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September 28, 2020

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

Attention: Ms. Marija Tresoglavic, Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599120

Annual Review for 2020 and 2021 Delivery Rates (Application)

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On August 12, 2020, FEI filed the Application referenced above. In accordance with BCUC Order G-209-20 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page no.**

A. SERVICE QUALITY INDICATORS

1.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2 (Application), Section 1.4, pp. 8–9

Directions from previous BCUC Decision

In the British Columbia Utilities Commission's (BCUC) Decision on the 2020-2024 Multi-Year Rate Plan (MRP), the BCUC directed the content for annual review filings:

> Review of the Utilities' performance with respect to SQI's [Service Quality Indicators]. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service;
>
> 5. Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews; [1]

1.1 Please explain whether FortisBC Energy Inc. (FEI) recommends any new SQIs that should be reviewed in future annual reviews. In your response, please provide any relevant assessments.

Response:

As stated in Table 1-1 of the Application, FEI does not have any recommendations for new SQIs to be considered at this time.

FEI recently completed an assessment of the SQIs as part of the MRP Application process. Based on the assessment, FEI replaced its Informational Indicator of Telephone Abandonment Rate with another Informational Indicator, Average Speed of Answer, but otherwise determined that the set of SQIs used during the previous PBR term continued to remain appropriate and useful in monitoring service quality during the MRP. In its recent decision on the MRP, the BCUC approved the SQIs as proposed by FEI to use in monitoring service quality.

[1] BCUC FEI MRP 2020-2024 Decision, p. 167.

B. LOAD FORECAST

2.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 3.2, p. 13

Demand forecast methodology

FEI states on page 13 of the Application that the demand forecast methodology for 2020 and 2021 is consistent with the forecasting method followed by FEI in previous years.

2.1 Please explain when FEI last conducted a comprehensive review of FEI's current demand forecast methodology for the purpose of setting rates.

Response:

FEI last conducted a review of the residential use rate, commercial use rate and commercial customer additions methods in the years spanning 2015 through 2019. In FEI's Annual Review for 2015 Rates Application, FEI's forecasting methods were reviewed in detail by the BCUC, and in its Decision and Order G-86-15, the BCUC directed FEI to review alternative methods for forecasting residential use rates, commercial use rates and commercial customer additions.

As directed, FEI reviewed a variety of forecasting methods and identified the ETS method as a candidate to replace the existing methods, although the data was initially insufficient to determine whether ETS was indeed superior. To further investigate the ETS method, FEI ran parallel forecasts using its existing method and the ETS method and reported the results at each Annual Review from 2016 through 2019. FEI's reports to the BCUC can be found online here:

- Annual Review for 2016 Delivery Rates, Appendix A3 - Demand Forecast Methodology, pg. 192: https://www.bcuc.com/Documents/Proceedings/2015/DOC_44495_B-2_FEI_Annual-Review-2016-Rates-Application.pdf
- Annual Review for 2017 Delivery Rates, Appendix A4 – Forecasting Directives: https://www.bcuc.com/Documents/Proceedings/2016/DOC_46873_B-2_FEI-Annual-Review-2017-Materials.pdf
- Annual Review for 2018 Delivery Rates, Appendix A3 – Demand Forecast Methods: https://www.bcuc.com/Documents/Proceedings/2017/DOC_49752_B-2_FEI_Annual_Review_2018_Rates.pdf
- Annual Review for 2019 Delivery Rates, Appendix A3 – Demand Forecast Methods: https://www.bcuc.com/Documents/Proceedings/2018/DOC_52169_B-2-FEI-Annual-Review-2019-Rates-Appl.pdf

In Appendix B2 of its 2020-2024 Multi-Year Rate Plan (MRP) Application, FEI provided the final result of its investigations into alternative forecasting methods and recommendations. FEI recommended switching to the ETS method for the residential and commercial use rate forecast. As FEI's analysis showed that the existing method for forecasting commercial customer additions was superior to the ETS method, FEI did not recommend any change to that component of the forecast. Appendix B2 to the MRP Application can be found online here: https://www.bcuc.com/Documents/Proceedings/2019/DOC_53565_B-1-1-FortisBC-2020-2024-Multi-YearRatePlan-Appendices.pdf

FEI has not conducted a review of its residential customer additions forecast because the current CBOC forecast method is the only guidance FEI is aware of that forecasts both BC single and multi-family housing starts independently. As the housing market transitions to more multi-family dwellings this distinction will continue to be important. In its Decision on FEI's Annual Review for 2015 rates, the BCUC did not direct FEI to include the residential customer additions forecast in its review of alternative forecasting methods, stating:

> **The Panel approves FEI's 2015 forecast for residential net customer additions and accepts the use of CBOC housing starts as a proxy for these additions.** Given that FEI capture rates are significantly different for single family versus multi-family dwellings, the disaggregated forecast provided by CBOC is a valuable tool for information which may not otherwise be readily available. Moreover, the impact on rates is small given the relatively minor impact a small variance on net customer additions has on total customers in a given year.

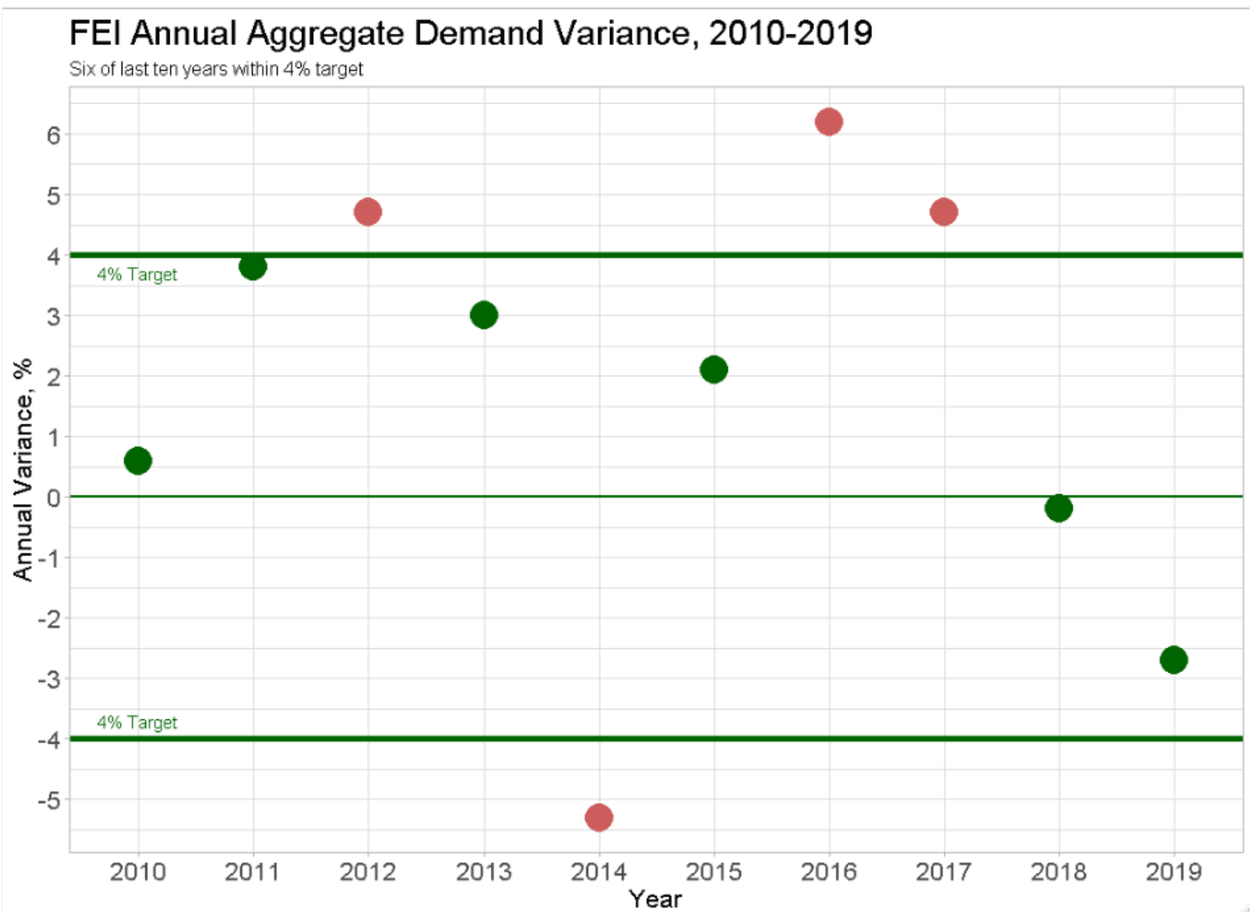
Additionally, FEI has not conducted a review of its industrial survey forecast. FEI has more than 1,000 industrial customers that span 80 industrial segments and, as a result, each customer is in the best position to forecast its future demand. Since 2014, the average annual industrial forecast error has been just over 2 percent. In its Decision on FEI's Annual Review for 2015 rates, the BCUC did not direct FEI to include the industrial forecast in its review of alternative forecasting methods, stating:

> **The Panel approves the FEI 2015 industrial demand forecast as filed.** FEI, in our view, has taken steps to identify the source of problems with industrial demand forecasting and made some progress in initiating measures which may begin to address the problem and improve forecast accuracy. In addition, FEI has been directed to make improvements to its Rate Schedule 22 forecasting methodology and expects to address these in its upcoming annual review application to be filed later in 2015. As a further consideration, variances in industrial forecast demand are a flow-through item and by their nature are self-correcting. Therefore, the issue is one more of timing rather than risk. Given these factors, the Panel considers the FEI 2015 industrial demand forecast to be reasonable.

In its report filed as Appendix A4 to FEI's Annual Review for 2017 Rates Application, FEI established 4 percent as a reasonable target for residential and commercial demand variations. This target was informed by the results of two ITRON surveys and a survey of similar utilities performed by Boreas Consulting. The internal 4 percent target was the mean absolute percent error (MAPE) and was established based on seven years of survey results. FEI has updated this data with ITRON survey results[2] from 2016 through 2019 in the following table.

ITRON, Gas	2014	2015	2016	2017	2018	2019	Average
Respondents	15	9	8	13	16	12	
Average variance	4.4%	4.0%	2.4%	6.3%	5.1%	5.7%	4.7%

The table above shows that the internal 4 percent target established in 2017 is lower than the most recent 6-year average of 4.7 percent from the ITRON survey. Therefore, FEI considers a 4 percent variance to be a reasonable target for its aggregate demand forecast. The following figure shows the aggregate demand variances compared to this target.



As shown above:

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[2] FEI has not participated in this survey.

- FEI's forecast performance has been better than or equal to the target in six of the past ten years;
- Variances are expected to fluctuate above and below 0 percent and will occasionally exceed the 4 percent target;
- In terms of consecutive forecasts, 2018 and 2019 performed better than all prior years; and
- There is no trend towards exceeding the target variance.

2.1.1 Please discuss whether FEI routinely conducts its demand forecast methodology. If yes, please explain the frequency of when a comprehensive review of its demand forecast methodology is conducted. If not, please explain why not.

Response:

FEI assumes that the question should read "Please discuss whether FEI routinely conducts a comprehensive review of its demand forecast methodology." The underlined words have been added.

FEI does not routinely conduct a comprehensive review of its forecast methods, as reviews are costly, resource and time intensive and FEI's forecasting methods have been working well. Comprehensive reviews should only be conducted if there is some objective reason to believe that the existing forecast methods need improvement or review, such as a trend of consistently high variances above available benchmarks. Specifically, FEI believes that a comprehensive review of its forecast methods should be conducted when the absolute aggregate demand forecast variance is higher than the target 4 percent for five consecutive years.

2.1.2 Please explain the factors that would suggest a need for a comprehensive review of FEI's demand forecast methodology.

Response:

Please refer to the response the BCUC IR1 2.1.1.

3.0 Reference: LOAD FORECAST

Exhibit B-2, Section 3.3.1.1, p. 15; Appendix A3, p. 6; Conference Board of Canada Provincial Outlook Economic Forecast Summer 2020, dated August 24, 2020[3]

Forecast Methodologies: Residential Customer Additions

In FEI Annual Review for 2020 and 2021 Delivery Rate Application (Application), FEI states:

> Consistent with past practice, FEI uses the Conference Board of Canada (CBOC) housing starts forecast as a proxy for residential net customer additions. The CBOC data used for the forecast, in Appendix A3, was issued prior to the start of the pandemic and, at the time of this filing, the CBOC had not issued an updated single or multi-family forecast.

Further, in Appendix A3, FEI states:

> The residential net customer additions forecast was developed based on housing starts data from CBOC forecast of December 5, 2019, Provincial Medium-Term Forecast: 20173 Run: 18, Table LTPF156 and LTPF157. The housing starts data was as follows:

Table A3-3: Housing Starts Data

Housing Type	2018	2019	2020	2021
SFD	11,163	9,480	9,063	7,957
MFD	29,694	36,246	28,789	26,933
Total	40,857	45,726	37,852	34,890

From the above housing starts forecast, the 2020 Projected Single Family Dwelling (SFD)growth rate is calculated as follows:[4]

$$2020P\ SFD\ Growth\ Rate = \left(\frac{9{,}063}{9{,}480}\right) - 1 = -4.4\%$$

The results of the growth rate on forecast residential customer additions are calculated from the tables provided in Appendix A3 as follows:

"Lower Mainland 2019 Actual 1 additions = 3,218 (column C)

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[3] https://www.conferenceboard.ca/focus-areas/canadian-economics/provincial-outlook?utm_source=pressrelease&utm_medium=ALL&utm_campaign=COMMS.

[4] Exhibit B-2, Appendix A3, p. 6.

LML 2019 $Actual\ SFD$ = 40% × 3,218 = 1,273 ($column\ D$)

LML 2020 $Projected\ SFD$ = −4.4%× 1,273 = 1,217 ($column\ F$)

LML 2020 $Forecast\ SFD$ = −12.2%× 1,217 = 1,069 ($column\ I$)" [5]

The CBOC recently published its Summer 2020 Provincial Outlook Economic Forecast, updated on August 24, 2020.

3.1 Please explain how often the CBOC produces an updated housing starts forecast.

<u>Response:</u>

The CBOC Provincial Medium-Term Forecast is published once a year. FEI uses the CBOC Provincial Medium-Term Forecast because it contains the breakdown of housing starts by single family dwelling (SFD) and multi-family dwelling (MFD). The SFD/MFD breakdown is a required input to the FEI residential customer additions method.

The CBOC recently published its Summer 2020 Provincial Outlook Economic Forecast, updated on August 24, 2020. This forecast does not contain the required SFD/MFD breakdown and cannot be used in the FEI forecast method.

3.2 Using the updated CBOC forecast dated August 24, 2020, please recalculate the residential customer addition forecast and the residential load forecast for 2020 and 2021, respectively.

3.2.1 If an updated load forecast is not available, please produce a sensitivity analysis for an impact of +/- 5% and +/-10% variance that housing starts will have on the overall residential load forecast for 2020 and 2021.

<u>Response:</u>

As stated in the response to BCUC IR1 3.1, the updated CBOC forecast cannot be used in the FEI forecast method. Instead, as requested, FEI completed a sensitivity analysis by increasing and decreasing the residential customer forecast by +/- 5 percent and +/- 10 percent and assuming the same level of change in the housing starts forecast.

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5 Exhibit B-2, Appendix A3, p. 7.

The results of the sensitivity analysis are shown in the table below:

Residential Demand, TJs	2020	2020 Impact	2021	2021 Impact
Demand as Filed	81,063		79,332	
5%	81,081	0.02%	79,380	0.06%
-5%	81,046	-0.02%	79,284	-0.06%
10%	81,099	0.04%	79,428	0.12%
-10%	81,028	-0.04%	79,236	-0.12%

Demand is a product of the total customer count and use rates, completed at the regional and monthly level. As customer additions are a small percentage of total customers, a 5 to 10 percent change in customer additions has a minimal impact on residential demand as shown in the table above. The largest impact would be from the +/-10 percent scenario in 2021, but the impact is only twelve hundredths of a percent (0.12 percent). While the impacts to demand are very small, the 2021 results are an order of magnitude greater than 2020 results because 2021 results are the cumulative effect of adjusting for both 2020 and 2021.

This analysis demonstrates that the demand forecast is not materially sensitive to variances in the customer additions forecast. Further, any variances in demand are subject to flow-through treatment and any resulting impacts on revenue requirements will be returned to or recovered from customers in future years.

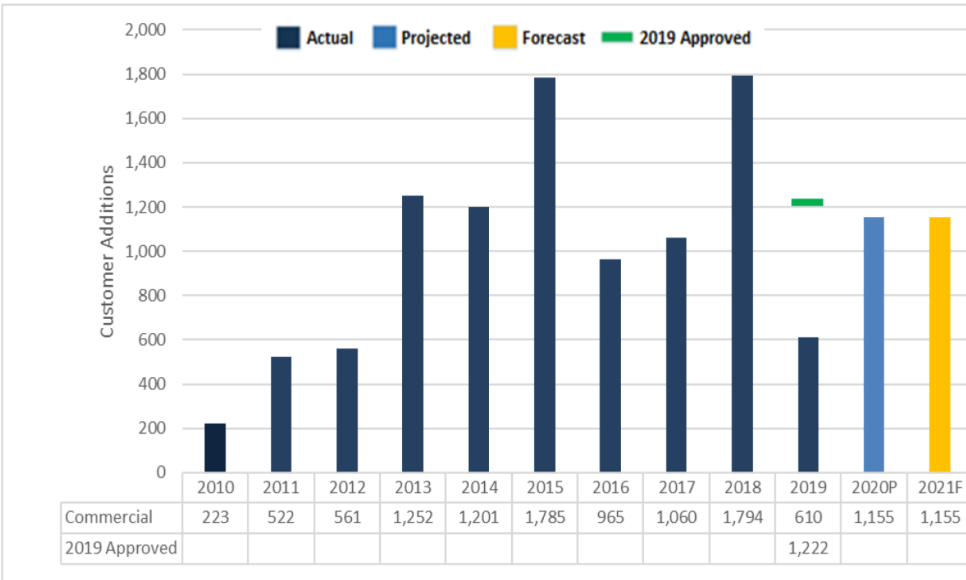
4.0 Reference: LOAD FORECAST

Exhibit B-2, Section 3.3.2.1, p. 19

Commercial Customer Additions

On page 19 of the Application, FEI provides Figure 3-5, Commercial Net Customers Additions:[6]

Figure 3-5: Commercial Net Customers Additions



4.1 Please explain the reasons for the variance between 2019 forecast and actual customer additions.

<u>Response:</u>

FEI is not able to explain the reasons for the variance. FEI's commercial customer additions forecast is based on historical data, not a prediction of which of the many commercial industry groups will experience growth or decline in any given year. Comparing FEI's forecast based on historical data to actual experience would be a complex task requiring a detailed understanding of numerous commercial industries, and is not needed for FEI's forecasting methodology or any other business needs.

Historically, actual commercial customer additions have varied widely from year to year. For example:

- In 2013 commercial customer additions were 223 percent of 2012;

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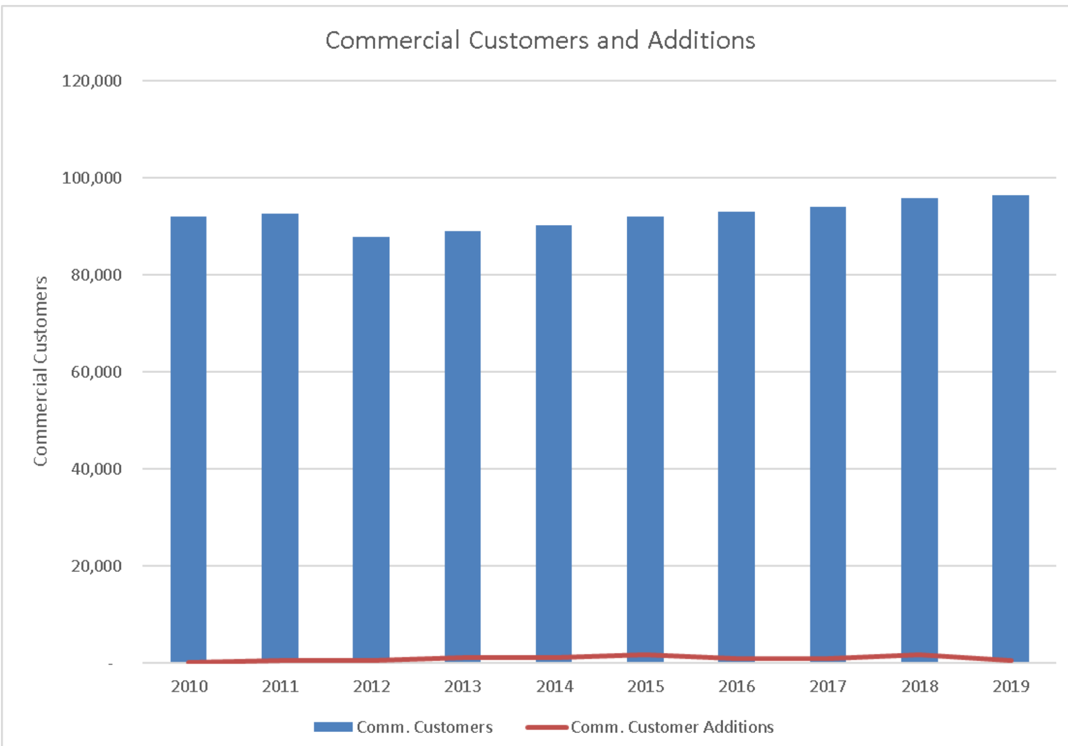
6 Exhibit B-2, p. 19.

- In 2015 commercial customer additions were 149 percent of 2014;
- In 2016 commercial customer additions were 54 percent of 2015; and
- In 2018 commercial customer additions were up 169 percent of 2017.

However, as shown in the figure below, relative to the total number of commercial customers used to forecast commercial demand, the fluctuations in the commercial customer additions are not material. For this reason, FEI's commercial demand forecast is not materially sensitive to commercial customer additions.

