	-	47,820	5,130
Hazardous Waste	tonnes	-	-	-
Environmental Fines and Penalties	$	0	0	0
SOCIAL[6]				
Health & Safety[7]				
Lost time injury rate (employees)	Cases/200,000 hours worked	0.77	0.53	0.43
Lost time injury rate (contractors)[8]	Cases/200,000 hours worked	-	-	-
Recordable injury rate (employees)	Cases/200,000 hours worked	3.50	2.55	3.07
Fatalities (employees)	number	0	0	1
Fatalities (contractors)	number	0	0	0
Employees[9]	number	7,781	7,524	7,726
Voluntary Turnover Rate[9]	per cent	12.8	-	7.0
Employees in Employee Unions or Associations[9]	per cent	54	-	56
Non-compliance incidents regarding safety of products and services	number	-	0	0
Diversity[9]				
Women in workforce[10]	per cent	29	-	30
Women in senior management	per cent	14	-	15
Women on Board of Directors	per cent	9	-	11
Human Rights and Ethics Incidents				
Discrimination incidents	number	-	0	0
Indigenous rights incidents	number	-	0	0
Corruption incidents	number	-	0	0
Customer Privacy Breaches[11]	number	40	82	83
Number of Regulatory Non-compliance Incidents	number	-	-	-
Fines and Penalties for Regulatory Non-compliance	$	-	-	-
ECONOMIC[12]				
Economic Value Generated[13]	$ million	3,266	3,109	3,486
Economic Value Distributed				
Suppliers	$ million	1,127	1,064	1,412
Employees[14]	$ million	466	405	540
Lenders	$ million	239	244	231
Shareholders	$ million	166	183	196
Governments[15]	$ million	365	358	343
Communities[16]	$ million	5	5	6
Economic Value Retained[17]	$ million	897	850	758
Financial Assistance Received from Governments[18]	$ million	-	3.28	3.42
Coverage of Defined Benefit Pension Plan Obligations	per cent	99	99	89

2011	2012	2013	2014
15,217	13,290	12,913	12,909
275	275	269	254
61,294	57,357	55,734	54,273
27,126	24,360	24,277	23,806
559	573	533	606
3,879	3,263	3,264	3,207
358	280	344	335
81	63	53	44
66	1	11	18
19.4	19.8	19.5	20.1
20	11	16	20
12,158	3,165	38,376	63,881
886	839	678	1,005
0	1,000	0	0
0.35	0.32	0.34	0.23
-	-	-	0.37
3.64	3.37	3.09	2.39
0	0	0	0
0	2	0	0
8,891	9,428	9,816	9,170
7.8	7.8	7.3	9.3
52	50	51	53
0	0	0	0
30	32	32	31
22	19	21	18
13	20	20	25
0	0	0	0
0	0	0	0
0	0	0	0
86	42	2	15
0	0	2	2
0	0	7,750	7,750
3,991	4,012	4,359	4,554
1,704	1,518	1,659	1,807
590	669	705	716
244	286	312	343
212	222	234	254
323	387	401	407
6	7	8	8
912	923	1,040	1,019
2.37	0.51	0.41	0.38
85	80	92	89

We strive to continually improve our tracking and measurement systems, and may adjust indicator definitions and performance data to reflect current best practice. In most cases, we use standard industry and regulatory calculation methodologies and definitions that may be updated periodically to improve accuracy.

NOTES

1 This report includes performance data on indicators that were not included in all previous reports. Data for the new indicators for previous years is not included, and is denoted with a "-" symbol.

2 Emissions figures include amounts that are required to be reported under federal, provincial, regional or other regulations, or under facility permits. We use standard industry calculation methodologies and emission factors, which sometimes change to be more accurate. Due to such changes, the figures for particulate matter, carbon monoxide and volatile organic compounds have been re-stated since the publication of our last report.

3 Data for indirect emissions currently includes six of our operating companies.

4 Water use = water diverted minus water returned to source. Includes estimated data from ATCO Australia, ATCO Electric Yukon, ATCO Energy Solutions, ATCO Pipelines, ATCO Structures & Logistics, and ATCO Power. Includes water for process use; does not include water used for domestic purposes. We estimate that these figures account for more than 99 percent of our water use.

5 Includes spills of the sizes that meet the thresholds for regulatory reporting in the jurisdiction in which they occurred. Volume spilled is often estimated due to variables such as duration, location and when the spill was identified. 2010 volume spilled has been restated since the publication of our last report. We improved reporting from previously including only significant spills, to now including all reportable spills, starting in 2011.

6 We are not able to report data for some employee indicators for 2009 because we integrated multiple data management systems into one during that year.

