OWEN • BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

August 27, 2018

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0192

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

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. - Annual Review for 2019 Delivery Rates ~ Project No. 1598966

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). Attached please find the CEC's first set of Information Requests with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: FortisBC Energy Inc.
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

INFORMATION REQUEST NO. 1

FortisBC Energy Inc. Annual Review for 2019 Delivery Rates
Project No. 1598966

August 27, 2018

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1. Reference: Exhibit B-2, page 14

To calculate the 2018 dead band adjustment, FEI notes that its actual 2017 capital exceeded the formula by approximately 9.88 percent, after the 2017 dead band adjustment. FEI is further projecting to exceed the 2018 formula by 40.01 percent as shown in Table 1-4 and discussed further in Appendix C-4. Therefore, the cumulative amount over the capital formula for calculating the two-year dead band adjustment is 49.89[12] percent. FEI must exclude from the Earnings Sharing calculation the greater of:

- The one-year capital dead band difference between the projected capital spending overage of 40.01 percent and the one year dead band limit of 10 percent, for a net adjustment of 30.01 percent; or
- The two-year capital dead band difference between the cumulative projected capital spending overage of 49.89 percent and the two year cumulative dead band limit of 15 percent, for a net adjustment of 34.89 percent.

Accordingly, FEI added 34.89 percent of its 2018 capital, or $54.145 million[13] to its opening plant in service for 2019 so that the two-year cumulative capital variance is within the two-year dead band at 15 percent. FEI also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($54.145 million), such that the earnings sharing with customers is increased (see Section 10 of the Application). In this way, there is no earnings sharing on the amount by which FEI exceeded the dead band.

[12] 9.88 percent plus 40.01 percent
[13] $217.301 million actual spending less $54.145 million = $163.156 million revised spending. When compared to $155.209 million approved formula this results in a revised capital spending variance of 5.12% over one year and 15% over two years.
[14] Section 10, Table 10-2, Line 33

1.1 Please confirm that the 2017 and 2018 formula capital amounts are different from each other and provide the formula capital amounts for 2017 and 2018.

1.2 Please provide the actual spending for 2017 and 2018.

1.3 Please confirm that it is mathematically incorrect to add two percentages (such as 9.88% and 40.01%) from different base figures (to arrive at a cumulative 49.89% for a two-year period).

For example Assume Yr 1 = 100; and Year 2 = 125:	9.88% * 100 = 9.88 40.01% * 125 = 50.0125 Total = **59.8925** 59.8925 = <u>48%</u> of 125 59.8925 = <u>53%</u> of 112.50
FEI Methodology:	9.88% + 40.01% = <u>49.89</u>% 49.89% * 125 = **62.3625**

1.4 Please provide the actual total amounts over the capital deadband for 2017 and 2018 and recalculate the cumulative amount over the capital deadband over the two years.

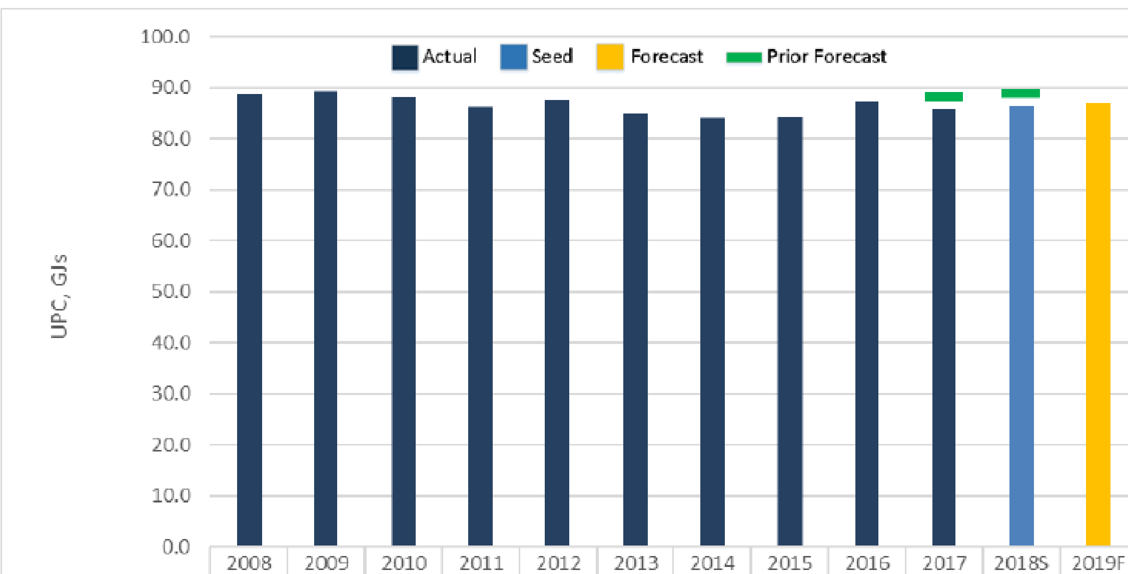
1.5 Please provide a graph of FEI's capital expenditures for the last 10 years.