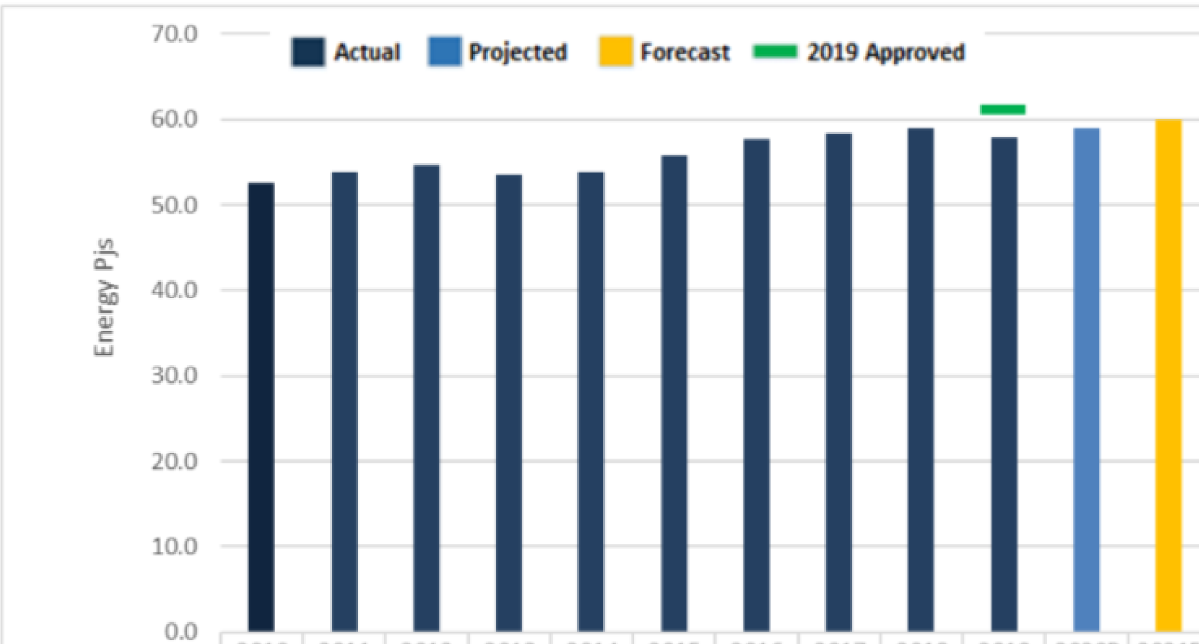


4.1.1 What are the reasons for the 2019 load forecast and why this is not anticipated to continue into 2020 and 2021.

Response:

The commercial demand forecast is shown in Figure 3-9 of the Application, which is reproduced below for ease of reference. The 2019 demand forecast (represented by the green line in Figure 3-9) was developed as the product of the 2019 commercial customers forecast and the 2019 commercial UPC forecast. The forecast for 2020P and 2021F used year end actual values up to 2019 as explained in Appendix A3. As shown in Figure 3-5 of the Application, the commercial customer additions were lower in 2019 than the prior three year average. Commercial use rates in 2019 were also lower than forecast. As a result of declines in both actual customer additions and use rates, the 2020P and 2021F forecasts are both lower than the 2019 forecast (but higher than 2019 actual).

Figure 3-9: Commercial Demand



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Commercial	52.5	54.0	54.7	53.5	53.9	55.7	57.7	58.3	59.0	57.9	59.0	60.0
2019 Approved										61.3		

4.1.2 Given that the state of emergency due to the COVID-19 pandemic was not announced until mid to late March 2020, please discuss the increase in 2020P commercial net customer additions compared to actual 2019 (before the pandemic).

Response:

The methodology used to develop 2020P forecast shown in Figure 3-5 considers actual customer additions data from all regions and all commercial rate classes for the years 2017, 2018 and 2019. Once the forecast was completed following the typical methodology, the monthly commercial customer additions for the months of January 2020 through to June 2020 were replaced with actual data values. The values for July through August 2020 were not adjusted as actual data was not available at that time.

Note that Figure 3-5 presents the year end (December) value.

4.1.3 Please discuss why FEI forecasts the commercial net customer additions to be the same in 2020P and in 2021F.

Response:

The following example shows how FEI calculated the 2020P and 2021F Lower Mainland Rate Schedule 2 customers and customer additions. Calculations for all other commercial rates and regions are identical.

As described in Section 4 of Appendix A3 of the Application, FEI developed the commercial customer additions forecast using a three year average and used the same forecast for both 2020P and 2021F. Therefore, FEI used years 2017, 2018 and 2019 (the last 3 years of actual data) to develop the additions for 2020P. While FEI did know six months of actual 2020 customer additions, those actuals do not affect the final annual additions calculation as described below. Hence, the additions in Figure 3-5 above for 2020P and 2021F are identical.

The following table shows actual Lower Mainland Rate Schedule 2 customer additions for the prior three years:

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	LML RS 2 Additions	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
2	2017	125	-71	97	64	45	-41	-102	-65	-35	146	164	203	530
3	2018	260	-343	115	19	-18	-52	-11	77	40	165	273	210	735
4	2019	175	-33	60	-55	-110	-131	-34	-23	-60	106	111	150	156
5	Forecast	186.7	(149.0)	90.7	9.3	(27.7)	(74.7)	(49.0)	(3.7)	(18.3)	139.0	182.7	187.7	473.7

The forecast in row 5 is the simple average for each month. Cell N5 shows the annual customer additions forecast. Row 5 is the customer additions forecast.

The Forecasting Information System (FIS) system works with customers so the customer additions are added to the prior year end customers, as shown in the following table.

The process starts with the 2019 year-end customers in N2 (54,211) of the table below. The January 2020 customer forecast is then the January additions (186.7 from B5 in the table above), plus the December 2019 value of 54,211. The total is 54,398 and is shown in B3 of the table below. The process continues for each month by adding the forecast additions from row 5 of the previous table to the prior month’s customer total.

The January 2021 value is equal to the 2020 December value plus the January forecast of additions.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	LML RS 2 Customers	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year End	Additions
2	2019													54,211	
3	2020	54,398	54,249	54,339	54,349	54,321	54,246	54,197	54,194	54,175	54,314	54,497	54,685	54,685	474
4	2021	54,871	54,722	54,813	54,822	54,795	54,720	54,671	54,667	54,649	54,788	54,971	55,158	55,158	474

Finally, as shown in the highlighted cells of the following table, the actual customer totals recorded for January to June 2020 are substituted back into the forecast, replacing the calculated values.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	2020 Projection	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year End	Additions
2	2019													54,211	
3	2020	54,261	54,637	54,576	54,438	54,359	54,378	54,197	54,194	54,175	54,314	54,497	54,685	54,685	474
4	2021	54,871	54,722	54,813	54,822	54,795	54,720	54,671	54,667	54,649	54,788	54,971	55,158	55,158	474

The annual customer additions are always calculated as the December value of one year less the December value of the prior year. This is shown in column O of the table above. In this case, because the December values are not affected by the substitution of actual values for January-June, the annual additions are identical.

This process is repeated in an identical manner for all regions and commercial rate schedules and the summation of the annual additions is shown in Figure 3-5.

The customer totals are entered into the FIS. FIS multiplies these monthly customer totals by the corresponding UPC values to determine monthly demand values.

4.2 Please provide the year-to-date commercial customer additions for 2020.

Response:

FEI has provided the year-to-date (January 2020 – June 2020) commercial customer additions as well as the projected July 2020 to December 2020 commercial customer additions below. The year-to-date commercial customer additions at June 2020 are minus 164. The minus 164 is due to the loss of customers outpacing the gain in customers for the first six months of 2020.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
Additions	120	19	(54)	(188)	(111)	50	237	(20)	(44)	317	460	369	1,155
	June 2020 YTD commercial customer additions:					**(164)**							

4.2.1 Please explain whether the year-to-date numbers indicate FEI will reach its 2020 projections.

Response:

Based on year-to-date numbers, FEI expects to reach the 2020 projections. However, there is always an element of uncertainty in the market. In addition, the impact of COVID-19 is not fully known and may have unanticipated impacts on projections.

5.0 Reference: LOAD FORECAST

Exhibit B-2, Appendix A3, p. 8

Forecast methodologies: commercial customer additions

FEI provides calculations on how it calculates forecast commercial customer additions:

> The three-year average additions was 474, so 474 net additions are forecast in each of 2020 and 2021. 2020P $Customers$ = 2019 $Customers$ + 3 Yr Avg $Additions$
>
> Using the data above:
>
> 2020P = 54,685 = 54,211 + 474

5.1 **In light of the commercial uncertainty caused by the COVID-19 pandemic, please explain whether FEI has considered alternative forecast methodology to better reflect the immediate impact of the COVID-19 pandemic in its 2020 and 2021 load forecast.**

5.1.1 **If yes, please elaborate on what methodologies are considered and why they were not adopted for preparing the 2020P and 2021F load forecast.**

5.1.2 **If no, please explain why not.**

Response:

FEI considered the potential impacts of the pandemic on customer additions and whether or not FEI was observing any subjective trends that could affect the forecast. FEI concluded that it did not have any numerical evidence of any trends with which to make a forecast adjustment. As a result, FEI applied the existing forecast methods without further adjustment.

In Appendix B2 of the 2020-2024 Multi-Year Rate Plan Application, FEI completed its review of alternate commercial customer additions methods. Based on the results, FEI concluded that the existing method that uses three years of commercial net customer additions provided the best performance.

As shown in that review, analyzing the effectiveness of alternate demand forecast methods is time consuming and must be done carefully, especially when most methods perform similarly. It would not be prudent to start altering methods when so little data is available and when it is unclear how events will unfold through 2021. Additionally, FEI has flow through[7] treatment for delivery revenue. Therefore, it is reasonable for FEI to continue with its existing forecast methods despite the potential impact that the pandemic may have on its load forecasts.

[7] Flow through treatment for delivery revenue means that any variances from forecast will be returned to or recovered from customers through FEI's RSAM or flow through deferral accounts in the following year

6.0 Reference: LOAD FORECAST

Exhibit B-2, Appendix A3, pp. 10-11

Forecast methodologies: ETS method

In Appendix A3, FEI details its 2020 monthly forecast using the ETS method for the Lower Mainland Rate Schedule (RS) 1 rate class: [8]

2020 UPC Forecast	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
93.8	14.70	11.49	10.73	7.82	4.62	3.27	2.71	2.58	3.27	6.50	10.77	15.33	93.8

FEI explains: "Due to the extraordinary circumstances related to COVID-19, FEI created a projected year for 2020 by replacing the forecast values with actual values for January through June. The monthly actual use rates are:" [9]

LOWER MAINLAND	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2020 Projection	14.72	12.88	12.02	7.73	4.54	3.62	2.71	2.58	3.27	6.50	10.77	15.33	96.7

6.1 Please explain the variance between the ETS method projections for the 2020 consumption and the actuals.

Response:

The values used for January to June 2020 are actuals as stated in Appendix A3 of the Application and are not weather normalized. The projected values they replaced were weather normalized. The following table provides the necessary weather normalization factors needed to do a variance comparison:

	LOWER MAINLAND	Jan	Feb	Mar	Apr	May	Jun
1	2020 UPC Forecast	14.70	11.49	10.73	7.82	4.62	3.27
2	2020 Projection	14.72	12.88	12.02	7.73	4.54	3.62
3	Normalization Factor	0.9846	0.9821	1.1581	1.0235	0.9547	1.0507
4	Normalized 2020	14.95	13.11	10.38	7.55	4.75	3.44
5	Variance (GJ)	(0.25)	(1.62)	0.35	0.27	(0.14)	(0.17)
6	Variance (%)	-1.7%	-12.3%	3.4%	3.5%	-2.8%	-4.9%

Rows 1 and 2 are copies of the tables cited in the preamble.

Row 3 shows the weather normalization factors for Lower Mainland, Rate Schedule 1 from January to June 2020.

[8] Exhibit B-1, Appendix A3, p. 11;
[9] ibid

The normalization factors are divisors so row 4 shows the 2020 normalized actuals. Note that row 4 is row 2 divided by row 3.

The variance in GJ and percent is shown in rows 5 and 6.

The year to date variance is 1.55 GJ or approximately 2.9 percent.

As the original 2020 forecast was produced using the ETS method FEI expects that there would be a variance once the actuals are recorded. Only in very rare cases do forecast values exactly match recorded values.

6.2 Please explain whether FEI anticipates increased consumption in the Lower Mainland RS1 rate class to continue if the pandemic persists into 2021.

6.2.1 If yes, please explain how this would impact the load forecast.

Response:

As shown in the response to BCUC IR1 6.1, the residential demand through June 2020 is 1.55 GJs higher than the ETS forecast method predicted. The March to June UPC variance from forecast was only 0.3 GJ.

Given the small variance in the months since the pandemic began, and with the understanding that the pandemic situation is unpredictable and changing rapidly, there is insufficient evidence to warrant forecast adjustments, either upwards or downwards.

7.0 Reference: LOAD FORECAST

Exhibit B-2, Appendix A2, pp. 4-19

Historical data: Percent error RS3 and RS23

In Appendix A2, FEI provides a number of tables in Sections 3.2 – 3.17. The 2019 column of each table has an asterisk next to percentage error for RS3 and RS23 rate classes with a footnote that reads “2019* Rate Switching (Large Commercial RS3 and RS23).”

7.1 Please provide another copy of each table showing the data if the RS3 and RS23 rate switching had not taken place. Please show the percent error from forecast for 2019 for RS3 and RS23 for each table in Sections 3.2-3.17.

<u>Response:</u>

The following tables are reproduced from Sections 3.1-3.17 of Appendix A2 of the Application.

Only the rows for RS3 and RS23 are shown as these were the only ones updated.

FEI has added an additional column to show the results as if rate switching had not occurred. This new column is identified with “**” and a footnote.

3.1 AMALGAMATED NET CUSTOMERS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	5,671	5,785	5,553	5,597	5,147	5,117	5,035	5,354	5,223	5,623	5,623
Actual	5,466	5,451	5,220	5,134	5,169	5,301	5,189	5,441	6,028	6,973	6,268
Error = (ACT-FCST)	(205)	(334)	(333)	(463)	22	184	154	87	805	1,350	645
Percent Error = (Error/ACT)	-3.8%	-6.1%	-6.4%	-9.0%	0.4%	3.5%	3.0%	1.6%	13.4%	19.4%	10.3%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	1,319	1,328	1,526	1,586	1,634	1,552	1,670	1,760	1,934	1,744	1,744
Actual	1,406	1,433	1,520	1,529	1,522	1,724	1,803	1,712	1,648	871	1,576
Error = (ACT-FCST)	87	105	(6)	(57)	(112)	172	133	(48)	(286)	(873)	(168)
Percent Error = (Error/ACT)	6.2%	7.3%	-0.4%	-3.7%	-7.4%	10.0%	7.4%	-2.8%	-17.4%	-100.2%	-10.7%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.2 AMALGAMATED NET CUSTOMER ADDITIONS

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	105	114	44	44	4	(52)	(51)	26	19	91	91
Actual	37	(16)	(104)	(86)	35	132	(112)	252	587	945	240
Error = (ACT-FCST)	(68)	(130)	(148)	(130)	31	184	(61)	226	568	854	149
Percent Error = (Error/ACT)	-183.8%	812.5%	142.3%	151.2%	88.6%	139.4%	54.5%	89.7%	96.8%	90.4%	62.1%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	9	9	60	60	57	30	30	18	66	16	16
Actual	58	27	88	9	(7)	202	79	(91)	(64)	(777)	(72)
Error = (ACT-FCST)	49	18	28	(51)	(64)	172	49	(109)	(130)	(793)	(88)
Percent Error = (Error/ACT)	84.5%	66.7%	31.8%	-566.7%	914.3%	85.1%	62.0%	119.8%	203.1%	102.1%	122.2%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	3,496	3,487	3,450	3,435	3,872	3,754	3,593	3,488	3,842	3,831	3,831
Actual	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517	3,501
Error = (ACT-FCST)	(11)	101	234	175	(299)	(167)	128	205	(292)	(314)	(330)
Percent Error = (Error/ACT)	-0.3%	2.8%	6.4%	4.8%	-8.4%	-4.7%	3.4%	5.5%	-8.2%	-8.9%	-9.4%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	4,680	4,680	4,901	4,927	5,546	5,309	5,382	5,227	5,399	5,492	5,492
Actual	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,345	5,051	4,937
Error = (ACT-FCST)	170	458	337	222	(286)	(135)	(103)	133	(54)	(440)	(554)
Percent Error = (Error/ACT)	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.6%	-2.0%	2.5%	-1.0%	-8.7%	-11.2%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.4 AMALGAMATED DEMAND

Demand, PJs	(Ctrl)	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	19.6	19.9	19.1	19.1	19.9	19.2	18.1	18.7	20.1	21.5	21.5
Actual	19.0	19.5	19.3	18.7	18.5	19.2	19.4	19.7	20.9	22.5	21.7
Error = (ACT-FCST)	(0.6)	(0.4)	0.2	(0.4)	(1.4)	(0.0)	1.3	1.0	0.9	1.0	0.2
Percent Error = (Error/ACT)	-3.2%	-2.1%	1.0%	-2.1%	-7.6%	-0.2%	6.7%	5.2%	4.1%	4.3%	1.0%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	6.1	6.2	7.2	7.5	8.7	8.3	9.0	9.2	10.3	9.6	9.6
Actual	6.6	7.4	7.8	7.9	8.0	8.6	9.3	9.5	9.0	7.3	8.0
Error = (ACT-FCST)	0.5	1.2	0.6	0.4	(0.7)	0.3	0.3	0.4	(1.3)	(2.3)	(1.5)
Percent Error = (Error/ACT)	7.6%	16.2%	7.7%	5.1%	-8.7%	3.5%	3.2%	3.9%	-13.9%	-31.3%	-19.0%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.5 MAINLAND NET CUSTOMERS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	5,083	5,191	4,962	5,002	4,577	4,560	4,497	4,667	4,608	5,029	5,029
Actual	4,882	4,863	4,675	4,598	4,625	4,671	4,605	4,867	5,478	6,291	5,687
Error = (ACT-FCST)	(201)	(328)	(287)	(404)	48	111	108	200	870	1,262	658
Percent Error = (Error/ACT)	-4.1%	-6.7%	-6.1%	-8.8%	1.0%	2.4%	2.3%	4.1%	15.9%	20.1%	11.6%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	1,319	1,328	1,526	1,586	1,634	1,552	1,582	1,609	1,669	1,562	1,562
Actual	1,406	1,433	1,520	1,529	1,522	1,573	1,614	1,546	1,458	800	1,404
Error = (ACT-FCST)	87	105	(6)	(57)	(112)	21	32	(63)	(211)	(762)	(158)
Percent Error = (Error/ACT)	6.2%	7.3%	-0.4%	-3.7%	-7.4%	1.3%	2.0%	-4.1%	-14.5%	-95.3%	-11.3%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.6 MAINLAND NET CUSTOMER ADDITIONS

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	101	108	40	40	-	(65)	(64)	(1)	2	81	81
Actual	41	(19)	(144)	(77)	27	46	(66)	262	611	813	209
Error = (ACT-FCST)	(60)	(127)	(184)	(117)	27	111	(2)	263	609	732	128
Percent Error = (Error/ACT)	-146.3%	668.4%	127.8%	151.9%	100.0%	241.3%	3.0%	100.4%	99.7%	90.0%	61.2%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	9	9	60	60	57	30	30	18	28	8	8
Actual	58	27	88	9	(7)	51	41	(68)	(88)	(658)	26
Error = (ACT-FCST)	49	18	28	(51)	(64)	21	11	(86)	(116)	(666)	18
Percent Error = (Error/ACT)	84.5%	66.7%	31.8%	-566.7%	914.3%	41.2%	26.8%	126.5%	131.8%	101.2%	69.2%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.7 MAINLAND NORMALIZED

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	3,346	3,347	3,334	3,316	3,769	3,599	3,537	3,517	3,770	3,746	3,746
Actual	3,370	3,484	3,566	3,517	3,529	3,524	3,658	3,625	3,477	3,468	3,450
Error = (ACT-FCST)	24	137	232	201	(240)	(75)	121	108	(293)	(278)	(295)
Percent Error = (Error/ACT)	0.7%	3.9%	6.5%	5.7%	-6.8%	-2.1%	3.3%	3.0%	-8.4%	-8.0%	-8.6%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	4,680	4,680	4,901	4,927	5,546	5,309	5,348	5,197	5,416	5,521	5,521
Actual	4,850	5,138	5,238	5,149	5,260	5,157	5,304	5,388	5,357	5,127	5,020
Error = (ACT-FCST)	170	458	337	222	(286)	(152)	(44)	191	(59)	(394)	(502)
Percent Error = (Error/ACT)	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.9%	-0.8%	3.5%	-1.1%	-7.7%	-10.0%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.8 MAINLAND NORMALIZED DEMAND

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	16.8	17.2	16.5	16.5	17.3	16.4	16.0	16.4	17.4	18.8	18.8
Actual	16.4	16.9	16.7	16.3	16.3	16.5	16.8	17.3	18.5	20.1	19.4
Error = (ACT-FCST)	(0.4)	(0.3)	0.2	(0.2)	(1.0)	0.0	0.8	0.9	1.2	1.3	0.6
Percent Error = (Error/ACT)	-2.4%	-1.8%	1.2%	-1.2%	-6.1%	0.3%	5.0%	5.4%	6.3%	6.4%	3.3%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast	6.1	6.2	7.2	7.5	8.7	8.3	8.4	8.3	9.0	8.6	8.6
Actual	6.6	7.4	7.8	7.9	8.0	8.0	8.4	8.6	8.1	6.6	7.2
Error = (ACT-FCST)	0.5	1.2	0.6	0.4	(0.7)	(0.3)	-	0.3	(0.8)	(2.0)	(1.4)
Percent Error = (Error/ACT)	7.6%	16.2%	7.7%	5.1%	-8.7%	-3.3%	0.0%	3.1%	-10.4%	-30.8%	-19.1%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

2019** No Rate Switching

3.10 VANCOUVER ISLAND NET CUSTOMERS

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	527	532	532	536	509	497	479	647	567	539	539
Actual	525	527	484	476	484	582	531	517	492	613	518
Error = (ACT-FCST)	(2)	(5)	(48)	(60)	(25)	85	52	(130)	(75)	74	(21)
Percent Error = (Error/ACT)	-0.38%	-0.95%	-9.92%	-12.61%	-5.17%	14.60%	9.79%	-25.15%	-15.24%	12.06%	-4.07%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							83	141	243	164	164
Actual						141	175	152	179	67	162
Error = (ACT-FCST)						141	92	11	(64)	(97)	(2)
Percent Error = (Error/ACT)							52.57%	7.24%	-35.75%	-144.78%	-1.23%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

2019** No Rate Switching

3.11 VANCOUVER ISLAND NET CUSTOMER ADDITIONS

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	4	5	4	4	4	13	13	32	19	11	11
Actual	(2)	2	39	(8)	8	98	(51)	(14)	(25)	121	26
Error = (ACT-FCST)	(6)	(3)	35	(12)	4	85	(64)	(46)	(44)	110	15
Percent Error = (Error/ACT)	300.0%	-150.0%	89.7%	150.0%	50.0%	86.6%	125.5%	328.6%	176.0%	90.9%	57.6%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							-	-	34	6	6
Actual						141	34	(23)	27	(112)	(17)
Error = (ACT-FCST)						141	34	(23)	(7)	(118)	(23)
Percent Error = (Error/ACT)							100.0%	100.0%	-25.9%	105.4%	135.3%

2019* Rate Switching (Large Commercial Rs3 and Rs23)

2019** No Rate Switching

3.12 VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	6,295	6,349	6,351	6,398	5,896	5,187	4,031	3,069	4,171	4,411	4,411
Actual	4,435	4,460	4,820	4,431	3,901	3,894	4,060	4,181	4,074	3,827	3,822
Error = (ACT-FCST)	(1,860)	(1,889)	(1,531)	(1,967)	(1,995)	(1,293)	29	1,112	(97)	(584)	(589)
Percent Error = (Error/ACT)	-41.9%	-42.4%	-31.8%	-44.4%	-51.1%	-33.2%	0.7%	26.6%	-2.4%	-15.3%	-15.4%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							5,996	5,636	5,344	5,282	5,282
Actual						5,636	5,052	5,158	5,260	4,369	4,257
Error = (ACT-FCST)							(944)	(478)	(83)	(913)	(1024)
Percent Error = (Error/ACT)							-18.7%	-9.3%	-1.6%	-20.9%	-24.1%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.13 VANCOUVER ISLAND NORMALIZED DEMAND