7 In cases where we direct the work of joint venture (JV) employees, we include their data in safety statistics.

8 Figures previously reported for 2012 and 2013 are not included here due to the discovery of inaccurate tracking of contractor exposure hours in those years, and the inability to recalculate the rates.

9 Does not include JV employees.

10 Does not include international employees.

11 All incidents were resolved successfully, and typically involved a call centre agent providing information to a caller who was not listed as an additional responsible party.

12 Figures for 2012 economic value generated, distributed and retained have been restated for the application of IFRS 11 Joint Arrangements requiring equity accounting for joint ventures and reclassifications resulting from discontinued operations. Prior years have not been restated.

13 Economic value generated includes revenues, gains on asset dispositions, and interest income.

14 Payments to employees include the expensed cost of wages and benefits.

15 Payments to governments include income, property, and franchise taxes.

16 Distributions to communities include donations, in-kind contributions, and sponsorships.

17 Economic value retained is economic value generated minus economic value distributed. This is not a financial reporting indicator and should not be confused with retained earnings.

18 Financial assistance received from governments includes tax relief/ credits, investment grants, R&D grants, financial awards, and favourable financing terms from domestic and foreign governments.

GRI Content Index

This report has been prepared using the Global Reporting Initiative's (GRI) 3.1 Sustainability Reporting Guidelines. The GRI Guidelines are the world's most widely referenced standards on sustainability reporting and disclosure. We self-declare this report and associated disclosures on our website as achieving Application Level B. Application levels reflect the level of disclosure and are not representative of sustainability performance. For more information on the GRI please visit **www.globalreporting.org**.

Category	GRI Indicator	Description	Page #
Strategy & Analysis	1.1	CEO statement	4-5
	1.2	Key impacts, risks and opportunities	10-13, 17-18, 27-31
Organizational Profile	2.1	Company name	8
	2.2	Primary brands, products, and/or services	2-3
	2.3	Operational structure	2-3
	2.4	Location of headquarters	Back Cover
	2.5	Countries where ATCO operates	2-3
	2.6	Nature of ownership and legal form	6
	2.7	Nature of markets served	2-3
	2.8	Scale of the company	2
	2.9	Significant changes during reporting period	8
	2.10	Awards received	IBC
Report Parameters	3.1	Reporting period	8
	3.2	Date of most recent previous report	8
	3.3	Reporting cycle	8
	3.4	Contact point for questions	Back Cover
	3.5	Process for defining report content	8
	3.6	Boundary of report	8
	3.7	Limitations on report scope or boundary	8, 33 (Notes)
	3.8	Basis for reporting on non-wholly owned operations	8
	3.9	Data measurement techniques and the bases of calculations	8
	3.10	Explanation of information restatements	8, 33 (Notes
	3.11	Significant changes in measurement	33 (Notes)
	3.12	List of GRI indicators addressed	34
	3.13	Policy and current practice on external assurance of report	Note 1
Governance, Commitments & Engagement	4.1	Governance structure, including major committees under the Board	6
	4.2	Independence of Board chair	6
	4.3	Independent, non-executive directors on Board	MPC p. 18
	4.4	Mechanisms for shareowner participation	MPC p. 25
	4.5	Link between compensation and ATCO's performance (including social and environmental performance)	MPC p. 44
	4.6	Processes for the Board to avoid conflicts of interest	MPC p. 25
	4.7	Process for determining qualifications and expertise of Board members for guiding ATCO's sustainability strategy	MPC p. 17
	4.8	Mission and values statements, internally developed codes of conduct or principles and policies	7
	4.9	Organizational structure for economic, environmental and social management	7
	4.10	Processes for evaluating Board performance, particularly with respect to economic, environmental, and social performance	MPC p. 24
	4.11	Application of the precautionary principle	Note 2
	4.12	Adoption of externally developed sustainability charters or principles	IBC
	4.13	Association memberships	IBC
	4.14	Stakeholder groups engaged	27
	4.15	Basis for identification and selection of stakeholders with whom to engage	27