2. Reference: Exhibit B-2, page 26 and 27

Individual UPC projections for each residential and commercial rate schedule are developed by considering the recent (three-year) historical weather-normalized UPC. The analysis of historical normalized residential use rates indicates an inclining trend for the residential and commercial rate schedules.

As shown in Figure 3-1, the Residential (Rate Schedule 1) UPC is forecast to increase by approximately 0.6 GJs (0.7 percent) in 2019.

Figure 3-1: Rate Schedule 1 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 1	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	85.8	86.4	87.0
Prior Year Forecast										88.3	89.1	

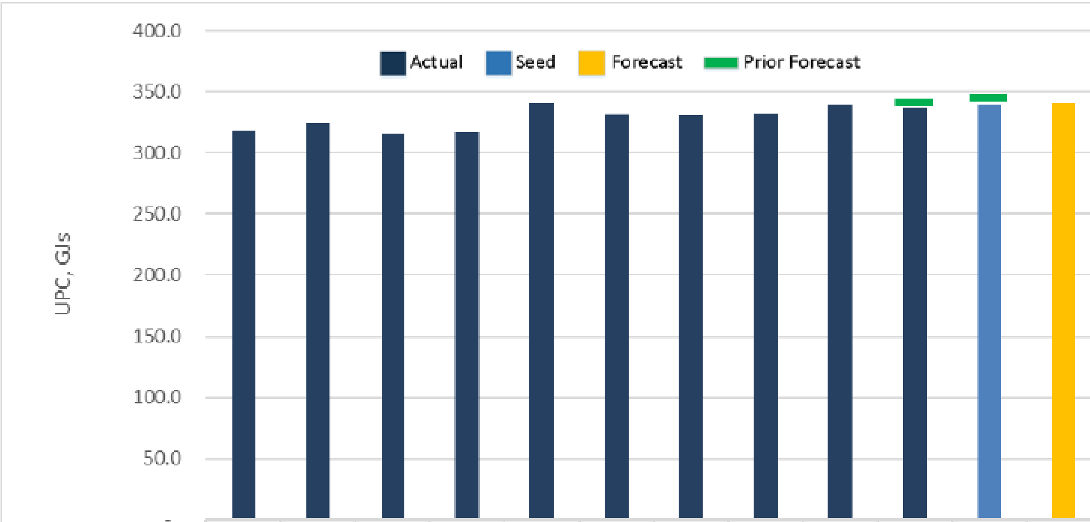
2.1 Please provide FEI's views as to what may have caused the UPC declines in RS 1 UPC in 2013 and 2014 relative to other years.

2.2 To what does FEI attribute the anticipated increase in RS 1 UPC? Please explain.

3. Reference: Exhibit B-2, page 27

As shown in Figure 3-2, the Small Commercial (Rate Schedule 2) UPC is forecast to increase by 2.3 GJs (0.7 percent) in 2019.

Figure 3-2: Rate Schedule 2 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 2	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	339.0	341.3
Prior Year Forecast										342.1	345.2	

3.1 Please provide FEI's views as to what may have caused the increase in RS 2 UPC in 2012 relative to other years.

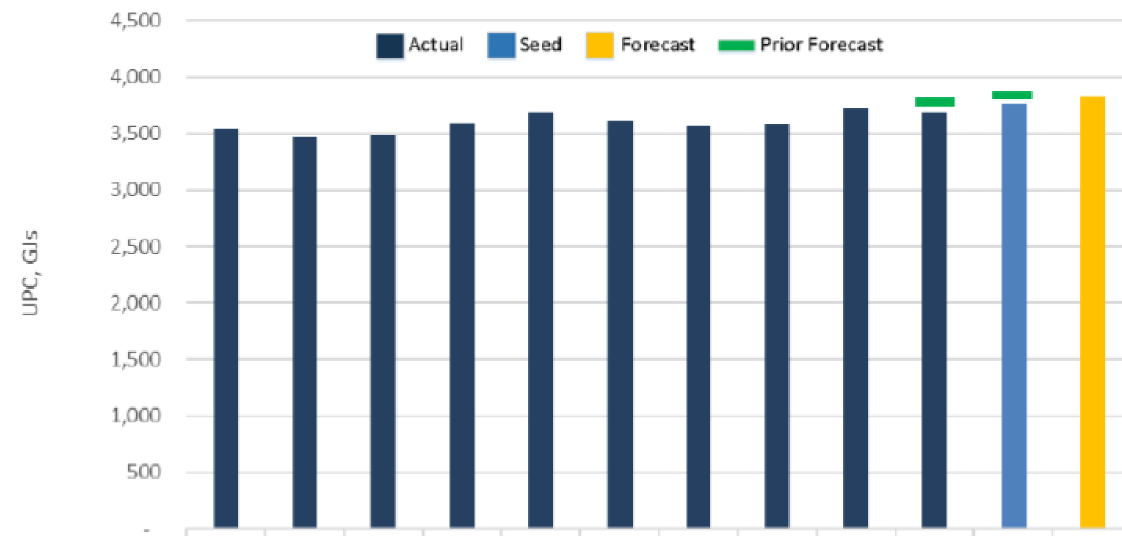
3.2 To what does FEI attribute the continued increases in RS 2 UPC over the last 4-5 years? Please explain.