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	2.5	2.5	2.4	2.4	2.4	2.5	1.9	2.0	2.4	2.4	2.4
Actual	2.3	2.3	2.3	2.1	1.9	2.4	2.2	2.1	2.1	2.0	2.0
Error = (ACT-FCST)	(0.2)	(0.2)	(0.1)	(0.3)	(0.5)	(0.1)	0.3	0.1	(0.3)	(0.3)	(0.4)
Percent Error = (Error/ACT)	-6.8%	-8.1%	-2.6%	-13.7%	-28.3%	-5.0%	13.6%	6.5%	-14.6%	-16.8%	-22.1%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							0.5	0.8	1.2	0.8	0.8
Actual						0.5	0.8	0.9	0.8	0.6	0.7
Error = (ACT-FCST)						(0.5)	(0.3)	(0.1)	0.4	0.2	0.1
Percent Error = (Error/ACT)							-37.50%	-9.16%	44.93%	32.22%	16.17%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.14 WHISTLER NET CUSTOMERS

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	61	62	59	59	61	60	59	39	48	55	55
Actual	59	61	61	60	60	48	53	57	58	69	63
Error = (ACT-FCST)	(2)	(1)	2	1	(1)	(12)	(6)	18	10	14	8
Percent Error = (Error/ACT)	-3.4%	-1.6%	3.3%	1.7%	-1.7%	-25.0%	-11.3%	31.6%	16.9%	20.2%	12.6%

Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							5	10	22	18	18
Actual						10	14	14	11	4	10
Error = (ACT-FCST)						10	9	4	(11)	(14)	(8)
Percent Error = (Error/ACT)							64.3%	28.6%	-100.0%	-350.0%	-80.0%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.15 WHISTLER NET CUSTOMER ADDITIONS

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast		1				-	-	(5)	(2)	(1)	(1)
Actual		2	(0)	(1)	(0)	(12)	5	4	1	11	5
Error = (ACT-FCST)		1				(12)	5	9	3	12	6
Percent Error = (Error/ACT)		41.1%					100.0%	225.0%	339.0%	109.1%	120.0%

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							-	-	4	2	2
Actual						10	4	-	(3)	(7)	(1)
Error = (ACT-FCST)						10	4	0	(7)	(9)	(3)
Percent Error = (Error/ACT)							100.0%		233.3%	128.6%	300.0%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.16 WHISTLER NORMALIZED USE PER CUSTOMER

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	4,894	4,114	3,876	3,630	3,595	3,822	4,326	6,707	6,824	5,886	5,886
Actual	4,512	4,271	3,822	4,213	4,285	5,618	5,638	5,108	5,747	5,392	5,422
Error = (ACT-FCST)	(382)	157	(54)	583	690	1,796	1,312	(1,599)	(1,077)	(495)	(464)
Percent Error = (Error/ACT)	-8.5%	3.7%	-1.4%	13.8%	16.1%	32.0%	23.3%	-31.3%	-18.7%	-9.2%	-8.6%

UPC, GJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							5,888	4,328	4,703	4,654	4,654
Actual						4,328	5,078	4,557	4,860	5,045	4,812
Error = (ACT-FCST)							(810)	229	157	391	157
Percent Error = (Error/ACT)							-16.0%	5.0%	3.2%	7.7%	3.3%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

3.17 WHISTLER NORMALIZED DEMAND

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 3											
Forecast	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Actual	0.3	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Error = (ACT-FCST)	(0.0)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	(0.0)	0.0	0.0
Percent Error = (Error/ACT)	-11.1%	3.8%	0.0%	15.4%	15.4%	17.9%	13.3%	3.5%	-3.8%	5.5%	3.8%

Demand, PJs	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	2019**
Rate Schedule 23											
Forecast							0.03	0.04	0.09	0.08	0.08
Actual						0.03	0.06	0.06	0.06	0.05	0.05
Error = (ACT-FCST)							0.03	0.02	-0.03	-0.03	-0.03
Percent Error = (Error/ACT)							50.9%	32.2%	-44.7%	-73.7%	-54.3%

2019* Rate Switching (Large Commercial Rs3 and Rs23)
2019** No Rate Switching

7.1.1 Please explain the reasons behind any variances from forecasts for customer classes RS3 and RS23 for 2019.

Response:

FEI services more than 7,950 customers in Rate Schedules 3 and 23. These customers represent 160 different industry groups. The large number of customers and industry groups result in demand variances in each forecast. FEI does not have sufficient data to explain the 2019 variance. Please refer to the response to BCUC IR1 4.1 for further commentary.

7.1.1.1 Please explain whether these issues were taken into account in preparation of the 2020 and 2021 forecast.

Response:

Once the rate switching was accounted for (as described in Section 4 of Appendix A3 of the Application), FEI did not have any other specific issues to take into account. The commercial forecast methods were followed without any further adjustments.

7.1.1.2 Please explain whether the reasons behind the 2019 variances from forecast, if any, are expected to recur in 2020 or 2021. Please explain why or why not.

Response:

Please refer to the response to BCUC IR1 7.1.1.

On page 5 of Appendix A2, FEI provides Amalgamated Net Customer Additions. In the Table for RS2, FEI states the Amalgamated Net Customer Additions for 2019 were -152.3% error. Actuals were 442, Forecast was 1,115.

7.2 Please explain the reasons for the variance.

Response:

It is difficult for FEI to pin point to specific reasons for the variance. As of 2019, FEI had 88,686 customers taking service under RS2 which were dispersed over approximately 170 industry sectors. To determine where the variance is coming from, FEI would need to investigate the business environment of over 100 sectors.

As discussed in the response to BCUC IR1 4.1, FEI's customer additions forecast is based on historical data, not a prediction of which of the industry groups will experience growth or decline in any given year. Comparing FEI's forecast based on historical data to actual experience would be a complex task requiring a detailed understanding of numerous commercial industries, and is not needed for FEI's forecasting methodology or any other business needs.

The variance from forecast to actual of 673 (forecast of 1115 minus actual of 442) represents only 0.76 percent of the entire commercial customer base. Therefore, the impact of the variance on the commercial customer volumes is negligible.

7.2.1 Please explain whether the reasons for the variance were taken into account in preparation of the 2020 and 2021 forecast.

Response:

Consistent with past practice, FEI did not make specific changes to the forecast method during the preparation of the 2020 and 2021 Rate Schedule 2 customer additions forecast.

FEI expects that the factors that caused actual net customer additions to vary from the forecast, as described in the response to BCUC IR1 7.2, will occur every year. Natural fluctuations in customer additions are smoothed out by the existing forecast method, which was shown to be the superior forecasting approach in Section 1.1.1.3 of the FEI Forecasting Method Study, in Appendix B2 of the 2020-2024 MRP Application.

The demand forecast is calculated using total customers, and not customer additions. The absolute customer variance was only 0.6 percent in 2019 as shown Section 3.1 of Appendix A2 of the Application.

7.2.2 Please explain whether the reasons for this variance are expected to recur in 2020 or 2021. Please explain why or why not.

Response:

As noted in FEI's response to BCUC IR1 7.2, the forecast for net customer additions is based on a formula using three years of historical data, and the actual customer count is based on customer activity that occurs throughout the year in many different industry sectors. As such, it is not possible to predict if the 2019 variance will recur, but trends will be reflected in the forecast over time due to the forecast method used.

On page 6 of Appendix A2 to the Application, FEI provides a Table showing Amalgamated Normalized Use per customer. 2019 Actuals show Amalgamated Normalized Use per customer actuals lower than forecast across all rate classes, ranging from -5.6% to -8.9%.

7.3 Please explain the reasons for the drop in Amalgamated Normalized Use per customer for each rate class in 2019.

Response:

FEI cannot definitively explain any change in UPC in a given year as it is a result of many factors that may be both compounding and offsetting. For example, use rates for RS 1 customers may go down due to increased appliance efficiency and/or improvements in building envelopes, but this may be offset by an increase in the number of appliances used in a home, a change in how appliances are used and/or the number of people in a home.

Small Commercial Rate Schedule 2 customers operate in 177 industry sectors, while Large Commercial Rate Schedule 3 customers operate in 159 industry sectors and Rate Schedule 23 customers operate in 88 industry sectors. These industry sectors and the customers within them each have heterogeneous requirements because they are all affected differently by many different factors and energy uses.

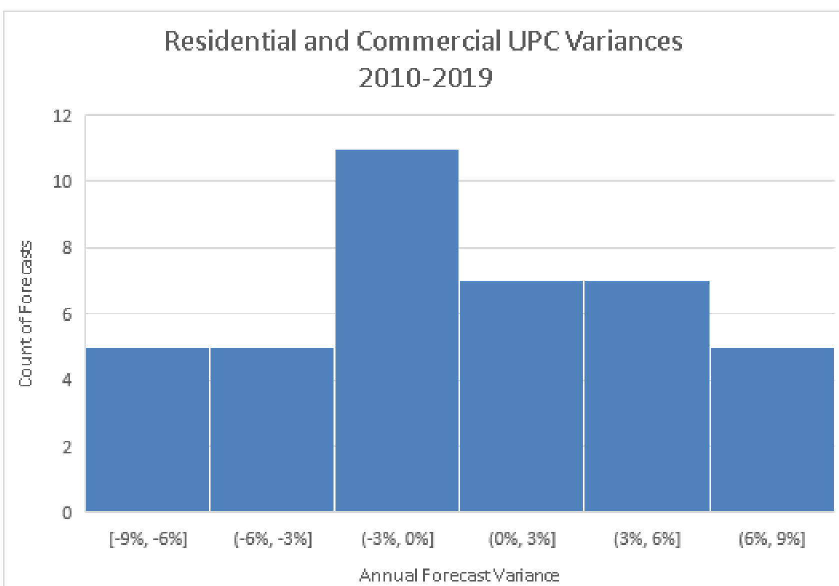
In addition, one-time or infrequent events (e.g. recessions) also impact customers and sectors in different ways.

While FEI's account managers work with larger commercial customers to understand their needs, the large number of industry sectors and individual heterogeneous requirements included in these rate schedules would require extensive market research to ascertain current and future customer requirements. This level of analysis would be cost prohibitive and FEI is not confident that there would be any additional value (or more accurate forecasts) from such an approach.

FEI believes the current methods remain appropriate. By applying a trend to, or averaging, the most recent data, annual fluctuations can be minimized and smoothed out. Smoothing techniques such as trending and averaging are common and well established practices to minimize year-over-year fluctuations.

FEI expects that its load will continue to be influenced by many factors that may have affected load variances in the past, including customer behavior, economic activity, DSM, government policies (such as environmental policy), new technology, housing formations, etc. The current methods fully account for all these intrinsic factors and together result in long term forecast performance that is significantly better than the industry average.

Further, an examination of the 40 residential and commercial variances (i.e., in RS 1, RS 2, RS 3 and RS 23) from 2010 to 2019, as presented in the table below, shows that they are normally distributed. Nineteen of the forty forecasts have a positive variance while 21 show a negative variance. The median variance is low at -0.3 percent. This demonstrates that the UPC forecast is accurate and not biased in any direction.



7.3.1 Please explain whether these reasons were considered in preparation of the 2020 and 2021 forecasts for Amalgamated Use per customer. If not, why not?

Response:

The ETS method that FEI uses to forecast UPC takes into account historical results, but not the reasons for those results. The ETS method considers ten years of historical data and will automatically place more emphasis on a trend if one exists. If a trend does not exist, the ETS method places more emphasis on recent observations. In this way, the ETS method will take into account any trend towards lower UPC if one exists and, if not, will give more weight to the UPC in recent years.

7.3.1.1 If not, please explain the impacts to the forecast demand if these factors were to recur in 2020 and/or 2021.

Response:

Please refer to the response to BCUC IR1 7.3.1.

7.3.2 Please explain whether the reasons for the drop in Amalgamated Normalized Use per customer in 2019 as explained above will likely recur in 2020 and/or 2021.

Response:

Please refer to the response to BCUC IR1 7.3.

While it is a subjective exercise for FEI to speculate whether these trends are likely to continue, the ETS method as discussed in BCUC IR1 7.3.1 does well at predicting future use rates by using historical information.

8.0 Reference: LOAD FORECAST

Exhibit B-2, Section 3.3.3, pp. 22–24

Industrial demand

On pages 22-23 the Application, FEI describes its method to forecast industrial demand using a customer survey:

> The response rate achieved in 2020 was 46.7 percent of industrial customers, representing approximately 89.3 percent of industrial volumes. There was no reply from 44.5 percent of industrial customers, who received the survey and three reminder notifications; this group represents only 9.5 percent of the industrial demand. Surveys could not be delivered to 8.8 percent of the industrial customers due to issues such as incorrect email addresses; this group represents 1.2 percent of the total industrial load. The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 11 percent of the total industrial demand) was set to equal 2019 Actual consumption.

8.1 Please compare the response rate and the corresponding load that the respondents represent as a percentage of industrial volume in years 2016 to 2020 in a table format.

Response:

The following table shows the response rate by demand and customers from 2016 through 2020. Overall, the response rate by both demand and customers has been very consistent through this period.

Industrial Survey Response Rate	2016	2017	2018	2019	2020
Demand	89.0%	88.6%	89.4%	89.1%	89.3%
Customers	51.0%	49.4%	49.4%	48.5%	46.7%

With respect to 2020:

- The response rate by volume was the second highest demand response rate recorded in the last five years. The highest response rate recorded in the last five years occurred in 2018 and was only one tenth of a percentage point higher than this year.
- The response rate by customer count was slightly lower, but FEI does not believe it is material or that a cause can be determined. FEI notes that 98 percent of all customers consuming 100 TJs or more responded to the survey.

It is important to focus on the demand response rate rather than the response rate by customer count because the forecast of demand is the input into the determination of revenue requirements.

8.1.1 Please comment on the trend on the customer survey response rate.

Response:

Please refer to the response to BCUC IR1 8.1.

8.1.2 Please explain the measures that FEI has taken to improve the customer survey response rate since 2016.

Response:

In 2018, FEI developed an improved reporting capability that is now used to track responding and non-responding customers during the survey. This enhanced reporting capability is now provided to the Key Account Managers so they can focus their efforts on the largest non-responding customers.

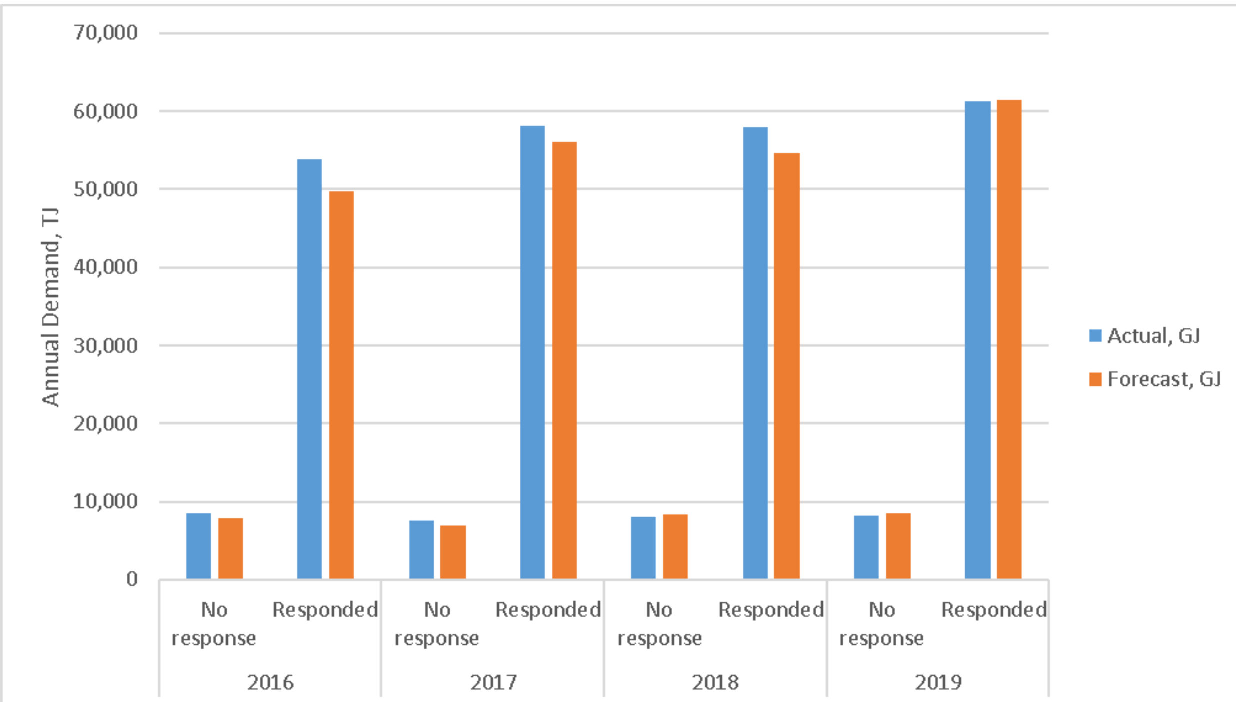
A phone call or email from a Key Account Manager is often enough to prompt customers to complete their survey.

As shown in the response to BCUC IR1 8.1, the Industrial Survey has consistently achieved a demand response rate of nearly 90 percent. FEI believes this high response rate is a result of the ease of use of the Industrial Survey Web Site tool. Customers can review their prior consumption and survey submissions online as they enter their future forecast.

8.2 If possible, please compare the forecast and actual load among non-respondents and respondents, respectively, from 2016 to 2020 in a bar graph and table format.

Response:

The following bar chart and table compare the forecast and actual load among non-respondents and responders from 2016 through 2019. FEI cannot provide the comparison for 2020 because the actual load will not be available until early 2021.



	Actual, GJ	Forecast, GJ
2016		
No response	8,448	7,890
Responded	53,790	49,688
2017		
No response	7,539	6,987
Responded	58,111	56,029
2018		
No response	8,036	8,298
Responded	57,968	54,599
2019		
No response	8,212	8,505
Responded	61,281	61,412

The chart shows that both the annual demand and the variance from the non-responding group of customers is very small, and in all cases the variance is smaller than the variance from the responders.

The four year average variance for the non-responding customer was 1.8 percent. Many of the non-responding customers are strata corporations that have very consistent demand year over year which is reflected in these results.

The four year average variance for the responding customers was 4.2 percent and is larger because demand for many of these customers depends on the demand for the goods and services they produce. In addition, other factors such as the cost of competing energy sources affects their consumption relative to the forecasts they provide. The absolute variance from the responders in 2019 was the lowest for both groups in the four years at 0.2 percent.

8.2.1 Based on the response above, please comment on the forecast accuracy among respondents and non-respondents, and explain the possible reasons for any difference between the two groups since 2016.

Response:

Please refer to the response to BCUC IR1 8.2.

8.3 Please explain why FEI sets non-respondents' 2020 projected consumption equivalent to 2019 actual consumption.

Response:

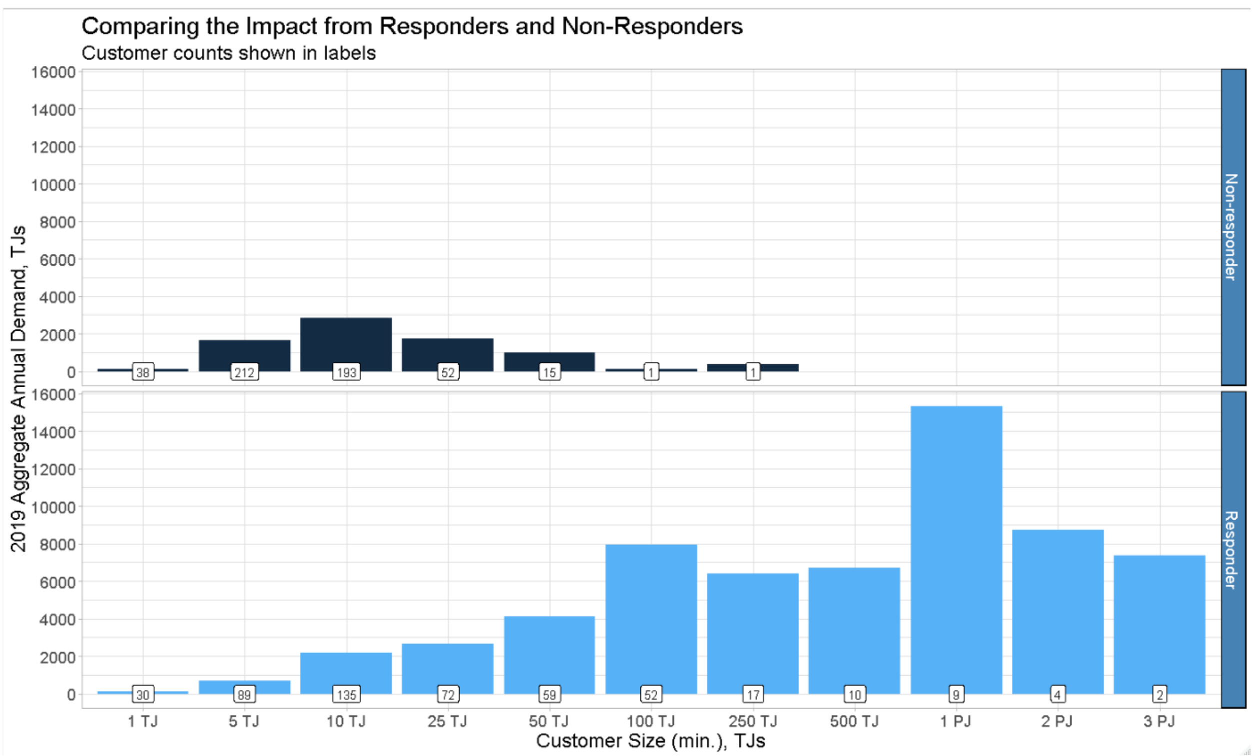
Setting the 2020 projected consumption of non-responders as equivalent to 2019 actual consumption is reasonable for a number of reasons:

- As the majority of customers that do not respond to the survey are smaller volume customers (as shown in the chart below) and, altogether, non-responders account for only approximately 11 percent of the industrial demand, the industrial forecast will not be materially sensitive to variances in the demand of non-responders.
- The majority of responding customers that are similar in size to the non-responding customers provide a "same as last year" response. For example, as shown in the chart below, there were 125 customers that consumed between 10 and 25 TJs that responded to the survey, while 193 similar sized customers did not. Of the 135 customers that responded, 70 percent provided a forecast that was equal to their 2019 actual consumption. Given the high percentage of responding customers that provided a "same

as 2019" forecast, it is reasonable to also assign 2019 actual consumption to similarly sized non-responding customers.

- Approximately 28 percent of the non-responding customers are strata corporations that have very consistent demand year over year.
- As shown in the response to BCUC IR1 8.2, the four-year average variance between forecast and actual non-responder demand is 1.8 percent.

The following chart shows the demand from survey responders and non-responders grouped by customer size. The values in the white labels at the base of each bar are the number of customers in that group. The bars themselves represent the aggregate 2019 demand from that group of customers.



