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September 25, 2018

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

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

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

Project No. 1598967

Annual Review for 2019 Rates (the Application)

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

On August 10, 2018, FBC filed the Application referenced above. In accordance with Commission Order G-142-18 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. EVALUATION OF THE PERFORMANCE BASED RATEMAKING (PBR) PLAN

1.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.1, p. 5; FBC Annual Review for 2018 Rates (FBC 2018 Annual Review), Exhibit B-3, BCUC IR 2.1, Table 1-2

O&M savings

On page 5 of the Fortis BC Inc. (FBC) Annual Review for 2019 Rates Application (Application), FBC states that it is projecting 2018 Operating & Maintenance (O&M) expenses, excluding items forecast outside of the PBR formula, to be approximately $1.0 million lower than the formula amount. Embedded Productivity Improvement Factor (PIF) savings for 2018 are $0.6 million as shown in Table 1-2:

Table 1-2: Formula O&M Savings 2014 to 2018 ($ millions)

	Actual	Formula	Variance	1.03% PIF
2014	$ 52.0	$ 52.7	$ 0.7	$ 0.5
2015	51.9	53.0	1.1	0.5
2016	51.8	53.6	1.8	0.6
2017	52.5	54.1	1.6	0.6
* 2018	53.8	54.8	1.0	0.6
Cumulative Savings			$ 6.1	$ 2.8

Further, FBC states on page 5 of the Application that it "continues to be faced with the challenge of finding new productivity opportunities to meet the annual savings embedded in the formula, and to sustain the level of incremental O&M savings achieved in recent years… Contributing also to the productivity challenge are new cost pressures the Company is facing."

1.1 Please confirm, or explain otherwise, that amounts shown as "1.03% PIF" savings in Table 1-2 above are <u>in addition</u> to amounts shown as "Variance" savings in the table.

<u>Response:</u>

Confirmed.

The savings shown under "Variance" result from the difference between actual O&M expenditures and formula allowed O&M. The savings under "1.03% PIF" are the embedded Productivity Improvement Factor (PIF) savings.

1.2 Please provide a breakdown of the projected 2018 O&M savings between one-time and sustainable savings as it relates to the $1.0 million formula savings and $0.6 million PIF savings.

Response:

FBC provides the following discussion of the formula and Productivity Improvement Factor (PIF) related O&M savings to enhance clarity and interpretation of the information. Formula savings are calculated by taking the difference between the actual O&M spending and the allowed O&M as provided using the formula approach (i.e. inflation, growth and productivity). Any savings calculated may be considered as one-time or permanent (sustainable), depending on the nature of the variance (i.e., temporary vacancy savings are considered one-time savings whereas a permanent headcount reduction would be considered permanent savings). On the other hand, the PIF-related savings are determined based on the approved PIF factor (1.03%) applied to the O&M Base. The PIF-related savings are imbedded as part of the formula and reduce the O&M Base funding by approximately $0.6 million each year. However, the savings cannot clearly be identified as permanent, as permanent savings are typically determined by comparing actual O&M spending to the allowed O&M funding available, instead of by reducing broadly the allowed funding available as the PIF does.

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

For 2018, the $0.6 million PIF savings are included in the allowed formula O&M and FBC is expecting additional formula savings (i.e. actual spending lower than the formula allowed funding). As discussed earlier, the PIF related savings cannot clearly be identified as permanent.

For the projected 2018 formula O&M savings of approximately $1.0 million, $0.4 million is considered sustainable with the remaining $0.6 million considered one-time. As indicated in the response to BCUC IR 1.1.2 in the 2018 FBC Annual Review, sustainable formula O&M savings include $0.3 million for the sharing of Gas and Electric Call Centre staff and $0.3 million of savings due to the Company's broad-based productivity focus (i.e., smaller scale improvements). In addition to the ongoing impact of the PIF and the increasingly difficult challenge of finding new productivity opportunities, cost pressures in 2018 reduce the projected sustainable formula O&M savings. These cost pressures are approximately $0.1 million required for staffing to support the Customer Service Systems group and approximately $0.1 million for cyber security costs which was discussed as part of the 2018 FBC Annual Review Application, Section 1.4.1, page 4.

The remaining projected $0.6 million of formula O&M savings (i.e., $1.0 million total formula O&M savings less $0.4 million permanent savings) are considered one time in nature and consist of labour savings and timing of expenditures which naturally fluctuate from year to year.

1.3 Please explain why FBC finds it challenging to sustain the level of incremental O&M savings achieved in recent years. As part of this response, please specifically identify the types of O&M savings achieved during the PBR term which FBC does not consider sustainable going forward and why these savings are not sustainable.

Response:

FBC clarifies the reference to "the level of incremental O&M savings achieved" is to formula O&M savings. The challenge of maintaining the level of formula O&M savings achieved in recent years is not necessarily due to the formula O&M savings achieved in recent years not being sustainable. Instead, it is due to the ongoing impact of the PIF factor, the increasingly difficult challenge of finding new productivity opportunities and cost pressures the Company is experiencing. Considering the increasingly difficult challenge of finding new productivity opportunities with significant incremental savings, the ongoing impact of the PIF factor itself reduces the allowed O&M funding each year by approximately $0.6 million.

Without sufficient productivity related savings to offset the decreased allowed funding as a result of the annual PIF challenge, all else equal, formula savings will be lower. The PIF influence coupled with the cost pressures discussed in the response to BCUC IR 1.1.2 are expected to contribute to the forecasted decline in annual formula savings.

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

1.4 Please explain what new cost pressures FBC is experiencing, including why they are considered new pressures for 2018 and beyond.

Response:

Please refer to the response to BCUC IR 1.1.2.

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 2.1 in the 2018 Annual Review, FBC stated:

> For 2017, FBC estimates that approximately $0.6 million of the $1.2 million [formula] O&M savings are one-time in nature. The remaining $0.6 million of projected sustainable savings consists of approximately $0.3 million from the sharing of Gas and Electric Contact Centre staff and $0.3 million of savings due to the Company's broad-based productivity focus…

On page 5 of the Application, Table 1-2 shows actual 2017 formula O&M savings were $1.6 million.

1.5 Please explain in detail the causes/factors which resulted in actual 2017 formula O&M savings being $0.4 million higher than what was projected in the FBC 2018 Annual Review application.

Response:

The approximate $0.4 million higher 2017 formula O&M savings than projected in the FBC 2018 Annual Review were primarily the result of labour savings due to vacancies and delayed hires and timing of expenditures in the Environmental Health and Safety and Human Resources departments. Several positions remained vacant longer than anticipated when the Application was filed mid year 2017. Lower non-labour expenditures also contributed to the savings observed.

1.6 Please provide a breakdown of actual 2017 formula O&M savings between one-time and sustainable savings.

Response:

Please refer to the response to BCUC IR 1.1.2.

2.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 5;

FBC 2018 Annual Review, Exhibit B-3, BCUC IR 4.1

Sharing of gas and electric contact centre staff

In response to BCUC IR 4.1 in the 2018 Annual Review, FBC explained the method for allocating costs between FBC and FortisBC Energy Inc. (FEI) for shared personal, stating:

> FBC and FEI are charging (allocating) costs between each other for shared personnel consistent with the requirements of the FEI All-inclusive Code of Conduct and Transfer Pricing Policy. Where the costs can be directly assigned, the costs of the shared personnel are charged based on timesheets and fully loaded hourly rates (i.e., including time off and benefits). Where the costs cannot be directly assigned, FBC and FEI use a cost driver approach as a fair and reasonable way to allocate the costs… In the situation of FEI CSRs [Customer Service Representatives] taking FBC customer calls, it is dificult [*sic*] to directly assign the costs of the FEI CSR personnel. FEI charges FBC on a per transation [*sic*] basis based on the number of FBC calls handled by FEI CSR personnel.

2.1 Please confirm, or explain otherwise, whether the method for allocating costs between FBC and FEI which is provided in response to BCUC IR 4.1 in the FBC 2018 Annual Review is still applicable.

Response:

Confirmed.

On page 5 of the Application, FBC states that the sharing of gas and electric contact centre staff is forecast to produce annual savings for FBC of approximately $0.300 million.

2.2 Please provide a breakdown of the $0.300 million annual savings between one-time and on-going labour and non-labour savings.

Response:

The forecast $0.300 million in annual savings represent on-going labour savings.

3.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 6; FBC 2018 Annual Review, Exhibit B-2, p. 5 and Exhibit B-3, BCUC IR 5.1

Interactive Voice Responses enhancements

On page 6 of the Application, FBC states that the estimated annual savings from new functionality introduced into the Interactive Voice Responses (IVR) system in 2017 are approximately $0.055 million.

On page 5 of the FBC 2018 Annual Review, FBC stated that new functionality will be introduced into the IVR system in 2017 and is "expected to reduce operating costs in the contact centre starting in 2018 with estimated annual savings of approximately $0.075 million."

3.1 Please explain in detail the causes/factors which resulted in FBC revising the estimated annual saving from IVR enhancement to be $0.020 million lower than what was projected in the FBC 2018 Annual Review application.

Response:

The original estimate of $75 thousand in savings was calculated by estimating the amount of calls that would be displaced from the contact centre telephony channel and resolved within the IVR.

Since that time, FBC has quantified actual savings where the customer has used the IVR to complete a transaction, displacing a call into the contact centre. There are likely additional calls avoided (and therefore additional savings) by the customer simply obtaining information through the IVR, but FBC is unable to quantify those instances with any certainty, which is why the actual savings is lower than the forecast savings.

In response to BCUR IR 5.1 in the FBC 2018 Annual Review, FBC estimated costs of $0.041 million in capital to implement the IVR system enhancements, with no expected O&M costs.

3.2 Please provide an update to the table provided in response to BCUC IR 5.1 in the FBC 2018 Annual Review for the final breakdown and description of the IVR system enhancements project cost.

Response:

The total cost of the IVR enhancements project was $29,300 for capital expenditures. There were no O&M costs. The following table shows the breakdown of the project costs. The costs were lower than anticipated due to a reduction in project scope due to not including a Credit Card payment option through a third party, as it was decided that that feature would be better offered through other available FortisBC channels.

Costs	Estimated Amount ($)	Actual Amount ($)
Contracted Labour	$25,400	$19,555
Internal Development	$11,000	$5,750
Internal Support / Testing	$5,000	$3,995
Total Labour Costs	$41,400	$29,300

3.2.1 Please provide an explanation for any significant variances identified between final IVR system enhancement project costs in the table provided in response to IR 3.2 above and BCUC IR 5.1 in the FBC 2018 Annual Review.

Response:

Please refer to the response to BCUC IR 1.3.2.

3.3 Please provide the estimated annual savings of the IVR system net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the final capital cost (i.e. annual depreciation, interest, return on equity, etc.).

Response:

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Annual O&M savings are estimated at $0.055 million and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs as a result of the project. Depreciation, cost of capital, and income tax rates are assumed to remain at existing rates.

	2019	2020	2026
		($000s)	
O&M savings (escalated)	$ (55)	$ (56)	$ (65)
Depreciation, Taxes and Financing	3	4	4
Net Revenue Requirements	$ (52)	$ (52)	$ (61)

1
2

4.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 6; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 7.1

SAP integration

On page 6 of the Application, FBC states that the total cost of the SAP integration project "remains on budget, estimated at $4.5 million" and that approximately $1.0 million of the cost will be allocated to FBC. In addition, FBC states O&M savings are expected to be approximately $0.9 million annually, with $0.06 million expected in FEI and $0.3 million in FBC.

4.1 Please provide the estimated annual savings of the SAP integration project (total and FBC's portion) net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the estimated total capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response:

Lines 23 to 26 at page 6 of the Application state: "*Total O&M savings for the project are expected to be approximately $0.9 million annually, with $0.6 million expected in FEI and $0.3 million in FBC.*" The annual estimated O&M savings for the SAP integration project are $0.920 million in total, of which $0.340 million is allocated to FBC.

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Annual O&M savings are estimated at $0.340 million and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs as a result of the project. Depreciation, cost of capital and income tax rates are assumed to remain at existing rates for each utility.

	FBC			Total		
	2019	2020	2026	2019	2020	2026
			($000s)			
O&M savings (escalated)	$ (340)	$ (348)	$ (401)	$ (920)	$ (942)	$ (1,084)
Depreciation, Taxes and Financing	(163)	85	141	(740)	618	788
Net Revenue Requirements	$ (503)	$ (263)	$ (260)	$ (1,660)	$ (324)	$ (296)

5.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 6;

FBC 2018 Annual Review, Exhibit B-3, BCUC IR 7.1

Outage management system

FBC states on page 6 of the Application that, in late 2017, it completed a project to implement an Outage Management System (OMS) to "improve its outage response through fault location prediction using customer calls and AMI meter messages, as well as update outages from the field using the MWM [Mobile Workforce Management System]."

In response to BCUC IR 7.1 in the FBC 2018 Annual Review, FBC provided a table showing a breakdown and description of the OMS project cost, including how much of the cost is capital and how much is O&M.

5.1 Please provide an update to the table provided in response to BCUC IR 7.1 in the FBC 2018 Annual Review for the final breakdown and description of the total OMS project cost, including how much of the cost was capitalized and how much was expensed.

Response:

FBC is unable to provide a final breakdown of the total actual cost for the OMS project, separate from the overall cost of the Advanced Distribution Management System (ADMS) initiative which also includes the MWM system. Many of the activities to implement both the OMS and MWM were running parallel in nature and timing, making it not feasible to accurately track the costs specifically related to the OMS.

FBC provides in the table below an update on the total costs for the overall ADMS initiative, including both OMS and MWM.

	Planned	Actual
	($ thousands)	
Capital Implementation Costs		
Hardware	$ 96.3	$ 3.9
Software Licensing	487.6	529.7
Vendor Professional Services	368.6	448.5
Project Management	136.5	167.1
Labour	459.0	802.5
Training and Change Management	30.7	267.6
Capital Costs	1,578.7	2,219.4
Contingency	236.8	-
Project Total	$ 1,815.5	$ 2,219.4
O&M Implementation costs		
Training	$ 98.3	N/A

For the ADMS project as a whole, the reasons for the higher costs included additional internal labour for development and higher change management activities. There were also additional licensing needs due to added end users and vendor professional services that arose as changes in the scope of the project were identified to better fit the needs of the business. Ongoing support required after initial deployment to support a system bug fix release caused additional costs.

FBC did not separately track the O&M implementation costs; they are included in the formula O&M expenses.

5.1.1 Please provide an explanation for any significant variances identified between final OMS project costs in the table provided in response to IR 5.1 above and BCUC IR 7.1 in the FBC 2018 Annual Review.

Response:

Please refer to the response to BCUC IR 1.5.1.

5.2 Please discuss FBC's experience since the implementation of OMS with respect to improved outage response. How does FBC measure this improvement and what are the results before/after implementation of OMS?

Response:

The OMS provides real time visibility of customer outages as they occur through the AMI system. This has allowed the customer contact centre and system operations centre to provide more timely, specific and complete information to field crews as they are being dispatched to the predicted outage location. The outage response time with the OMS is measured from when an AMI meter or customer reports an outage to when the field crews arrive on site.

Prior to OMS, FBC would dispatch field crews to distribution related outages after the customer called to report the outage, which could be minutes to hours, and typically to a customer address. The outage response time was measured from when the customer called to when the field crews arrived on site.

The OMS streamlined the manual outage management process by predicting the location of the outage and automating the creation of outage cases as they occur. OMS eliminated the need to record and track these outages manually across multiple internal systems by acting as the central repository for all outage-related information. With the OMS, the field crews will be dispatched and arrive at outages more quickly due to improved outage notification times provided by the AMI meters rather than having to wait for customers to call to report an outage. Online and offline work order updates will be available to field crews.

While field crews will arrive at outages more quickly, since the greatest component in the calculation of outage response times is the travel time to the outage, FBC does not expect a notable improvement in measured outage response times.

Other benefits include decreasing call volumes as customers become educated about the outage map, improved safety through near real-time visualization of outages. OMS will also improve the accuracy and efficiency of producing reliability metrics, including Emergency Response Time, SAIDI and SAIFI.

Customer benefits include the provision of a website that will display near real-time outage notifications. Finally, the ADMS is estimated to result in annual O&M savings of $0.200 million.

5.3 Please provide the estimated annual savings of the OMS project net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the final capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response:

Justification for the ADMS project was largely based on safety and customer service improvements related to distribution outage management, including a greater situational awareness for System Control Centre and Field Operations personnel and a near real time outage map for both FBC's employees and customers. An additional benefit of the project was automation of manual processes which provided O&M savings.