3.3 How does FEI believe that the UPC for Rate Schedule 2 might be impacted by another recession such as that in 2008? Please explain.

4. Reference: Exhibit B-2, page 28

As shown in Figure 3-3, the Large Commercial (Rate Schedule 3) UPC is forecast to increase by 68 GJs (1.8 percent) in 2019.

Figure 3-3: Rate Schedule 3 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 3	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,763	3,831
Prior Year Forecast										3,781	3,842	

4.1 Please provide FEI's views as to the main factors that contribute to variability in the Rate Schedule 3 UPC.

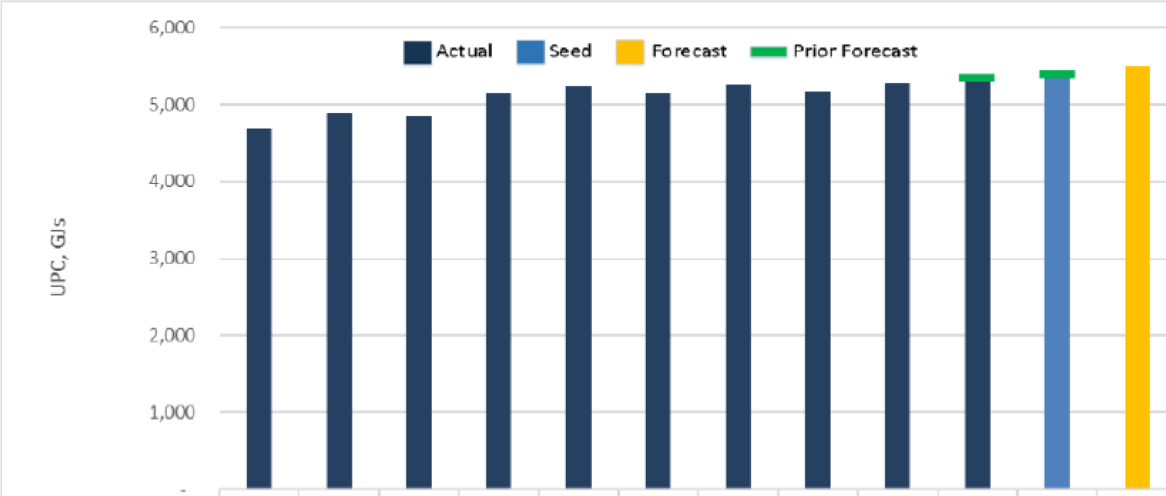
4.2 What factors does FEI believe are contributing to the expected increase in UPC for Rate Schedule 3? Please explain.

4.3 Please discuss how the UPC for Rate Schedule 3 might be impacted in the event of another recession like 2008.

5. Reference: Exhibit B-2, page 29

As shown in Figure 3-4, the Large Commercial Transportation (Rate Schedule 23) UPC is forecast to increase by 56.4 GJs (1.0 percent) in 2019.

Figure 3-4: Rate Schedule 23 UPC



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 23	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,435	5,492
Prior Year Forecast										5,353	5,399	

5.1 Please confirm that the UPC for Rate Schedule 23 also relies on weather-normalized data.

5.2 To what does FEI attribute the general increase in UPC since 2008?

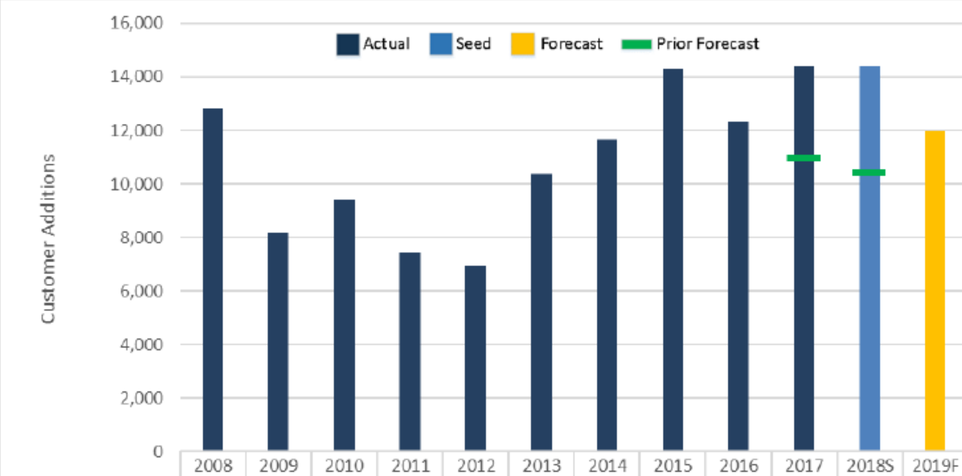
5.2.1 If 2008 represents a low point as a result of the recession, does FEI expect UPC to 'top off' in the near future? Please explain why or why not.