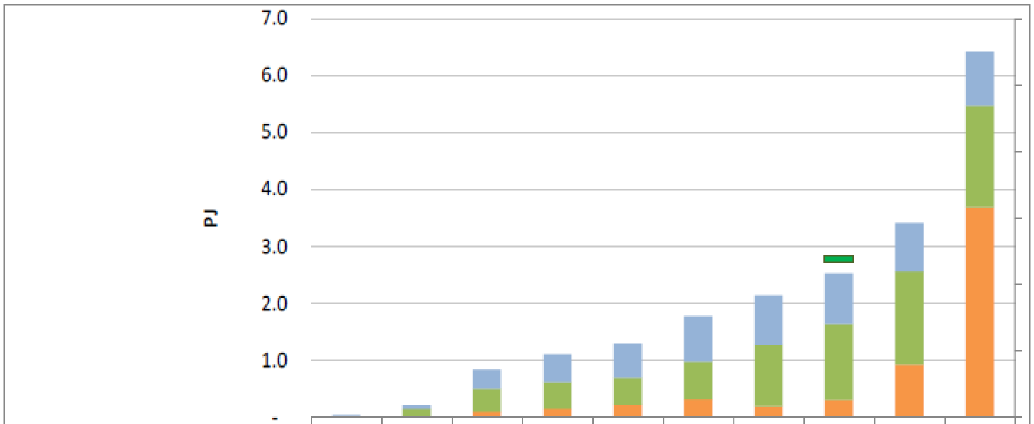
9.0 Reference: LOAD FORECAST

Exhibit B-2, Section 3.3.4, p. 25

Natural gas for transportation and Liquefied Natural Gas demand

On page 25 of the Application, FEI provides Figure 3-11:

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[17]



	2011A	2012A	2014A	2015A	2016A	2017A	2018A	2019A	2020P	2021F
RS 3/5/23/25/6P - CNG (NGT)	0.0	0.1	0.3	0.5	0.6	0.8	0.9	0.9	0.8	1.0
RS 46 - LNG (NGT)	0.0	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.6	1.8
RS 46 - LNG (Non-NGT)	-	-	0.1	0.1	0.2	0.3	0.2	0.3	0.9	3.7
2019 Approved								2.8		
Total CNG & LNG	0.0	0.2	0.8	1.1	1.3	1.8	2.1	2.5	3.4	6.4

FEI provides the following discussion of the projected 2020 and 2021 demand:

> The 2020 Projected demand is approximately 0.9 PJ higher than the 2019 Actual demand of 2.5 PJs. Of this 0.9 PJ increase, approximately 0.3 PJ (or approximately 30.2 percent) is attributed to demand that serves NGT [natural gas for transportation] customers while the rest of the increase is attributed to non-NGT demand involving LNG [liquefied natural gas] exports (approximately 0.6 PJ or 69.8 percent).
>
> For 2021, the CNG demand for NGT customers is forecasted to increase by approximately 0.11 PJ (approximately 13 percent) from the 2020 Projected level. This is primarily attributable to incremental load from existing customers and two new CNG [Compressed Natural Gas] stations to be in-service starting in mid-2020 with demand ramp up by 2021. The LNG demand for NGT customers is forecast to increase by approximately 0.14 PJ (approximately 9 percent) from the 2020 Projected level which is primarily attributed to increased volumes from BC Ferries and Seaspan due to two additional fleet vessels.

For non-NGT demand, FEI expects the 2021 Forecast will continue to increase as a result of expanded LNG exports. This is an approximately 2.7 PJ increase from the 2020 Projected level.

9.1 Please elaborate on the source of the load increase anticipated in 2020 and 2021 (e.g. new customers, increased demand from existing operations, increased demand from new operations)

Response:

The overall CNG and LNG demand is broken out by CNG for NGT, and RS46 LNG for NGT and Non-NGT demand for export. The overall increase in CNG and LNG demand in 2020 and 2021 can be attributed to the Non-NGT containerized export customers. FEI has provided additional details below on the demand projections by segment for 2020 projected and 2021 forecast.

NGT Customer- CNG

For the 2020 projected demand, CNG volume is expected to decrease by approximately 10 percent due to reduced operations primarily at TransLink and BC Transit as a result of COVID-19. TransLink and BC Transit account for more than 40 percent of the overall CNG demand and any potential reductions in their service will impact the overall CNG demand. This reduction in operation resulted in a decrease in CNG volume for 2020P as the decrease is expected to be greater than the additional load from the two new CNG stations (London Drugs and Fresh Direct) which were operational in 2020.

The 2021 NGT CNG demand is expected to increase from the 2020 projected demand by 13 percent as FEI expects demand from TransLink and BC Transit demand to return to pre-COVID levels and the expected volume from the full year operation of London Drugs and Fresh Direct, as well as the expected in-service date of one new CNG station by mid-2021. FEI is in discussions with the potential customers to secure the demand for this new station and will bring forward an application for approval once all the agreements have been executed.

NGT Customer- RS46 LNG

For the RS46 LNG NGT demand, the 2020 projected demand is expected to increase by 23 percent or 0.3 PJ from the 2019 Actuals primarily due to the increase in LNG consumption from BC Ferries as a new vessel was commissioned in May 2019 which will be fully operational in 2020. FEI has been in discussions with BC Ferries and Seaspan Ferries during COVID-19 and both customers have indicated that they expect their vessels to consume the contracted level of LNG for the rest of 2020. FEI has projected a modest growth of 8 percent in 2021 from the 2020 projected demand due to an increase in demand from Seaspan Ferries from the adoption of two new ferries to their fleet in 2021. FEI has only factored in partial months of operation from the two new ferries for 2021.

Non-NGT Customer – RS46 LNG

Although the COVID-19 pandemic temporarily forced a pause on offtake from Top Speed Energy Corp, FEI expects to start delivering mid October 2020 and gradually meet the projected volume forecasted. FEI expects 2021 shipments to steadily rise with favourable market conditions with a projected increase of 2.7 PJ per the contracted amount.

9.2 To the extent possible, please provide references to support the volume and timing of the anticipated increase in CNG and LNG loads in 2020 and 2021.

Response:

Please refer to the response to BCUC IR1 9.1

9.3 Please discuss the level of certainty FEI has in its LNG and CNG demand forecast for 2020 and 2021.

Response:

At this time, FEI is reasonably certain in its CNG and LNG demand projections for 2020 and 2021, as the forecast is based on historical customer demand, discussions with existing customers and anticipated future load growth based on discussions with potential customers at this time. However, given the uncertainty associated with COVID-19 and depending on the severity of a second wave of COVID and subsequent potential lockdowns, FEI's demand forecast could be reduced if large customers like BC Ferries and the transit authorities curtail operations again. Most of the other CNG/LNG NGT customers are performing essential services such as courier service, food delivery, beverage delivery, package delivery, and waste hauling and as such FEI does not believe their demand for CNG/LNG will be impacted by the pandemic.

Most of the demand growth in 2020 and 2021 is driven by Non-NGT demand customers who will export to Asia using ISO containers. All current market information indicates an increase in demand given the heating load this winter, increasing government regulation forcing the use of lower carbon fuels, and production in China ramping up after the world lockdown; however, a resurgence of COVID-19 could impact the market. Customer demand obligations will be met once markets return to normal demand post pandemic.

FEI notes that these revenues are subject to flow-through treatment, such that any variances will be returned to or recovered from customers in future rates.

10.0 Reference: LOAD FORECAST

Exhibit B-2, pp. 1, 4–5

Sensitivity analysis

On page 2 of the Application, FEI requests existing 2020 interim rates be made permanent, effective January 1, 2020; and requests a permanent delivery rate increase of 6.59 percent, effective January 1, 2021.

On pages 5 and 6, FEI presents Figures 1-1 and 1-2 showing the Delivery Revenue Deficiency ($ millions) in 2020 and 2021, respectively.

10.1 In a table format, please calculate how the load forecast impacts FEI's revenue surplus/deficiency and requested rate change for 2020 and 2021, respectively, if the load forecast in the following rates classes are -10%, -5%, 0%, +5%, and +10% than the forecast presented in the Application, respectively, assuming all else equal:

- Residential;
- Commercial;
- Industrial;
- CNG and LNG load; and
- Equal adjustment to the demand across all rate classes.

Response:

Please refer to Table 1 and Table 2 below for the impact of varying load forecasts on FEI's revenue surplus/deficiency and requested rate change for 2020 and 2021, respectively.

The analysis assumed there is no change to the amount of the deferred 2020 revenue deficiency (i.e., $10.338 million, Section 11 – 2020, Schedule 1, Line 29) and the amount of the 2021 revenue deficiency, which is drawn from the 2017 & 2018 Revenue Surplus Deferral Account (i.e., -$35.287 million, Section 11 – 2021, Schedule 1, Line 29). However, if the load forecasts were changed from the level included in the Application, FEI could adjust the deferred 2020 revenue deficiency accordingly to maintain the 2020 delivery rate change at 2 percent, which in turn will affect the 2021 revenue deficiency/surplus.

FEI also notes that variances between the forecast and actual delivery margin are captured in the Revenue Stabilization Adjustment Mechanism (RSAM) deferral account for variances in Rate Schedule 1, 2, 3, and 23 use rates, or the Flow-through deferral account for all other demand variances, and the resulting revenue requirement impacts are returned to or recovered from customers through the amortization of these deferral accounts in the subsequent years. In this way, customers are kept whole for any demand forecast variances.

Table 1: Impact to FEI's 2020 Revenue surplus/deficiency and Delivery Rate Change

Line	Particular	Unit	2020	2020	2020	2020	2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***Residential (RS 1)***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	72,958	77,011	81,064	85,117	89,170	Section 11 - 2020, Schedule 19, Line 3, Column 10 (for 0%)
3	Change in Demand	TJ	(8,106)	(4,053)	-	4,053	8,106	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	6.120	6.120	6.120	6.120	6.120	Section 11 - 2020, Schedule 19: Line 3, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(49,609)	(24,804)	-	24,804	49,609	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	764,359	789,163	813,968	838,772	863,576	Line 6 - Section 11 - 2020, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	830,268	830,268	830,268	830,268	830,268	Section 11 - 2020, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiency (Surplus)	$000s	65,909	41,104	16,300	(8,504)	(33,309)	Line 8 - Line 7
11	Delivery Rate Change	%	8.62%	5.21%	2.00%	-1.01%	-3.86%	Line 10 / Line 7
12	Variance to 2020 Rate Change per Application	%	6.62%	3.21%	0.00%	-3.02%	-5.86%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2020	2020	2020	2020	2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***Commercial (RS 2, 3, 23) - excl. CNG***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	53,082	56,031	58,980	61,929	64,878	Section 11 - 2020, Sch 19, Sum of Line 5 to 7, Col 10 (for 0%), excl. CNG
3	Change in Demand	TJ	(5,898)	(2,949)	-	2,949	5,898	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	3.937	3.937	3.937	3.937	3.937	Section 11 - 2020, Schedule 19: Sum of Line 5 to 7, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(23,222)	(11,611)	-	11,611	23,222	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	790,746	802,357	813,968	825,578	837,189	Line 6 - Section 11 - 2020, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	830,268	830,268	830,268	830,268	830,268	Section 11 - 2020, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiency (Surplus)	$000s	39,522	27,911	16,300	4,689	(6,922)	Line 8 - Line 7
11	Delivery Rate Change	%	5.00%	3.48%	2.00%	0.57%	-0.83%	Line 10 / Line 7
12	Variance to 2020 Rate Change per Application	%	3.00%	1.48%	0.00%	-1.43%	-2.83%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2020	2020	2020	2020	2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***Industrial (RS 4, 5, 6, 7, 22, 25, 27) - excl. CNG***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	52,482	55,397	58,313	61,229	64,144	Section 11 - 2020, Sch 19, Sum of Line 9 to 16, Col 10 (for 0%), excl. CNG
3	Change in Demand	TJ	(5,831)	(2,916)	-	2,916	5,831	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	1.447	1.447	1.447	1.447	1.447	Section 11 - 2020, Schedule 19: Sum of Line 9 to 16, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(8,437)	(4,219)	-	4,219	8,437	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	805,530	809,749	813,968	818,186	822,405	Line 6 - Section 11 - 2020, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	830,268	830,268	830,268	830,268	830,268	Section 11 - 2020, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiency (Surplus)	$000s	24,737	20,519	16,300	12,081	7,863	Line 8 - Line 7
11	Delivery Rate Change	%	3.07%	2.53%	2.00%	1.48%	0.96%	Line 10 / Line 7
12	Variance to 2020 Rate Change per Application	%	1.07%	0.53%	0.00%	-0.53%	-1.05%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2020	2020	2020	2020	2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***CNG (RS 3, 23, 5, 6P, 25)***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	761	803	845	887	930	Section 3, Table 3-2, 2020 Projected CNG Demand
3	Change in Demand	TJ	(85)	(42)	-	42	85	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	3.063	3.063	3.063	3.063	3.063	Section 11 - 2020, Sch 19: Sum of Line 6, 7, 10, 11 & 15, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(259)	(129)	-	129	259	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	813,709	813,838	813,968	814,097	814,226	Line 6 - Section 11 - 2020, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	830,268	830,268	830,268	830,268	830,268	Section 11 - 2020, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiency (Surplus)	$000s	16,559	16,429	16,300	16,171	16,041	Line 8 - Line 7
11	Delivery Rate Change @ Each Scenario	%	2.03%	2.02%	2.00%	1.99%	1.97%	Line 10 / Line 7
12	Variance to 2020 Rate Change per Application	%	0.03%	0.02%	0.00%	-0.02%	-0.03%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2020	2020	2020	2020	2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***LNG (RS 46)***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	2,309	2,437	2,566	2,694	2,822	Section 3, Table 3-2, 2020 Projected LNG Demand + non-NGT Demand
3	Change in Demand	TJ	(257)	(128)	-	128	257	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	5.312	5.312	5.312	5.312	5.312	Section 11 - 2020, Schedule 19: Line 23, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(1,363)	(681)	-	681	1,363	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	812,605	813,286	813,968	814,649	815,330	Line 6 - Section 11 - 2020, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	830,268	830,268	830,268	830,268	830,268	Section 11 - 2020, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiency (Surplus)	$000s	17,663	16,981	16,300	15,619	14,937	Line 8 - Line 7
11	Delivery Rate Change @ Each Scenario	%	2.17%	2.09%	2.00%	1.92%	1.83%	Line 10 / Line 7
12	Variance to 2020 Rate Change per Application	%	0.17%	0.09%	0.00%	-0.09%	-0.17%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2020	2020	2020	2020	2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***All Rate Schedules & LNG RS46***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	181,592	191,680	201,768	211,857	221,945	Section 11 - 2020, Schedule 19, Line 17 + Line 23, Col 10 (for 0%)
3	Change in Demand	TJ	(20,177)	(10,088)	-	10,088	20,177	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	4.086	4.086	4.086	4.086	4.086	Section 11 - 2020, Schedule 19: Line 17, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(82,445)	(41,223)	-	41,223	82,445	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	731,522	772,745	813,968	855,190	896,413	Line 6 - Section 11 - 2020, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	830,268	830,268	830,268	830,268	830,268	Section 11 - 2020, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiency (Surplus)	$000s	98,745	57,523	16,300	(24,923)	(66,145)	Line 8 - Line 7
11	Delivery Rate Change @ Each Scenario	%	13.50%	7.44%	2.00%	-2.91%	-7.38%	Line 10 / Line 7
12	Variance to 2020 Rate Change per Application	%	11.50%	5.44%	0.00%	-4.92%	-9.38%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Table 2: Impact to FEI's 2021 Revenue surplus/deficiency and Delivery Rate Change

Line	Particular	Unit	2021	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***Residential (RS 1)***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	71,399	75,366	79,332	83,299	87,266	Section 11 - 2021, Schedule 19, Line 3, Column 10 (for 0%)
3	Change in Demand	TJ	(7,933)	(3,967)	-	3,967	7,933	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	6.292	6.292	6.292	6.292	6.292	Section 11 - 2021, Schedule 19: Line 3, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(49,918)	(24,959)	-	24,959	49,918	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	774,979	799,938	824,897	849,856	874,814	Line 6 - Section 11 - 2021, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	879,286	879,286	879,286	879,286	879,286	Section 11 - 2021, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiecy (Surplus)	$000s	104,307	79,348	54,389	29,430	4,471	Line 8 - Line 7
11	Delivery Rate Change	%	13.46%	9.92%	6.59%	3.46%	0.51%	Line 10 / Line 7
12	Variance to 2021 Rate Change per Application	%	6.87%	3.33%	0.00%	-3.13%	-6.08%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2021	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***Commercial (RS 2, 3, 23) - excl. CNG***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	53,987	56,986	59,985	62,984	65,984	Section 11 - 2021, Sch 19, Sum of Line 5 to 7, Col 10 (for 0%), excl. CNG
3	Change in Demand	TJ	(5,999)	(2,999)	-	2,999	5,999	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	4.017	4.017	4.017	4.017	4.017	Section 11 - 2021, Schedule 19: Sum of Line 5 to 7, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(24,094)	(12,047)	-	12,047	24,094	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	800,803	812,850	824,897	836,944	848,991	Line 6 - Section 11 - 2021, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	879,286	879,286	879,286	879,286	879,286	Section 11 - 2021, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiecy (Surplus)	$000s	78,483	66,436	54,389	42,342	30,295	Line 8 - Line 7
11	Delivery Rate Change	%	9.80%	8.17%	6.59%	5.06%	3.57%	Line 10 / Line 7
12	Variance to 2021 Rate Change per Application	%	3.21%	1.58%	0.00%	-1.53%	-3.03%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2021	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***Industrial (RS 4, 5, 6, 7, 22, 25, 27) - excl. CNG***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	49,257	51,994	54,730	57,467	60,203	Section 11 - 2021, Sch 19, Sum of Line 9 to 16, Col 10 (for 0%), excl. CNG
3	Change in Demand	TJ	(5,473)	(2,737)	-	2,737	5,473	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	1.521	1.521	1.521	1.521	1.521	Section 11 - 2021, Schedule 19: Sum of Line 9 to 16, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(8,325)	(4,163)	-	4,163	8,325	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	816,572	820,734	824,897	829,059	833,222	Line 6 - Section 11 - 2021, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	879,286	879,286	879,286	879,286	879,286	Section 11 - 2021, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiecy (Surplus)	$000s	62,714	58,552	54,389	50,226	46,064	Line 8 - Line 7
11	Delivery Rate Change	%	7.68%	7.13%	6.59%	6.06%	5.53%	Line 10 / Line 7
12	Variance to 2021 Rate Change per Application	%	1.09%	0.54%	0.00%	-0.54%	-1.07%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2021	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***CNG (RS 3, 23, 5, 6P, 25)***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	761	803	845	887	930	Section 3, Table 3-2, 2020 Projected CNG Demand
3	Change in Demand	TJ	(85)	(42)	-	42	85	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	3.118	3.118	3.118	3.118	3.118	Section 11 - 2021, Sch 19: Sum of Line 6, 7, 10, 11 & 15, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(264)	(132)	-	132	264	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	824,633	824,765	824,897	825,028	825,160	Line 6 - Section 11 - 2021, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	879,286	879,286	879,286	879,286	879,286	Section 11 - 2021, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiecy (Surplus)	$000s	54,653	54,521	54,389	54,257	54,125	Line 8 - Line 7
11	Delivery Rate Change @ Each Scenario	%	6.63%	6.61%	6.59%	6.58%	6.56%	Line 10 / Line 7
12	Variance to 2021 Rate Change per Application	%	0.03%	0.02%	0.00%	-0.02%	-0.03%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2021	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***LNG (RS 46)***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	4,923	5,196	5,470	5,743	6,017	Section 3, Table 3-2, 2020 Projected LNG Demand + non-NGT Demand
3	Change in Demand	TJ	(547)	(273)	-	273	547	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	5.184	5.184	5.184	5.184	5.184	Section 11 - 2021, Schedule 19: Line 23, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(2,835)	(1,418)	-	1,418	2,835	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	822,062	823,479	824,897	826,314	827,732	Line 6 - Section 11 - 2021, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	879,286	879,286	879,286	879,286	879,286	Section 11 - 2021, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiecy (Surplus)	$000s	57,224	55,807	54,389	52,971	51,554	Line 8 - Line 7
11	Delivery Rate Change @ Each Scenario	%	6.96%	6.78%	6.59%	6.41%	6.23%	Line 10 / Line 7
12	Variance to 2021 Rate Change per Application	%	0.37%	0.18%	0.00%	-0.18%	-0.37%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

Line	Particular	Unit	2021	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	***All Rate Schedules & LNG RS46***		-10%	-5%	0%	5%	10%	
2	Demand @ Each Scenario	TJ	180,422	190,445	200,469	210,492	220,516	Section 11 - 2021, Schedule 19, Line 17 + Line 23, Col 10 (for 0%)
3	Change in Demand	TJ	(20,047)	(10,023)	-	10,023	20,047	Line 2, Demand @ Each Scenario - Column 5
4								
5	Effective Margin $/GJ	$/GJ	4.230	4.230	4.230	4.230	4.230	Section 11 - 2021, Schedule 19: Line 17, Col 3 / Col 10
6	Change in Margin @ Existing Rate	$000s	(84,803)	(42,402)	-	42,402	84,803	Line 3 x Line 5
7	Non-Bypass Margin @ Existing Rate	$000s	740,093	782,495	824,897	867,298	909,700	Line 6 - Section 11 - 2021, Schedule 19, Line 17, Column 3
8	Non-Bypass Margin @ Revised Rate	$000s	879,286	879,286	879,286	879,286	879,286	Section 11 - 2021, Schedule 19, Line 17, Column 5
9								
10	Revenue Deficiecy (Surplus)	$000s	139,192	96,791	54,389	11,987	(30,414)	Line 8 - Line 7
11	Delivery Rate Change @ Each Scenario	%	18.81%	12.37%	6.59%	1.38%	-3.34%	Line 10 / Line 7
12	Variance to 2021 Rate Change per Application	%	12.21%	5.78%	0.00%	-5.21%	-9.94%	Line 11, Delivery Rate Change @ Each Scenario - Column 5

10.1.1 Please explain all assumptions used to produce the above analysis, including which rate schedule(s) correspond with each of the residential, commercial, industrial, and CNG and LNG customer classes.

Response:

Please refer to the response to BCUC IR1 10.1.

C. COST OF GAS

11.0 Reference: COST OF GAS

Exhibit B-2, Section 4, pp. 28-29

Cost of gas calculation

FEI sets out the forecast cost of gas at existing rates, by RS group in Table 4-1 on page 29 of the Application.

11.1 Please provide a breakdown of the calculated cost of gas amount presented in Table 4-1, including the assumed load, corresponding cost of gas rates, and Unaccounted for Gas (UAF), for each rate class in a functional excel spreadsheet.

Response:

A breakdown by rate class of the 2020 and 2021 cost of gas forecasts included in Table 4-1 is included in the excel spreadsheet provided in Attachment 11.5. FEI notes that it is not requesting approval of its gas cost in this filing; it has been included only for the purpose of calculating the delivery margin, but it does not affect the delivery margin or delivery rates:

Revenues (including Cost of Gas Revenues) - Cost of Gas = Delivery Margin

12.0 Reference: COST OF GAS

Exhibit B-2, Appendix B, p. 4, Schedule 1; FEI 2019 Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account Status Report dated April 30, 2019, Tab 3 Page 1

Core market administration expense costs – Information Systems

FEI filed its 2019 Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account Status Report (2019 Status Report) on April 30, 2019. In this report, FEI shows that Information Technology cost was 21% higher than forecast and explains that "[c]omputer costs higher due to Gas Supply related Energy Trading & Risk Management (ETRM) System costs."

In Schedule 1 of Appendix B of the Application, FEI shows the actual costs for 2016 through 2019, 2020 projected, and the budget request for 2021. FEI also shows Information Systems (IS) cost was 12% higher than forecast in 2020.

On page 4 of Appendix B of the Application, FEI explains that:

> … 2020 and 2021 continue to be transition years related to the replacement of the current Entegrate deal capture system with a new Energy Trading and Risk Management (ETRM) system. During the transition period, software maintenance and support costs will be incurred on both systems until the new system is fully functional and the Entegrate system can be retired.

12.1 Please provide a breakdown on the IS line item into the following categories for each of 2016 to 2019 Actuals, 2020 projected, and for 2021 budget request: i) the current Entegrate deal capture system; ii) the ETRM system; and iii) others.

Response:

The table below provides the requested breakdown of the annual IS (Information Systems) costs, as well as the year to year comparison requested in BCUC IR 1.12.2.