For the reasons explained in the response to BCUC IR 1.5.1, FBC is unable to determine the costs and savings attributable to only the OMS component of the ADMS. The following analysis is based on the total ADMS project costs and savings.

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Annual O&M savings attributed to implementation of the ADMS project are estimated at $0.2 million and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs as a result of the project. Depreciation, cost of capital, and income tax rates are assumed to remain at existing rates.

	2019	2020	2026
	($000s)		
O&M savings (escalated)	$ (200)	$ (205)	$ (236)
Depreciation, Taxes and Financing	231	300	288
Net Revenue Requirements	$ 31	$ 95	$ 52

6.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, pp. 6–7

Redesigning FortisBC website

On pages 6 and 7 of the Application, FBC describes the project to redesign the FortisBC website. FBC states that estimated annual savings from the project are forecast to be $0.15 million, shared between FEI and FBC, and that it is expected to be completed in 2019.

6.1 Please provide a breakdown and description of the total project cost for the FortisBC website redesign, including how much is capital and how much is O&M.

Response:

The total costs for the project are forecast to be approximately $1.4 million, with $1.3 million for capital and $0.1 million for O&M.

The project costs are expected to be allocated between FEI and FBC based on the number of customers of each company, with FEI's share at 88 percent and FBC's share at 12 percent.

The project started in late 2017 and is expected to be completed in the first quarter of 2019.

6.1.1 Please explain how the total project cost of the FortisBC website redesign will be allocated between FEI and FBC, including FBC's estimated amount of the cost (capital and O&M).

Response:

Please refer to the response to BCUC IR 1.6.1.

6.2 Please explain the nature of the estimated $0.15 million annual savings from the FortisBC website redesign and clarify the timing of the when the savings will begin.

Response:

The estimated $0.15 million annual savings are comprised of labour savings for Communication staff involved in developing and managing web content. The new content management technology platform and workflow functionality will reduce and simplify workload. Content authoring and publishing will become much more streamlined. In addition to gaining operational efficiencies, the new technology and publishing process will help facilitate collaborative team work internally. This will reduce duplicated effort with content management and publishing processes between Communications and Web Services, help improve information flow between service teams, and optimize service levels across channels. The annual savings are anticipated to start being fully realized in 2020 after some time to operationalize the new functionality available.

6.3 Please provide the amount of the estimated $0.15 million annual savings from the FortisBC website redesign which will be allocated to FBC, including an explanation for the allocation method.

Response:

Please refer to the response to BCUC IR 1.6.1.

6.4 Please provide the estimated annual savings from the FortisBC website redesign (total and FBC's portion) net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the estimated total project capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response:

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Estimated annual O&M savings are assumed to be realized 50 percent in 2019 and 100 percent in 202, and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs. Depreciation, cost of capital, and income tax rates are assumed to remain at existing rates for each utility.

	FBC			Total		
	2019	2020	2026	2019	2020	2026
			($000s)			
O&M savings (escalated)	$ (9)	$ (18)	$ (21)	$ (75)	$ (154)	$ (177)
Depreciation, Taxes and Financing	(13)	13	22	(114)	188	234
Net Revenue Requirements	$ (22)	$ (5)	$ 1	$ (189)	$ 34	$ 57

7.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.3, 2.7.2, Table 1-3, pp. 2, 7–8; Appendix B2, Table B2-1, pp. 2, 3, 5, 6, 9–11 and Table B3-1 and Figure B3-1, p. 9

FBC 2018 Annual Review, Exhibit B-2, Table 1-2, p. 7; Exhibit B-3, BCUC IR 8.1;

Capital spending results

In Table 1-2 in the FBC 2018 Annual Review application, the forecast 2017 variance between formula and actual capital was $15.306 million.

In Table 1-3 of the current Application, the actual 2017 variance between formula and actual capital was $15.799 million.

7.1 Please explain in detail the causes/factors which resulted in the actual 2017 variance in capital being $0.493 million higher than was projected in the FBC 2018 Annual Review application.

Response:

The primary cause of the variance between the 2017 Projected and Actual capital expenditures was an increase in new customer connection costs due to higher than forecast customer additions.

7.2 Please explain FBC's process for identifying the specific factors that contribute to spending in excess of the dead band (i.e. those items that are listed in Table B2-1) and how it distinguishes these items from other capital spending that is included in the formula and within the dead band.

Response:

FBC quantified the specific factors included in Table B2-1 in response to a Commission directive in Order G-38-18, which requested the breakdown as an aid to explaining the variance between actual/forecast capital expenditures and the approved formula capital amount. In creating Table B2-1, FBC has sought to provide as much clarity as it can to understand the reasons for variances from formula; however, there is in fact no definitive or correct way to identify which of its total capital expenditures are within the formula amount, within the dead band, or outside of the dead band.

The items identified as pressures within Table B2-1 are those that were not included in the capital expenditures "forecast" from the PBR Application. FBC also classifies projects reprioritized from previous years as pressures as they were not anticipated to be executed in subsequent years at the time of developing the PBR plan. Table B2-1 and accompanying

discussion in Appendix B-2 help explain the reasons that it has been necessary at an aggregate level for FBC to exceed the formula capital amount.

Although FBC has, from necessity, relied on the specific projects and timing that it identified in the capital expenditures "forecast" from the PBR Application to respond to the Commission's directive, this forecast did not form the basis of a capital "budget" for the PBR term. Rather, FBC's Base Capital was approved by the Commission to be equal to FBC Approved 2013 capital, as adjusted, which is then subject to the formula over the term of the PBR Plan. The Company anticipated, based on the flexibility endowed by entering into a PBR Plan, that it would re-evaluate the need and timing of capital projects on an ongoing basis. There is therefore no definitive way to identify what capital is inside or outside of the formula amount.

FBC relies on prudent capital management practices, and adheres to consistent policies and procedures to execute on the required capital expenditures both to support growth in customers and to maintain the safety and integrity of the gas system, regardless of whether capital expenditures fall within the dead band or outside of the dead band. FBC considers the nature and prioritization of all its capital projects. This process is described in section 3.1 of Appendix B2.

7.3 Please confirm, or explain otherwise, that other than the projects categorized as "Project re-prioritization" items on line 13 of Table B2-1, all other projects listed in Table B2-1 may be considered as "new projects that were identified to address safety, compliance, reliability issues and to replace end of life of equipment."

Response:

Not confirmed. In Table B2-1, new projects that were identified to address safety, compliance, reliability issues, and to replace end of life of equipment are specifically identified on lines 6, 7, 8, and 9. Items on the remaining lines can be characterized as unforeseen items or items driven by regulatory requirements, growth, weather events, cyber security needs, and third party requirements.

7.3.1 If not confirmed, please quantify and provide details on the specific projects which comprise the two categories of project prioritization (i.e. "catch-up on accumulation of re-prioritized work from prior years" and

"new projects to address safety, compliance, reliability and replace end of life equipment") in 2017 and 2018.

Response:

The tables below provide a breakdown of work re-prioritized into 2017 and 2018 and a summary of new projects. FBC notes the omission of the SAP Integration project from the 2018 re-prioritized work in Table B2-1 of Appendix B2 and has filed an Errata concurrently with these IR responses to correct the omission.

Additionally, the 2017 and 2018 Reprioritized work tables provide a justification for why each project was evaluated to be Essential in the year in which it was completed.

As described in Table B2-1 of the Application, essential projects include:

- Those necessary to maintain service to customers;
- Condition or obsolescence-related replacement of critical assets; and
- Planned major inspections (transmission & distribution rehabilitation programs).

All of the projects reprioritized from previous years into 2017 were in this category and were essential to complete. These projects could not be deferred to a future year, as they were required to limit increasing safety and reliability risk exposure in the system, to avoid unplanned and urgent capital work resulting from equipment failures, and to address end of life infrastructure and software.

2017 Work Reprioritized

Project	Justification	($ millions)	
Distribution Rehabilitation			
PLA1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	$0.14	
LEE1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.07	
PLA3 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.07	
PAS1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.03	
OSO1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.03	
			$0.35
38 Line Condition Assessment and Rehabilitation	Planned major inspections, infrastructure condition		0.35
Transmission Rehabilitation			
72 Line Rehabilitation	Planned major inspections, infrastructure condition	0.05	
74 Line Rehabilitation	Planned major inspections, infrastructure condition	0.05	
27 Line Rehabilitation	Planned major inspections, infrastructure condition	0.02	
			0.12
Distribution Line Rebuilds			
Eagle Graphite Rebuild	Infrastructure condition	0.33	
WEB2 Duchess & Newton Rebuild	Infrastructure condition	0.05	
Midgely Mountain Rebuild	Infrastructure condition	0.14	
			0.52
KRE8 Ellis St 79JC017 to 79MS016 Cable Replacement	Infrastructure condition		0.03
Glenmore Feeder 5 (Summit Drive) Capacity Upgrade	Maintain service to customers		0.3
Installation of oil containment at Keremeos substation	Mitigate environmental risk		0.23
Bulk Oil Circuit Breaker Replacement			
KER FDR1 & KER FDR 2	Condition of equipment, maintain service to customers	0.26	
LEE T3T, LEE T4T, & LEE FDR1	Condition of equipment, maintain service to customers	0.39	
			0.65
Princeton Roof Replacement	Condition of equipment		0.16
Rooftop HVAC Replacement	Compliance		0.76
Vehicle Replacement Projects	Maintain service to customers		0.2
SAP Integration (Project One)	O&M cost reductions and business efficiencies		0.32
2017 Reprioritized Work			$4.00

2018 Work Reprioritized

Project	Justification	($ millions)	
Distribution Rehabilitation			
PLA1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	$0.15	
LEE1 Feeder Rehab	Planned major inspections, infrastructure condition	0.14	
PLA3 Feeder Rehab	Planned major inspections, infrastructure condition	1.12	
			$0.41
SAU7 Leon & Abbott Switcher Replacement	Condition of equipment, maintain service to customers		0.15
KRE6 Doyle Ave. Cable Replacement	Infrastructure condition		0.05
Pine Street T2 Station Smart Devices	Condition of equipment, maintain service to customers		0.17
SAP Integration (Project One)	O&M cost reductions and business efficiencies		0.59
2018 Reprioritized Work			$1.37

The table below provides a summary of new projects identified to address safety, compliance, reliability issues, and to replace end of life of equipment. These projects correspond to Line 6 through 9 of Table B2-1 of Appendix B2.

Appendix B2 Table B2-1	Line	Project	Year	($ millions)
Line 8	1	Reconfiguration of the distribution system south of the Crawford Bay substation to improve area reliability.	2018F	$0.37
	2	ROW improvements along the 30L transmission line from South Slocan substation to Coffee Creek substation to mitigate the potential for vegetation-related outages.	2018F	$0.20
Line 9	3	Replacement of Lee Terminal T4 transformer Load Tap Changer in order to extend the life of the transformer.	2017	$1.15
	4	Generating station switchyard improvements such as structure and switch replacements, concrete structure remedial work, grounding improvements for personnel safety, and transformer oil treatment to extend the life of the assets.	2018F	$0.55
Line 6	5	Compliance with OHS rules related to guarding of rotating parts - OHS 12.16 and OHS 12.3.	2017	$0.11
	6	Compliance with OHS rules related to guarding of rotating parts - OHS 12.16 and OHS 12.3.	2018F	$0.19
	7	Compliance with OHS rules for platforms - OHS 4.59 related to the load rating of hatches, plates and covers.	2017	$0.03
	8	Compliance with OHS rules for platforms - OHS 4.59 related to the load rating of hatches, plates and covers.	2018F	$0.39
Line 7	9	Compliance with OHS 9.18(3)(b) rules related to single device isolation certification.	2018F	$0.25

Line 3 in Table B2-1 shows the cumulative capital expenditure variance attributable to "System Improvements to accommodate growth" is $8.6 million.

7.4 Please explain whether the $8.6 million cumulative variance is attributable to a specific customer class or group of classes.

Response:

FBC is currently reviewing its 2018 capital expenditures forecast in conjunction with its 2019 capital budget; once FBC has completed this process, an updated IR response will be provided.

7.5 Please explain whether "System Improvements to accommodate growth" are related to customer additions or other factors related to customer growth (e.g. location).

Response:

The System Improvements to accommodate growth are related to the number of customer connections, the size of connected loads, and the geographic distribution of the connected loads. These factors are difficult to forecast when looking further into the future. Please also refer to section 2.1 of Appendix B2.

FBC states on page 3 of Appendix B2 of the Application that it anticipates capital expenditure to exceed the formula in 2019, and lists five contributing factors.

7.6 For each of the five factors listed on page 3 of the Appendix B2, please provide the amount of the forecast capital expenditure in 2019 and the expected variance from formula capital attributable to that factor in 2019.

Response:

Please refer to the response to BCUC IR 1.7.8. FBC will provide a response to this information request concurrently with that information request filing.

7.7 Please confirm, or explain otherwise, that capital expenditures to catch up on an accumulation of work re-prioritized from previous years is not a factor for why 2019 capital expenditures are anticipated to exceed the formula, given that this is not one of the factors listed on page 3.

Response:

Please refer to the response to BCUC IR 1.7.2.

7.7.1 If confirmed and excluding the projects identified in Table B3-1 as delayed beyond the PBR term, does this mean that FBC is otherwise "caught up" on work that had been re-prioritized from previous years by 2019? Please explain.

Response:

Please refer to the response to BCUC IR 1.7.8. FBC will provide a response to this information request concurrently with that information request filing.

7.8 Please provide total forecast capital expenditures in 2019 and the amount which is anticipated to exceed the formula.

Response:

The variance between forecast capital spending and the formula amount for 2019 that was forecast at the time of the 2018 Annual Review was approximately $10.4 million. FBC is currently finalizing its 2019 capital budget; once FBC has completed this process, an updated IR response will be provided.

On pages 5 and 6 of the Appendix B2 of the Application, FBC provides a list of work re-prioritized from previous years into 2017 and 2018 respectively.

7.9 Please explain whether the variance between formula and actual capital spending would have exceeded the capital dead band in years prior to 2017 if work had not been re-prioritized.

Response:

The table below shows the variances in capital expenditures assuming the initially-planned timing of projects re-prioritized from 2015 and 2016. The capital spending would have exceeded the dead band beginning in 2016.

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 42,774	$ 42,193	$ 581	$ 46,250	$ 42,384	$ 3,866	$ 48,430	$ 42,874	$ 5,556
Pension/OPEB	6,396	6,396	-	4,253	4,253	-	3,674	3,674	-
Total	$ 49,170	$ 48,589	$ 581	$ 50,503	$ 46,637	$ 3,866	$ 52,104	$ 46,548	$ 5,556
One-Year Variance			1.20%			8.29%			11.94%
Two-Year Variance Before Adjustment						9.49%			20.23%

	2017			2018			Cumulative		
	Actual	Formula	Variance	Forecast	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 55,362	$ 43,254	$ 12,108	$ 54,606	$ 43,818	$ 10,788	$247,423	$214,523	$ 32,900
Pension/OPEB	3,539	3,539	-	3,620	3,630	-	$ 21,482	$ 21,492	-
Total	$ 58,901	$ 46,793	$ 12,108	$ 58,226	$ 47,448	$ 10,778	$268,905	$236,015	$ 32,890
One-Year Variance			25.88%			22.72%			13.94%
Two-Year Variance Before Adjustment			46.10%			48.59%			

In adjusting the projects for inflation, FBC used the annual average (actual) CPI and AWE values, weighted by the same factors used to escalate the capital formula. Cumulatively, capital expenditures increased by $0.135 million compared to undertaking the projects in 2015 and 2016.

In response to BCUC IR 8.1 in the FBC 2018 Annual Review, FBC explained that Contributions in Aid of Construction (CIAC) are excluded from the capital expenditures formula envelope in the PBR plan. FBC provided a table which show capital expenditures for years 2014 to 2016 actual and 2017 forecast assuming the capital formula was net of CIAC.

7.10 Please provide 2017 actual and 2018 forecast capital expenditures net of CIAC in the same format as the response to BCUC IR 8.1 in the FBC 2018 Annual Review.

Response:

The 2017 actual and 2018 forecast capital expenditures net of CIAC are shown in the table below. The "Formula" CIAC values assume the 2013 base value for CIAC to be the approved 2013 CIAC value, escalated using the same factors as formula capital.