5.2.1.1 If yes, when does FEI expect to see a 'top off' in Rate Schedule 23 UPC? Please explain.

5.3 Please discuss how the UPC for Rate Schedule 23 might be impacted in the event of another recession like 2008.

6. Reference: Exhibit B-2, page 30 and page 31

Figure 3-5: Total Net Customer Additions

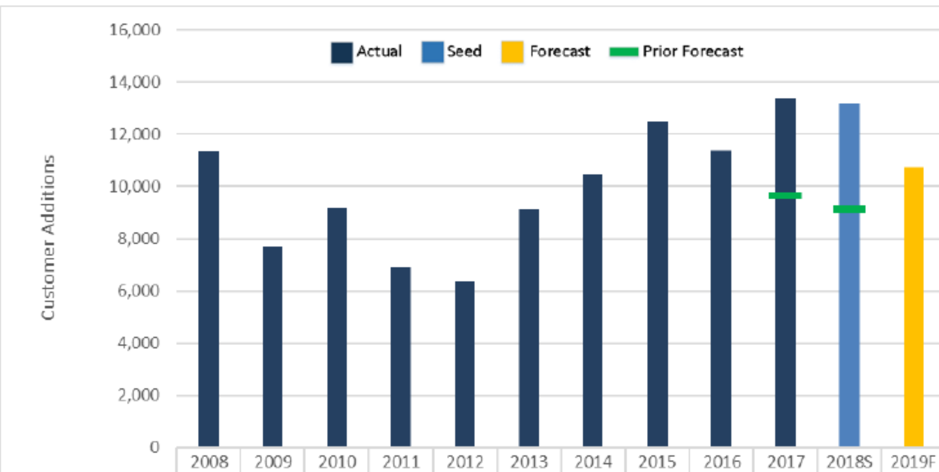


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Total	12,825	8,179	9,409	7,433	6,932	10,391	11,673	14,293	12,324	14,417	14,417	11,946
Prior Year Forecast										10,986	10,435	

The Conference Board of Canada (CBOC) housing starts forecast found in Appendix A1 provides a proxy for residential net customer additions. The commercial net customer additions forecast is based on the average of the actual net customer additions over the last three years for which a full year of actual data is available (i.e., 2015 to 2017).

Figure 3-6 provides the residential net customer additions for 2008 through 2019.

Figure 3-6: Residential Net Customer Additions



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Rate Schedule 1	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	13,195	10,724
Prior Year Forecast										9,696	9,141	

As shown in the preceding figure, residential net customer additions started to recover in 2013. The 2019 Forecast of 10,724 additions reflects a lower CBOC housing starts forecast for BC than experienced in 2017 or projected for 2018.

6.1 Please provide FEI's interpretation of what caused the significant decline in residential and total net customer additions from 2008 to 2012.

6.2 Please provide FEI's interpretation of what caused the significant increase in residential and total net customer additions in 2017 that were not anticipated by FEI's forecasting methodology.

6.3 Does FEI believe that the CBOC housing starts forecast could be replaced by a better alternative? Please explain why or why not.

6.3.1 If yes, please provide recommendations for alternative sources of information that could be employed in forecasting following the conclusion of this PBR period.

7. Reference: Exhibit B-2, page 35 - 36

As shown in Table 3-1 below, the response rate achieved in 2018 was 49 percent of industrial customers, representing approximately 89 percent of industrial volumes. Of the remaining

industrial customers, 44 percent received the survey and three reminder notifications but did not reply. This group represents 9 percent of the industrial demand. Surveys could not be delivered to 7 percent of the industrial customers due to issues such as incorrect email addresses. This group represents 1 percent of the total industrial load.

Table 3-1: Industrial Survey Response Rates

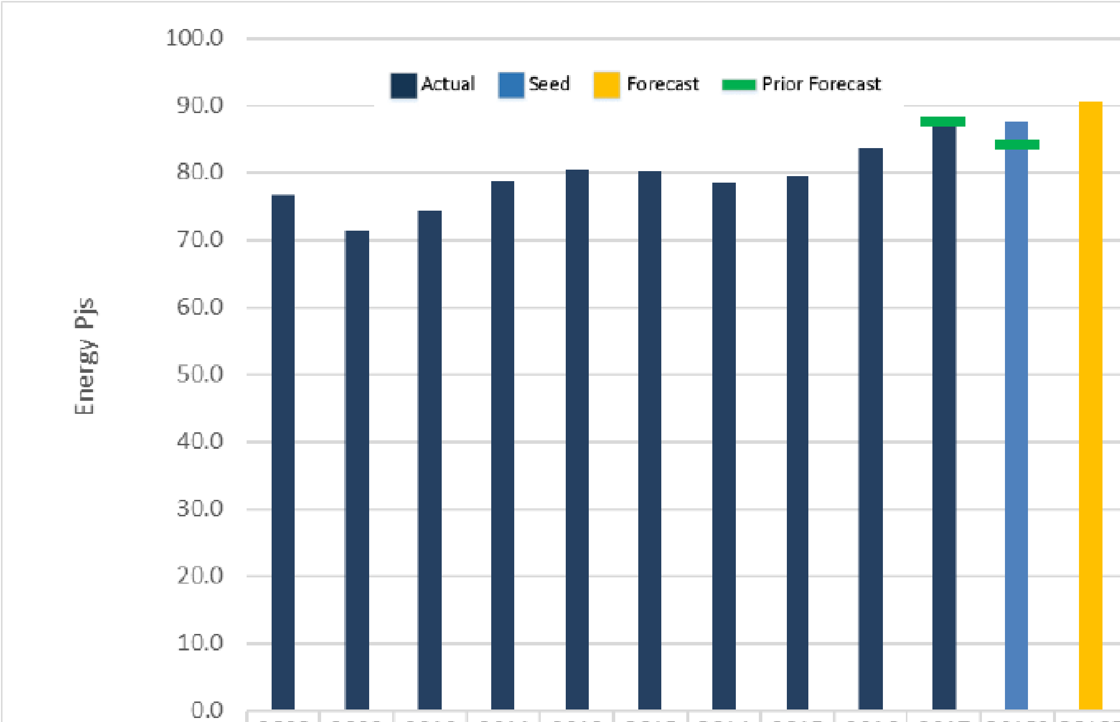
2018 Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	49.35%	89.39%
Survey delivered but not completed	The survey was delivered , but after three follow-up emails was not completed.	43.86%	9.44%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	6.79%	1.17%
Total		100.00%	100.00%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 10 percent of the total industrial demand) was set to 2017 actual consumption.