IS (Information Systems) Costs Broken into Various Components

IS Cost Component *($000, unless specified otherwise)*	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Projected**	**2021 Budget Request**
Entegrate Deal Capture System	172	230	201	213	299	308
New ETRM System (Allegro Horizon)	-	-	-	65	108	125
Other	77	44	110	64	75	81
IS Total	**249**	**274**	**311**	**342**	**482**	**514**

IS (Information Systems) Year to Year Total Cost Comparison

IS Annual Cost Comparative *(year over year change shown in %)*	**2017 vs 2016**	**2018 vs 2017**	**2019 vs 2018**	**2020 vs 2019**	**2021 vs 2020**
Percentage Change	**10%**	**14%**	**10%**	**41%**	**7%**

Explanations for the year to year differences:

2017 Actual vs 2016 Actual – Higher costs primarily due to a one-time cost for amending Entegrate user licenses to reflect the business requirements, and the associated higher annual support costs; partially offset by the timing difference related to the processing delay of the 2017 Sendout invoice which shifted those annual software maintenance costs to 2018.

2018 Actual vs 2017 Actual – Higher costs primarily due to the 2017 annual Sendout software maintenance fee being booked to 2018, due to the invoice processing delay discussed above, as well as the 2018 annual Sendout software maintenance fee.

2019 Actual vs 2018 Actual – Higher costs primarily due to completing some ETRM predesign work related to the review of a number of FEI's requirements on the Allegro Horizon system prior to commencing the FEI Gas Supply – Phase 2 project work; partially offset by the Sendout software maintenance costs for 2019 returning to an annualized amount, compared to the two years of Sendout software maintenance costs reflected in the 2018 actuals.

2020 Projected vs 2019 Actual – Higher costs primarily due the annual maintenance and support costs for the Entegrate system and the Allegro Horizon system. A greater portion of the annual Entegrate support costs were allocated to FEI in 2020 as a result of ACGS going live onto Allegro Horizon during the year and beginning to transition off of the Entegrate system. As well, the annual software maintenance and support costs for the Allegro Horizon system, after apportioning with ACGS, were charged to FEI.

2021 Budget Request vs 2020 Projected – Marginally higher costs are forecast in 2021 to include the anticipated software maintenance / support contract service levels, inflationary increases, and changes to the shared cost allocations with ACGS during the ongoing transition period.

12.2 Using the 2016 to 2019 Actuals, 2020 projected, and 2021 budget request figures for the IS line item presented in Schedule 1 of Appendix B, please calculate the year to year difference (%) in IS cost from 2016 to 2021.

Response:

Please refer to the response to BCUC IR 1.12.1.

12.3 Please elaborate on the timing and key milestones of the ETRM system transition, including when costs from ETRM were first recovered as an Core Market Administration Expense (CMAE) under the IS line item and when the costs from the current Entegrate system are expected to drop off in the future.

Response:

The Allegro Horizon ETRM system is a multi-business, multi-phase IS project. The project is broken into three phases. Phase 1 focused primarily on the FortisBC Midsteam Inc. / Aitken Creek Gas Storage ULC (ACGS) storage business requirements. Phase 2 focuses on the FEI gas supply business requirements. Phase 3 focuses on the FortisBC Inc. (FBC) power supply business requirements.

Phase 1 of the Allegro Horizon ETRM project began in January 2019. Phase 1 focused primarily on the ACGS storage business requirements and was comprised of the design, configuration / build, and testing of the system, as well as a short period of parallel operation with the existing Entegrate system, prior to going live into the production environment. Phase 1 also included the design, configuration, and testing related to areas of common system functionality such as interfaces to enable input pricing feeds, and to enable data transfer between the Allegro Horizon ETRM system and the SAP financial system. Common system functionality encompassed system security requirements to ensure complete separation and financial walls between the individual businesses. Phase 1 was completed with ACGS going live onto Allegro Horizon on April 1, 2020.

Phase 2 of the Allegro Horizon ETRM project began in May 2020. Phase 2 is focused primarily on the FEI gas supply business requirements and is comprised of the design, configuration / build, and testing of the system, as well as a short period of parallel operation with the existing Entegrate system, prior to going live into the production environment. FEI has recently completed the design work related to Phase 2 and will be commencing the configuration / build stage shortly.

Prior to commencing the configuration / build stage for FEI, a minor system upgrade is being rolled out to the Allegro Horizon system. Regression testing of this newer version release is currently being completed. The upgrade is anticipated to be deployed into the production environment in October 2020 for use by ACGS, and the updated version of Allegro Horizon will be used for the system configuration / build for FEI.

FortisBC has planned a short series of discovery workshops during the fourth quarter of 2020 to assess the potential scope for Phase 3 of the Allegro Horizon ETRM related to the FBC power supply business requirements as FBC is not currently using a deal capture or energy trading system. Phase 3 is anticipated to begin around fall 2021, after completion of Phase 2.

Based on the current Phase 2 timeline, the FEI gas supply business related Allegro Horizon ETRM configure / build, and testing work is anticipated to continue through until late summer 2021. FEI is currently anticipating a one month parallel run during the August / September 2021 timeframe with a go live date of around October 1, 2021 (prior to the start of the gas year and the winter season).

Entegrate will not be retired immediately as the current fiscal and gas years will encompass data bridging the two systems. Archiving of the Entegrate data (creation of a database of the Entegrate historical data) and retirement of the Entegrate system would likely occur around mid-year 2022. Entegrate licensing and support costs are expected to become lower after the transition to the Allegro Horizon ETRM as fewer user licenses and reduced support will be required. However, the Entegrate licensing and support costs will not be fully eliminated until the Entegrate system is retired, and all licenses and support services are terminated.

Lastly, as discussed in the response to BCUC 1.12.4, costs related to the new ETRM system were first recovered through the CMAE in 2019. These initial costs were for some predesign work related to reviewing a number of FEI's requirements on the Allegro Horizon ETRM system prior to commencing the Phase 2 project work.

12.4 Please expand Schedule 1 to include a comparison of the actuals and forecasted IS cost in years 2016 through 2019, as well as the percentage difference between actuals and forecast for each year, respectively.

Response:

The table below provides the additional information requested for 2016 through 2019. FEI has also included data for Year 2020 to assist in addressing BCUC IR 1.12.5 within this response.

IS (Information Systems) 2016-2020 Annual Costs - Actual/Projected to Approved Comparison

IS Annual Costs	2016			2017			2018			2019			2020		
($000, unless specified otherwise)	Actual	Approved	Variance %	Actual	Approved	Variance %	Actual	Approved	Variance %	Actual	Approved	Variance %	Projected	Approved	Variance %
Totals	249	359	-31%	274	280	-2%	311	283	10%	342	283	21%	482	430	12%

Annual IS Cost Variance Explanations:

- 2016 Actual lower than Approved primarily due to FortisBC Midstream Inc. (FMI) / Aitken Creek Gas Storage ULC (ACGS) moving onto the Entegrate platform during 2016 and FEI achieving savings through the sharing of some of the system support costs.
- 2017 Actual slightly lower than Approved due to an invoice processing delay at year end, shifting the cost related to the annual Sendout software maintenance fee for 2017 to 2018, offsetting other minor cost pressures incurred during 2017.
- 2018 Actual higher than Approved primarily due to the invoice processing delay at 2017 year end, which shifted costs to 2018.
- 2019 Actual higher than Approved primarily due to some unbudgeted predesign work being completed in 2019 prior to commencing the FEI Gas Supply – Phase 2 of the new ETRM (Allegro Horizon) system. The predesign work related to reviewing a number of FEI's requirements on the Allegro Horizon ETRM system prior to commencing the Phase 2 capital project work.
- 2020 Projected higher than Approved due to the Entegrate and Allegro Horizon systems licensing and support costs being higher than budgeted.
  - The Entegrate licensing and support cost variances are primarily due to the 2020 budgeted amount being based on the forecast fees for the US currency denominated services contract and the forecast US exchange rate at the time the budget was prepared. The US currency denominated licensing and support fees incurred are higher than budgeted, and the US exchange rate worsened from that used in the budget.
  - The Allegro Horizon licensing and support cost variances are primarily due to the 2020 budgeted amount being based on the forecast fees for the Canadian currency denominated services and the forecast allocations between businesses of the shared platform support costs at the time the budget was prepared. The licensing and support fees incurred are higher than budgeted, and the allocation to FEI greater than was anticipated in the budget.

12.5 Please explain any unforeseen circumstances that resulted in the actual IS costs exceeding forecast in 2019 and 2020, respectively.

<u>Response:</u>

Please refer to the response to BCUC IR 1.12.4.

D. OTHER REVENUE

13.0 Reference: SOUTHERN CROSSING PIPELINE THIRD PARTY REVENUE

Exhibit B-2, Section 5.3, Table 5-6, pp. 34-36

Southern Crossing Pipeline revenue

Table 5-6 of the Application projects Southern Crossing Pipeline (SCP) revenue to decrease from $17.072 million in 2019 to $10.877 million in 2020 and $14.053 million in 2021.

On pages 35 and 36 of the Application, FEI states:

> As noted above and explained in the 2020/2021 ACP, FEI will not be renewing the NW Natural SCP Agreement. With the expiration of the NW Natural contract for SCP east to west capacity on October 31, 2020, FEI will increase its holding of SCP east to west capacity to the full amount of 105 MMcfd starting November 1, 2020. This capacity will provide more flexibility for future load growth, supply restrictions, or other marketplace constraints. Therefore, effective November 1, 2020, the cost of the 105 MMcfd of SCP east to west capacity contracted by FEI within its midstream portfolio needs to be charged to the Midstream.

13.1 Please discuss the revenue requirement impact as a result of the SCP revenue forecast to decrease from $17.072 million in 2019 to $10.877 million in 2020 and $14.053 million in 2021.

Response:

The revenue requirement impact is equal to the change in the SCP revenue forecast, as shown in line 3 of the table below. The table below also shows the delivery rate impact for 2020 and 2021, which is 0.76 percent and 0.37 percent, respectively, when compared to the 2019 approved delivery rates.

Line	Particular	Unit	2020 Projected	2021 Forecast	Cross Reference
1	SCP Third Party Revenue	$000s	10,877	14,053	Section 11 - 2020/2021, Schedule 23, Line 5
2	2019 Approved SCP Third Party Revenue	$000s	17,072	17,072	Section 11 - 2020/2021, Schedule 23, Line 5
3	Change in SCP Third Party Revenue (compared to 2019 Approved)	$000s	(6,195)	(3,019)	Line 1 - Line 2
4					
5	2020 Non-Bypass Delivery Margin at Existing 2019 Rates	$000s	813,968	813,968	Section 11 - 2020, Schedule 1, Line 33
6	Delivery Rate Impact (compared to 2019 Rates)	%	0.76%	0.37%	-Line 3 / Line 5

13.2 Given the significance in the reduction in SCP revenue, please provide reference to where the change in the treatment of the cost of SCP was discussed in FEI's MRP Application. If it was not discussed in the MRP Application, please discuss why.

Response:

As discussed in the responses to BCUC IR1 13.4.1 and BCUC IR1 14.2, the reduction in the Total SCP Revenue shown in Table 5-6 is not related to the expiration of the NW Natural contract or the revaluation of the SCP east to west capacity to be held in the gas supply midstream portfolio effective November 1, 2020. Rather, the reduced revenues are a result of the lower mitigation value of the west to east capacity on SCP, as more fully explained in the response to BCUC IR1 14.1.

Since the October 31, 2016 expiration of the T-South Enhanced Service agreement with Westcoast Energy Inc., FEI has been seeking other opportunities to contract the west to east capacity on SCP. The relatively high west to east mitigation revenue FEI has generated over the past several years has been a result of the market conditions in the region. Further, FEI has consistently indicated that the forecasts of SCP west to east mitigation are based on the then current forward market price differentials for the respective summer periods, which have reflected the pipeline capacity constraints within the region, and that these market conditions will change over time with mitigation revenues expected to decrease as regional constraints are addressed.

The MRP Application was filed on March 11, 2019, and FEI's Application for Approval of 2020 Rates on an Interim Basis, effective January 1, 2020 (2020 Interim Rate Application) was filed on October 29, 2019. At the time of those filings, the forward market price differentials did not indicate as much of a decrease in the SCP west to east mitigation revenue. In the 2020 Interim Rate Application, at pages 9-10, FEI noted a forecast decrease in Other Revenue of approximately $2 million primarily related to a decrease in the mitigation revenue associated with the SCP west to east capacity based on the then current forward market price differentials for summer 2020.

Any variance from the forecast SCP Third Party Revenues will continue to be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a two-year period.

13.3 Please provide a sensitivity analysis for the impact to rates if SCP third party revenues is +/- 5 percent, and +/- 10 percent, of the current forecast.

Response:

Please see Table 1 and Table 2 below for the sensitivity analysis on the impact of SCP third party revenues on delivery rates in 2020 and 2021, respectively. The impact to delivery rates is zero percent when rounded to two decimal places.

As described in Section 5.3.2 of the Application, the MCRA revenue shown in Table 5-6 is a cost reclassification from delivery rates to storage and transport rates, and therefore, it is not third party revenue for the SCP. As such, FEI completed the sensitivity analysis shown in the tables below for the NW Natural and the Net Other Mitigation Revenue only.

Table 1: Sensitivity Analysis for 2020 SCP Third Party Revenue

Line	Particular	Unit	2020	2020	2020	2020	2020	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			-10%	-5%	0%	5%	10%	
1	SCP Third Party Revenue							
2	NW Natural	$000s	3.739	3.946	4.154	4.362	4.569	Table 5-6 of Application (for 0%)
3	Net Other Mitigation Revenue	$000s	1.353	1.428	1.503	1.578	1.653	Table 5-6 of Application (for 0%)
4	Total SCP Third Party	$000s	5.091	5.374	5.657	5.940	6.223	Line 2 + Line 3
5								
6	Change in SCP Third Party Revenue	$000s	(0.57)	(0.28)	-	0.28	0.57	Line 4 @ Each Scenario - Column 5
7								
8	2020 Revenue Deficiency (Surplus)	$000s	16,300	16,300	16,300	16,300	16,300	Section 11 - 2020, Schedule 1, Line 31
9	Adjusted 2020 Revenue Deficiency (Surplus)	$000s	16,301	16,300	16,300	16,300	16,299	Line 8 - Line 6
10								
11	2020 non-bypass Delivery Margin @ Exisitng Rate	$000s	813,968	813,968	813,968	813,968	813,968	Section 11 - 2020, Schedule 1, Line 33
12	Delivery Rate Change (Rounded to 2 decimal places)	%	2.00%	2.00%	2.00%	2.00%	2.00%	Line 9 / Line 11

Table 2: Sensitivity Analysis for 2021 SCP Third Party Revenue

Line	Particular	Unit	2021	2021	2021	2021	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
			-10%	-5%	0%	5%	10%	
1	SCP Third Party Revenue							
2	NW Natural	$000s	-	-	-	-	-	Table 5-6 of Application (for 0%)
3	Net Other Mitigation Revenue	$000s	0.692	0.731	0.769	0.807	0.846	Table 5-6 of Application (for 0%)
4	Total SCP Third Party	$000s	0.692	0.731	0.769	0.807	0.846	Line 2 + Line 3
5								
6	Change in SCP Third Party Revenue	$000s	(4.96)	(4.93)	(4.89)	(4.85)	(4.81)	Line 4 @ Each Scenario - Column 5
7								
8	2020 Revenue Deficiency (Surplus)	$000s	54,389	54,389	54,389	54,389	54,389	Section 11 - 2021, Schedule 1, Line 31
9	Adjusted 2020 Revenue Deficiency (Surplus)	$000s	54,394	54,394	54,394	54,394	54,394	Line 8 - Line 6
10								
11	2020 non-bypass Delivery Margin @ Exisitng Rate	$000s	824,897	824,897	824,897	824,897	824,897	Section 11 - 2021, Schedule 1, Line 33
12	Delivery Rate Change (Rounded to 2 decimal places)	%	6.59%	6.59%	6.59%	6.59%	6.59%	Line 9 / Line 11

13.4 Please explain the reasons FEI needs the additional capacity for future load growth, including where the future load growth is coming from, and the likelihood it will materialize.

Response:

FEI first discussed its strategy not to renew the NW Natural SCP Agreement in its 2019/20 ACP filed on May 1, 2019. As FEI explained in the 2019/20 ACP, the additional capacity is needed for future load growth and to mitigate future supply risks. By Letter L-32-19 dated June 19, 2019, the BCUC accepted FEI's 2019/20 ACP. The BCUC also requested that FEI file an update to the 2019/20 ACP to address the expected return of transmission service customers to bundled service. FEI filed the update to the 2019/20 ACP on July 15, 2019, which the BCUC accepted via Order L-40-19, dated August 8, 2019.

The expected load growth is based on FEI's forecast design peak day and winter design demand for Rate Schedule 1-7 and Rate Schedule 46 customers, which is included in the ACP filings. Some of the future load growth has already materialized due to over 900 transportation service customers returning to bundled service as of November 1, 2019. FEI's design peak day demand forecast in its 2020/21 ACP, as accepted by the BCUC in Letter L-31-20 dated June 5, 2020, continues to show load growth within the next 1-5 years for RS 1-7 customers, as well as increasing demand from RS 46 customers.

Although load growth was one reason for not renewing the SCP agreement with NW Natural, FEI's primary reason for taking back the capacity was to increase supply diversity in its portfolio, which is needed from a resiliency perspective, especially in light of the T-South incident. As stated on page 35 of the Application, taking this capacity back was FEI's only opportunity in the marketplace to diversify its portfolio.

13.4.1 Please discuss if FEI believes the revenue from future load growth will eventually replace the revenues from the NW Natural contract. When does FEI foresee this happening?

Response:

As noted in the response to BCUC IR1 13.4, the primary reason why FEI did not renew the SCP agreement with NW Natural, and instead held the additional SCP east to west capacity in its gas supply midstream portfolio, was to increase supply diversity in its portfolio, which is needed from a resiliency perspective, especially in light of the T-South incident.

FEI is not forecasting a decrease to the SCP east to west capacity revenue stream. The revenue associated with the east to west capacity on SCP is comprised of the NW Natural and

MCRA line items in Table 5-6. As reflected in Table 5-6, the SCP east to west capacity related revenues are $9.363 ($5.763 + $3.600) million for Approved 2019 and Actual 2019, $9.374 ($4.154 + $5.220) million for Projected 2020, and $13.284 ($0 + $13.284) million for Forecast 2021. Thus, the delivery margin revenue stream associated with the SCP east to west capacity has not decreased as a result of the expiration of the NW Natural contract. The revenue stream associated with the SCP east to west capacity has in fact increased.

The SCP revenues shown at the Net Other Mitigation – West to East Capacity line in Table 5-6 of the Application reflect the significant decreases forecast in the Projected 2020 and Forecast 2021 amounts due to changing market conditions. The reduced SCP west to east capacity mitigation is the reason for the lower Total SCP Revenue for Projected 2020 and Forecast 2021 in Table 5-6, not the expiration of the NW Natural contract for east to west capacity on SCP.

In Section 5.3.2 of the Application, FEI incorrectly implied that SCP related revenues credited to delivery margin can be replaced by mitigation revenues credited to the gas costs via the MCRA. FEI stated on page 36, lines 6-8: *"In addition to increasing its holding of SCP, FEI has entered into a T-South mitigation agreement that offsets the lost revenue from NW Natural's contracted capacity on the SCP. The mitigation revenue will be accounted for in the MCRA and flow to FEI's Sales Customers."* To clarify, the following paragraphs provide a detailed explanation of the revenue streams.

The NW Natural revenues presented in Table 5-6 relate directly to the contracted SCP east to west capacity they hold until October 31, 2020 and are a delivery margin related revenue stream. As discussed above, the SCP east to west capacity available due to expiration of the NW Natural contract will be taken into the gas supply midstream portfolio. The forecast credit amount to be booked to the delivery margin for all of the SCP east to west capacity, which will be held in the gas supply midstream portfolio effective November 1, 2020, ensures no deterioration to the delivery margin revenue stream associated with the SCP east to west capacity upon expiration of the NW Natural contract.

The MCRA line in Table 5-6 reflects the annual credit amounts booked to the delivery margin Other Revenue category for the SCP east to west capacity held in the FEI gas supply midstream portfolio, for which there are offsetting debit amounts charged to the MCRA. FEI plans its gas supply commodity and midstream portfolios to provide secure and reliable physical gas supply to customers on a daily basis under most operating conditions. The costs incurred for the various transportation and storage resources, including the SCP east to west capacity, held within the gas supply midstream portfolio are captured in the MCRA. Resources not required to meet the customer load on a day, or during non-heating season periods, are mitigated and those mitigation revenues are also captured in the MCRA, thereby reducing the gas supply costs borne by sales customers.

The mitigation revenues associated with the T-South mitigation agreement FEI has entered into with NW Natural will be captured in the MCRA and will reduce the total MCRA costs, including the MCRA costs related to the SCP east to west capacity held in the gas supply midstream portfolio.

13.4.2 Please discuss how FEI plans to mitigate the loss in revenues from the NW Natural contract should the future load growth or supply restrictions not materialize.

Response:

Please refer to the response to BCUC IR1 13.4.1.

On page 36 of the Application, FEI states:

> FEI reviewed the valuation of the SCP capacity to be used in the transfer of costs to the MCRA. FEI considered various approaches to the valuation including Avoided Cost, Market Based, and Cost of Service (COS) approaches. Under the Avoided Cost and Market Based approaches there is uncertainty due to market factors such as new projects increasing regional demand, future pipeline expansions, flow dynamics, future Enbridge tolls and Enbridge system reliability. Given this uncertainty and considering that FEI owns the SCP assets, FEI valued the SCP capacity based on the cost of service of the SCP pipeline. Most regulated pipelines determine tolls through a comparable process.

13.5 Please explain in detail the criteria that were used to determine that the COS approach was better than the other alternatives.

Response:

The COS approach is best suited for valuing the SCP Pipeline in the MCRA based on the following criteria:

1. Transparency, Supportability and Stability

The COS approach is based on cost data that is transparent, easily supported and stable. FEI is able to provide a granular breakdown of the cost elements, including Operation and Maintenance Costs, Property Taxes, Depreciation and Amortization Expense, Other Revenue, Income Taxes and Earned Revenue. Providing this data offers clarity around the resources required in providing SCP service for customers.

Other alternatives such as a Market Based and Avoided Cost approach are not as transparent, supportable or stable as they rely on the quantity and quality of data available at the time, as well as inherent biases that may exist on views of future states and scenarios. This is because these approaches rely on anticipating future upstream spending which can vary under different market conditions. The natural gas industry has experienced fundamental changes over the years, due to factors such as resource abundance and affordability, environmental restrictions, technology advances, versatility for heating and cooling, power generation and transportation. These types of ongoing changes in the industry make future assumptions and scenarios hard to anticipate and predict. Therefore, these approaches require annual revaluation and adjustment based on the latest information.

A Market Based approach can be useful when substantial data and information is available between comparable pipelines and market conditions. In the case of the SCP Pipeline in British Columbia where the region is constrained, with limited options for pipeline expansion, it would be difficult to find a similar pipeline for comparison and analytical purposes.

The above features make a Market Based or Avoided Cost approach less transparent, more difficult to support and unstable compared to a COS approach. Using the COS valuation approach is the most straightforward approach in which actual costs are utilized and is therefore an uncomplicated way to internally allocate the costs and recoveries in a manner which does not require an annual adjustment to the amount allocated due to changing market conditions.