	2017			2018		
	Actual	Formula	Variance	Forecast	Formula	Variance
Formula Capital	$ 59.053	$ 43.254	$ 15.799	$ 55.212	$ 43.818	$ 11.394
CIAC	(12.533)	(11.431)	(1.102)	(12.239)	(11.580)	(0.659)
Pension/OPEB	3.539	3.539	-	10.649	10.649	-
Total	$ 50.059	$ 35.362	$ 14.697	$ 53.622	$ 42.887	$ 10.735
Variance			41.56%			25.03%
Variance excluding CIAC			33.76%			20.92%

In Figure B3-1 in Appendix B2 of the Application, FBC states that projects are assigned one of three capital priority classifications: "Mandatory", "Essential", and "Flexible."

FBC states on page 6 of Appendix B2 of the Application that the priority classification for the SAP Integration is "Project One."

7.11 Please define what the "Project One" priority classification assigned to the SAP Integration is, including why the SAP Integration was not assigned one of the three capital priority classifications in Figure B3-1.

Response:

The internal name of the project was changed from "SAP integration" to "Project One" and was presented for clarification. The classification should have read "Essential".

On page 10 of the Appendix B2 of the Application, FBC states that it is implementing an Asset Investment Planning (AIP) tool in 2018.

7.12 Please provide a breakdown and description of the AIP tool project costs, including a breakdown between one-time and ongoing capital and O&M costs.

Response:

The table below details the total actual capital costs, and the forecast annual operating cost. The costs are separated to show the allocation of costs between FEI and FBC. The costs for

AIP implementation for Gas System assets and Electric Network assets were allocated 100 percent to the respective utilities. The allocation of costs for AIP implementation for shared services (Information Systems, Fleet, Facilities) is allocated based on the employee count of each of the utilities (77% FEI and 23% FBC).

Business Unit	Actual Capital (FEI) ($million)	Actual Capital (FBC) ($million)	Total Actual Capital ($million)	Annual Operating Cost FEI ($000)	Annual Operating Cost FBC ($000)
PHASE 1 AIP Implementation					
Gas System Assets	1.89	0	1.89	159	0
PHASE 2 AIP Implementation					
Electric Network Assets	0	0.78	0.78	0	67
Information Systems	0.44	0.14	0.58	25	7
Facilities, Fleet	0.11	0.04	0.15	6	2
Phase 2 Total	**0.55**	**0.96**	**1.51**	**31**	**76**
Project Total	**2.44**	**0.96**	**3.40**	**190**	**76**

7.13 Please provide the capital priority classification (as set out in Figure B3-1 of Appendix B2) for the AIP tool.

Response:

FBC classified the AIP tool in the Essential category.

7.14 Please clarify whether the AIP tool is expected to produce annual savings for FBC. If yes, please provide the expected amount of annual savings.

Response:

The fundamental justification for an Asset Investment Planning solution is that it produces an optimized investment portfolio for given resource constraints, whether financial, time, labour or risk-related. While the implementation of the AIP solution within FBC was not justified on the basis of O&M and/or capital savings, FEI did consider the potential cost benefits of the solution.

Other users of AIP solutions have typically experienced a 1 percent to 10 percent "efficiency improvement" in capital investments following the implementation of an AIP tool. While this efficiency could result in overall reduced capital investments, in most cases users report replacing lower priority/value work that is screened out by the tool with higher priority/value work that was identified by the tool. Similarly, FortisBC expects that with the transition from the current manual and labourious project planning, prioritizing and scheduling process to a more robust automated solution would have similar benefits. To be conservative, FortisBC has estimated a 1 percent reduction of total capital expenditures could result from this optimization efficiency and has classified these as soft financial benefits. The total efficiency is, therefore, $0.7 million annually on a portfolio of approximately $70 million, starting in 2020. While these are not "cost savings" in a traditional sense, they are of value to the organization in that they represent more optimally allocated capital investments.

7.15 Please provide the expected amount of annual savings from the AIP tool of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the estimated total project capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response

In its response to BCUC IR 1.7.14, FBC explains that the value of an AIP tool is a more optimal allocation of capital investment, and not "cost savings" in a traditional sense.

Based on the costs presented in the response to BCUC IR 1.7.12, the table below shows the O&M and capital-related revenue requirements for the next two years and for 2026. O&M expense of $0.076 million is escalated annually using the 2019 formula escalation factor. Depreciation, cost of capital and income tax are assumed to remain at existing rates.

	2019	2020	2026
		($000s)	
O&M Expense (escalated)	$ 76	$ 78	$ 90
Depreciation, Taxes and Financing	28	100	130
Net Revenue Requirements	$ 104	$ 178	$ 219

8.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.3.2, p 10

Treatment of capital spending outside of the dead band

On page 10 of the Application, FBC states:

> Accordingly, FBC added 17.64 percent of its 2018 formula capital, or $8.372 million to its opening plant in service for 2019 so that the two-year cumulative capital variance is within the two year dead band of 15 percent. FBC also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($8.372 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 FBC exceeded the dead band.

8.1 Please confirm, or explain otherwise, that FBC is requesting approval to remove the 2018 capital expenditures in excess of the two-year cumulative dead band from the earnings sharing calculation for 2018 and add it to FBC's opening 2019 plant additions balance.

Response:

Similar to other components of the PBR Plan that are reflected in FBC's proposed 2019 rates, FBC does not believe that further approval is necessary for the treatment of capital outside the dead band. FBC is treating the capital outside the dead band as approved by the PBR Decision (summarized on pages 9 to 13 of FBC's Annual Review for 2018 Rates), and as further confirmed by Commission Order G-38-18. Section 1.4.3.2 of the Application discusses this treatment and the determinations made in the aforementioned orders.

9.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 3.1

Staffing levels

In response to BCUC IR 3.1 in the FBC 2018 Annual Review, FBC provided a table showing the actual average full-time equivalents (FTEs), headcount and unfilled vacancies for years 2013 to 2016 and projected/forecast average FTEs, headcount and unfilled vacancies for years 2017 and 2018.

9.1 Please provide actual average FTEs, headcount and unfilled vacancies for actual 2017, projected 2018 and forecast 2019 in the same format as the response to BCUC IR 3.1 in the 2018 Annual Review.

Response:

The requested information is provided in the table below.

	Average FTEs	Headcount	Unfilled Vacancies
2013 Actual[1]	421	482	8
2014 Actual[1]	492	511	21
2015 Actual	518	511	9
2016 Actual	495	488	10
2017 Actual	503	512	14
2017 Projected	502	517	n/a
2018 Projected	518	530	n/a
2019 Forecast	n/a	n/a	n/a

Note: [1] 2013 and 2014 levels staffing impacted by labour disruption.

The variance between the 2017 Projected and Actual Average FTEs and Headcount was negligible.

For the 2018 projected headcount/FTE, factors such as unanticipated staff turnover, timing of recruitment activities (i.e., being able to successfully recruit staff), changing business priorities (i.e., position no longer required) and substituting internal labour with consultants on a short term basis may affect staffing levels previously forecast. In some areas like the Customer Service department, forecasting headcount is particularly challenging given the prevalence of part-time and temporary employees. For the Customer Service department, the average FTE measure is more relevant and meaningful than the headcount measure, as headcount is measured at a specific point in time (i.e., December 31, 2016), making it difficult to forecast when part-time and temporary employees are involved.

For 2018, staffing levels are expected to increase from 2017 primarily due to increased staffing in the Generation and Operations and Engineering departments. Increases are expected to support capital activities, Mandatory Reliability Standards, succession planning and additional apprentice hires.

For 2019, at this time, staffing levels are expected to remain consistent with 2018 levels.

With regard to the Unfilled Vacancies information requested, FBC understands "Unfilled Vacancies" to mean existing positions that become temporarily vacant due to turnover. For FBC, the proxy to measure this is by taking the number of job bulletins identified as for "replacement" in a given year and calculating how long the job bulletins are vacant. The days vacant estimated are then converted to an FTE basis. However, FBC is unable to determine specifically for all the job vacancies in a given year how many are related to O&M or Capital, or whether in the interim the vacancy was filled by the use of a contractor or a consultant, or by additional overtime (paid or unpaid) by existing employees. Due to the difficulties described, FBC has not forecast Unfilled Vacancies (i.e., 2018 Projected, 2019 Forecast).

9.1.1 Please provide an explanation for: i) projected/forecasted 2018 and 2019; and ii) any significant variances identified between projected and actual 2017.

Response:

Please refer to the response to BCUC IR 1.9.1.

B. LOAD FORECAST AND REVENUE AT EXISTING RATES

10.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.3, p. 18; Table 3-1,p 20; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 17.7

Demand side management and other savings

On page 18 of the Application, FBC states:

> The forecast of gross system energy load includes the impacts of forecast energy savings, which includes Demand Side Management (DSM) savings, the Customer Information Portal (CIP), the Advanced Metering Infrastructure (AMI) program and future rate changes.

On page 20 of the Application, FBC provides Table 3-1 showing DSM and other savings:

Line No.	Description	DSM	AMI	CIP	Rate-Driven	Total
1	Residential	(10)	8	(4)	(0)	(7)
2	Commercial	(21)			(0)	(21)
3	Wholesale	(2)			(0)	(2)
4	Industrial	(3)				(3)
5	Lighting	(3)				(3)
6	Irrigation	(0)				(0)
7	Net	(39)	8	(4)	(0)	(36)
8	Losses	(3)	(5)			(9)
9	Gross Load	(42)	2	(4)	(0)	(44)

In response to BCUC IR 17.7 in the FBC 2018 Annual Review, FBC states that "CIP savings are calculated by taking the before-savings load and then multiplying it by the annual CIP cumulative target" FBC also shows a table illustrating CIP savings calculation, with a CIP cumulative target of 0.3 percent for 2018.

10.1 Please confirm, or explain otherwise, that the CIP savings calculation methodology and CIP cumulative target remains the same in this Application as in the FBC 2018 Annual Review.

Response:

Confirmed.

10.1.1 Please provide the CIP savings calculation for 2019.

Response:

The 2019 CIP value was calculated by taking the 2019 Before-Savings Residential load of 1,365 GWh and multiplying it by the CIP cumulative target of 0.3 percent. The equation is below:

$$2019\ CIP\ Savings = 1{,}365\ GWh \times 0.3\% = 4\ GWh$$

11.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Appendix A3, p. 6; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 17.3; FBC Application for Acceptance of 2018 DSM Expenditures, Exhibit B-1, Table 1, p. 4

DSM and other savings

FBC states on page 6 of Appendix A3 of the Application that "the forecast DSM savings is consistent with the Company's 2018 DSM Expenditure Schedule, which was approved by Order G-113-18."

In response to BCUC IR 17.3, in the FBC 2018 Annual Review, FBC explains that "The main reason for the difference is that the 2017 Forecast presents the DSM savings numbers as cumulative starting in 2016 (DSM savings are embedded in historical data), whereas the DSM Plan shows the savings as incremental (the savings for each plan year are shown separately)."

In FBC's Application for Acceptance of 2018 DSM Expenditures (2018 DSM Expenditures) dated November 15, 2017, FBC includes Table 1 showing the estimated DSM savings by customer class from the2018 DSM expenditure schedule:

Table 1: Proposed 2018 DSM Expenditure Plan

		2017 Approved		2018 Plan			2018/17 Difference	
		Savings MWh	Cost ($000s)	Savings MWh	Cost ($000s)	TRC[4] B/C Ratio	Cost ($000s)	% Diff
1	**Sector**							
2	Residential	10,493	2,718	7,132	2,486	1.4	-231.6	-9%
3	Commercial	13,666	3,131	19,165	3,473	2	341.6	11%
4	Industrial	1,556	309	1,188	496	2.8	187.2	61%
5	**Subtotal**	**25,715**	**6,158**	**27,486**	**6,456**	**1.8**	**297.2**	**5%**
6	Supporting Initiatives		674		742		67.9	10%
7	Portfolio		777		743		-34.2	-4%
8	**Total**		**7,610**		**7,940**	**1.6**	**330.8**	**4%**

11.1 Please provide an update to FBC's response to BCUC IR 17.3 in the FBC 2018 Annual Review proceeding, including a reconciliation of the DSM savings reported in the Application versus those estimated in the 2018 DSM Expenditures application

Response:

As discussed in FBC's response to BCUC IR 1.17.3 in the FBC Annual Review for 2018 Rates proceeding, the savings values are not directly comparable between the 2018 DSM

Expenditures plan savings (27,486 MWh) and the Forecast DSM savings values (14 GWh in 2018S). The forecast is based on the DSM Expenditures plan savings. The difference occurs as a result of the way that the DSM Plan savings are presented, attributed, and disaggregated in the load forecast.

The main reason for the difference is that the 2018 Forecast in the Application presents the DSM savings numbers as cumulative starting in 2018 (DSM savings are embedded in historical data), whereas the DSM Plan shows the savings as incremental (the savings for each plan year are shown separately).

The DSM Plan represents annualized energy savings for the DSM projects, by major customer sector, planned to be undertaken in that calendar year only. The forecast presented in FBC's Annual Review factors in the timing of DSM projects: as some of the DSM project savings are attributed to the year following the project. For example, if a project with 12,000 kWh of savings was completed in December 2017, the DSM Plan shows all of those savings in 2017. The forecast numbers, however, reflect only 1/12 of the savings in 2017 (1,000 kWh of savings in December 2017) and the remaining 11/12 of the project's savings are reflected in 2018 (11,000 kWh of savings from January to November 2018). Overall, as a result of pro-rating when the savings land, the 14 GWh savings in 2018S is approximately one half of the 2018 DSM Expenditures plan savings of 27,486 MWh.

Finally, FBC disaggregates a number of sub-categories of DSM for forecasting purposes in the Application, which are not shown in the DSM Expenditure plan savings. For example, "Residential" in the plan savings includes the residential portion of the "Wholesale" savings (for the City of Penticton and the other municipal utilities) presented in the load forecast. Similarly, the "Commercial" plan savings contain the "[Street] Lighting" and "Irrigation" values shown separately in the load forecast. The forecast also isolates the (line) "Losses" associated with the DSM program savings.

12.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.7, pp. 28-30

System losses

On page 28 of the Application, FBC states:

> System losses consist of:
>
> - Losses in the transmission and distribution system;
> - Company use;
> - Losses due to wheeling through the BC Hydro system; and
> - Unaccounted-for energy (meter inaccuracies and theft).
>
> Consistent with past practice, FBC assumed a loss rate of 8 percent of gross load, before the AMI impact, which is explained below. The 8 percent loss rate was based on a loss study that was conducted in 2012, which is in line with the loss rate that FBC is recording on an annual basis. FBC is currently working on an updated loss study that will utilize AMI data. The updated study is projected to be complete for the 2020 forecast.

12.1 Please provide a breakdown of system losses in GWh and as a percentage of load for each year in the PBR term, attributed to losses, company use, wheeling losses and unaccounted for energy.

Response:

The following table provides a breakdown of system losses in GWh and as a percentage of gross load for each year in the PBR term, through the end of June 2018. Losses are forecast on an aggregate basis, and therefore the breakdown beyond June 2018 is not included in the table below. Note that the table represents actual system losses, as FBC does not have a breakdown of normalized losses.

(GWh)	2014	2015	2016	2017	YTD June 2018
Gross Load	3,450	3,384	3,387	3,596	1,785
Station Service Plants 1-5	6	6	5	6	3
Company Use	7	7	7	7	4
BC Hydro Losses (ARWA)	51	46	46	58	40
FortisBC T&D Losses (including meter inaccuracies and theft)	207	209	208	218	98
% of Gross Load					
Station Service Plants 1-5	0.2%	0.2%	0.2%	0.2%	0.2%
Company Use	0.2%	0.2%	0.2%	0.2%	0.2%
BC Hydro Losses (ARWA)	1.5%	1.3%	1.4%	1.6%	2.2%
FortisBC T&D Losses (including meter inaccuracies and theft)	6.0%	6.2%	6.1%	6.1%	5.5%

12.1.1 Please explain how this breakdown is calculated.

Response:

FBC forecasts total System losses as 8 percent of gross load, before the AMI impact. The 8 percent loss rate was based on a loss study that was conducted in 2012, and is consistent with the loss rate that FBC is recording on an annual basis.

Station Service for Plants 1 through 5 is calculated from meter readings at the plant. Company use is calculated from meter readings taken from all of the applicable FBC properties. BC Hydro Losses are physical loss schedules delivered to BC Hydro on an hourly basis as calculated under the Amended and Restated Wheeling Agreement between the Company and BC Hydro.