Category	GRI Indicator	Description	Page #
	4.16	Approaches to stakeholder engagement	26-30
	4.17	Key topics and concerns raised through stakeholder engagement	28
Economic	EC1	Direct economic value generated and distributed	32-33
	EC3	Coverage of defined benefit plan obligations	32-33
	EC4	Significant financial assistance received from government	32-33
Environmental		Disclosure on Management Approach - Environment	Website
	EN6	Initiatives to provide energy-efficient products and services	11
	EN7	Initiatives to reduce indirect energy consumption	11-12
	EN8	Water use	15, 32-33
	EN14	Strategies, actions and plans for managing impacts on biodiversity	12
	EN16	Greenhouse gas emissions	13, 32-33
	EN18	Initiatives to reduce greenhouse gas emissions	11, 13
	EN19	Emissions of ozone depleting substances	13, 32-33
	EN20	NOx, SOx, and other significant emissions	13, 32-33
	EN22	Wastes	32-33
	EN23	Number and volume of significant spills	14, 32-33
	EN28	Environmental non-compliance and fines	32-33
Social		Disclosure on Management Approach - Employees	Website
	LA1	Workforce profile	23-24, 32-33
	LA2	Employee turnover rate	25, 32-33
	LA4	Employees in employee unions or associations	32-33
		Disclosure on Management Approach - Safety	Website
	LA7	Standard injury and lost day rates and fatalities	17-19, 32-33
	LA13	Diversity	22-24, 32-33
	HR4	Incidents of discrimination and actions taken	32-33
	HR9	Incidents of violations of indigenous rights and actions taken	32-33
		Disclosure on Management Approach - Communities	Website
	SO4	Incidents of corruption and actions taken	7
	SO5	Participation in public policy development	7
	SO7	Incidents of anti-competitive behaviour	7
	SO8	Regulatory non-compliance and fines	7, 32-33
	PR2	Non-compliance incidents regarding safety of products and services	32-33
	PR8	Customer privacy breaches	7, 32-33

Notes

1 Senior management and relevant staff have reviewed all information and believe it is an accurate representation of our performance. We undertook a variety of internal and external assurance activities on information presented in this report, including financial, environmental, health and safety performance, and management systems. However, third-party assurance of this report has not been conducted.

2 Although ATCO has not formally adopted the precautionary principle (as described in the U.N. Rio Declaration of 1992), our implementation of sustainability practices demonstrates a commitment to proactively identify, and prevent or mitigate negative impacts.

MPC = 2014 Management Proxy Circular.

IBC = Inside Back Cover.

ASSOCIATIONS AND INITIATIVES

ATCO companies participate in a variety of industry associations and related groups to understand and share best practices. The major groups include:

- Alberta Common Ground Alliance
- Alberta Energy Efficiency Alliance
- Alberta One-Call
- Alberta Power Industry Consortium
- Alberta Water Council
- American Gas Association
- Australian Institute of Energy
- Australian Pipeline & Gas Association
- Canadian Council for Aboriginal Business
- Canadian Electricity Association
- Canadian Energy Partnership for Environmental Innovation
- Canadian Energy Pipeline Association
- Canadian Gas Association
- Canadian Natural Gas Vehicle Alliance
- Canadian Off Grid Utilities Association
- Clean Air Strategic Alliance
- Committee for Economic Development of Australia
- Electric Power Research Institute
- Energy Networks Association (Australia)
- Energy Supply Association of Australia
- International Council on Large Electric Systems
- Modular Building Institute
- Pipeline Research Council International
- Utility Vegetation Management Association
- Various business associations and chambers of commerce
- Various safety-related associations
- Various watershed and airshed alliances
- Western Energy Institute

We have also signed on to or subscribe to the following externally developed initiatives that specify sustainability related principles or commitments:

- Canadian Energy Pipeline Association Integrity First® Program
- Sustainable Electricity Program (Canadian Electricity Association)

RECOGNITION

External recognition we receive for our initiatives and operational excellence is a measure of our performance and gives us a benchmark for further improvement in these activities. The following is a sample of the significant external recognition we received in 2013-2014:

- Alberta Professional Planners Institute: 2013 Award of Planning Merit for Special Studies, for ATCO Electric's Historical and Archaeological Protection Program
- Association of Fundraising Professionals (AFP): 2014 Outstanding Corporation, for numerous initiatives, including ATCO EPIC
- Canadian Council for Aboriginal Business: 2014 Silver-Level Certification in Progressive Aboriginal Relations, for ATCO Structures & Logistics
- Canadian Gas Association: 2014 Leadership Award in Public Safety, for ATCO Gas' Carbon Monoxide Awareness Week
- Electricity Human Resources of Canada: 2014 Award of Excellence for training management system
- International Energy Agency Solar Heating Programme: 2013 SHC Solar Award, for involvement in Drake Landing
- Alberta Roadbuilders & Heavy Construction Association: 2014 Environment Award, for ATCO Pipelines' Elbow River pipeline exposure mitigation project

Andrew Watt, President & CEO, AFP, (left) presents Erhard Kiefer, Senior Vice President & Chief Administration Officer, ATCO Group, (right) with the 2014 Outstanding Corporation Award.

For more information, contact ATCO at sustainability@atco.com

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