2. Industry Standards

The COS approach is the predominant approach used by other pipelines in the region, including all those regulated by the Canadian Energy Regulator (CER). Please refer to FEI's response to BCUC IR1 13.7.

13.6 Please explain what impact the other valuation approaches would have had on FEI's Other Revenue, and the resulting impact on delivery rates for 2020 and 2021.

Response:

Market and/or avoided cost approaches could have a wide range of potential impacts on a calculated SCP toll, as they can be drastically different depending on market conditions. The market conditions underlying these other valuation approaches are always changing, and there is uncertainty related to potential new demand within the region, how infrastructure will be developed and when to meet the needs of the region. To illustrate, when utilizing a market and/or avoided cost approach, the forward price market is used, which changes on a daily basis based on market conditions. Forward prices used in March of 2019 showed SCP tolls in the range of $0.45/GJ to $0.65/ GJ, but the same analysis using prices from June 2020 shows a SCP toll in the range of $0.14/GJ to $0.35/GJ.

As described in the Application, the reclassification to the MCRA is a cost reclassification from delivery rates to storage and transport rates. A change in the valuation method would serve to change the reclassification amount. For each $1 million of reclassification, delivery rates change by approximately 0.1 percent. Using the COS as the valuation approach will provide stability of the annual charge to MCRA. The other valuation methods considered would require annual revaluations and introduce market speculation variability into both delivery and MCRA rates.

13.7 Please provide a list of the regulated pipelines that determine tolls through a comparable process.

Response:

The following key pipelines in the region utilize a cost of service methodology: Alliance Pipeline, Enbridge Pipeline and TC Energy. The Canadian Energy Regulatory (CER) regulates 97 companies that own/or operate interprovincial or international pipelines. One item of regulation under its jurisdiction is pipeline tolls and tariffs. All CER regulated pipelines use cost of service regulation and they have to meet minimum requirements per the CER's Filing Manual. The guidance provided in the Filing Manual details how to utilize a cost of service approach. Although it is ultimately the responsibility of the applicant to make its case, the CER has published this manual to provide direction regarding the type of information the CER would typically expect to see addressed in a filing that involves cost of service tolling. This method requires that the operator submit cost and revenue data supporting a requested rate. The CER expects shippers to take an active role in representing their interests as tolls and tariffs change. It is through this process that the CER can determine that rates are just and reasonable.

14.0 Reference: SCP THIRD PARTY REVENUE

Exhibit B-2, Section 5.3.3, p. 37

Net other mitigation revenue

On page 37 of the Application, FEI states that "[t]he significant decrease in the 2020 Projected mitigation revenue for the SCP west to east capacity compared to the 2019 Approved amount is due to changing market conditions." Then on page 38, FEI states that "[t]hese market conditions will continue to change over time and mitigation revenues have decreased significantly since 2019".

14.1 Please explain what is driving the market price differentials to narrow. Are there any other opportunities that FEI is aware of to contract the capacity?

Response:

The projected SCP mitigation revenue for west to east capacity is mainly based on the forward market price differential between the Station 2 supply and the Kingsgate market hub during the summer period (April to October). Over the past several years, the forward market prices at Station 2 were heavily discounted compared to other supply/market hubs due to an over-supply of production at Station 2 and planned and unplanned maintenance on the Westcoast T-South and T-North, NOVA, and Alliance pipelines, which restricted gas flows to markets out of BC. However, FEI expected that over time rebalancing could occur with either a cycle of declining investment in the regional supply basin, and/or new pipeline capacity being developed to move the gas to market.

The most significant change to these market conditions occurred when TC Energy's North Montney Phase 1 project was placed into service on January 31, 2020. This project provided greater optionality for producers to send their supply to either the Station 2 and/or AECO/NIT supply hubs. Since the project came online, the forward prices at Station 2 steadily narrowed in relation to the AECO/NIT hub, and as of September 15, 2020 are now trading at a premium to the AECO/NIT hub. The Kingsgate market price is influenced by the pricing at the AECO/NIT supply hub specifically during the summer period (April to October). Therefore, the rebalancing between Station 2 and AECO/NIT reduced the value for the SCP west to east capacity, limiting FEI's ability to contract the capacity to a counterparty during the summer period. As a result, the mitigation revenue that FEI was experiencing over the past several years for the SCP west to east capacity is projected to decline.

14.2 Please discuss if FEI reconsidered renewing its firm service contract with NW Natural, given that the market price differentials have narrowed significantly. Why or why not?

Response:

The mitigation revenue for west to east pipeline capacity discussed in the preamble above is not associated with the NW Natural contract which related to the SCP east to west capacity. Please refer to the responses to BCUC IR1 13.4 and 13.4.1 with regard to FEI's decision not to renew the SCP contract with NW Natural and explanation of the revenues associated with the SCP east to west capacity, including the NW Natural contract.

E. O&M EXPENSE FORECAST OUTSIDE THE FORMULA

15.0 Reference: O&M EXPENSE FORECAST OUTSIDE THE FORMULA

Exhibit B-2, Section 6.3.1, pp. 43-44

Pension and Other Post-Employment Benefits expense

On page 43 of the Application, FEI explains the $10.710 million increase in projected 2020 pension Other Post-Employment Benefits (OPEB) expense in part as:

- An approximately $10.3 million increase in amortization of actuarial losses and increases in current service costs and interest costs due to decline in discount rates. The discount rates, which are determined with reference to the market rate of interest on high quality debt instruments at a point in time, decreased from 3.5 percent, which was used to determine 2019 Approved expense, to 3.0 percent, which is used to determine 2020 Projected expense;

15.1 Please provide the reference point in time that was used to determine the discount rates for 2020 projected expense.

Response:

The discount rates used in determining 2020 projected Pension and OPEB expense were based on the market rates of return for high quality fixed income investments that existed as of December 31, 2019. 2020 Actual pension and OPEB expense will be equivalent to the 2020 Projected Expense as it is determined pursuant to US GAAP using actuarial assumptions, including discount rates, that exist at the end of the prior year. Actuarial assumptions that are tied to capital markets, such as discount rates and expected return on assets, may change throughout the year. However, it is the determination of such actuarial assumptions at the end of the year which are then used to measure the actual pension and OPEB expense for the subsequent year as per Financial Accounting Standards Board (FASB) Accounting Standards Codification No. 715 Compensation Retirement Benefits.

15.1.1 Please explain if FEI has an update to these discount rates, given the recovery in capital markets since the beginning of the pandemic.

Response:

FEI does not have a formal re-measurement of updated discount rates at the time of this response. However, discussions with FEI's external actuary, Willis Towers Watson, in mid 2020 indicated that a baseline of discount rates could approximate 3.0 percent, which was subsequent to certain of the capital market volatility.

As explained in the response to BCUC IR1 15.1, both the Projected and Actual 2020 pension and OPEB expense utilize a discount rate of 3.0 percent which was determined as at prior year-end, December 31, 2019, pursuant to US GAAP. Therefore, changes in discount rates at different points in time throughout 2020 will not affect the Projected or Actual 2020 pension and OPEB expense.

15.2 Please provide a sensitivity analysis that shows what the impact of a 0.1 percent change in discount rates has on projected 2020 expense compared to 2019 actual expense.

Response:

A 0.1 percent change in discount rates is expected to result in a change in pension and OPEB expense of approximately $2.0 million. This approximation is based on the $10.3 million increase in pension and OPEB expense described in the preamble which resulted from a decline in discount rates from 3.5 percent used for 2019 Approved expense to 3.0 percent used for 2020 Projected and Actual expense. As explained in the response to BCUC IR1 15.1, both the Projected and Actual 2020 pension and OPEB expense utilize a discount rate of 3.0 percent which was determined as at prior year-end, December 31, 2019, pursuant to US GAAP. Therefore changes in discount rates at different points in time throughout 2020 will not affect the Projected or Actual 2020 pension and OPEB expense.

On page 44 of the Application, FEI further states:

> The 2021 pension and OPEB expense is forecasted to be $2.917 million higher than 2020 Projected expense primarily due to two factors. First there is a forecasted further decline in discount rates in mid-2020 due to the volatility in capital debt markets. Second, while there has been a recovery in the value of pension plan assets since the beginning of the pandemic in 2020, it is still expected that the estimated annual asset return for 2020 will remain lower than expected and this expectation has been incorporated into the determination of the 2021 pension and OPEB expense.

15.3 Please explain if FEI has an update to the estimated annual asset return for 2020, given the recovery of capital markets since the beginning of the pandemic.

Response:

FEI does not have a formal remeasurement of expected return on assets at the time of this response. However, the determination of the 2021 Forecast Pension and OPEB expense included in this Application took into account a 2020 annualized return on assets of 3.0 percent which incorporated recovery of capital markets through to mid-2020 based on estimates provided by FEI's third party external actuary, Willis Towers Watson (WTW), in mid 2020. Based on recent discussions with WTW in reviewing market performance through to September, there has not been a significant change in the overall forecasted 2020 annual asset return assumptions used to determine the 2021 pension expense in the Application and therefore no update to pension and OPEB expense is warranted at this time. Variances between Forecast Pension and OPEB expense included in the 2020-2021 Rate Filing and the 2021 actual pension and OPEB expense, which will be determined and measured as at December 31, 2020, are recorded in an approved deferral account and amortized over three years.

16.0 Reference: O&M EXPENSE FORECAST OUTSIDE THE FORMULA

Exhibit B-2, Section 6.3.2, p. 44

Insurance expense

On page 44 of the Application, FEI explains the projected insurance expense increases as a result of "various insurers reducing their capacity and increasing restrictions and retentions."

16.1 Please explain in detail what is meant by "reducing their capacity and increasing restrictions and retentions."

Response:

As the insurance market hardens (a hard insurance market is characterized by a high demand for insurance coverage and a reduced supply), insurance underwriters may take portfolio remediation approaches to reduce their risks and exposures by reducing their capacity, increasing restrictions and retentions.

In this context, insurance "capacity" refers to the limits of insurance that an insurance company agrees to assume from underwriting a risk. Reducing insurance capacity allows an insurer to continue to underwrite a risk but reduce their exposure. This results in the need for other insurers of the existing policies to increase their capacity or the need to seek new insurers who are willing to participate in the existing insurance program. Different insurers have different pricing philosophies and some insurers may increase their existing capacity at a higher premium.

Some insurers may limit their risks by adding new exclusions to exclude or restrict coverages for a particular event. Additionally, the increase of policy deductibles or self-insured retentions raises the threshold of an insured event for indemnification under a policy.

The above factors are contributing to FEI's projected insurance expense increases.

16.2 Please explain how many different insurers FEI works with. Has FEI sought out any alternatives to the current insurers? If not, please explain.

Response:

FEI's policies are insured by over twenty different insurers combined. Insurance policies are placed through our insurance broker who seeks all markets, both domestically and overseas, to secure the required insurance with the most favorable terms and the most reasonable pricing.

17.0 Reference: O&M EXPENSE FORECAST OUTSIDE THE FORMULA

Exhibit B-2, Section 6.3.3, p. 45, Table 6-7

Integrity digs

Table 6-7 of the Application provides the forecast number of integrity digs for 2020 and 2021, as well as the forecasted cost per dig, compared to the actual number of digs and cost per dig for 2017, 2018, and 2019.

17.1 Please provide the forecasted number of integrity digs for 2019 and explain any variances to the actual number of digs for 2019.

Response:

FEI forecasted 90 integrity digs for 2019 and completed 117. The table below provides a further breakdown of 2019 integrity digs and includes forecasted numbers of integrity digs for 2019 provided through FEI's past submissions to the BCUC, along with the actual number of digs. Consistent with FEI's responses to BCUC IR1 1.7 and 1.8 from FEI's Annual Review for 2018 Rates, strain-based criteria for dent digs continue to require a significant volume of digs on FEI's system (Line 2). FEI's integrity digs are determined on an ongoing basis from FEI's analysis, and these previously unidentified digs comprise the increase to the number of ILI digs attributed to changes to industry practices or standards. In the second half of 2019, FEI also allocated more resources for required Non-ILI digs than originally forecast (Line 4).

Line No.	Reason for Digs	2019 Forecast BCUC IR1, 1.3, from FEI Annual Review for 2019 Rates (September 18, 2018)	2019 Year-End Forecast MRP 2020-2024 Application (June 17, 2019)	2019 Actual FEI Annual Review for 2020 and 2021 Rates (as reported August 12, 2020)
1	ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment	Under development	10	11
2	ILI digs attributed or projected due to changes to industry practices or standards (e.g., strain-based criteria for dent digs) requiring a corresponding change from FEI's past integrity dig practices	Under development	30	45
3	Ongoing ILI digs not covered by a category above	Under development	45	37
4	Non-ILI digs identified through above-ground cathodic protection and coating surveys	Under development	5	24
5	Total Integrity Digs	≈ 105 +/- 10%	90	117

On page 45, FEI states that "[c]osts associated with integrity digs are primarily outside of FEI's control, and there can be considerable uncertainty related to scope, cost, timing and volume of expected digs."

17.2 Please explain in detail why the cost per dig is increasing from $26,000 in 2019, to $30,000 in 2020 and $31,000 in 2021.

Response:

The average cost per integrity dig fluctuates from year to year. The scope and cost for integrity digs, including for FEI's 2020 and 2021 forecasts, varies depending on location, surface and subsurface conditions, depth, proximity to geographic features (i.e., river crossings, environmental zones, and highways), season, and the number of imperfections requiring visual inspection and repair.

The following table demonstrates the fluctuation in the average cost per dig from 2011 to present. While there may have been increases in dig costs in recent years, FEI does not believe this is necessarily suggestive of an ongoing trend.

Reason for Digs	Number of Digs per Year										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020 YEF	2021 Forecast
Total Integrity Digs	**54**	**38**	**50**	**62**	**66**	**74**	**98**	**86**	**117**	**145**	**155**
Total Expenditures ($000s)	$1,600	$1,800	$1,400	$2,300	$2,300	$2,500	$3,200	$2,500	$3,100	$4,400	$4,800
Cost per dig ($000s)	$30	$47	$28	$37	$35	$34	$33	$29	$26	$30	$31

17.3 Please explain what measures FEI has in place to ensure that the uncertainty related to scope, cost, timing and volume is mitigated.

Response:

FEI performs up-front planning for the portion of its integrity dig scope that can be identified the year prior to performing these planned digs. This improves FEI's certainty with respect to scope and cost of its planned integrity digs by identifying any site-specific challenges with permits, site access, restoration, procurement of materials, and resourcing. There is remaining uncertainty relating to scope and cost for planned integrity digs that cannot be understood and mitigated until the pipe is exposed and inspected, such as whether the excavation will need to be extended based on observed pipe and/or coating condition or whether a structural repair will be required. In addition, as integrity digs are determined and prioritized on an ongoing basis, there is a portion of FEI's annual integrity dig scope that requires more timely operational response, and for which FEI's standard up-front planning timelines are not feasible. Given that the scope, timing and volume of integrity digs are substantively determined by engineering analysis of the various factors listed above, the cost of integrity digs will continue to remain largely outside of FEI's control.

17.4 Please explain if FEI has analyzed any learnings from the Enbridge pipeline explosion that occurred in 2018, and how it has applied that knowledge to future integrity digs or other safety measures.

Response:

FEI has analyzed the learnings from the Enbridge pipeline explosion and reviewed this incident as part of FEI's management review process for its Integrity Management Program – Pipeline (IMP-P).

FEI reviewed the Pipeline Safety Advisory issued by the Transportation Safety Board of Canada on the subject of "Management of stress corrosion cracking on susceptible pipelines" (released on June 26, 2019), and assessed the Transportation Safety Board of Canada's report on the incident (released March 4, 2020). The key findings in these documents, relevant to FEI's transmission pipeline operations, are:

1. The extent of Stress Corrosion Cracking (SCC) on the segment of pipe was not identified, or predicted accurately; and
2. Insufficient records of in-line inspection (ILI) deferral were available.

SCC can be identified and its extent predicted with reasonable confidence through EMAT[10] ILI. As part of its TIMC project development activities, FEI has run EMAT ILI in two pipeline segments. Further, FEI is developing its EMAT analysis and re-inspection interval determination processes for its ongoing crack-detection activities. FEI considers evolving standards/regulations, recent technical references/publications (such as the Enbridge incident report), and/or changes to industry practice when establishing such processes.

With respect the second finding listed above, FEI maintains ILI records and has an existing metric in its IMP-P dashboard for completion of its annual ILI tool runs. ILI deferrals are escalated as required for management approval. As FEI develops its EMAT-related processes,

[10] EMAT refers to Electro-Magnetic Acoustic Transducer in-line inspection technology.

FEI will assess the existing process for adequateness and appropriateness. As part of the ongoing continual improvement of its IMP-P, FEI will consider opportunities to enhance any processes for ILI or other activity deferrals.

F. CAPITAL

18.0 Reference: CAPITAL

Exhibit B-2, Section 7.1, p. 53

Regular capital expenditures: Variance in 2019 net capital expenditures

On page 53 of the Application, FEI provides Table 7-1:

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Formula Growth Capex	40.143	88.454	68.199	62.657	Table 7-2, Line 5
2	Formulaic CIAC			2.452	2.253	Section 11, Schedule 9, Line 2
3	Formula/Forecast Sustainment & Other Capex	122.928	151.476	161.300	162.860	Section 11, Schedule 4, Lines 15 + 16
4	Flow through Capex	25.210	8.080	10.398	27.012	Section 11, Schedule 4, Sum of Lines 11 through 14
5	Total Gross Regular Capex	188.281	248.010	242.349	254.782	Sum of Lines 1 through 4
6	Less: Formula CIAC	(5.812)	(5.700)	(2.452)	(2.253)	- Line 2
7	Less: Forecast CIAC	-	-	(4.767)	(3.752)	Section 11, Schedule 9, - Line 6/1000 - Line 6
8	Net Regular Capex	182.469	242.310	235.130	248.777	Sum of Lines 5 through 7

The Table shows 2019 actual net regular capital expenditures were $242.310M, compared to 2019 forecast of $182.469M.

18.1 Please provide a detailed explanation, by category, of the variances between the 2019 approved forecast and 2019 actuals. In your response, please describe any capital projects that were advanced, delayed or cancelled, and any other relevant information.

Response:

Formula Growth Capex Variance

As discussed on Pages B-34 and B-35 of the FEI-FBC MRP 2020-2024 Application, actual growth capital has outpaced the formula-generated growth capital in every year over the PBR term, as increases in growth capital to meet customer demand have been the main contributor to overall capital expenditure variances. In summary, the annual variances, including the variance in 2019, can be attributed to two main factors:

- Developments during the PBR term that were not initially anticipated in 2013 base year growth capital expenditures caused an increase in unit costs. These developments include changes to the mix of customer type and location of new attachments. For instance, the increase in industrial mains during the PBR compared to the base year assumptions has led to increased mains additions unit costs. Further, the increase in service line additions activity on Vancouver Island (where costs are higher) compared to the base year has also led to an increase in overall unit costs.

- The use of historical values for formula inputs and the 50 percent reduction in the formulas' growth factors, has resulted in a higher per installation cost than was utilized in calculating the approved formula growth capital amounts.

In Appendix B8-1 of the FEI-FBC MRP 2020-2024 Application, FEI also provided a detailed breakdown and explanation of growth capital variances divided into the two major categories of service line addition-related growth capital variances and mains-related growth capital variances. FEI has updated this analysis below.

Service Line Additions Growth Capital Variance

There are four main factors contributing to the increase in the growth capital unit costs for service line additions. FEI addresses each of these factor below.

1. Increase in Customer Attachments per Service Line

FEI experienced an increase in the number of customer attachments per Service Line Addition (SLA) due to changing housing market trends from single detached homes to multi-family developments. The number of customers per SLA increased from approximately 1.2 customers per SLA in 2012 to approximately 1.3 customers per SLA in 2019. (The average customer per SLA ratio during the PBR term is 1.3.) The costs associated with servicing multi-family developments were higher than that of single detached homes as larger pipe, additional fittings and a larger riser are typically required.

2. SLA Activity on Vancouver Island

The increase in activity on Vancouver Island, where the cost per SLA is one of the highest in BC due to its geography, subsurface conditions and municipal, pavement and traffic control requirements, is one of the primary drivers contributing to the cost per SLA variance. The increase in service line activities is largely a result of the transition to common delivery rates. At the time that the FEI base capital was adjusted to include FortisBC Energy Vancouver Island ("FEVI"), the Vancouver Island SLAs were 2,167, which represented 21 percent of the total SLAs of 10,156. Since amalgamation, FEI has experienced an increased volume of SLAs on Vancouver Island compared to the proportion accounted for in the base capital assumption: 26 percent for 2015, 29 percent for 2016, 28 percent for 2017, 35 percent for 2018 and 31 percent for 2019.

3. USD Exchange Rates

FEI has seen an increase in the cost of equipment and supplies purchased from the United States due to the unfavorable exchange rate. FEI's base capital was set based on an expectation that the exchange rate would be close to par, whereas capital expenditures during the 2014-2019 PBR term have incurred at an exchange rate averaging 0.79.

4. Evolving Local Government Requirements

As discussed in Section 2.1.2.4 of Appendix C4 of the FEI Annual Review for 2019 Delivery Rates, local governments have implemented regulations that have increased requirements on utilities. Within the bounds of new or existing bylaws, local government are placing more restrictions and limitations on FEI than it has experienced in the past, such as work hour restrictions and paving requirements. FEI must comply with these requirements in order to obtain the necessary utility permits to undertake the work.

Mains Growth Capital Variance

1. Growth in Large Industrial Mains Additions

The variance in costs for customer mains is driven in part by the growth in large industrial mains. In 2010, the year that was used to develop the 2013 Base for the PBR formula, there was one new main with a cost greater than $100 thousand. This compares to 19 and 39 new mains greater than $100 thousand in 2018 and 2019, respectively. The number of larger new mains (greater than $100 thousand) is on average 7 times more in 2018 and 2019 compared to that of 2014.

The primary factors contributing to the increased number of main extensions over $100 thousand are the economic growth in the province and the competitive advantage of natural gas rates, which have increased demand. Examples include requests for large main extensions required to serve the natural gas load for new subdivisions in a community plan build-out, industrial customers switching from propane to natural gas and natural gas mains to service customers' CNG stations. While larger (wider diameter pipe) mains may be required to serve the natural gas load of these customers, additional cost pressures have also been experienced.

2. Other Factors Contributing to the Variance for Mains

Some of the cost pressures contributing to the SLA growth capital variance also contribute to the Mains growth capital variance. An increased cost of equipment and supplies purchased from the United States due to the unfavorable exchange rate and local government requirements are contributing to the mains growth capital cost variance.

3. Customer Driven System Upgrades

In addition, FEI has seen a large increase in the number of Customer Driven System Upgrade Projects (CDSUs) in 2019, which has added significant pressure to its growth unit costs. A CDSU is an unanticipated distribution main gas pipe upgrade to a distribution system required to address a capacity shortfall created by a new customer addition or residential/commercial development that is an exception to the forecasted system load. These projects are incremental to the approved growth unit cost given that FEI has incurred very few CDSUs prior to 2019 so would not have included these expenditures in the 2013 Growth Capital which formed the growth capital base for FEI's 2014 - 2019 PBR Application. These projects also tend to be high in cost, with little or no service line attachments associated with them during the same period, further exacerbating growth unit cost pressures. The total CDSUs incurred in 2019 was approximately $9.2 million.