7.1 Please provide the participation rates as provided in Table 3-1 for the last 3 years.

8. Reference: Exhibit B-2, page 37

Figure 3-11: Industrial Demand[20]



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Industrial	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.4	87.7	90.6
Prior Year Forecast										87.7	84.3	

The Industrial demand in the figure above includes demand under Rate Schedule 22. The 2019 forecast Rate Schedule 22 demand is 43.2 PJs, up approximately 4.9 PJs from the 2018 Approved demand.

8.1 Please provide a brief discussion of the factors that FEI believes are the primary influences in industrial demand.

9. Reference: Exhibit B-2, page 46 and 47

5.3.2 MCRA

The revenue of \$3.6 million per year is related to the inclusion of SCP capacity in the MCRA portfolio. To realize the full benefits of a longer term for the PBR Plan, Order G-138-14 directed

FEI to extend the term of the PBR to the end of 2019 from the original proposal of 2018. However, through Order G-138-14, the Commission approved the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for only the **2014 to 2018** PBR Period. To align with the extension of the PBR term to the end of 2019, in this Application, FEI seeks approval for the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million for 2019, the last year of the current PBR term. Consistent with current practice, the MCRA will continue to pay for the cost of its portion of the Spectra Energy Kingsvale South capacity.

The Company believes that this treatment of costs and revenues is appropriate as the SCP capacity is an essential part of FEI's midstream portfolio, meeting the objectives of safe, reliable and cost-effective resources, and continues to provide optimal benefits to customers.

9.1 Please provide a brief discussion of the impacts on FEI and/or ratepayers if the Commission does not approve the continuation of the debiting of the MCRA and crediting of the delivery margin revenue.

9.2 Why did the Commission not approve the continuation of the MCRA when it extended the term of the PBR?

10. Reference: Exhibit B-2, page 51

6.3.2 Insurance

The insurance expense relates to insurance premium expense allocated to FEI by Fortis Inc.

The 2019 insurance expense is forecast at $5.473 million, an increase of $0.113 million or 2.1 percent from what was approved for 2018. The 2019 Forecast is calculated by taking the known annual insurance premium of $5.339 million which is applicable to the first six months of 2019 and escalating that amount by five percent for the remaining six months[34]. In forecasting insurance premium increases, FEI uses a five percent escalation unless there are indications which suggest significant increases are forthcoming as a result of loss history for the Company or the industry as a whole.

[34] $5.339 million/2 = $2.670 million x 1.05 = $2.803 million. $2.670 million + $2.803 million = $5.473 million.

10.1 Please provide the basis on which FEI uses a 5% escalation unless there are other indications.

11. Reference: Exhibit B-2, page 52

Table 6-5: Biomethane O&M by Project ($ millions)

Line No	Description	2018 Approved	2018 Projected	2019 Forecast
1	Program Overhead	0.545	0.912	0.986
2	City of Surrey biofuel	0.011	0.081	0.010
3	Kelowna upgrader	0.318	0.673	0.147
4	Salmon Arm upgrader	0.200	0.218	0.180
5	New 2018 Project	-	-	-
6	**Sub-total - Transferred to BVA**	**1.074**	**1.884**	**1.322**
7				
8	Fraser Valley Biogas	0.011	0.011	0.011
9	Salmon Arm Landfill	0.011	0.011	0.011
10	Kelowna Landfill	0.011	0.011	0.011
11	Seabreeze Farms	0.011	0.011	0.011
12	Lulu Island WWTP	0.003	-	0.001
13	Dicklands Farm	-	-	-
14	**Sub-total - Recovered in delivery rates**	**0.047**	**0.043**	**0.046**
15				
16	**Total Biomethane O&M**	**1.121**	**1.928**	**1.369**

The 2019 forecast of total Biomethane O&M is $1.369 million as shown in the table above. Of this total, $1.322 million (shown in Table 6-1 above) relates to upgrader O&M, interconnection O&M and program overhead[35] which is transferred to the BVA for recovery through the Biomethane Energy Recovery Charge (BERC). The remaining O&M of $0.046 million is the O&M associated with interconnection stations which pre-dated or were approved in Order G-210-13[36], and is recovered through delivery rates.