FortisBC T&D Losses, which includes metering inaccuracies and theft, are calculated as total system losses less Station Service for Plants 1-5, Company Use, and BC Hydro Losses.

13.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.7.1, pp. 29–30; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 17.4

AMI savings

On page 29 of the Application, FBC states: "The 2017 AMI impact to losses related to theft detection and deterrence is 3.9 GWh, which is consistent with the original forecast. The 2017 loss figures are embedded in the 2018 – 2019 loss figures noted in Table 3-4."

On page 29 of the Application, FBC provides Table 3-4 showing system losses before and after AMI:

Table 3-4: System Losses Before and After AMI, 2013 – 2019

		Before AMI				After AMI	
Line No.	Year	Normalized Actuals and Before-Savings Gross Load	% of Gross Load	Normalized Actual and Forecast Losses (GWh)	Incremental AMI Impact (GWh)	% of Gross Load	Losses (GWh)
1	2013 Actual	3500.0	7.95%	278.1			
2	2014 Actual	3433.6	7.86%	269.9			
3	2015 Actual	3446.2	7.91%	272.5			
4	2016 Actual	3480.3	7.87%	274.1			
5	2017 Actual	3511.8	8.02%	281.8			
6	2018 Seed	3570.0	8.03%	286.6	(4.2)	7.89%	281.8
7	2019 Forecast	3601.6	8.06%	290.5	(7.6)	7.84%	282.5

In response to BCUC IR 17.4 in the 2018 Annual Review, FBC provides the forecast loss reduction provided as part of the AMI CPCN application (as adjusted by Order C-7-13):

	2013	2014	2015	2016	2017	2018	2019	2020	2021
					(MWh)				
As Filed	(4,628)	(2,342)	(3,261)	(3,636)	(5,241)	(4,062)	(3,148)	(2,440)	(735)
Adjusted by Order C-7-13	(3,471)	(1,757)	(2,445)	(2,727)	(3,931)	(3,047)	(2,361)	(1,830)	(551)

13.1 Please confirm, or explain otherwise, that the 3.9 GWh 2017 AMI losses related to theft detection are incorporated into the 2018 seed forecast.

Response:

The 2017 AMI losses of 3.9 GWh (3,931 MWh, above) are not incorporated into the 2018 Seed forecast. The AMI impacts are incremental to the losses before AMI in each forecast year. Therefore, the forecast does not include any AMI impacts that have been actualized. Forecast

losses of 3,047 MWh and 2,361 MWh are included in the 2018S and 2019F forecasts, respectively.

13.2 Using the forecast loss reduction from the AMI Certificate of Public Convenience and Necessity (CPCN) application, please explain how the incremental AMI impact in Table 3-4 of the application for 2018 Seed and 2019 Forecast are calculated.

Response:

The AMI impact for 2018 Seed in row 6 of Table 3-4 is based on the forecast change in the number of theft sites from 2017 to 2018 as forecast in the AMI CPCN, multiplied by the assumed annual energy usage per theft site (as modified by Order C-7-13). The AMI impact in 2019 in row 7 of Table 3-4 is the cumulative amount of the 2018 seed year and the 2019 forecast year.

Please note, Exhibit B-2, Application, Table 3-4 showed an AMI impact of (4.2) GWh for 2018 Seed and (7.6) GWh for 2019 Forecast, as well as After-AMI losses of 281.8 GWh for 2018 Seed and 282.5 GWh for 2019 Forecast. The correct values are an AMI impact of (3.0) GWh in 2018 Seed and (5.4) for 2019 Forecast, as well as After AMI losses of 282.5 GWh for 2018 Seed and 282.8 GWh for 2019 Forecast. As well, 2019 Forecast losses before AMI have been amended to exclude the cumulative AMI impact from 2018. Typographic errors do not affect the forecast, as can be seen by comparing the 2018S and 2019F loss values in Table 3-3 of the Application with the corrected Table 3-4 below. FBC has provided the corrected table in the Errata filed concurrently with these IR responses.

Table 3-4: System Losses Before and After AMI 2013-2019

			Before AMI			After AMI	
Line No.	Year	Normalized Actuals and After-Savings Gross Load (GWh)	% of Gross Load	Normalized Actual and Forecast Losses (GWh)	AMI Impact (GWh)	Losses (GWh)	% of Gross Load
1	2013 Actual	3,500.0	7.95%	277.9			
2	2014 Actual	3,433.6	7.86%	269.9			
2	2015 Actual	3,446.2	7.91%	272.5			
4	2016 Actual	3,480.3	7.87%	274.1			
5	2017 Actual	3,511.8	8.02%	281.8			
6	2018 Seed	3,570.0	8.00%	285.5	(3.0)	282.5	7.91%
7	2019 Forecast	3,601.6	8.00%	288.2	(5.4)	282.8	7.85%

On page 30 of the Application, FBC states: "FBC has implemented its energy balancing program, and is also leveraging the tamper detection functionality of the AMI system for theft identification."

13.3 Please discuss the energy balancing program, the effects this will have on load forecasts and the timeframe in which FBC expects these effects will be observed.

Response:

Consistent with the description of activities provided in the AMI CPCN application, FBC is now leveraging the AMI system to conduct energy balancing analyses on select portions of the distribution system to identify and deter energy theft. It is projected that these activities will result in a reduction of 4.7 GWhs related to energy theft between 2019 and 2021. This is consistent with the forecast provided in the AMI CPCN application as adjusted for the determinations in Order C-7-13 which included a reduction in the assumed annual energy losses per theft site to 113,000 kWh. FBC expects that its energy balancing activities will continue to have a mitigating impact on energy theft, both in terms of detection and deterrence, for the foreseeable future.

14.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.1, p. 22; Appendix A2, p.7; Appendix A3, pp.3–4

Residential Use Per Customer (UPC)

On page 22 of the Application, FBC provides Figure 3-2 showing normalized after-savings residential Use Per Customer (UPC). In Figure 3-2, the UPC for 2017 is 11.42 GWh.

On page 7 of Appendix A2, FBC provides Table 4 showing normalized after-savings UPC:

MWh/Customer	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Residential	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.30	11.27

On page 3 of Appendix A3, FBC states: "FBC reviews the forecast methods on an annual basis and found that there was no trend in the most recent three years of UPC data and therefore applied a three year average. FBC uses the most recent UPC data since the UPC can be influenced by technology and customer behaviour patterns that are changing on an ongoing basis."

On page 4 of Appendix A3, FBC provides Table A3-3 showing the results of the residential UPC regression:

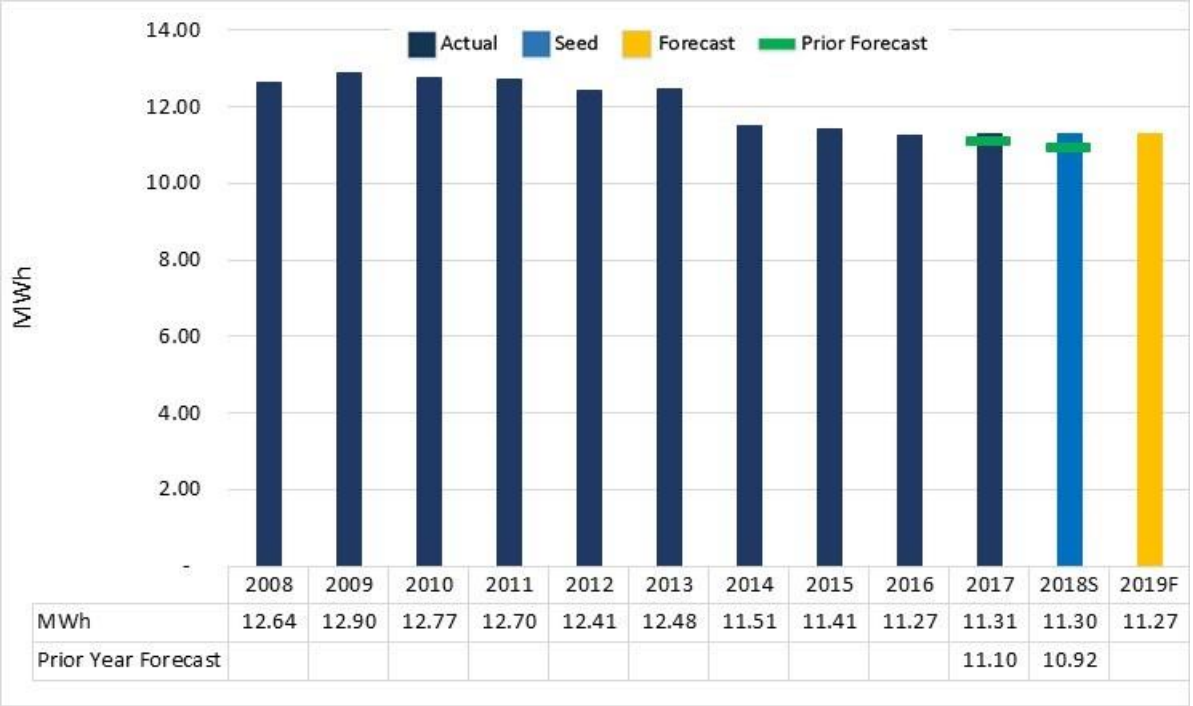
Regression	UPC
Start Year	2015
End Year	2017
R^2	0.00
Adjusted R^2	-1.00
df	2
Intercept	4
Slope UPC	0.00

14.1 Please reconcile the residential normalized after savings UPC for 2017 in Figure 3-2 (11.42) and the 2017 UPC found in Appendix A2 Table 4 (11.31).

Response:

Figure 3-2 erroneously showed the 2017 Normalized After-Savings UPC as 11.42 MWh. The correct value is 11.31 MWh, which is shown in Exhibit B-2, Appendix A2, Table 4. This typographical error does not affect the load forecast. Figure 3-2 has been corrected below.

Figure 3-2: Normalized After-Savings Residential UPC (MWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
MWh	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.30	11.27
Prior Year Forecast										11.10	10.92	

14.2 Please explain which 2017 UPC value (11.42 or 11.31) is used to perform the UPC trend analysis, and whether the results differ using the two different values.

Response:

Please refer to the response to BCUC IR 1.14.1.

14.3 What are the main reasons for the forecast decline in residential UPC year-over-year from 2017 to 2019F? Please discuss.

Response:

The before-savings UPC forecast is developed using a three-year average of historic actuals. The UPC is then forecast to remain constant. DSM and other savings are deducted from the before-savings forecast, resulting in the slight decline in 2018 and 2019.

14.4 Please discuss the reasons why the 2017 actual residential UPC and the forecast 2018S residential UPC are greater than those forecasted in the FBC 2018 Annual Review.

Response:

FBC cannot definitively explain the approximately 0.3 percent increase in residential UPC from 11.27 MWh in 2016 to 11.31 MWh in 2017. Any change in residential UPC in a given year is a result of many factors that may be both compounding and offsetting.

For any given year, input data will exhibit some degree of variability. FBC believes the current approach of calculating the three-year average of historical UPCs as a proxy for the future before-savings UPC is appropriate. By averaging the most recent data, annual fluctuations can be minimized and smoothed out. A smoothing technique such as averaging is a common and well established practice to minimize year over year fluctuations.

14.4.1 Please discuss how FBC factored in the reasons for underestimating residential UPC in 2017 into its residential demand forecast for 2019.

Response:

FBC cannot definitively explain the underestimation of the 2017 residential UPC. Changes in the residential UPC in a given year are a result of many factors that may be both compounding and offsetting. As a result FBC did not factor in any reasons for underestimating the 2017 residential UPC. The 2017 UPC is the actual UPC and is calculated by taking the actual normalized load and dividing it by the actual annual average customer count.

FBC notes that the normalized 2017 UPC was used as an input to the 2019 UPC forecast, so the causes of the variance are now incorporated into the forecast.

15.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Appendix A3, p. 6

Lighting

On page 6 of Appendix A3, FBC provides Table A3-6 showing the results of the lighting regression:

15.1 Please confirm, or otherwise explain, that the results of lighting trend analysis are based upon lighting load, and not lighting UPC, as noted in Table A3-6.

Response:

Confirmed. The results of the lighting trend are based on the historic lighting loads and not the UPC. Exhibit B-2, Appendix A-3, Table A3-6 showed UPC in the table heading instead of LGT, however this typographical error does not affect the load forecast. Table A3-6 has been corrected below.

Table A3-6: Results of Lighting Trend Analysis

Regression	LGT
Start Year	2013
End Year	2017
R^2	1.00
Adjusted R^2	0.99
df	4
Intercept	(174,942)
Slope	93.60
Slope CoK Event	2,134

15.1.1 Please explain how DSM such as LED street lighting technology is properly accounted for to produce 2018S and 2019F.

Response:

FBC notes that Table A3-6 represents the lighting forecast equation before DSM savings.

Table A2-7 shows the resulting Before-Savings lighting load forecast of 16,081 MWh for 2018S and 2019F, as well as the After-savings net load of 15,131 and 13,380 MWh for the same two years respectively. The load forecast reduction of 2,701 MWh reflects a major DSM project,

1 namely the Kelowna LED streetlight retrofit project, which is being incented under FBC's DSM
2 programs.

3

16.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Appendix A3, pp. 1–3

Load forecast methods

On page 1 of Appendix A3, FBC states:

> Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation. Industrial and street lighting loads are typically insensitive to the weather. Currently the residential, wholesale and commercial load classes are normalized because the associated regression results showed high R2 values for these load classes. The commercial class data is normalized from 2014 to 2017 since a correlation presented itself in those years so far, therefore all data prior to 2014 is actuals data and not normalized since it did not show a correlation to weather at that point in time.

On page 2 of Appendix A3, FBC provides regression tables showing the results of the normalized regressions for residential, wholesale, commercial, and irrigation customer classes.

16.1 For each class, please provide and explain the appropriateness of the time period over which the energy consumption data was regressed.

Response:

Consistent with past practices a ten year period was used for weather normalization for each class. FBC believes this is an appropriate time period since it is long enough to smooth out extreme weather but still short enough to adjust to changing weather patterns.

16.2 What value of adjusted R2 does FBC use as an indicator to determine statistical significance and whether the forecast is based on trend analysis or uses the historical average? Please discuss.

Response:

FBC assumes a strong correlation exists when the adjusted R^2 is approximately 80 percent or higher. A number of other factors are also considered including the size, volatility and long term past performance of the rate class. The decision to use a trend analysis or a historical average

is ultimately arrived at during discussions between the Forecast Manager, Forecast Analysts, Regulatory and other staff.

16.2.1 Do the adjusted R2 values observed for irrigation indicate a correlation between energy consumption and weather for spring and summer? Please discuss.

Response:

The adjusted R^2 values observed for the irrigation class do indicate a correlation between energy and consumption for the spring and summer months for the period from 2008 to 2017. However, in the 2018 Annual Review, Exhibit B-2, Appendix A3, Table A3-2 the summer adjusted R^2 for the irrigation class was just 0.21 indicating no correlation. FBC applies weather normalization to load classes only after high R^2 values are recorded in consecutive years, ensuring that it is an actual trend and not just a one-time event.

16.3 Please demonstrate the accuracy of FBC's load forecast in each annual review over the PBR period, and discuss its performance and the merits of looking into other forecast methods, including but not limited to time weighting data, using historical data over a longer period, or alternative forecast models.

Response:

The accuracy of FBC's load forecast in each annual review over the PBR period can be found in Exhibit B-2, Appendix A-2, Table 6-2. In preparing this response, it has come to FBC's attention that Tables 6.1 and 6.2 in Appendix A-2 are incorrect. FBC has provided the corrected tables in the Errata filed concurrently with these IR responses.

Researching and testing alternate forecast methods is both complex and time consuming. Therefore, prior to conducting such research, FBC believes that the performance of the current methods should be evaluated in comparison to industry peers to determine if further research is needed. A comparison of FBC's forecast accuracy against industry peers is shown in the table below.

Energy, GWh		2014	2015	2016	2017	MAPE
Actual	Gross	3,433	3,446	3,480	3,512	
Forecast	Gross	3,519	3,499	3,540	3,559	
Variance		-86	-53	-60	-47	
Variance %		-2.5%	-1.5%	-1.7%	-1.3%	
APE		2.5%	1.5%	1.7%	1.3%	1.8%
ITRON	Respondents	66	71	62	71	
	APE	1.5%	1.3%	1.9%	1.6%	1.6%

As shown in the table above, FBC achieved a mean absolute percent error (MAPE[1]) score of 1.8 percent on the gross demand forecast for the PBR term (2014 to 2017).