Sustainment/Other Capex Variance

FEI cannot provide a detailed explanation for the variance between the 2019 approved and actual expenditures as the approved Sustainment/Other capital expenditures set out in the PBR term are based on 2013 Base Sustainment/Other amounts. The Sustainment/Other base capital was not set through a forecast of FEI's capital requirements over the PBR term, but rather used FEI's Approved 2013 capital expenditures as a starting point, with adjustments to add in the Vancouver Island and Whistler service areas in 2015[11]. Over the course of the PBR term, the approved Base Capital was increased and determined by formula, and not on a forecast of specific capital projects and expenditures. Therefore, a comparison of capital projects under the approved and actual scenarios is not possible.

Flow Through Capex Variance

Flow through Capex variances of approximately $12 million between the 2019 approved and actual expenditures are primarily due to a delay in spending on the City of Vancouver Biomethane project, as discussed on page 55 of the Application. Additionally, $6 million was approved to construct CNG/LNG fueling stations with actual expenditures totaling approximately $2 million.

[11] Based on Vancouver Island and Whistler Approved 2014 capital expenditures less the $6.258 million reduction from Order G-106-15.

19.0 Reference: CAPITAL

Exhibit B-2, Section 7.3, p. 59

2020 and 2021 plant additions

On page 59 of the Application, FEI provides Table 7-8:

Table 7-8: Reconciliation of 2020 and 2021 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	Projected 2020	Forecast 2021	Reference
1	Formula Growth Capex	70.651	64.910	Section 11, Schedule 4, Line 8
2	Forecast Sustainment & Other Capex	161.300	162.860	Section 11, Schedule 4, Lines 15 + 16
3	Flow through Capex	10.398	27.012	Section 11, Schedule 4, Sum of Lines 11 through 14
4	Total Gross Regular Capex	242.349	254.782	Sum of Lines 1 through 3
5	Capitalized Overheads	50.306	52.703	Section 11, Schedule 5, Line 18
6	AFUDC	3.648	3.654	Section 11, Schedule 5, Line 19
7	Change in Work in Progress	(3.880)	(17.300)	Section 11, Schedule 5, Line 21
8	Total Regular Additions to Plant	**292.423**	**293.839**	
9				
10	Special Projects and CPCN Capex			
11	LMIPSU	28.630	16.170	Section 11, Schedule 5, Line 7
12	IGU	45.846	60.630	Section 11, Schedule 5, Line 8
13	Tilbury Expansion Project	8.062	4.147	Section 11, Schedule 5, Line 9
14	Special Projects and CPCN AFUDC	2.930	2.301	Section 11, Schedule 5, Line 25
15	Change in Special Projects and CPCN Work in Progress	242.427	(2.380)	Section 11, Schedule 5, Line 27
16	Total Special Projects and CPCN Additions to Plant	**327.895**	**80.868**	
17				
18	Total Plant Additions	**620.318**	**374.707**	

On line 15 of Table 7-8, FEI states Projected 2020 "Change in Special Projects and CPCN Work in Progress" of $242.427M.

19.1 Please provide a breakdown of the expenses contained in this line item.

Response:

The breakdown of the Projected 2020 "Change in Special Projects and CPCN Work in Progress" of $242.427 million is provided in the table below:

Major Projects	Opening WIP	Expenditures	AFUDC	Transfer to Gross Plant in Service	Ending WIP	Change (Opening WIP - Closing WIP)
LMIPSU CPCN	307.757	28.630	0.982	(304.415)	32.954	(274.802)
Inland Gas Upgrade	8.236	45.846	1.264	-	55.346	47.110
Tilbury Expansion Project	14.735	8.062	0.684	(23.481)	-	(14.735)
Total	**330.728**	**82.538**	**2.930**	**(327.896)**	**88.300**	**(242.427)**

G. DEFERRED CHARGES

20.0 Reference: DEFERRED CHARGES

Exhibit B-2, Section 11, Schedules 11, 11.1, 12

Unamortized deferred charges and amortization (rate base and non-rate base)

20.1 In the same format as is provided in Schedules 11, 11.1 and 12 in Section 11 of the Application, please provide the previous years' information on unamortized deferred charges by starting with the actual 2018 ending deferral account balances and including the actual 2019 deferral account additions and the actual 2019 amortization.

<u>Response:</u>

Please refer to Attachment 20.1.

21.0 Reference: DEFERRED CHARGES

Exhibit B-2, Section 7.5.1.2, pp. 64-67 and Table 7-10

2022 Long-Term Gas Resource Plan Application Deferral Account

On pages 64-67 of the Application, FEI is seeking a deferral account to capture the costs of external resources required for the 2022 Long-Term Gas Resource Plan Application Deferral Account (LTGRP). FEI estimates that the total costs of the LTGRP application will be $0.850 million incurred in 2020, and a further $0.430 million incurred in 2021.

21.1 For each category in Table 7-10, please provide an explanation of how the total estimated expenditures were calculated.

<u>Response:</u>

FEI clarifies that, as discussed on page 66 of the Application, $0.850 million is the total estimated expenditures, with $0.295 million of that amount projected to be incurred in 2020 and $0.430 million of that amount forecasted to be incurred in 2021.

The cost estimates for the tasks in Table 7-10 of the Applicatoin were calculated in three ways, as follows:

1. Where the same or similar activities were outsourced during prior LTGRP preparation, or where work was required to begin early enough in 2020 that a cost estimate was obtained, the estimates were based on either actual costs incurred during the 2014 and 2017 LTGRPs or a detailed cost estimate provided by a consultant.
2. Where similar activities were not outsourced during prior LTGRP preparation and where FEI has not yet been able to finalize detailed scopes of work and/or acquire cost estimates from consultants, the potential extent of work was estimated based on past experience with other outsourced projects.
3. A combination of 1 and 2 above.

In Table 1 below, FEI uses these three descriptions to explain the nature of the cost estimates for each task provided in Table 7-10 of the Application.

Table 1: 2022 LTGRP Estimated Expenditures and Nature of the Cost Estimate Provided

Activity	Deferral Account Expenditure Estimates			Total Estimated Expenditures	Nature of Cost Estimate
	2020 Forecast	2021 Forecast	2022 Forecast		
Scenario Development	$ 50,000	$ 25,000	--	$ 75,000	1
Comparison of Demand Forecasting Methods	$ 45,000	--	--	$ 45,000	1
End-use Demand Forecast	$ 100,000	$ 50,000	--	$ 150,000	1
Alternative Residential and Commercial Customer Additions Forecast	--	--	--	$ -	
Alternative Industrial Customer Additions and Demand Analysis	$ 25,000	$ 25,000	--	$ 50,000	1
Impact of New End-use Trends on Time-of-day Use and Linking the Annual and Peak Demand Forecasts	$ 25,000	$ 90,000	--	$ 115,000	3
Incremental Consultation Activities	$ 20,000	$ 20,000	$ 10,000	$ 50,000	1
DSM Portfolio Scenario Analysis & Alternative DSM Funding/Saving Scenarios	$ 30,000	$ 60,000		$ 90,000	3
Analyze and Report on Peak Demand Infrastructure Avoidance/ Deferral Opportunities	--	$ 60,000	$ 20,000	$ 80,000	3
Infrastructure Contingency Plans	--	$ 10,000	$ 10,000	$ 20,000	2
Analysis of Impact on GHG Targets	--	$ 10,000	$ 10,000	$ 20,000	2
Addressing Security of Supply / Resiliency	--	$ 40,000	$ 10,000	$ 50,000	2
Address Implications of the CleanBC Plan/ Initiatives being developed by the Provincial Government	--	$ 40,000	$ 10,000	$ 50,000	2
Additional Regulatory Assistance (if needed)	--	--	--	$ 55,000	2
	$ 295,000	$ 430,000	$ 70,000	$ 850,000	

With respect to the allotment of these costs between years, FEI estimated the timing of the work based on experience with past LTGRP preparation cycles in order to complete all tasks in time to prepare the final LTGRP by the submission date of March 31, 2022. These are approximate timing estimates. Within a particular task, costs may shift to some degree between years. The intermittent nature of these activities and the uncertainty for some of these tasks with respect to a detailed scope of work and timing make deferral account treatment appropriate, since only those costs actually incurred in each year are captured for recovery in future rates,

21.2 Please provide an estimate of the $0.430 million for 2021 costs, broken down by category, in the same format of Table 7-10.

Response:

Please refer to the response to BCUC IR1 21.1.

21.2.1 For each category, please provide an explanation of how the total estimated expenditures were calculated.

Response:

Please refer to the response to BCUC IR1 21.1.

On page 67, FEI states:

> Consistent with past practice, FEI is also requesting approval to capture regulatory application and proceeding costs such as legal fees, intervener and participant funding costs, BCUC costs, required public notification costs, and miscellaneous administrative costs related to the LTGRP Application within the same deferral account. FEI estimates total regulatory and proceeding costs associated with the LTGRP application will be $0.350 million….

21.3 Please confirm that the $0.350 million in total regulatory and proceeding costs are not included in the costs shown in Table 7-10. If not confirmed, please explain which categories contain these costs.

Response:

FEI confirms that the requested $0.350 million in total regulatory and proceeding costs are not included in the costs identified in Table 7-10. FEI developed the estimate based on the actual regulatory and proceeding costs incurred for the 2017 LTGRP proceeding, which were approximately $0.333 million, and included inflation to arrive at the $0.350 million estimate in this Application. Although the regulatory costs of $350 thousand were not included in Table 7-10, they will not occur until 2022; therefore, they do not affect the financial schedules or rates for 2020 or 2021.

21.3.1 Please provide an explanation for how the $0.350 million in total regulatory and proceeding costs for the LTGRP application were calculated.

Response:

Please refer to the response to BCUC IR1 21.3.

1

22.0 Reference: DEFERRED CHARGES

Exhibit B-2, Section 7.5.2.3, p.73

2020 Revenue Requirement proceeding deferral account

On page 73 of the Application, FEI is proposing to amortize the 2020 Revenue Requirement proceeding deferral account over five years commencing January 1, 2020, which represent the period covered by the MRP application.

22.1 Please provide a detailed breakdown of the actual costs recorded in the 2020 Revenue Requirement proceeding deferral account, and compare to the original estimated costs, providing explanations for any variances over 10 percent.

Response:

FEI first provided estimates for the 2020 Revenue Requirement/MRP proceeding in the financial schedules provided in the Annual Review for 2019 Rates, which showed $250 thousand in 2018 and $1.0 million in 2019 for a total of $1.250 million. In FEI's 2020 interim rates filing, this amount was updated to $1.102 million based on more current information. The current balance in the 2020 Revenue Requirement (MRP) proceeding deferral account as at August 31, 2020, is $1.028 million, which is approximately 22 percent lower than the original estimate and 7 percent lower than the most recent estimate. FEI does not have a detailed breakdown of the original $1.250 million and therefore cannot compare variances by category, although generally notes that the MRP proceeding was written and FEI had budgeted for the potential for an oral hearing.

The following table provides the detailed breakdown of actuals to August 31, 2020 (rounded to the nearest thousand). Some additional BCUC invoices may be received in the coming months for BCUC and Commissioner costs or expenses, but they are unlikely to be material. All costs presented in the table are FEI's directly attributable MRP proceeding costs as well as FEI's 50 percent allocation of MRP proceeding costs split with FBC.

Description	Amount ($000s)
BCUC	61
Intervener PACA	221
External Legal	309
External Consultants (Studies)	392
Other (Notice Publication, Courier Costs)	45
Total:	**$ 1,028**

H. FINANCING AND RETURN ON EQUITY

23.0 Reference: FINANCING AND RETURN ON EQUITY

Exhibit B-2, Section 8.3.1, p. 75

Long-term debt

On page 75 of the Application, FEI states it issued long-term debt of $200 million at rate of 2.82 percent in August 2019, and then another $200 million at a rate of 2.54 percent in July 2020. FEI then states:

> FEI plans to issue additional long-term debt of approximately $200 million in 2021 to finance FEI's capital expenditure program and repay existing indebtedness. The 2021 issuance is reflected in the financial schedules in July 2021 at a rate of 3.30 percent.

23.1 Please explain why the rate for debt issued in 2021 is higher than 2019 and 2020, and explain how the impact of the COVID-19 pandemic on market rates is reflected in the higher rate of 3.30 percent.

Response:

To estimate future interest rates on long-term debt issuances, FEI uses 30-year benchmark Government of Canada Bond interest rate forecasts as provided by Canadian Chartered banks with historical indicative credit spreads applied. The past several years has been a period of historically low interest rates in Canada and globally, which are reflected in the interest rates of recent issuances at FEI. During this period, it has been typical for Canadian Chartered bank projections to include an expectation that long-term benchmark yields will regress back to more historically representative rates in the future, which may provide some explanation for the higher projected rates compared to recent issuances. The forecasts may also incorporate an element of economic uncertainty during the post-COVID-19 pandemic period.

I. TAXES

24.0 Reference: TAXES

Exhibit B-2, Section 9.2, pp. 79-80

Property taxes

On page 79 of the Application, property tax expense in 2021 is projected to increase 5.7 percent from 2020. FEI states the increase is due to construction activities, market value increases, and changes in tax policies of local taxing authorities. On page 80, FEI states that forecast changes in the assessed values of FEI's property are based on the increases that BC Assessment was proposing at the time the forecast was developed.

24.1 Please explain when the forecast was developed and discuss the potential impact of the COVID-19 pandemic on the forecast increases.

Response:

The forecast was developed in late May 2020.

The pandemic is not expected to have any significant impact on the valuation of our overall assessment portfolio. The valuation in 2020 was based on market values pre-pandemic at July 2019. The valuation in 2021 is based on expected market values as of July 1, 2020.

Municipalities generally responded to the COVID pandemic by either:

1. moving the penalty date to later in the year rather than the date taxes were due; or
2. changing the due date to sometime later in 2020.

Neither of these responses impact Property Tax expense.

J. RATE RIDERS

25.0 Reference: RATE RIDERS

Exhibit B-2, Section 10.2.2, p. 89; FEI Annual Review for 2019 Delivery Rates, Section 11, Schedule 11

Revenue Stabilization Adjustment Mechanism

On page 89 of the Application, FEI states that the projected balance in the Revenue Stabilization Adjustment Mechanism (RSAM) account at the end of 2020 is a debit of $17.667 million. In the FEI Annual Review for 2019 Delivery Rates (2019 Annual Review), the projected balance at the end of 2018 was a credit of $8.9 million.

25.1 Please provide a continuity schedule, in the same format as section 11, schedule 11, showing the change from the 2018 ending balance to the projected 2020 ending balance.

Response:

Please refer to Attachment 25.1 for the requested 2018 to 2020 continuity schedule for the RSAM balance. Note the amount shown on page 89 of the Application also includes RSAM interest, so FEI has included the RSAM interest account within the continuity schedule attached as well.

The projected 2018 ending balance of the RSAM account itself was initially estimated as a credit of $8.9 million, excluding RSAM interest; however, the actual 2018 ending balance was a debit of $10.6 million, excluding RSAM interest, as shown in the continuity schedule attached. The variance between the 2018 projected and actual ending balance is described in further detail in the response to BCUC IR1 25.1.1, as well as the remaining variances to arrive at the actual 2020 ending RSAM balance of $17.7 million, including RSAM interest.

25.1.1 Please explain in detail the driver(s) behind the change in the account balance from a credit of $8.9 million to a debit of $17.667 million.

Response:

The projected 2018 ending balance of the RSAM account, as shown on page 87 of the FEI Annual Review of 2019 Rates, was $9.3 million, including RSAM interest, owing to customers, whereas the actual 2018 ending balance was $10.2 million, including RSAM interest, recoverable from customers. This 2018 difference of $19.5 million was driven by actual volumes being lower than projected volumes. This decrease was primarily due to 2018 weather being 2 percent warmer than normal for Lower Mainland, 7 percent warmer than normal for Vancouver Island and 3 percent warmer than normal for Whistler, which resulted in lower actual consumption. Additionally, the Enbridge pipeline rupture occurred in early October 2018, which resulted in customers being asked to conserve natural gas consumption which further decreased actual volumes compared to projected volumes.

The opening actual 2019 balance was $10.2 million compared to the ending actual 2019 balance of $26.4 million, both of which were recoverable from customers. This total 2019 change of $16.2 million was comprised of $11.6 million recoverable from customers driven by actual volumes being lower than projected volumes and a $4.6 million rider recoverable from customers related to prior year balances. The $11.6 million increase was primarily a result of the Enbridge pipeline rupture and weather. As mentioned above, the Enbridge pipeline ruptured in early October 2018, which resulted in customers being asked to conserve natural gas consumption into early 2019 resulting in actual volumes being lower compared to projected volumes. Additionally, overall, the 2019 weather was 5 percent colder than normal for Lower Mainland and 1 percent warmer than normal for Vancouver Island; however, the weather changed significantly month to month, resulting in overall lower actual consumption throughout the year. In 2019, five of the months were significantly warmer than normal (>10 percent), and this was offset by only two of the months being exceptionally colder than normal (>10 percent) with the remaining months having less than 10 percent change in weather compared to normal.

The projected 2020 ending balance is $17.7 million recoverable from customers. The difference between the projected 2020 ending balance and actual 2019 ending balance is $8.7 million owing to customers, which was comprised of $0.7 million owing to customers due to an opening balance adjustment as well as a projected rider of $8.0 million owing to customers related to prior year balances.

K. ACCOUNTING AND EXOGENOUS FACTORS

26.0 Reference: EXOGENOUS (Z) FACTORS

Exhibit B-2, Section 12.2.1, p. 162

COVID-19 pandemic

On page 162 of the Application, FEI states:

> Due to the uncertainty, FEI is not seeking approval of exogenous factor treatment for incremental impacts related to COVID-19 at this time. Instead, over the coming months, FEI will evaluate the COVID-19 incremental costs and related savings. If the incremental costs and savings are determined to be significant, FEI proposes to include the amounts in the previously approved COVID-19 Customer Recovery Fund Deferral Account. The amounts will then be reviewed in 2021 when actual 2020 amounts and forecasts for future years can be ascertained, and an appropriate recovery method can be determined.

26.1 Please confirm that FEI did not seek approval to record the incremental costs and savings to the COVID-19 Customer Recovery Fund Deferral Account in the original FEI COVID-19 Customer Recovery Fund Deferral Account Application.

<u>Response:</u>

Confirmed.

26.1.1 If confirmed, please explain why FEI is now asking to include these incremental costs and savings, when it did not ask for their inclusion in the original application.

<u>Response:</u>

In the preparation of the COVID-19 Customer Recovery Fund Deferral Account Application in May 2020, the primary focus was on seeking approval of customer relief measures as expeditiously as possible and not necessarily on the potential net incremental impact to FEI's O&M expenses. Additionally, at that time, FEI was uncertain of the impact of COVID-19 on FEI's O&M expenses in 2020. As a result, there was no specific discussion of potential exogenous factor treatment related to net O&M expenses included as part of the COVID-19 Customer Recovery Fund Deferral Account Application.

Further, in FEI's view, the review of any requests related to exogenous factor treatment is best undertaken as part of the Annual Review process. This approach is consistent with the BCUC's determination in the MRP Decision, whereby the BCUC determined that the MRP Annual Review framework should include, among other things, a review of exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.[12]

With the impact of COVID-19 now expected to continue at least over the near term, FEI recognizes the possibility of incremental impacts related to COVID-19 on net O&M expenses, which would eventually require disposition and recovery.

As both the COVID-19 Customer Recovery Fund Deferral Account and the potential exogenous factor treatment for incremental O&M impacts are related to COVID-19, FEI believes it is appropriate to combine the two parts together for review and for determining their eventual disposition and recovery. As indicated in the Application, the amounts will be reviewed in 2021 when actual 2020 amounts and forecasts for future years can be ascertained, and an appropriate recovery method can be determined.

26.2 Please provide the incremental costs and savings incurred to-date, broken down by category. Please also provide a forecast, if possible, for the remainder of 2020, and 2021.

<u>Response:</u>

Below is a table outlining the approximate incremental and offsetting O&M cost reductions related to the COVID-19 pandemic as at the end of August 2020. The incremental costs are grouped into categories by department and include a description of the costs incurred by each department/area.

[12] MRP Decision, p. 167.

COVID-19 Net Incremental O&M
$ millions

Incremental COVID-19 costs

Categories of Costs	**Description**	**2020 Year to Date**
Field Operations	PP&E, system damage claims recoveries and miscellaneous other	$ 0.75
Facilities	Safety supplies, furniture storage, additional cleaning, first aid coverage, signage	$ 0.28
Customer Service	Activities to support appropriate social distancing in the work environment, such as expanded hours at the Willindon Park facility	$ 0.13
Public Affairs Emergency Team / Communications	Public Affairs Emergency communications activities to keep our customers informed	$ 0.42
Other	Including Information Systems, Human Resources and Regulatory costs	$ 0.06
Subtotal		$ 1.64
Offsetting COVID-19 cost reductions		
Employee expenses	Lower expenses due to activities / travel restrictions in response to COVID-19 pandemic	$ (2.41)
Estimated Total COVID-19 Net Incremental O&M		$ (0.77)

Year-to-date, the net incremental O&M impact is estimated at ($0.77) million, with incremental costs totaling to approximately $1.64 million and cost reductions consisting of employee expenses totaling to approximately ($2.41) million. The temporary lower employee expenses are primarily the result of restrictions on FEI employees' activities and travel during the COVID-19 pandemic, including course fees, travel, meals, company function expenses, accommodations, employee hiring and relocation expenses. During the remainder of the year, employee expenses are expected to increase, with higher expenditures required for the implementation of the Gas Workforce Management project scheduled for later this year.

Considerable uncertainty remains about the impact of the COVID-19 pandemic on FEI's O&M costs. As indicated in the Application, with the uncertainty regarding COVID-19's expected duration and impact (i.e., timing of transition to and from Phases 2, 3, and 4 of the Province's BC Restart Plan), FEI at this time is unable to provide a forecast of incremental impacts related to COVID-19 for the remainder of 2020 or for future years.

27.0 Reference: ACCOUNTING AND EXOGENOUS FACTORS

Exhibit B-2, Section 12.4.1.3, p. 170

Flow-through deferral account

On page 162 of the Application, FEI states:

> Similar to the discussion in Section 10.1 on FEI's 2020 Projected earnings sharing amount, FEI is not projecting a flow-through balance for 2020. This is because FEI has included actual amounts up until June 30, 2020 within its Projected 2020 revenue requirement throughout this Application and is not projecting any further variances for the remainder of the year from the amounts included in this Application. Therefore there are no amounts to include within the 2020 Flow-through projection.

27.1 Please provide a table showing the projected flow-through deferral account balances embedded in rates for each of the previous 5 years, as projected in each of the previous Annual Reviews. For example, in the Compliance Filing for the FEI 2019 Annual Review, the projected 2018 flow-through deferral account balance embedded in 2019 rates was a credit of $24.478 million.

<u>Response:</u>

The amount of $24.478 million in the question excludes the forecast 2019 financing addition to the deferral account. The amount embedded in 2019 rates for the Flow-through deferral account was actually $25.146 million per Table 2 of the September 26, 2018 Evidentiary Update for the FEI Annual Review of 2019 Rates. That amount is also shown in Schedule 12, Line 3, Column 6 of the financial schedules filed in the Compliance Filing for that Application.

To provide transparency and help reconcile between the various projections, which included true-ups from prior years and forecasted financing amounts, FEI provides two tables below. The first table shows the amounts recovered in rates via amortization of the Flow-through deferral account in each of 2014 through 2020, either through the various Compliance Filings or in this Application. The second table shows the actual 2014-2019 flow-through deferral additions and projected 2020 financing addition. The cumulative total of each of the tables is equal.