The 2019 forecast O&M of $1.369 million is $0.248 million higher than the 2018 Approved O&M primarily due to assignment of additional resources to support supply development to meet the growing demand. This increase is partially offset by an estimate for the recovery of costs for the Kelowna fire insurance claim. In December 2017 there was a fire at the Kelowna upgrader and the remediation costs were recorded in 2018 with the expected net insurance claim recovery of approximately $0.213 million occurring in 2019.

[35] The 2019 forecasted Program Overhead of $986 thousand is comprised of $318 thousand for Customer Education costs, $60 thousand in future development costs and $608 thousand for resourcing.

[36] These projects were Fraser Valley Biogas, Salmon Arm Landfill, Kelowna Landfill, Seabreeze Farms, Lulu Island WWTP, and Dicklands Farm.

11.1 Please identify the line item that refers to 'interconnection O&M'.

11.2 The projected Program Overhead for 2018 and forecast for 2019 is nearly double the 2018 Approved. Please detail the increases in that occurred in this line item.

11.3 Please provide a justification for the overhead costs related to customer education, future development costs, and resourcing, and relate these to program profitability.

12. Reference: Exhibit B-2, page 56

7.1 INTRODUCTION AND OVERVIEW

The 2019 Rate Base for FEI is forecast to be $4.481 billion. Rate Base is composed of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income tax, and LILO benefit.

12.1 Please provide the definition of 'LILO benefit' or identify where this is described in the Application and provide quantification.

13. Reference: Exhibit B-2, page 57

Unlike the O&M formula, the capital expenditure formula has two growth components in addition to formula inflation, resulting in separate calculations of Growth Capital and Other Capital. For 2019, the annual capital expenditures under the formula are calculated as:

2019 Growth Capital = 2018 Growth capital x [(1 + (I Factor – X Factor)] x [1 + SLA customer growth][42]

2019 Other Capital = 2018 Other Capital x [(1 + (I Factor – X Factor)] x [1 + customer growth][43]

13.1 Please identify the types of expenditures that are included in 'Growth Capital' and those that are included in 'Other Capital'.

14. Reference: Exhibit B-2, page 61

LMIPSU PROJECT CPCN

The LMIPSU Project CPCN application was filed with the Commission in December 2014 and approved through Order C-11-15. The LMIPSU Project includes the Coquitlam Gate IP Project, which will address an increasing number of gas leaks on the Coquitlam Gate IP line and restores operational flexibility and resiliency to the Metro Vancouver IP system. The LMIPSU Project also includes the Fraser Gate IP Project, which will provide required seismic upgrades to the Fraser Gate IP line. Only the Vancouver section of the Coquitlam Gate IP Project and the East 2nd and Woodland station are forecast to be in service in 2018, and to be added to rate base January 1, 2019. The projected cost of the Vancouver section and of the East 2nd & Woodland Station equal $59.151 million and $11.791 million respectively totalling $70.942 million added to rate base January 1, 2019. The estimated capital cost for the LMIPSU Project, including AFUDC and abandonment/demolition costs, is $511.517 million. FEI forecasts expenditures of $168.832 million and $171.642 million[44] in 2018 and 2019, respectively. The 2019 capital expenditures are forecasted to be added to rate base in future years, and are therefore not included in 2019 delivery rates.

14.1 Does FEI expect the LMIPSU project to be completed within the approved budget?

14.1.1 If not, please explain why not.

14.1.2 If not, how will the Commission be advised of cost-overruns?

15. Reference: Exhibit B-2, page 67 and 68

Table 7-8: 2017 LTRP Approved Deferral Costs

Activity	Total Approved Expenditure
Scenario Development	$ 75,000
Comparison of End-Use Demand Forecasting Methodologies	$ 45,000
Alternative Residential and Commercial Customer Additions Forecast	$ 25,000
End-Use Demand Forecast	$ 180,000
Alternative Industrial Customer Additions and Demand Analysis	$ 145,000
Impact of New End-Use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 150,000
Incremental Consultation Activities	$ 50,000
DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios	$ 200,000
Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 80,000
Infrastructure Contingency Plans	$ 70,000
Analysis of Impact on GHG Targets	$ 30,000
Total	**$ 1,050,000**

To date, total actual costs for this work have been $0.431 million with a further $0.100 million of expected costs by the time the regulatory proceeding for the LTGRP is completed and a small

amount of related stakeholder consultation in 2019. Costs have been lower than the original estimate as a result of FEI being able to complete more of the work using its own internal resources than originally estimated, as well as obtaining better commercial terms from external consultants than was estimated when preparing Table 7-8. The timing of these expenditures have been extended as a result of receiving approval from the Commission to extend the submission date for the LTGRP from June to December 2017 and continued work on these activities required to complete the regulatory proceeding.