The ITRON row in the table above reflects the results of the annual ITRON survey for forecast accuracy, which includes the responses from more than 60 electric utilities. FBC does not participate in this survey. As shown in the table, the MAPE from the ITRON respondents was 1.6 percent.

FBC believes that a gross demand MAPE score of 1.8 percent is reasonable and comparable with the average from the ITRON survey. FBC therefore does not believe there is a need to conduct further research on the suitability or performance of other forecast methods.

[1] MAPE – Mean Absolute Percent Error is a commonly used and accepted metric for measuring forecast accuracy.

17.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.3, p. 24; Appendix A2, pp. 8, 10

Wholesale energy forecast

On page 24 of the Application, FBC states: "after-savings wholesale energy is forecast to increase by 6 GWh in 2018S and 14 GWh in 2019F. The increase in 2019F is partially due to commercial developments within certain wholesale customer's territories."

On page 8 of Appendix A2, FBC provides the following table, showing normalized after-saving wholesale energy:

Wholesale (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
BCH Lardeau	7	6	10	8	6	6	6	6	6	8	7	7
BCH Kingsgate	3	4	3	3	5	5	5	5	5	5	5	5
City of Grand Forks	41	41	41	41	41	41	39	41	41	39	47	54
City of Nelson	107	109	90	88	80	83	81	83	80	86	77	80
City of Penticton	346	346	341	344	341	348	342	348	345	338	340	340
District of Summerland	92	78	97	96	95	98	94	97	98	98	104	107
City of Kelowna	312	324	314	329	332	94	-	-	-	-	-	-
City of Princeton	-	-	-	-	-	-	-	-	-	-	-	-
Total	908	908	895	910	899	675	567	580	574	574	580	594

On page 10 of Appendix A2, FBC presents Table 6.2 showing the historical load variance from 2012 to 2017. The wholesale variance is replicated below

Wholesale Energy (GWh)	2012	2013	2014	2015	2016	2017
Normalized	899	675	567	580	574	574
Forecast	926	935	581	593	579	585
Variance (GWh)	-27	-260	-14	-13	-5	-11
Variance (%)	-3.0%	-38.5%	-2.5%	-2.2%	-0.8%	-1.9%

17.1 Please discuss the reasons why wholesale energy load for the City of Grand Forks is forecast to grow by approximately 20 percent between 2017 and 2018S, and 14 percent between 2018S and 2019F.

Response:

In addition to FBC's annual survey of industrial and wholesale customers, FBC also conducted site visits with most of its wholesale customers in 2018. Through the combined processes of the survey and site visits FBC learned that the load for The City of Grand Forks was expected to grow by approximately 20 percent from 2017 to 2018 due to the addition of a significant new customer being added in Q2 of 2018. The increase from 2018 to 2019 is due to the full load of this new customer being realized in 2019.

17.2 Please explain why the wholesale class energy has been over forecast relative to normalized over the 2012–2017 period.

Response:

Excluding the high variance in 2013 that resulted from the City of Kelowna acquisition, the average over-forecast variance from the remaining years is approximately 2 percent. FBC cannot definitively explain the cause of a variance of this magnitude as it is a result of many factors that may be both compounding and offsetting from multiple wholesale customers each with a different mix of customers and rate classes.

FBC believes that each wholesale customer is best able to provide the most accurate forecast for their service area. To gain additional understanding FBC conducted site visits to most of the wholesale customers this year. These site visits confirmed that each wholesale utility is more knowledgeable about future changes in their service area including upcoming projects and programs that could affect their loads. For example in the case of Grand Forks, the increase in demand was explained to FBC as the result of a new project coming online in 2018. FBC does not believe that other forecast methods exist that would be able to capture these changes with any greater accuracy.

17.2.1 Has FBC identified an alternative forecast methodology to address this trend? Please discuss.

Response:

Please refer to the response to BCUC IR 1.17.2.

18.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.8, p. 30

Peak demand

On page 30 of the Application, FBC states: "The peak load forecast is produced using the ten-year average of historical peaks. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system."

18.1 Please provide the methodology and an illustrative example of how FBC calculates the gross load growth rate.

Response:

The gross load growth rates for actual years are calculated by taking the current year's actual gross load and subtracting the previous year's actual gross load and then dividing that number by the previous year's actual gross load.

For example,

$$2017\ Gross\ Load\ Growth\ Rate = \frac{2016\ Gross\ Load - 2017\ Gross\ Load}{2016\ Gross\ Load}$$

Numerically:

$$2017\ Gross\ Load\ Growth\ Rate = \frac{3{,}387\ GWh - 3{,}596\ GWh}{3{,}387\ GWh} = 6.2\%$$

The process is the same for the forecast years, except that before-savings load is used instead of actuals. For forecast years, the before-savings gross load is used since DSM is subtracted from the peaks once they have been calculated.

18.1.1 Please confirm, or otherwise explain, that the calculated gross load growth rate is used to escalate each historical peak.

Response:

Confirmed.

19.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Sections 3.6, 12.4.2.5, pp. 31, 118; Order G-124-17

Revenue forecast

On August 17, 2017 the BCUC issued Order G-124-17 approving FBC's application to provide a credit to customers who receive service under certain FBC Electric Tariff Rate Schedules for the 2017 charges that would otherwise have applied under those rate schedules during the period the customer was under an Evacuation Order due to wildfires.

On page 31 of the Application, FBC provides Table 3-5 showing the approved, projected and forecast revenue for 2018 and 2019.

On page 118 of the Application, FBC provides Table 12-4 showing the 2018 Flow-through deferral account additions.

19.1 Please provide the total number of customers by class which received the evacuation relief in 2017 approved by the BCUC pursuant to Order G-124-17.

Response:

The table below shows the total number of residential, commercial, and irrigation services which received evacuation relief in 2017:

FBC Rate Schedule	Number of Services[2]
Residential RS 1, 2A, 3, 3A, 95	860
Commercial Service RS 20, 21, 22A, 23A	68
Irrigation and Drainage RS 60, 61	15

FBC has provided the total number of services by rate schedule rather than number of customers because there were situations were one customer had multiple services under different rate schedules and therefore separate credit amounts on each invoice. The total actual amount of the credits provided to these customers due to the wildfires in 2017 based on Order G-124-17 was $21,536. This amount was treated as a revenue shortfall, was recorded in the

[2] In an informal response to staff dated August 15, 2018, related to the application by FortisBC Energy Inc. and FBC Application for Approval to Exempt from Applicable Residential and Commercial Tariff Charges for Customers Under Evacuation Orders and Application for Approval of Tariff Changes to Permit Relief for Customers Under Evacuation Orders, FBC stated that there were a total of 866 FBC customers (941 services); however, the updated actual total number is 868 customers (943 services).

Flow-through deferral account in 2017, and will be recovered from ratepayers in 2019 rates (as part of the calculation of the final 2017 Flow-through deferral account balance as set out in the response to BCUC IR 1.37.1).

Amortization of the $21,536 from wildfire relief embedded in the Flow-through deferral account results in a one-time rate increase in 2019 of 0.006 percent for all ratepayers or approximately $0.11 for an average residential customer in 2019.

19.2 Please provide the total impact on FBC's 2017 revenue resulting from the evacuation relief provided.

Response:

Please refer to the response BCUC IR 1.19.1.

19.2.1 As part of the above response, please identify the variance between the approved 2017 and the actual 2017 sales revenue that are due to the customer credits approved by Order G-124-17.

Response:

Please refer to the response BCUC IR 1.19.1.

19.3 Please explain how the revenue variance resulting from the evacuation relief bill credits was treated, including whether, and in what year, the variance was recorded in the Flow-through deferral account and in what year the variance will be recovered from ratepayers.

Response:

Please refer to the response to BCUC IR 1.19.1.

19.3.1 Please provide the rate impact of the amortization of the revenue variance resulting from the customer credits.

Response:

Please refer to the response to BCUC IR 1.19.1.

C. POWER SUPPLY

20.0 Reference: POWER SUPPLY

Exhibit B-2, Application, Section 4.5 and 4.6, pp. 35, 37; FBC 2018 Annual Review, Exhibit B-2, p. 37

BC Hydro Power Purchase Agreement (PPA) expense

On page 37 of the FBC 2018 Annual Review application, FBC states it "submitted a PPA nomination for the 2017/18 contract year of 642 GWh on June 27, 2017…" On page 35 of the current Application, FBC states it "submitted a PPA nomination for the 2018/19 contract year of 725 GWh on June 25, 2018…"

On page 37 of the Application, FBC states:

> BC Hydro PPA expense increased by $13.551 million in the 2019 Forecast compared to the 2018 Projected. A forecast BC Hydro rate increase of 2.6 percent on April 1, 2019 accounts for $1.480 million, whereas higher purchased volume (211 GWh) increases the 2019 Forecast expense by $13.071 million.

20.1 Please explain how FBC calculates an increase in PPA purchases by 211 GWh from 2018 to 2019, including an explanation on the volumes assumed in the Projected 2018 BC Hydro PPA expense.

Response:

BC Hydro PPA energy purchases increased from 549 GWh in the 2018 Projected to 759 GWh in the 2019 Forecast, which rounded to a 211 GWh increase. The volumes in the 2018 Projected are based on actuals through June 30, 2018 and a forecast for the remainder of the year, which may be further reduced by mitigation opportunities. This increased reliance on BC Hydro PPA energy is mainly a result of reduced Market and Contracted purchases included in the 2019 Forecast. The 2019 Forecast only includes those market purchases for 2019 that FBC was able to execute prior to filing. FBC continues to monitor system and market conditions for additional opportunities for 2019 and has included a $2 million reduction to BC Hydro expense in the 2019 Forecast to account for additional opportunities, which would reduce the BC Hydro PPA 2019 Forecast volumes, as described in Section 4.6 of the Application.

21.0 Reference: POWER SUPPLY

Exhibit B-2, Application, Section 3.7, p. 38

Wheeling expense

On page 38 of the Application, FBC provides the following table, showing wheeling expenses:

Table 4-4: Wheeling Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,490	2,490	2,400
3	Creston	444	444	471
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.590	$ 4.573	$ 4.514
7	Creston	0.534	0.542	0.577
8	Other	0.048	0.165	0.144
9	Total Wheeling Expense	$ 5.171	$ 5.281	$ 5.235

On page 33 of the Application, FBC states that "the 2019 Forecast wheeling expense is forecast to increase due to increased wheeling rates."

On page 38, FBC states:

> In 2018 and 2019, ARWA costs are forecast to account for all of FBC's wheeling expense, except for $0.165 million and $0.144 million of OATT and Teck wheeling in 2018 and 2019 respectively. Increased use of both Emergency Wheeling and Teck wheeling in early 2018 caused the 2018 Projected OATT wheeling expenses to exceed Approved…. As shown in Table 4-4 above, 2019 wheeling expense is forecast to decrease by $0.022 million over 2018 Projected.

21.1 Please discuss the reasons for increased used of emergency wheeling and Teck wheeling in early 2018.

Please confirm, or otherwise explain, that 2019 wheeling expense is forecast to decrease by $0.046 million over 2018 projected.

Response:

In early 2018, FBC increased its use of Emergency Wheeling because of an unplanned transmission outage that persisted throughout the first three months of the year. FBC also increased the use of Teck wheeling above the 2018 Approved amount due to an increased

volume of Market and Contracted purchases on 71 Line. The increase in Teck wheeling is more than offset by the increase in market savings that the market purchases produced.

With that background, it is confirmed that 2019 wheeling expense is forecast to decrease by $0.046 million over 2018 projected.

D. OTHER REVENUE

22.0 Reference: OTHER REVENUE

Exhibit B-2, Application, Section 5.5, p. 41

Late payment charges

On page 41 of the Application, FBC states that beginning with 2019, it is forecasting late payment charges as part of Other Revenue. FBC states it "has historically not forecast late payment charges as part of its revenue requirement. When these charges were earned, they were flowed through to customers."

22.1 Please explain why FBC decided to forecast late payment charges as part of Other Revenue, beginning in 2019.

Response:

Historically, FBC recorded late payment charges in sales revenue and had not forecast the amounts explicitly. On January 1, 2018, FBC began to record late payment charges as Other Revenue, which is consistent with FEI's accounting treatment and is the more appropriate classification, consistent with the treatment of connection charges as non-sales revenue. FBC then began to forecast late payment charges for the 2019 revenue requirements.

22.2 Please explain and provide the 2019 impact of forecasting late payment charges as part of Other Revenue on FBC's revenue requirement, as compared to a flow through to customers as charges are earned.

Response:

The impact of forecasting late payment charges in revenue requirements is simply a matter of timing since variances in Other Revenue are included in the Flow-through deferral account. When late payment charges are forecast, the forecast reduces revenue requirements in the test year and is trued up in the following year(s). If late payment charges are not forecast, then the benefit to revenue requirement all occurs when the variance in the Flow-through deferral account is amortized into rates.

The $0.861 million forecast for late payment charges in 2019 is equivalent to a (negative) rate impact of 0.23 percent ($0.861 million divided by $370.534 million).

E. OPERATING & MAINTENANCE (O&M) EXPENSE

23.0 Reference: O&M EXPENSE

Exhibit B-2, Application, Section 6.3.3, Table 6-5, p. 46

AMI project

In Table 6-5 on page 46 of the Application, FBC compares 2014 through 2019 net AMI savings to the net savings forecast in the AMI CPCN application. Table 6-5 shows that 2019 forecast costs are $2.055 million compared to $1.951 million in the AMI CPCN application, while 2019 forecast savings are $3.216 million compared to $4.244 million in the AMI CPCN Application.

23.1 Please provide an explanation and breakdown of the $0.104 million increase in the current 2019 forecast AMI costs and $1.028 million decrease in the forecast AMI savings, compared to the forecasts in the AMI CPCN application.

Response:

Forecast post-AMI costs are approximately $0.1 million higher than CPCN due to manual disconnect and reconnect costs. The higher post-AMI costs are due to not forecasting an increase in the unit cost of manual disconnects and reconnects at substantially lower post-AMI volumes in the CPCN application.

The forecast post-AMI savings are approximately $1.0 million lower than CPCN for the reasons listed in Sections 6.3.3.1, 6.3.3.2 and 6.3.3.3, excluding the manual disconnects and reconnects reason listed above (which explains an increase in costs).

F. RATE BASE

24.0 Reference: REGULAR CAPITAL EXPENDITURES FORECAST OUTSIDE THE FORMULA

Exhibit B-2, Application, Section 7.2.2, Table 7-3, p. 55

AMI sustainment capital

On page 55 of the Application, FBC provides Table 7-3 showing 2019 forecast capital expenditures outside of the formula:

Table 7-3: 2019 Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Pension/OPEB (Capital Portion)	$ 3.630	$ 3.630	$ 3.612
2	AMI Sustainment Capital	0.265	0.324	0.937
3	Mandatory Reliability Standards Incremental Capital	0.050	0.050	2.780
4	Employer Health Tax	-	-	0.624
5	MSP Reduction	-	(0.182)	(0.182)
6	Forecast Capital Expenditures	$ 3.945	$ 3.822	$ 7.771

24.1 Please explain in detail the causes/factors for why FBC forecasts 2019 AMI sustainment capital ($0.937 million) to be $0.613 million higher than 2018 projected ($0.324 million).

Response:

The 2019 AMI sustainment capital reflects the requirement to upgrade the systems that operate the AMI network at FBC. The components of the AMI system that require upgrading include all the supporting applications, security appliances, operating systems and databases. These systems were implemented in 2012 at the beginning of the AMI project. The upgrades are required to maintain support and ensure security and reliability of the AMI network.

Sustaining capital in years leading up to 2019 was used to apply regular patching and minor support upgrades. In 2019 new versions of the supporting AMI systems will need to be implemented. The costs indicated for 2019 reflect this additional effort. The timing of this effort is consistent with other systems at FBC. Significant version upgrades to enterprise solutions, such as AMI, are normally required after 5 years.

24.2 Please clarify whether forecast 2019 AMI sustainment capital expenditures are consistent with the forecast for 2019 in the AMI CPCN application. If not, please explain why not.

Response:

FBC's 2019 AMI sustainment capital expenditures were forecast at $0.955 million in the AMI CPCN application, which is consistent with the forecast 2019 AMI sustainment capital expenditures of $0.937 million as detailed in Table 7-3 from the Application (Exhibit B-2).