Table 1: Flow-through deferral (credits)/debits amortized in rates

($millions)	2014	2015	2016	2017	2018	2019	2020	Total
Flowthrough deferral amortization	$ -	$ (3.166)	$ (0.734)	$ (5.160)	$(12.855)	$(25.146)	$(36.392)	$(83.453)

Table 2: Actual Flow-through deferral (credits)/debits

($millions)	2014	2015	2016	2017	2018	2019	2020	Total
Gross Additions	$ (3.073)	$ (4.264)	$ (11.218)	$ (7.750)	$ (28.417)	$ (22.243)	$ -	$ (76.965)
Financing	-	(0.176)	(0.622)	(0.991)	(1.499)	(2.058)	(1.142)	(6.488)
Total Additions	$ (3.073)	$ (4.440)	$ (11.840)	$ (8.741)	$ (29.916)	$ (24.301)	$ (1.142)	$ (83.453)

27.2 Please discuss if the actual amounts that are included in this Application are different from what FEI was originally forecasting for the months of January to June 2020.

Response:

FEI interprets the reference to "originally forecasting" as the 2020 forecasted cost of service included in the October 29, 2019 FEI Application for Approval of 2020 Rates on an Interim Basis. FEI confirms that the 2020 forecasted costs of service incorporated in this Application are different than the 2020 forecasted amounts in the October 2019 Interim filing given that the former incorporates the actual results from January 2020 through to June 2020 and updated projections for the remainder of 2020.

27.3 Please explain in detail why FEI is not projecting any further variances for the remainder of the year, given that July to December do not include actual amounts.

Response:

FEI's July 2020 to December 2020 projected amounts are based on the most recent information available to FEI at the time of preparing the Application and are FEI's best estimate of the expected results over that same period. While there will inevitably be a variance between actual and approved amounts, FEI does not have any information at this time on which to quantify any such variance, or to determine whether it will be positive or negative. Any variance that materializes between the actual and approved amounts over the remainder of the year will be captured in the Flow-through deferral account, and either recovered from customers or returned to customers in future rates.

Further on page 162, FEI states:

> An adjustment to include the difference between the projected amount of zero and final actual amounts for 2020 subject to flow-through will be recorded in the deferral account in 2021 and amortized in 2022 rates.

27.4 Please discuss if including a projected amount for 2020 would allow the increase in 2021 rates to be lower than the current projected increase of 6.59 percent.

Response:

Including a projected credit balance, owing to customers, for 2020 would decrease 2021 rates from what FEI has proposed, and including a projected debit balance, recoverable from customers, for 2020 would further increase 2021 rates. However, as explained in the response to BCUC IR1 27.3, there is no additional flow-through amount to project for 2020 based on the information available. The projected increase of 6.59 percent already incorporates all the latest projected amounts.

27.4.1 Would recording the adjustment solely in 2021 and amortizing in 2022 rates cause the change between 2021 and 2022 rates to be unnecessarily lumpy, rather than if FEI included a projected amount in 2021 rates?

Response:

Although there will inevitably be variances from the amounts forecast for the flow-through items, FEI is not able to project the materiality of any variances for the six months of the year (July to December) that have not been updated for actuals, and is therefore unable to conclude if this factor by itself could cause rates to be “lumpy” (a rate change in one direction followed by a rate change in the other direction the following year). After the 2022 revenue requirements have been determined and if a rate decrease is forecast, FEI would follow its usual approach of requesting a revenue surplus deferral account to smooth rate changes over time.

L. PERFORMANE BASED RATEMAKING ELEMENTS

28.0 Reference: PERFORMANCE BASED RATEMAKING ELEMENTS

Exhibit B-2, Section 14.3, Table 14-1, p. 184; 2019 Annual Review, Exhibit B-3, BCUC IR 22.1

2019 Flow-through deferral account

In response to BCUC IR 22.1 in the 2019 Annual Review, FEI provided a table similar to Table 14-1 in the current Application which showed the approved and actual 2017 amounts recorded in the flow-through deferral account.

28.1 Please provide the same table as was provided in response to BCUC IR 22.1 in the FEI 2019 Annual Review, but showing the breakdown of the approved and actual 2018 amounts recorded in the flow-through deferral account.

Response:

FEI provides the requested table below.

Line No.	Particulars	FEI APPROVED G-196-17	FEI 2018 ACTUAL	Flow-Through Variance
	(1)	(2)	(3)	(4)
1	Delivery Margin			
2	Residential (Rate 1)	$ (484.373)	$ (488.447)	$ (4.073)
3	Commercial (Rate 2, 3, 23)	(235.157)	(240.050)	(4.893)
4	Industrial (All Others)	(102.503)	(110.780)	(8.277)
5	Total Delivery Margin	(822.033)	(839.277)	(17.244)
6				
7	O&M Tracked outside of Formula			
8	Insurance	5.360	5.203	(0.157)
9	Bio-Methane	1.121	2.634	1.513
10	Bio-Methane O&M transferred to BVA	(1.074)	(2.597)	(1.523)
11	NGT O&M	1.838	2.099	0.261
12	LNG Production O&M	6.650	6.547	(0.103)
13	MSP	-	(0.789)	(0.789)
14				
15	Property and Sundry Taxes	67.157	62.596	(4.561)
16				
17	Depreciation and Amortization	222.212	208.086	(14.126)
18				
19	Other Operating Revenue	(46.048)	(45.666)	0.382
20				
21	Interest Expense	134.461	135.880	1.419
22				
23	Income Taxes	50.137	56.649	6.512
24				
25	2018 Actual After-Tax Flow-Through Addition to Deferral Account (excluding financing)			(28.417)
26	2018 Projected After-Tax Flow-Through Addition to Deferral Account (excluding financing)			(17.111)
27				
28	2018 After-Tax Flow-Through Addition True-up to Deferral Account (excluding financing)			(11.306)
29	2018 Financing True-up			(0.311)
30				
31	2018 Ending Deferral Account Balance True-up			(11.617)

On page 184 of the application, FEI states that, with regards to the 2019 flow-through deferral account:

> The final amount to be distributed to customers in 2020 is a credit of $36.392 million (after tax) and is comprised of the following:
>
> A net variance between approved and actual of $22.243 million (credit) in flow-through items for 2019. The variance is primarily the result of higher delivery

margin revenue, lower income taxes and lower depreciation expense, partially offset by higher flow-through O&M expenses;

A true-up to actual of $11.617 million (credit) to the projected ending 2018 Flow-through account balance, resulting from higher delivery margin revenue and lower depreciation expense. The $11.617 million credit is the difference between the projected ending 2018 flow-through deferral account balance embedded in 2019 delivery rates of $24.478 million (credit) and the actual ending 2018 deferral account balance of $36.095 million (credit);

…

28.2 Please explain in detail, by rate-class, the variances resulting from higher delivery margin revenue.

Response:

FEI has provided a breakdown of the variances in delivery margin revenue between approved and actual by rate class for both 2018 and 2019 in the tables below, including explanations for material variances.

For 2018, the total variance between actual and approved shown in Table 1 below is $17.244 million, $9.796 million of which was projected in the FEI Annual Review for 2019 Rates, with the remaining $7.448 million included as part of the true-up to actual credit of $11.617 million referred to in the question.

Table 1: 2018 FEI Delivery Margin Flow-through Variances by Rate Class

Line No.	Particulars	FEI APPROVED G-196-17	FEI 2018 ACTUAL	Flow-Through Variance	Explanation
	(1)	(2)	(3)	(4)	(5)
1	**Non-Bypass Delivery Margin**				
2	**Residential**				
3	Rate Schedule 1	$ (484.373)	$ (488.446)	$ (4.073)	Customers higher than forecast, due to higher opening number of customers and higher customer additions.
4	**Commercial**				
5	Rate Schedule 2	(132.839)	(131.465)	1.374	Customers lower than forecast, due to lower opening number of customers and lower customer additions.
6	Rate Schedule 3	(67.355)	(76.740)	(9.385)	Customer additions higher than forecast partially due to transportation customers switched from Rates 23 and 27 to Rate 3.
7	Rate Schedule 23	(34.965)	(31.845)	3.120	Customers lower than forecast, partially due to customers switched to Rate 3.
8	**Industrial**				
9	Rate Schedule 4	(0.284)	(0.302)	(0.018)	Immaterial variance
10	Rate Schedule 5	(7.195)	(9.431)	(2.236)	Higher consumption than forecast, primarily due to transportation customers switching to Rate 5.
11	Rate Schedule 6	(0.131)	(0.129)	0.002	Immaterial variance
12	Rate Schedule 7	(0.397)	(1.341)	(0.944)	Immaterial variance
13	Rate Schedule 22 - Firm	(6.260)	(8.512)	(2.252)	Higher consumption than forecast, primarily due to higher consumption by customers in cement and pulp industries.
14	Rate Schedule 22 - Interruptible	(19.059)	(18.631)	0.428	Immaterial variance
15	Rate Schedule 25	(31.257)	(31.627)	(0.370)	Immaterial variance
16	Rate Schedule 27	(10.964)	(9.940)	1.024	Customer lower than forecast, primarily due to customers switching to Rates 3 and 7.
17					
18	**Bypass and Special Rates Delivery Margin**				
19	Rate Schedule 22 - Firm	(0.642)	(0.675)	(0.033)	Immaterial variance
20	Rate Schedule 25	(0.464)	(0.465)	(0.001)	Immaterial variance
21	Rate Schedule 46	(5.370)	(6.760)	(1.390)	Higher consumption than forecast, primarily due to increased consumption by BC Ferries and Seaspan.
22	Byron Creek	(0.106)	(0.116)	(0.010)	Immaterial variance
23	BC Hydro IG	(15.735)	(15.595)	0.140	Immaterial variance
24	VIGJV	(4.637)	(7.256)	(2.619)	Higher consumption than forecast, due to interruptible volumes not included in forecast.
25					
26	**Total Delivery Margin**	**$ (822.033)**	**$ (839.277)**	**$ (17.244)**	

Table 2: 2019 FEI Delivery Margin Flow-through Variances by Rate Class

Line No.	Particulars	FEI APPROVED G-237-18/G-10-19	FEI 2019 ACTUAL	Flow-Through Variance	Explanation
	(1)	(2)	(3)	(4)	(5)
1	**Non-Bypass Delivery Margin**				
2	**Residential**				
3	Rate Schedule 1	$ (491.826)	$ (495.069)	$ (3.243)	Customers higher than forecast, due to higher opening number of customers.
4	**Commercial**				
5	Rate Schedule 2	(132.829)	(132.446)	0.383	Immaterial variance
6	Rate Schedule 3	(73.977)	(84.259)	(10.282)	Customers higher than forecast, partially due to a higher opening number of customers, as well as customers switched from Rate 23.
7	Rate Schedule 23	(32.174)	(27.962)	4.212	Customers lower than forecast, partially due to customers switched to Rate 3.
8	**Industrial**				
9	Rate Schedule 4	(0.291)	(0.324)	(0.033)	Immaterial variance
10	Rate Schedule 5	(8.127)	(13.064)	(4.937)	Customers higher than forecast, due to Rate 25 customers switching to Rate 5.
11	Rate Schedule 6	(0.123)	(0.070)	0.053	Immaterial variance
12	Rate Schedule 7	(0.493)	(4.185)	(3.692)	Customers higher than forecast, due to Rates 22 & 27 customers switching to Rate 7.
13	Rate Schedule 22 - Firm	(6.424)	(8.799)	(2.375)	Rate schedule 22 combined lower revenues were due to lower consumption than forecast, partially due to decreased consumption by cement industries customers, as well as customers switched to Rate 7.
14	Rate Schedule 22 - Interruptible	(22.764)	(18.117)	4.647	
15	Rate Schedule 25	(33.294)	(29.075)	4.219	Lower consumption than forecasted, partially due to customers switching to Rate 5.
16	Rate Schedule 27	(11.834)	(9.165)	2.669	Lower consumption than forecasted, partially due to customers switching to Rate 7.
17					
18	**Bypass and Special Rates Delivery Margin**				
19	Rate Schedule 22 - Firm	(0.597)	(0.679)	(0.082)	Immaterial variance
20	Rate Schedule 25	(0.461)	(0.456)	0.005	Immaterial variance
21	Rate Schedule 46	(8.401)	(8.215)	0.186	Immaterial variance
22	Byron Creek	(0.118)	(0.192)	(0.074)	Immaterial variance
23	BC Hydro IG	(15.736)	(15.868)	(0.132)	Immaterial variance
24	VIGJV	(4.689)	(7.720)	(3.031)	Higher consumption than forecast, due to interruptible volumes not included in forecast.
25					
26	**Total Delivery Margin**	**$ (844.157)**	**$ (855.665)**	**$ (11.508)**	

28.3 Please explain what is driving the variances in lower income taxes and depreciation expense.

Response:

The variance between 2019 actual and approved income taxes of $10.951 million is primarily driven by higher actual Capital Cost Allowance (CCA) than approved, due to the Accelerated Investment Incentives discussed in Section 9.5 of the Application which allowed FEI to claim additional CCA deductions in the year of addition. The 2019 Approved forecast for income taxes was initially determined in the last half of 2018 and did not take into account the change in tax legislation which became effective in June 2019 after 2019 delivery rates were established and approved. Any future changes in tax legislation, which are beyond the control of the Company, that result in a variance from 2020 or 2021 forecasted income tax expense, either favourable or unfavourable, would be captured in the Flow-through deferral account.

The variance between the 2019 actual and approved depreciation and amortization expense of $4.249 million was mainly due to lower actual 2019 opening gross plant balances for general plant and intangible assets, partially offset by a higher actual 2019 opening gross plant balance for transmission plant than was included in the formula. Those opening balances multiplied by the approved depreciation rates for both actuals and the forecast resulted in the depreciation expense variance.

Of the total 2018 flow-through true-up credit of $11.617 million, $2.549 million of the variance relates to depreciation and amortization ($208.086 million actuals compared to $210.635 million projected as shown in Table 12-5 of the FEI Annual Review for 2019 Delivery Rates) and is due to the same reasons as described above for 2019. For completeness, FEI notes the total 2018 flow-through credit related to the variance between actual and approved depreciation and amortization was $14.126 million ($208.086 million actuals compared to $222.212 million approved) and, in addition to the reasons described above, was also due to the delayed in-service date for the Tilbury Expansion Project.

28.4 Please quantify the impact that the credit of $36.392 million has on 2020 delivery rates. What would the 2020 rate increase over 2019 rates have been if this credit did not exist?

Response:

The impact of the credit to amortization expense of $36.392 million and the related credit to tax expense of $13.460 million ($36.392 million / (1-27 percent) x 27 percent) is a total credit of $49.852 million. This credit of $49.852 million divided by the 2020 non-bypass margin at existing rates of $813,968 million results in a 6.12 percent delivery rate change.

Therefore, all else equal, the 2020 delivery rate increase would have been 8.12 percent without the amortization of the flow-through deferral account (2.00 percent interim rate increase plus 6.12 percent); however, this would not have been likely as FEI may have requested to return more of the 2018-2019 Revenue Surplus deferral account in 2020, as opposed to 2021, in order to hold 2020 permanent rates at the 2.00 percent interim level.

Attachment 11.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 20.1

FORTISBC ENERGY INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ (4,192)	$ -	$ (17,608)	$ 4,754	$ -	$ 3,197	$ (863)	$ (14,711)	$ (9,452)	
3	Commodity Cost Reconciliation Account (CCRA)	(9,807)	-	(1,793)	484	-	-	-	(11,116)	(10,461)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	10,568	-	15,606	(4,214)	-	6,018	(1,625)	26,353	18,461	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(7,341)	-	1,542	(417)	200	269	(73)	(5,820)	(6,582)	
6	Revelstoke Propane Cost Deferral Account	-	-	408	(110)	-	-	-	298	149	
7	SCP Mitigation Revenues Variance Account	786	-	3,113	(840)	(275)	-	-	2,784	1,785	
8	Pension & OPEB Variance	(4,093)	-	(3,645)	-	2,845	-	-	(4,893)	(4,493)	
9	BCUC Levies Variance	2,603	-	2,533	(684)	(2,527)	-	-	1,925	2,264	
10	TESDA Overhead Allocation Variance	596	-	777	(210)	(596)	-	-	567	582	
11		$ (10,880)	$ -	$ 934	$ (1,236)	$ (353)	$ 9,484	$ (2,561)	$ (4,612)	$ (7,747)	
12	**2. Rate Smoothing Accounts**										
13											
14	**3. Benefits Matching Accounts**										
15	Demand-Side Management (DSM)	$ 100,790	$ 30,393	$ 29,969	$ (8,092)	$ (15,103)	$ -	$ -	$ 137,957	$ 134,570	
16	NGV Conversion Grants	51	-	1	-	(20)	-	-	32	42	
17	Emissions Regulations	(6,442)	-	-	-	998	-	-	(5,444)	(5,943)	
18	On-Bill Financing Pilot Program	2	-	-	-	-	-	-	2	2	
19	Greenhouse Gas Reduction Regulation Incentives	29,050	-	8,247	(2,227)	(4,438)	-	-	30,633	29,842	
20	CNG and LNG Recoveries	(534)	-	(549)	148	399	-	-	(536)	(535)	
21	2014-2019 PBR Requirements	245	-	-	-	(245)	-	-	-	123	
22	2016 Cost of Capital Application	839	-	-	-	(419)	-	-	420	630	
23	2015-2019 Annual Review Costs	101	-	5	(1)	(97)	-	-	7	54	
24	2017 Rate Design Application	1,313	-	-	-	(261)	-	-	1,052	1,183	
25	2017 Long Term Resource Plan Application	575	-	83	(22)	(170)	-	-	465	520	
26	2019-2022 DSM Expenditures Application Costs	-	86	35	(9)	(40)	-	-	71	79	
27		$ 125,990	$ 30,479	$ 37,790	$ (10,204)	$ (19,397)	$ -	$ -	$ 164,659	$ 160,567	

FORTISBC ENERGY INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 11.1

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 7,928	$ -	$ -	$ -	$ (739)	$ -	$ -	$ 7,189	$ 7,559	
3	2010-2011 Customer Service O&M and COS	4,807	-	-	-	(3,251)	-	-	1,556	3,182	
4	Gas Asset Records Project	1,761	-	636	(172)	(850)	-	-	1,375	1,568	
5	BC OneCall Project	444	-	-	-	(260)	-	-	184	314	
6	Gains and Losses on Asset Disposition	20,444	-	-	-	(3,987)	-	-	16,457	18,451	
7	Net Salvage Provision/Cost	(83,598)	-	15,459	-	(37,238)	-	-	(105,377)	(94,488)	
8	PCEC Start Up Costs	744	-	-	-	(44)	-	-	700	722	
9	2020–2024 MRP Application	268	-	635	(172)	-	-	-	732	500	
10	City of Surrey Operating Terms Application Costs	262	-	109	(29)	(97)	-	-	245	254	
11		$ (46,940)	$ -	$ 16,839	$ (373)	$ (46,466)	$ -	$ -	$ (76,939)	$ (61,938)	
12	**4. Retroactive Expense Accounts**										
13											
14	**5.Other Accounts**										
15	Pension & OPEB Funding	$ (169,940)	$ (69,311)	$ 828	$ -	$ -	$ -	$ -	$ (238,423)	$ (238,837)	
16	US GAAP Pension & OPEB Funded Status	76,365	69,311	-	-	-	-	-	145,676	145,676	
17	BFI Costs and Recoveries	(442)	-	(134)	36	-	-	-	(539)	(491)	
18	Residual Delivery Rate Riders	1,045	-	-	-	(1,045)	-	-	-	523	
19	BVA Balance Transfer	3,166	1,917	-	-	-	(3,583)	967	2,467	1,858	
20		$ (89,806)	$ 1,917	$ 694	$ 36	$ (1,045)	$ (3,583)	$ 967	$ (90,819)	$ (91,271)	
21											
22	**Total**	$ (21,636)	$ 32,396	$ 56,258	$ (11,777)	$ (67,260)	$ 5,901	$ (1,594)	$ (7,712)	$ (389)	
23	Less: Net Salvage Amortization Transferred to Biomethane BVA					26					
24	**Net Rate Base Deferred Amortization Expense**					$ (67,234)					

FORTISBC ENERGY INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Schedule 12

Line No.	Particulars	12/31/2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2019	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Biomethane Variance Account	$ -	$ (1,917)	$ 2,301	$ (383)	$ -	$ -	$ -	$ 1	$ 959	
3	Flowthrough (2014-2019)	(36,095)	-	(24,301)	-	25,146	-	-	(35,250)	(35,673)	
4	Marketer Cost Variance	(22)	-	32	(9)	-	-	-	1	(11)	
5		$ (36,117)	$ (1,917)	$ (21,968)	$ (392)	$ 25,146	$ -	$ -	$ (35,248)	$ (34,725)	
6	**2. Rate Smoothing Accounts**										
7	2017 & 2018 Revenue Surplus Account	$ (29,870)	$ -	$ (1,725)	$ -	$ 259	$ -	$ -	$ (31,336)	$ (30,603)	
8	City of Vancouver Biomethane Purchase Agreement	-	-	-	-	-	-	-	-	-	
9		$ (29,870)	$ -	$ (1,725)	$ -	$ 259	$ -	$ -	$ (31,336)	$ (30,603)	
10											
11	**3. Benefits Matching Accounts**										
12	Demand-Side Management (DSM) - Non Rate Base	$ 30,393	$ (30,393)	$ 34,793	$ (9,335)	$ -	$ -	$ -	$ 25,458	$ 12,729	
13	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
14	IGU Application and Preliminary Stage Development Costs	-	25	379	(1,572)	-	-	-	(1,168)	(572)	
15	Transmission Integrity Management Capabilities	3,540	-	11,908	(3,105)	-	-	-	12,343	7,942	
16	2019-2022 DSM Expenditures Application Costs	86	(86)	-	-	-	-	-	-	-	
17		$ 31,621	$ (30,454)	$ 47,080	$ (14,012)	$ -	$ -	$ -	$ 34,235	$ 17,701	
18	**4. Retroactive Expense Accounts**										
19											
20	**5.Other Accounts**										
21	Mark to Market - Hedging Transactions	$ 8,866	$ -	$ (10,487)	$ -	$ -	$ -	$ -	$ (1,621)	$ 3,623	
22	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
23	2014-2019 Earning Sharing Account	(975)	-	954	(272)	1,466	-	-	1,173	99	
24		$ 7,891	$ -	$ (9,533)	$ (272)	$ 1,466	$ -	$ -	$ (448)	$ 3,722	
25											
26											
27	**Total Non Rate Base Deferral Accounts**	$ (26,475)	$ (32,371)	$ 13,855	$ (14,676)	$ 26,871	$ -	$ -	$ (32,797)	$ (43,905)	

Attachment 25.1

FORTISBC ENERGY INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RSAM
($000s)

Line No.	Particulars	**Actual 12/31/2018**	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	**Actual 12/31/2019**	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	RSAM	10,568	-	15,606	(4,214)	-	6,018	(1,625)	26,353	18,461	
2	RSAM Interest	(369)	-	248	(67)	-	269	(73)	8	(180)	
	Total	**10,199**	**-**	**15,854**	**(4,280)**	**-**	**6,287**	**(1,697)**	**26,362**	**18,281**	

Line No.	Particulars	**Actual 12/31/2019**	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	**Projected 12/31/2020**	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	RSAM	26,353	-	(982)	265	-	(10,908)	2,945	17,674	22,013	
2	RSAM Interest	8	-	(17)	5		(3)	1	(7)	1	
	Total	**26,362**	**-**	**(999)**	**270**	**-**	**(10,912)**	**2,946**	**17,667**	**22,014**	