With this Application, FEI is requesting approval to also capture the legal fees, intervener and participant funding costs, Commission costs, required public notification costs, and miscellaneous administrative costs related to the LTRP Application, which are currently forecasted at approximately $0.260 million, in this existing deferral account. FEI is seeking recovery of these costs, given they also were not included in the FEI base O&M under the PBR. This request is similar to other requests FEI has made previously to recover application and regulatory proceeding related costs through deferral accounts. FEI believes this is the appropriate account to use given the account was already created to capture costs related to the LTRP that were not embedded in FEI's formula O&M.

15.1 What was the original intention for where legal fees, Commission costs, public notification costs, etc. would be captured? Please explain and provide any rationale of which FEI is aware.

15.2 Please provide evidence that the legal fees, intervener and participant funding costs, Commission costs, etc. were not included in the FEI base O&M under the PBR.

16. Reference: Exhibit B-2, page 68

7.5.2.2 2017 Rate Design Application

As part of the Annual Review for 2015 Rates Application, FEI received approval through Commission Order G-86-15 to establish the 2017 Rate Design Application deferral account to capture the costs related to filing that application and the regulatory proceeding to review it. FEI noted in that it would request an amortization period for this account in an upcoming annual review filing once there was greater certainty over the process and forecast balance of this deferral account.

Given this proceeding has concluded in 2018, FEI is now seeking approval to amortize these costs over five years beginning in 2019. This amortization period is appropriate given it is consistent with other recovery periods for regulatory proceeding related costs and FEI expects to file a new COSA study within five years as directed by Commission Order G-4-18.

16.1 Other than consistency, is there any other rationale for why 5 years is the appropriate time frame for amortization?

16.2 Please elaborate on the importance of consistency with other recovery periods for regulatory related costs.

16.3 Over what issues in the process did FEI require greater certainty before setting the amortization period?

16.4 How does the forecast balance impact the appropriate time frame for amortization? Please explain.

16.5 Please identify and describe any alternative amortization period options and the advantages and disadvantages of each.

17. Reference: Exhibit B-2, page 76

> On October 21, 2014, the provincial government introduced an LNG income tax on net income from LNG facilities in BC. The new LNG income tax was expected to apply to income from liquefaction activities at, or in respect of, LNG facilities in BC, for taxation years beginning on or after January 1, 2017 but has not yet come into force because the regulation by the Lieutenant Governor in Council required to proclaim this tax in force has not yet occurred. On March 22, 2018, the provincial government announced its intention to repeal this tax provided the LNG Canada project proponents conclusively decide to proceed with their projects on or before November 30, 2018. This would ensure this tax legislation and its application to FEI would be permanently deleted and would have to be re-enacted by the BC legislature in the future should a successor government wish to re-introduce this tax.
>
> If it proceeds, the proposed LNG income tax would be a two-tier tax that applies a minimum 1.5 percent tax on LNG facilities' profits before recovery of capital investment costs and a 3.5 percent tax on LNG facilities' profits once payback is achieved (which increases to 5.0 per cent in 2037 and thereafter). This LNG income tax would apply to income earned at the existing Tilbury Facility, the Tilbury Expansion and the Mt. Hayes LNG Facility on Vancouver Island.
>
> In conjunction with the LNG income tax legislation, the provincial government also proposed a Natural Gas Tax Credit (NGTC) against the current 11 percent BC corporate income tax. The NGTC is effectively equal to the lesser of (i) 3.0 percent of the cost of gas owned and liquefied by the taxpayer at the LNG facility and (ii) the BC corporate income tax payable by the taxpayer from all sources (not just LNG income), but cannot be greater than the amount that would reduce the effective BC corporate income tax rate to less than 8 percent.
>
> Because the LNG income tax legislation is not in force and the provincial government announced that it intends to repeal this legislation should the LNG Canada project proponents make a conclusive decision to proceed by November 30, 2018, estimates of the LNG income tax and NGTC have not been included in forecast 2019 rates.

17.1 Please provide estimates of the LNG income tax and NGTC if the LNG income tax legislation comes into force.

17.2 If the tax and tax credits come into effect, when would this likely occur, and when would the impacts be transmitted to ratepayers?

17.3 What are FEI's expectations with regard whether or not LNG Canada will conclusively decide to proceed with their projects by November 30, 2018? Please explain.