25.0 Reference: CPCN AND SPECIAL PROJECTS CAPITAL EXPENDITURES

Exhibit B-2, Application, Section 7.3, p. 56; FBC Application for a CPCN for the Corra Linn Dam Spillway Gate Replacement Project, Order C-1-17

Corra Linn Dam Spillway Gate Replacement Project

On page 56 of the Application, FBC states, for 2019 it forecasts the Corra Linn Dam Spillway Gate Replacement Project to be completed in 2021 at a cost of $66.844 million, with $14.459 million of this amount incurred in 2019.

In FBC's Application for a CPCN for the Corra Linn Dam Spillway Gate Replacement Project, FBC estimated the capital cost for the project in as-spent dollars to be $62.694 million.

25.1 Please explain in detail the causes/factors for why the current forecast to complete the Corra Linn Dam Spillway Gate Replacement Project is $4.150 million higher than what was forecast in the CPCN application. As part of your response, please include explanations for any variances/changes to project scope and/or the timing of costs if appropriate.

Response:

In response to BCUC Order C-1-17, FBC filed a Contract Finalization report with the BCUC on April 4, 2018, which addresses the increased project costs in detail. This response is intended to provide a summary of the key points outlined in the Contract Finalization report.

The Open Book Phase (OBP) of the project was completed collaboratively with HMI Canada Inc (HMI) as the design/engineer consultant, Knight Piésold (KP) as the owners engineer representing FBC, and FBC. The OBP process resulted in sufficient engineering, design, and procurement work to develop the Project scope, schedule, and contract price. HMI was required to tender approximately 70 percent of the sub-contractor costs to ensure market pricing was used to develop the contract price. The total Project cost is now a Class 1 estimate at $66.844 million, as compared to the original Class 3 cost estimate included in the Application of $62.694 million. This represents a variance of $4.15 million or approximately 7 percent, which is well within the accuracy ranges of an AACE Class 3 cost estimate and is primarily attributable to the refining and maturing of the Project definition and scope that took place through the OBP process.

The following table is provided to outline the differences in costs from the class 3 estimate to that of the class 1 estimate.

	Application (Class 3) As-Spent ($ million)	OBP (Class 1) Estimate ($ million)	Variance ($ million)
Contractor's Costs			
Engineering	2.506	2.897	0.392
Supply, Installation & Testing	19.304	22.947	3.643
Site-Support Work	10.071	10.483	0.412
Indirect Costs	0.666	0.484	(0.182)
Project Management	4.610	5.994	1.384
Subtotal	***$ 37.156***	***$ 42.805***	***$ 5.649***
Removal Cost	5.804	7.554	1.750
Construction Contingency	2.148	1.371	(0.777)
Total Contractor Costs	***$ 45.108***	***$ 51.730***	***$ 6.622***
FBC Owner's Costs			
FBC – Project Management	3.155	3.674	0.519
Generation Admin Overhead	0.589	0.505	(0.084)
Project Contingency	7.328	4.000	(3.328)
Pre-Approval Project Costs	1.081	0.934	(0.147)
Subtotal (Contractor & Owner's Costs)	***$ 57.260***	***$ 60.844***	***$ 3.584***
Allowance for Funds Used During Construction (AFUDC)	5.434	6.000	0.566
TOTAL Project Capital Costs	***$ 62.694***	***$ 66.844***	***$ 4.150***

When combined, the estimate for the supply, installation, testing, and site-support work has increased by approximately $4.1 million. The following is a brief summary of the main items:

- New hoists – The need for new hoists and associated works contributed to an increase of approximately $1.6 million. The Class 3 cost estimate in the Application was developed based on the assumption that refurbishment would be sufficient to handle the increased gate weight; however, detailed analysis and engineering of the existing hoist components could not assure the required safety factors.

- Tower and bridge reinforcements - The cost is approximately $2.5 million higher than the estimate included in the Application primarily due to additional requirements for tower and bridge reinforcements to support the new hoists.

The financial forecast of the project has changed from what was submitted in the CPCN as follows:

	2017 $ (000)	2018 $ (000)	2019 $ (000)	2020 $ (000)	2021 $ (000)	2022 $ (000)	Total $ (000)
Original CPCN Forecast	11,595	21,968	18,555	9,774	0.802	0	62,694
Revised Forecast	3,911	17,347	18,430	15,536	11,267	0.351	66,844

The revised forecast is based upon a negotiated milestone payment schedule, which was developed at the conclusion of the OBP, after the CPCN was submitted.

26.0 Reference: CPCN AND SPECIAL PROJECTS CAPITAL EXPENDITURES

Exhibit B-2, Application, Section 7.3, Table 7-4, pp. 56, 57; Appendix C, Section 3, pp. 19–20; Appendix D, Section 3, pp. 11–12

2019 plant additions

On page 57 of the Application, FBC provides Table 7-4 showing a reconciliation of capital expenditures to 2019 plant additions. The table shows that additions to plant, related to special projects and CPCNs, are expected to total $14.775 million.

FBC states on page 56 that special project and CPCN costs, which will be included in rate base in 2019, are "the portion of the UBO Project [Upper Bonnington Old Units Refurbishment Project] attributable to the refurbishment of Unit 4" and the Ruckles Substation Project, which is expected to be completed in 2018.

26.1 Please provide a breakdown of the $14.775 million special projects and CPCN additions to plant by project. Please ensure that the breakdown reconciles to the "forecast expenditures to completion" for Unit 4 of the UBO Project and the Ruckles Substation Project, as provided in Section 3 of both Appendix C and D.

Response:

The breakdown of the 2019 Special Projects and CPCN Projects Additions to Plant is provided in the table below, along with the reconciliation of the Ruckles Substation Rebuild and UBO Refurbishment Project totals to Appendix D and Appendix C, respectively. Note that the project cost table for the UBO Refurbishment Project (Appendix C, Table C-2) contains an error. Forecast AFUDC is reported at $1.188 million. The correct value of $1.198 million as seen in the table below. A correction to Appendix C, Table C-2 is included in the response to BCUC IR 1.42.1. FBC has also provided the corrected table in the Errata filed concurrently with these IR responses.

Line No.	Description	2019 Corra Linn	2019 Ruckles	2019 UBO	2019 Total, Table 7-4	Project Total UBO
1	Special Projects and CPCN Capital Expenditures	$ 12.750	$ -	$ 7.449	$ 20.199	$ 30.585
2	Special Projects and CPCN AFUDC	1.709		0.373	2.082	1.198
3	Special Projects and CPCN Cost of Removal	(2.751)		(0.333)	(3.084)	(1.496)
4	Special Projects and CPCN Work in Progress	(11.708)	6.690	0.596	(4.422)	-
5	Special Projects and CPCN Additions to Plant	$ -	$ 6.690	$ 8.085	$ 14.775	$ 30.287
6						
7	Add Cost of Removal		0.223			1.496
8	Total Project Cost per Appendix D (Ruckles) and Appendix C (UBO)		$ 6.913			$ 31.783

G. FINANCIAL SCHEDULES

27.0 Reference: FINANCIAL SCHEDULES

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

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

27.1 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 2017 ending deferral account balances and including projected 2018 deferral account additions and amortization.

Response:

The requested schedules are provided below.

In the schedules FBC has reduced its 2018 forecast for two deferral accounts

- The 2017 Rate Design Application (Schedule 12.1, Line 8) deferral account is reduced by $0.398 million, as explained in the response to BCUC IR 1.36.1, and
- The 2016 Long Term Electric Resource Plan (Schedule 12.1, Line 7) deferral account is reduced by $0.037 million, based on costs to date.

These revisions will be included in FBC's Evidentiary Update.

FORTISBC INC. Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/17	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/18	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	1. Forecasting Variance Accounts								
2									
3	2. Rate Smoothing Accounts								
4									
5	3. Benefits Matching Accounts								
6	Demand Side Management	$ 22,427	$ -	$ 7,900	$ (2,133)	$ (3,711)	$ 24,483	$ 23,455	
7	Deferred Debt Issue Costs	3,826	-	2	(119)	(165)	3,543	3,685	
8	Preliminary and Investigative Charges[1]	330	-	(140)	-	-	191	260	Note 1
9	Right of Way Reclamation (Pine Beetle Kill)	173	-	-	-	(173)	-	87	
10	Accounting Treatment of non-AMI Meters	2,163	-	-	-	(1,082)	1,082	1,623	
11		$ 28,920	$ -	$ 7,762	$ (2,252)	$ (5,131)	$ 29,298	$ 29,109	
12	4. Retroactive Expense Accounts								
13									
14	5. Other Accounts								
15	Pension and OPEB Liability	(17,298)	-	493	-	-	(16,805)	(17,052)	
16		$ (17,298)	$ -	$ 493	$ -	$ -	$ (16,805)	$ (17,052)	
17									
18	**Total Rate Base Deferral Accounts**	$ 11,622	$ -	$ 8,255	$ (2,252)	$ (5,131)	$ 12,493	$ 12,058	
19									

20 Note 1: Gross additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress.
1 Additions of $0.150 million - transfers of $0.290 million = $(0.140) million.

2

FORTISBC INC.

Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 12

Line No.	Particulars	12/31/17	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/18	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	1. Forecasting Variance Accounts								
4	Revenue and Power Supply[(1)]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Flow-Through Accounts	(9,356)	-	(10,534)	-	7,102	(12,788)	(11,072)	
6	Pension & Other Post Retirement Benefits (OPEB) Variance	(367)	-	(617)	-	289	(695)	(531)	
7		$ (9,723)	$ -	$ (11,151)	$ -	$ 7,391	$ (13,483)	$ (11,603)	
8	2. Rate Smoothing Accounts								
9	2018 Revenue Deficiency	$ -	$ -	$ 896	$ (242)	$ -	$ 654	$ 327	
10									
11	3. Benefits Matching Accounts								
12	2014-2019 Performance Based Ratemaking Application	493	-	-	-	(246)	246	369	
13	Annual Reviews for 2015-2019 Rates	32	-	205	(55)	(102)	79	55	
14	Self-Generation Policy Application, Stage II	(19)	-	75	(20)	-	35	8	
15	Net Metering Program Tariff Update	87	-	52	(14)	(88)	38	63	
16	BCUC Residential Inclining Block Rate Report	(19)	-	3	(1)	22	5	(7)	
17	2017 Demand Side Management Expenditure Schedule Application	10	-	-	-	(11)	(1)	5	
18	2018 Demand Side Management Expenditure Schedule Application	-	2	70	(19)	-	54	28	
19	BC Hydro Application for Power Purchase Agreement with FBC	(7)	-	-	-	7	-	(3)	
20	Community Solar Pilot Project	-	51	71	(19)	(130)	(27)	12	
21	Tariff Applications	(74)	-	-	-	-	(74)	(74)	
22	Electric Vehicle Charging Stations Rate Design and Tariff Application	-	11	45	(12)	-	44	28	
23		$ 502	$ 65	$ 519	$ (140)	$ (548)	$ 399	$ 483	
24	4. Retroactive Expense Accounts								
25									
26	5. Other Accounts								
27	2014-2019 Earnings Sharing Account	(744)	-	(169)	46	615	(252)	(498)	
22	Castlegar Office Disposition	31	344	(813)	-	-	(439)	(469)	
23	BC Hydro Waneta 2017 Transactions	-	33	79	(21)	-	91	62	
24		$ (713)	$ 377	$ (903)	$ 24	$ 615	$ (601)	$ (905)	
25									
26	**Total Deferral Accounts at Short Term Interest**	$ (9,934)	$ 441	$ (10,638)	$ (358)	$ 7,457	$ (13,031)	$ (11,698)	
27									
28	Financing Costs at STI	$ (289)	$ -	$ (405)		$ 361	$ (333)	$ (311)	
29									

1 30 Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term.

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/17	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/18	Mid-Year Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**							
2								
3	1. Forecasting Variance Accounts							
4								
5	2. Rate Smoothing Accounts							
6								
7	3. Benefits Matching Accounts							
8	CPCN Projects Preliminary Engineering	$ 130	$ -	$ 125	$ -	$ -	$ 255	$ 192
9	2016 Long Term Electric Resource Plan	382	-	233	(63)	(141)	412	397
10	2017 Rate Design Application	124	-	852	(230)	-	746	435
11	Transmission Customer Rate Design	2	-	-	-	(2)	-	1
12	2020 Revenue Requirements	-	-	225	(61)	-	164	
13	2019 - 2022 Multi-Year DSM Expenditure Schedule	-	74	115	(31)	-	158	116
14	2018 Joint Pole Use Audit	-	-	200	(54)	(29)	117	58
15		$ 638	$ 74	$ 1,750	$ (439)	$ (172)	$ 1,852	$ 1,200
16	4. Retroactive Expense Accounts							
17								
18	5. Other Accounts							
19	US GAAP Pension and OPEB Transitional Obligation	$ 2,728	$ -	$ (827)	$ -	$ -	$ 1,901	$ 2,314
20	Advanced Metering Infrastructure Radio-Off Shortfall	88	-	-	-	-	88	88
21		$ 2,816	$ -	$ (827)	$ -	$ -	$ 1,989	$ 2,403
22								
23								
24	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ 3,455	$ 74	$ 923	$ (439)	$ (172)	$ 3,841	$ 3,603
25								
26	Financing Costs at WACD	$ 447	$ -	$ 198		$ (499)	$ 147	$ 297
27								
28	**Deferral Accounts Financed at AFUDC**							
29								
30	3. Benefits Matching Accounts							
31	On Bill Financing (OBF) Participant Loans	$ 9	$ -	$ (1)	$ -	$ -	$ 8	$ 9
32								
33	Financing Costs at AFUDC	$ 1	$ -	$ 1	$ -	$ (1)	$ 1	$ 1
34								
35	**Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50
36								
37	**Total Non Rate Base Deferral Accounts (including financing)**	$ (6,260)	$ 515	$ (9,923)	$ (797)	$ 7,146	$ (9,317)	$ (7,531)

28.0 Reference: FINANCIAL SCHEDULES

Exhibit B-2, Application, Section 11, Schedule 12.1, p. 88; FBC 2018 Annual Review, Exhibit B-2, p. 120

Unamortized deferred charges and amortization (non-rate base)

In the FBC 2018 Annual Review, FBC stated on page 120 of its application that its portion of the costs related to the next revenue requirement application following the end of the current PBR term will include the costs of a benchmarking study. FBC stated that it anticipates completing the benchmarking study by year-end 2018 at an estimated cost of $0.030 million in 2017 and $0.070 million in 2018. Further, on line 8 of Schedule 12.1, in Section 11, FBC forecasted a 2018 ending balance of $53,000 in the 2020 Revenue Requirements deferral account. FBC further stated, "Forecast costs for the remainder of the application and its regulatory review will be updated at a later time."

On line 13 of Schedule 12.1 in Section 11 of the Application, FBC shows that the 2019 opening balance in the 2020 Revenue Requirements deferral account is $164,000.

28.1 Please explain in detail the causes/factors which resulted in the 2019 opening balance of the 2020 Revenue Requirement Application deferral account balance to be $111,000 higher than what was projected in the FBC 2018 Annual Review application.

Response:

On a before-tax basis, the forecast 2019 opening balance in the deferral account increased by $0.125 million from the forecast in the Annual Review for 2018 Rates. Of this, $0.100 million is the estimated cost to conduct a depreciation study for filing with the 2020 Revenue Requirements. Income tax on the account was affected by the change in the tax rate, which was not included in the initial filing for 2018 Rates, and by an overstatement of the tax impact for this account, which was corrected in the compliance filing for 2018 rates.

28.2 Please describe the nature of the forecast $975,000 in additions to the 2020 Revenue Requirement Application deferral account which is shown on line 13 of Schedule 12.1 in Section 11 of the Application.

Response:

The forecast additions in 2019 include the Commission's direct costs, participant assistance cost awards, notice publication costs, consulting and expert fees, external legal counsel fees, courier and miscellaneous administrative costs.

28.2.1 Please discuss the expected timing for when FBC will provide an update on the forecast costs of the 2020 Revenue Requirements application.

Response:

FBC expects to file its filing to set 2020 rates and will update its forecast application costs in that filing.

H. ACCOUNTING MATTERS AND EXOGENOUS ITEMS

29.0 Reference: EXOGENOUS ITEMS

Exhibit B-2, Application, Sections 6.3.4, 7.2.2 and 12.2.3, pp. 47, 49, 55, 106–107

Mandatory Reliability Standards (MRS)

On pages 106 and 107 of the Application, FBC states the following related to complying with changes to BC's MRS program:

> For 2019, the incremental MRS costs that qualify for exogenous factor treatment are forecast to be $3.720 million, comprised of $0.940 million in incremental O&M expense and an incremental $2.780 million in capital expenditures. These costs continue to exceed the Commission-defined materiality threshold of $0.301 million.

On page 47 of the Application, FBC shows a breakdown of the forecast $0.940 million in incremental O&M expenses in Table 6-6:

Table 6-6: MRS Incremental O&M Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Assessment Report No. 8	$ 0.540	$ 0.540	$ 0.540
2	Assessment Report No. 10	0.180	0.150	0.400
3	2018 Compliance Audit	0.350	0.350	-
4	Forecast O&M	$ 1.070	$ 1.040	$ 0.940

FBC states on page 49 of the Application that the incremental O&M expenditures associated with Assessment Report No. 10 "are primarily for resource additions in System Operations that will be required to ensure full compliance with October 1, 2020."

On page 55 of the Application, FBC provides a breakdown of the forecast $2.780 million in incremental capital expenditure in 2019 into one-time capital for Assessment Report No. 10 of $2.700 million and sustainment capital for Assessment Report No. 8 of $0.080 million).

29.1 Please provide a list of the individual adopted standards, including a description of the scope of work and individual cost estimate (one-time and ongoing) for the standard, as it relates to the following 2019 cost estimates:

a) $0.540 million incremental O&M for Assessment Report No. 8;

b) $0.400 million incremental O&M for Assessment Report No. 10;

c) $0.080 million incremental capital for Assessment Report No.8; and

d) $2.780 million incremental capital for Assessment Report No. 10

Response:

BCUC Order R-38-15 provides a list of the adopted standards for Assessment Report 8. Of those standards, the suite of CIP v5 standards (total of 10) and PER-005-2 (Operations Personnel Training) attribute to the incremental ongoing O&M and capital costs for AR8. There are no one-time costs in 2019 for AR8.

Standard	Tasks	O&M Cost
CIP-002-5.1 CIP-003-5 CIP-004-5.1 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1	Support the installed systems and tasks which include ongoing efforts to maintain processes and systems that ensure and address physical and cyber security controls, continuous monitoring, change management, patch management and vulnerability assessments. The effort is primarily labour and annual software/hardware licensing fees.	$520,000
PER-005-2	Maintain and continue to deliver required training to support personnel for system operations and control.	$ 20,000
Standard	**Tasks**	**Capital Cost**
CIP-002-5.1 CIP-003-5 CIP-004-5.1 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1	Support of the infrastructure that was required for CIP v5 such as annual software upgrades for maintaining support and avoiding potential security, productivity and reliability issues. Also includes leveraging new functionality and features available that the vendors have developed through continued investment in their products.	$ 80,000

BCUC Order R-39-17 provides a list of the adopted standards for Assessment Report 10. Of those standards, three were identified that require significant effort. FBC reviewed the standards as a group as some tasks and tools are similar to achieve compliance. These standards are:

- IRO-017-1 Outage Co-ordination
- TOP-001-3 Real Time Contingency Analysis
- TOP-002-4 Next-Day Operational Planning Analysis

FBC is continuing to develop the scope and select the tools and support systems required. Based on the evaluation to date, the 2019 estimates for AR10 are one-time costs and are as follows.

Standards	Tasks	Operating Cost
IRO-017-1, TOP-001-3 & TOP-002-4	Qualified and trained personnel required in System Operations group (system control centre) to support the new standards coming into effect by October 1, 2020. This would include continuously performing real-time pre- and post-contingency assessments every 30 minutes, meeting outage coordination requirements, and implementing outage scheduling timelines and next day studies as well as obtaining training equivalent to a System Operator. Training for these tasks typically takes approximately 12 to 18 months.	$400,000
Standards	**Tasks**	**Capital Cost[3]**
IRO-017-1, TOP-001-3 & TOP-002-4	Purchase and install the necessary hardware and software systems (including backup) and resources to meet the requirements. This includes Real Time Contingency Analysis (RTCA) software, outage coordination tool to comply with RC processes, operational planning analysis and (daily) assessments. The infrastructure will be required to be within the boundaries of and integrated with the SCADA network.	$2,700,000

29.2 Please explain what is meant by "resource additions in System Operations" (e.g. technology assets, employee additions, other) for the incremental O&M expenditures associated with Assessment Report No. 10.

Response:

The above refers to adding qualified and trained personnel in the System Operations group (system control centre) to support the new standards coming into effect by October 1, 2020. The costs associated are primarily labour and training.

29.3 Please provide a list of any MRS in Assessment Report No. 8 and No. 10 held in abeyance, including its justification, respective risk(s) to the electric system, mitigating solutions and associated cost.

[3] FBC notes the question has a typographical error, where the amount shown as $2.780 million in item d) should instead by $2.700 million.

Response:

Standards that have been held in abeyance have generally been standards applicable to the Planning Authority/Planning Coordinator (PA/PC) function, with the exception of CIP-003-6 in Assessment Report 10. Until such time that the PA/PC function responsibilities are clarified for the Province, these standards cannot be assessed. Commission Order R-41-13 stated that PA/PC responsibilities for the Province require clarification and standards that apply to PA/PCs have been held in abeyance since then.

AR8 Standards held in abeyance include:

- MOD-032-1Data for Power System Modeling and Analysis;
- MOD-033-1 Steady-State and Dynamic System Model Validation; and
- PRC-023-3 Transmission Relay Loadability.

AR10 Standards held in abeyance include:

- PRC-023-4 Transmission Relay Loadability
- PRC-026-1Protection Coordination/Loadability
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- CIP-003-6 Cyber Security — Security Management Controls

FBC had also recommended that CIP-003-6 standard be held in abeyance. The next revision of this standard (CIP-003-7(i)) is in the final stages of approval. FBC recommended this version of the standard be held in abeyance or have an effective date to align with CIP-003-7(i) implementation to avoid potential stranded costs.

Additional standards that pertain to the PA/PC function from Assessment Reports 7 and 9 include:

- EOP-003-2 Load Shedding Plans
- FAC-013-2 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon
- PRC-006-2 Automatic Underfrequency Load Shedding
- PRC-010-2 Under Voltage Load Shedding

Note that FBC is unable to evaluate the risk(s) to the electric system, mitigating solutions and associated costs as it has not historically been the PA/PC entity responsible for the standards held in abeyance.

30.0 Reference: EXOGENOUS ITEMS

Exhibit B-2, Application, Section 12.2, pp. 104–107

Exogenous (Z) factors

On pages 104 to 105 of the Application, FBC describes the Employer Health Tax (EHT) announced as part of the provincial government's budget in February 2018, which will come in effect on January 1, 2018. FBC states that EHT costs are estimated at $1.2 million in 2019 ($0.576 million in O&M and $0.624 million in capital).

On page 106 of the Application, FBC states on December 27, 2017, the provincial government announced the reduction of MSP premiums by 50 percent, effective January 1, 2018, and the elimination of MSP premiums by January 1, 2020. FBC states MSP savings are forecast at $0.350 million in 2018 and 2019 ($0.168 million in O&M and $0.182 million in capital in each year).

30.1 Please explain FBC's methodology for estimating the 2019 forecast for EHT costs and MSP premiums reductions.

Response:

The EHT is an employer-paid payroll tax based on the remuneration to employees. The tax is calculated based on a remittance rate of 1.95 percent of the remuneration.

To estimate the EHT for 2019, FBC started with the actual 2017 employee remuneration ($59.8 million) and applied an annual inflation factor of 2.5 percent for each of 2018 and 2019 to arrive at the forecast remuneration for 2019. The tax of 1.95 percent was then applied to the 2019 forecast remuneration ($62.8 million) to arrive at the $1.2 million estimated EHT for 2019.

The MSP reduction in 2019 is equal to the estimate of MSP to be paid in 2018 (since no MSP would be paid in 2019). To estimate the MSP to be paid in 2018 FBC doubled its MSP costs for the first half of 2018 to represent a full year.

Any variance from forecast for these items will be returned to or recovered from customers by way of the Flow-thru deferral account.

Further, FBC states on page 106 of the Application that incremental MRS costs for 2019 that qualify for exogenous factor treatment are forecast to be $3.720 million ($0.940 million in O&M and $2.720 million in capital).

30.2 Please explain the method of allocating costs/savings between O&M and capital for the following and how it was determined to be appropriate:

- EHT costs
- MSP premium reduction
- Incremental MRS costs

Response:

The EHT costs and MSP premium reduction are included in O&M and capital similar to how OPEB and pension expenses are included. The amounts follow the expected labour allocation between O&M and capital, which is approximately 48 percent and 52 percent, respectively. Just like the OPEB and pension expenses, the EHT costs (starting in 2019) and MSP premiums are included in FBC's labour loadings, and therefore the allocation between O&M and capital, along with other labour loadings, is based on where the labour is expected to be charged.

The incremental MRS costs are included in O&M and capital based on FBC's capitalization policy. FBC capitalizes costs in accordance with generally accepted accounting principles; the determination as to whether costs are capitalized or expensed depends on the nature of the expenditure. MRS costs related to investing in hardware and software, as well as infrastructure additions, were included in capital in order to achieve requirements in the standards.

31.0 Reference: EMERGING US GAAP ACCOUNTING GUIDANCE

Exhibit B-2, Application, Section 12.3.1.2, pp. 108–110

Cloud computing

FBC states on page 108 of the Application that Accounting Standards Update 2015-05 (ASU 2015-15) was issued in 2015, relating to the accounting treatment for cloud computing arrangements. Based on ASU 2015-05, "if a cloud computing arrangement does not meet the criteria of 'having a software licence'… the entity procuring the cloud service should account for the arrangement as a service contract, which would generally mean expensing such costs."

31.1 Please confirm, or explain otherwise, that FBC currently applies ASU 2015-15 as it relates to accounting for cloud computing arrangements.

Response:

FBC will be applying ASU 2018-15 which was finalized on August 29, 2018 and permits the capitalization of cloud computing vendor implementation costs beginning in 2018 as per the transitional provisions of the standard.

FBC first began utilizing cloud computing service in 2009 when it implemented the Fleet Complete Automated Vehicle Locate (AVL) system, which was a hosted solution. However, the implementation of this project occurred before Accounting Standards Update (ASU) 2015-05 Intangibles – Goodwill and Other – Internal – Use Software – Cloud Computing Arrangements which became effective in 2015. Additionally, ASU 2015-05 was applied prospectively (i.e. was not applied retrospectively to existing systems), as permitted in the transition provisions of the standard, and therefore had no effect on the costs associated with the legacy AVL hosted project.

Since ASU 2015-05 became effective in 2015, there have been two cloud computing solutions, of which approximately $170 thousand of vendor implementation costs is estimated to not meet the capitalization criteria set out in ASU 2015-05. These cloud computing solutions were employee facing applications which were shared with FEI and as such the capital costs were allocated to each of FEI and FBC based on the number of employees per company. FBC is in the process of implementing these two cloud computing solutions during 2018. FBC requested Commission approval for variance from GAAP for regulatory purposes to allow for treatment of the vendor implementation costs consistent with FBC's traditional on-premise software.

However, Accounting Standards Update (ASU) No. 2018-15 *(Subtopic 350-40) Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is A Service Contract,* was recently issued on August 29, 2018. The transitional provisions of ASU No. 2018-15 permit FBC to adopt the new guidance to support capitalization of cloud computing

vendor implementation costs beginning in 2018 in accordance with generally accepted accounting principles.

Due to these recent developments in accounting guidance, FBC expects to capitalize $170 thousand of vendor implementation costs associated with cloud computing solutions within the PBR capital formula, rather than being expensed, during 2018. As such, it is no longer necessary for FBC to request a variance from GAAP, as originally outlined in 12.3.1.2 in Section 12 of the Annual Review for 2019 Rates.

31.1.1 If confirmed, please reconcile this to the statement made on page 110 of the Application, which states: "The proposed approach would avoid a one-year change in capitalization policies and the associated potential volatility in O&M and capital" [emphasis added] given that the current proceeding is to set rates for 2019.

Response:

At the time of filing FBC's Annual Review for 2019 Rates, the outcome of the final ASU 2018-15, including the transitional provisions on when it could be applied, was not certain. If ASU 2018-15 only permitted capitalization of such costs beginning in 2020 on a prospective basis and FBC did not receive regulatory approval to capitalize vendor implementation costs on cloud computing arrangements, such costs would be expected to be expensed pursuant to ASU 2015-05. This would then result in a "one-year change in capitalization policies and the associated potential volatility in O&M and capital" associated with cloud computing vendor implementation costs under ASU 2015-05 until such time that ASU 2018-15, which permitted such capitalization of such costs, became effective. However, ASU 2018-15 was recently issued and finalized on August 29, 2018 and the transitional provisions permit FBC to capitalize cloud computing vendor implementation costs beginning in 2018 in accordance with generally accepted accounting principles.

31.2 Please clarify whether expensing cloud computing implementation costs has been an issue in previous years of the PBR term.

Response:

The regulatory accounting treatment of cloud computing vendor implementation costs has not been an issue during the term of the PBR plan as cloud computing was not a prevalent Information System when the PBR plan was first established. The base capital formula established at the beginning of the PBR term included traditional on-premise software and did not forecast cloud computing solutions with vendor implementation costs. The base O&M formula also did not include any cloud computing implementation costs.

31.2.1 If yes, please explain how FBC addressed the treatment of these costs in the past, and why it is not able to treat this issue in the same manner it has been dealt with in previous years.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.2.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.31.1.

FBC states on page 110 that "The proposed approach keeps FBC's O&M and capital funding envelopes consistent with the 2013 Base O&M and capital amounts for the final year of the PBR term, which were based on the assumption that IS [Information Systems] implementation costs would be capitalized."

31.3 Please provide the amount of IS implementation costs for cloud computing solutions which was assumed in setting FBC's base O&M and capital amounts for the PBR term.

Response:

Please refer to the response to BCUC IR 1.31.2.

31.4 Please provide the actual 2015 to 2017 and projected/forecast 2018 number of cloud computing solutions and total IS implementation costs incurred by FBC (O&M and capital). If any cloud computing services are shared between FBC and FEI, please separately identify these and discuss also the cost allocation methodology.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.5 Please quantify the cloud computing implementation costs that FBC expects to recognize as capital expenditures for 2019 in the event it is approved to vary from US GAAP for 2019.

Response:

At this time, there is only one cloud computing project that is expected to occur in 2019 of which approximately $85 thousand represents vendor implementation costs. There are likely other cloud computing solutions that could be considered during 2019; however, as described in section 12.3.1.2 of the Application, “the form in which the solution is offered, either through traditional on-premise software or through cloud computing, is not known until discussions occur with the external vendor.” Accordingly, the amount of vendor implementation costs for cloud computing solutions in 2019, other than the $85 thousand noted above which will be included in the 2019 formulaic capital expenditures, is not known at this time. As a result of the final ASU 2018-15 being issued on August 29, 2018, the transition provisions permit FBC to capitalize such costs under generally accepted accounting principles.

31.5.1 As part of the above response, please estimate the impact that the change in capitalization policies would have on O&M and capital in 2019 if FBC's request to vary from US Generally Accepted Accounting Principles (GAAP) in 2019 was not approved.

Response:

Please refer to the response to BCUC IR 1.31.5.

On page 109 of the Application, FBC states the following:

> In June 2018, the Financial Accounting Standards Board (FASB) agreed to issue a final ASU in the third quarter of 2018 based on the March 1, 2018 issuance of the *Exposure Draft: Proposed ASU (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is A Service Contract.* The primary consensus reached for the new ASU is that the capitalization of implementation costs incurred for a cloud computing arrangement that is a service contract is consistent with the capitalization of implementation costs incurred to develop or obtain on-premise software and hardware… While the new ASU 350-40 supports the capitalization of initial external vendor cloud computing implementation costs and can be applied retroactively, it is not expected to become effective until [January 1,] 2020.

31.6 Please provide the transitional guidance issued by FASB with respect to retroactive adoption of the new ASU 350-40, and explain whether FBC's proposal for a one-year variance from US GAAP for 2019 is consistent with that guidance.

Response:

The transitional provisions for ASU 2018-15, shown below, permit FBC to capitalize cloud computing vendor implementation costs effective 2018 and onwards.