18. Reference: Exhibit B-1, page 85

Table 10-8: BERC Revenue and Volume

Line No	Volume and Revenue	2017 Actual	2017 Projected	2017 Variance	2018 Projected
1	Volume (TJ)				
2	**Short-term**				
3	Rate Schedule 1B	88.4	84.9	3.5	103.5
4	Rate Schedule 2B	13.2	10.9	2.3	15.8
5	Rate Schedule 3B	16.2	8.1	8.2	22.3
6	Rate Schedule 5B	-	-	-	-
7	Rate Schedule 11B	98.7	80.6	18.1	53.7
8	Rate Schedule 30	-	-	-	-
9	Sub-total	216.5	184.4	32.1	195.3
10					
11	**Long Term (a)**				
12	Rate Schedule 11B	16.6	35.5	(18.9)	146.9
13	Sub-total	16.6	35.5	-	146.9
14					
15	**Total Sales Volume (TJ)**	233.1	219.9	13.2	342.2
16					
17	Recoveries ($000s)				
18	**Short-term**				
19	Rate Schedule 1B	$ 931.5	$ 894.5	$ 37.0	$ 1,039.7
20	Rate Schedule 2B	138.8	114.7	24.1	158.6
21	Rate Schedule 3B	171.2	85.2	86.1	223.6
22	Rate Schedule 5B	-	-	-	-
23	Rate Schedule 11B	1,040.2	849.6	190.6	539.6
24	Rate Schedule 30	3.5	3.5	(0.0)	-
25	Sub-total	2,285.3	1,947.6	337.7	1,961.5
26					
27	**Long Term (a)**				
28	Rate Schedule 11B	166.0	374.1	(208.2)	1,475.2
29	Sub-total	166.0	374.1	(208.2)	1,475.2
30				-	
31	**Total Sales**	$ 2,451.2	$ 2,321.7	$ 129.6	$ 3,436.7

18.1 To what does FEI attribute the significant increase in sales volume and recoveries occurring in 2018? Please explain.

18.2 To what does FEI attribute the significant variance between 2017 Actual and 2017 Projected for Rate Schedule 11B?

19. Reference: Exhibit B-2, page 86

Table 10-9: RNG Customers by Rate Schedule

2018 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short-term	
Rate Schedule 1B	10,358
Rate Schedule 2B	197
Rate Schedule 3B	14
Rate Schedule 11B	6
Rate Schedule 5B	-
Rate Schedule 30 Off System	-
Long-term	
Rate Schedule 11B	3
Total	10,578

19.1 Please provide historical participation rates for the last 5 years.

19.2 Please provide a brief discussion of any major trends FEI sees in customer participation and why these are occurring.

20. Reference: Exhibit B-2, page 127 and 129

12.4.1 New Deferral Accounts

FEI is seeking approval of one new non-rate base deferral account to capture the two-phase development costs for FEI's Transmission Integrity Management Capabilities (TIMC) project[55]. The TIMC project will consist of system modifications required to enable the use of crack-detection inline inspection technology, also known as EMAT (Electro-Magnetic Acoustic Transducer). FEI expects to file a CPCN application for the TIMC project in mid-2020.

12.4.1.1 Transmission Integrity Management Capabilities (TIMC) Development Costs

FEI has initiated the development of the TIMC project, which will consist of modifications to FEI's transmission pipeline system to enable inline inspection with recently proven and commercialized crack-detection tools (commonly referred to as "EMAT tools", as the technology relies upon electro-magnetic acoustic transducers). EMAT tools[56] are primarily used for detecting and sizing anomalies associated with stress corrosion cracking and longitudinal seam welds (e.g. anomalies that may be associated with low-frequency electric resistance welding manufacturing processes) in FEI's transmission pipeline system.

The following table shows a forecast of expenditures related to Phases 1 and 2:

Table 12-1: CPCN Development Costs ($000s)

Line No.	Phase	2018	2019	2020	Total
1	Phase 1	$ 5,680	$ 5,710	$ 230	$ 11,620
2	Phase 2	-	19,000	11,000	30,000
3					
4	Total	**$ 5,680**	**$ 24,710**	**$ 11,230**	**$ 41,620**

FEI will propose an appropriate recovery treatment and period in its CPCN application for the TIMC project which will be submitted in conjunction with Phase 2.

20.1 Please discuss the process that would occur if the Commission approves the new non-rate base deferral account at this time, but does not approve the CPCN in mid-2020? Please include who would be responsible for the costs incurred up to the time of denial, and any remediation or other going forward costs that would be incurred.

20.2 Could FEI apply for a CPCN at this time? Please explain why or why not.

21. Reference: Exhibit B-2, page 138 and page 143

Table 13-1: Approved SQI, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2017 Results	2018 June YTD Results
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.75	2.58

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2017 result was 0.75 which was better than the benchmark of 5.0. The June 2018 year-to-date performance is 2.58 which is also better than the benchmark. No significant billing issues have arisen in 2017 or so far in 2018.

21.1 Would FEI agree that it would be more appropriate to record the 'Threshold' as being >5? Please note the arrow direction.

21.1.1 If not, why not.

22. Reference: Exhibit B-2, page 149, and page 150

Table 13-14: Transmission Incidents by Severity Level

OGC Severity Level	Reportable Incidents in 2015	Reportable Incidents in 2016	Reportable Incidents in 2017	Reportable Incidents June YTD 2018
Level 1 (moderate)	3	3	4	2
Level 2 (major)	0	0	0	0
Level 3 (serious)	0	0	0	0

22.1 Please confirm that the reportable incidents are a result of third party interaction with the pipelines, and that none of the reportable incidents in 2017 or 2018 are a result of FEI actions.

22.2 Please provide a brief description of what constitutes Level 1, Level 2 and Level 3 severity levels and provide quantification in terms of $ impacts.