> **Transition and Open Effective Date Information**
>
> **> Transition Related to Accounting Standards Update No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract***

350-40-65-3 The following represents the transition and effective date information related to Accounting Standards Update No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*:

a. For **public business entities**, the pending content that links to this paragraph shall be effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2019.

b. For all other entities, the pending content that links to this paragraph shall be effective for annual periods beginning after December 15, 2020, and interim periods in annual periods beginning after December 15, 2021.

c. Earlier application of the pending content that links to this paragraph is permitted, including adoption in any interim period for:

    1. Public business entities for periods for which financial statements have not yet been issued

    2. All other entities for periods for which financial statements have not yet been made available for issuance.

d. An entity shall apply the pending content that links to this paragraph using one of the following two methods:

    1. Prospectively to costs for activities performed on or after the date that the entity first applies the pending content that links to this paragraph

    2. Retrospectively in accordance with the guidance on accounting changes in paragraphs 250-10-45-5 through 45-10.

e. A public business entity that elects prospective transition shall disclose the following in the interim and annual periods of adoption:

    1. The nature of and reason for the change in accounting principle

    2. The transition method

    3. A qualitative description of the financial statement line items affected by the change.

f. A public business entity that elects retrospective transition shall disclose the following in the interim and annual periods of adoption:

    1. The nature of and reason for the change in accounting principle

    2. The transition method

    3. A qualitative description of the financial statement line items affected by the change

4. Quantitative information about the effects of the change.

g. All other entities shall disclose the information in (e) or (f) for prospective transition or retrospective transition, respectively, in the annual period of adoption, unless the entity elects to early adopt the pending content that links to this paragraph in an interim period, in which case the entity also shall disclose that information in the interim period of adoption.

31.7 In the event that the FBC proposal for a one-year variance from US GAAP for 2019 for the cloud computing costs is not approved, please provide the impact on the revenue requirement and rates, and forecast O&M and capital spending.

Response:

Please refer to the responses to BCUC IRs 1.31.1 and 1.31.5.

31.8 Please explain how FBC would apply retroactive adoption of the new standard (if at all) under a scenario where: (i) FBC is approved to vary from US GAAP for 2019; and ii) FBC is not approved to vary from US GAAP for 2019. Please quantify the impact of applying ASU 350-40 retroactively in each scenario, both from a cost perspective and a rate impact perspective.

Response:

In addition to the following response, please refer to the response to BCUC IR 1.31.1.

In a hypothetical situation where a finalized ASU 2018-15 was not issued on August 29, 2018, and FBC were approved for its initial request of a variance from USGAAP ASU 2015-05 in order to capitalize cloud computing vendor implementation costs, this treatment would be permitted under USGAAP pursuant to ASC 980 Rate-Regulated Operations. As a result, no retroactive adoption of the new standard would be required.

Conversely, in a hypothetical situation where a finalized ASU 2018-15 was not issued on August 29, 2018, and FBC were not approved for its initial request for a variance USGAAP ASU 2015-05, FBC would expense the vendor implementation costs. If the standard were applied in 2020 with retroactive application, FBC would have to consider whether a retroactive application was feasible or desirable, based on the timing of the standard in relation to FBC's rate filing with the

Commission, the impact, and any other relevant factors at the time. As ASU 2018-15 was, in fact, issued on August 29, 2018, FBC has not sought to quantify the impact of applying ASU 350-40 retroactively in this hypothetical scenario.

31.9 Please discuss the likelihood that ASU 350-40 will come into effect on January 1, 2020.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.9.1 In the event that the new ASU 350-40 does not come into effect on January 1, 2020 or there is a material change between the Exposure Draft and the final new ASU 350-40, how does FBC propose to address this delay or change?

Response:

Please refer to the response to BCUC IR 1.31.1.

31.10 Please confirm, or explain otherwise, that FBC's practice is generally not to request regulatory approval for changes related to proposed accounting or government-related changes (e.g. income tax rates) until the change has been made effective or enacted.

Response:

FBC agrees that it does not generally request approval for income tax rate changes until they have been enacted. Income tax rate changes, and many other legislated changes, have to go through a separate process for implementation after they have been announced, and there can be changes to these announcements before the final enactment. However, FBC may still

discuss treatment options in its filings in advance of the government finalizing changes where there is value to be gained from exploring options with the Commission and interveners.

For proposed accounting changes, the timing of requesting approval will often depend on the timing of applications that FBC is filing, the term that is covered by the application(s), and the implementation options for the accounting changes. Under the current PBR, FBC is required to bring forward accounting changes as part of the annual review process, which provides some opportunity to wait for accounting changes to be finalized before proposing adoption. Certain accounting standards may have transitional provisions that permit the guidance to be applied retroactively or early adopted. Other than the cloud computing accounting guidance, there have not been any recent accounting standards where FBC has intended to early adopt or retrospectively apply for rate setting purposes.

31.10.1 As part of the above response, please provide examples where FBC has requested approval from the BCUC to change its application of accounting standards or government policies in advance of the standard/policy being made effective/enacted the BCUC's decision.

Response:

While FBC has not recently requested such changes in advance, Commission Order G-141-09 approved FEI to prepare its 2010 and 2011 Revenue Requirements based on the International Accounting Standards Board (IASB) Exposure Draft on rate regulated activities, which supported the recognition of regulatory assets and liabilities. This approval was based on an Exposure Draft but prior to the issuance of the final International Financial Reporting Standard for rate regulated activities. If there was a difference between the Exposure Draft and the final standard, FEI was directed to apply to the Commission to seek changes in regulatory treatment. Additionally, Commission Order G-6-04 approved FBC's request for a variance from GAAP to treat the lease obligation for the Brilliant Terminal Station agreement as an operating lease rather than as a capital lease for regulatory purposes.

32.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.1.2, p. 114

Rate Design and Rate for Electric Vehicle Direct Current Fast Charging Service Application

On page 114 of the Application, FBC describes the proposed Electric Vehicle Charging Stations Rate Design and Tariff Application deferral account.

32.1 Please discuss why a short term interest (STI) return, as opposed to weighted average cost of debt (WACD) return, is proposed for the Electric Vehicle Charging Stations Rate Design and Tariff Application deferral account.

Response:

FBC should have requested a WACD rate of return. Since the deferral account is not being amortized at this time, a WACD rate of return is consistent with the treatment of FBC's other multi-year deferral accounts. FBC will reflect this change in Schedules 12 and 12.1 in its Evidentiary Update.

32.2 Please provide a breakdown of the forecast $0.060 million additions to the above-noted deferral account between cost which have been incurred to-date and expected future costs when the proceeding resumes.

Response:

FBC's current forecast of the costs for this application is provided below. At this time FBC does not know the scope of the regulatory review of this application, which was adjourned pending the conclusion of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service, and has assumed that the scope will be limited.

	Spent	Forecast	Total
		($ millions)	
Commission and Intervener Costs	-	$ 0.040	$ 0.040
Legal Fees	0.015	0.005	0.020
Consulting Fees	-	-	-
Other External Costs	-	-	-
	$ 0.015	$ 0.045	$ 0.060

32.2.1 Please confirm, or explain otherwise, whether the after-tax forecast additions to the above-noted deferral account are intended to be $0.044 million as opposed to $0.44 million as shown on page 114 of the Application.

Response:

Confirmed. The after-tax amount is $0.044 million.

33.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.1.3, p. 114

BC Hydro Waneta 2017 Transaction

On page 114 of the Application, FBC describes the proposed BC Hydro Waneta 2017 Transaction deferral account and states that it incurred external legal costs of $0.124 million for its participation in this proceeding. FBC seeks "approval of a deferral account attracting a STI return to capture the costs of participation and proposes to amortize the costs over one year, in 2019."

33.1 Please explain the purpose of FBC's participation in the BC Hydro Waneta 2017 Transaction proceeding.

Response:

FBC participated in the BC Hydro Waneta 2017 Transaction proceeding in order to ensure that the interests of FBC's customers were considered during the proceeding.

As explained in FBC's Final Argument,[4] FBC believes that since FBC is a direct customer of BC Hydro that FBC ratepayers will participate in the benefits that BC Hydro is expected to realize from the Waneta 2017 Transaction.

In addition, given the changes to the system that FBC shares with Teck, there were several technical matters that required discussion and agreement that were relevant to the proceedings. These resulted in letter agreements with both Teck[5] and BC Hydro[6]. As submitted in FBC's Final Argument, these letter agreements provide stability and certainty in terms of FBC's access to Line 71 during the term of the Lease. Line 71 is used to purchase cost effective market power. Ensuring continued access to Line 71 during the term of the Lease was therefore important to ensure FBC continues to have access to market resources.

33.2 Please discuss whether FBC considered making an application for Participant Assistance/Cost Awards (PACA) for its participation in the BC Hydro Waneta 2017 Transaction, and if so, why an application for PACA was not chosen in favour of FBC's current proposal.

4 http://www.bcuc.com/Documents/Arguments/2018/DOC_51599_05-17-2018-FBC-FinalArgument.pdf.
5 http://www.bcuc.com/Documents/Proceedings/2018/DOC_50817_C1-10_FBC-Teck-Agreement-Executed.pdf.
6 http://www.bcuc.com/Documents/Proceedings/2018/DOC_50819_B-17_BCH_FBC_Agreement.pdf.

Response:

FBC did not consider making a PACA application for its participation in the BC Hydro Waneta proceeding. The PACA Guidelines in effect prior to August 31, 2016, had the provision that, except in limited circumstances, eligibility for PACA was limited to "ratepayer" groups. That provision established the historical practice of utilities being expected to fund their active participation in other utilities' proceedings as part of their cost of service being recovered from their own ratepayers. The current PACA Guidelines[7] no longer include this eligibility provision; however, FBC and the other FortisBC utilities[8] (the FBCU) continue to observe this long-standing principle and practice. The FBCU have never made a PACA claim against BC Hydro or any other utility (irrespective of utility size) for costs related to interventions into other utility proceedings. When the FBCU actively intervene in other utility processes, it is because of a direct interest in an issue or issues which have the potential to impact the operation of the utility and the utility's respective customers/ratepayers. FBC is of the understanding that each utility is to fund its own interventions on behalf of its customers. As such, FBC believed it was not appropriate to make a PACA application under these circumstances.

33.3 Please discuss why an amortization period of one year is appropriate for the BC Hydro Waneta 2017 Transaction deferral account.

Response:

When determining an amortization period for deferral accounts, FBC takes into account the relationship between the recovery period and the benefits of the expenditure, the impact on rate stability, and the goal of disposing of the deferral account expeditiously. As identified in the response to BCUC IR 1.33.1, there are ongoing benefits to FBC's participation in this proceeding; however, given the size of the deferral account, matching the amortization to the benefit period would result in small annual amounts. FBC therefore believes that it is more reasonable to fully amortize the account in one year.

[7] Approved by Order G-97-17 dated June 15, 2017.
[8] FortisBC Energy Inc. and FortisBC Alternative Energy Inc.

34.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.1, pp. 114–115

2018-2019 Revenue Surplus deferral account

On page 115 of the Application, FBC seeks approval to "add the forecast 2019 revenue surplus to the 2018 Revenue Deficiency [deferral] account and rename the account the 2018-2019 Revenue Surplus account."

34.1 In the event that the request is not approved, please provide the impact on 2019 rates (i.e. if the 2018 revenue deficiency was amortized in 2019 rates and the 2019 projected revenue surplus was recorded in separate deferral account for disposition in a future year).

Response:

Amortizing the 2018 revenue deficiency in 2019 would result in a rate increase of 0.24 percent for 2019.

35.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.2, pp. 111, 115

2019-2022 DSM Expenditures application

On page 115 of the Application, FBC states that it proposes to amortize the 2019-2022 DSM Expenditures application deferral account over "a four-year period beginning in 2019 which is the term to be covered by the expenditure schedule."

On page 111 of the Application, FBC explains that the proposed term of each regulatory proceeding cost deferral account "encompasses the preparation and filing of the relevant regulatory application and its review by the Commission."

35.1 Please reconcile the difference between the two statements noted in the preamble above. As part of the response, please provide FBC's rationale for why a four-year amortization period which is based on the term to be covered by the expenditure schedule is appropriate as opposed to another amortization period which is based on the preparation and filing of the 2019-2022 DSM Expenditures Application (as stated on page 111 of the Application).

Response:

The statement on page 115 refers to the four-year period to which the 2019-2022 DSM Expenditure Schedule will apply and to the proposed amortization period. The statement on page 111 refers to the period for which the deferral accounts themselves are approved for (the period of time during which FBC expects to add costs to the deferral accounts), which includes both the application preparation time and the application review time.

Regarding the second question and given the clarification provided above, it would not be appropriate to amortize a deferral account over the period of time that there are costs being incurred: first because FBC does not know the balance in the deferral account at that time, and second because there is no link between the time period an application is being developed over (which can span years prior to filing) and the benefits associated with that time period. FBC believes there should be a causal relationship between the recovery period and the benefits associated with the expenditure, and that it is generally most reasonable, and is accepted regulatory practice, for the recovery term of regulatory application cost deferral accounts to align with the term over which the decisions apply. This is consistent with the principle that the amortization period for a deferral account should consider the timing of associated benefits.

36.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.3, pp. 111, 115–116; FBC Annual Review for 2016 Rates (2016 Annual Review), Exhibit B-1, p. 104

2017 Cost of Service Analysis (COSA) and Rate Design Application (RDA)

On page 115 of the Application, FBC states that Order G-202-15 (relating to the 2016 Annual Review) approved the creation of a deferral account to capture the external costs for the preparation and review of its COSA/RDA. The expected cost of that proceeding is $1.520 million ($1.110 million after tax) which FBC proposes to amortize over a five-year period beginning in 2019, stating "this amortization period is consistent with that generally used for rate design applications by FBC and consistent with the anticipated time between filing a COSA and RDA.

On page 104 of the 2016 Annual Review application, FBC stated that it expects the balance in the 2017 RDA deferral account to range between $0.600 and $0.700 million.

36.1 Please explain in detail the causes/factors which resulted in FBC revising the estimated balance in the 2017 RDA deferral account to be $0.920 million to $0.820 million higher than what was projected in the 2016 Annual Review application.

Response:

FBC does not have a breakdown of the components of the initial 2016 forecast of proceeding costs.

When reviewing the forecast in preparation for its Annual Review for 2018 Rates, FBC considered that the original forecast should be revised in light of the actuals incurred in the review of its last RDA, and increased the forecast to $1.9 million (pre-tax). At this time, FBC is reducing the forecast RDA proceeding costs to $1.120 million, based on lower expert consulting and legal expenses incurred to date. This revision is included in the Evidentiary Update filed on September 25, 2018.

The table below shows the actual costs of the 2009 RDA review compared to the forecast costs of the 2017 RDA as presented in the Annual Review for 2018 Rates and as currently forecast.

	2009 RDA Actual	2017 RDA Forecast	
		2018 AR	2019 AR
	($ millions)		
Commission and Intervener Costs	$ 0.562	$ 0.600	$ 0.600
Legal Fees	0.579	0.500	0.200
Consulting Fees	0.768	0.750	0.300
Other External Costs	0.042	0.050	0.020
	$ 1.951	$ 1.900	$ 1.120

FBC has based this current estimate on the expectation of the COSA/RDA proceeding being concluded by way of a written hearing but notes that the process for completion of the proceeding has not yet been determined. The proceeding still includes the potential for an oral hearing component, which is not accounted for in this estimate.

36.2 Please provide a breakdown of the $1.520 million in expected costs related to the 2017 COSA/RDA by cost category.

Response:

Please refer to the response to BCUC IR 1.36.1.

On page 111 of the Application, FBC explains that the proposed term of each regulatory proceeding cost deferral account "encompasses the preparation and filing of the relevant regulatory application and its review by the Commission."

36.3 Please provide FBC's rationale for why a five-year amortization period based on the anticipated time between filing a COSA and RDA is appropriate as opposed to another amortization period which is based on the preparation and filing of the 2017 COSA and RDA (as stated on page 111 of the Application).

Response:

Please refer to the response to BCUC IR 1.35.1.

37.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.5, p. 117–119

Flow-through deferral account

On page 117 of the Application, FBC states "it has also included an adjustment for the difference between the projected ending 2017 deferral account credit balance of $7.102 million embedded in 2018 rates and the actual ending 2017 deferral account credit balance of $9.356 million, a credit difference of $2.254 million." This is shown on line 30 of Table 12-4 on page 118 of the Application.

On page 119 of the Application, FBC states that the true-up of $2.254 million is "primarily the net result of higher sales revenue net of power purchase expense due to weather-related increases in load, in addition to higher savings on market purchases of power."

37.1 Please provide a table in the same format as Table 12-4, to show the breakdown of the projected ending 2017 deferral account balance of $7.102 million and actual ending 2017 deferral account balance of $9.356 million in order to explain true-up amount of $(2.254) million.

Response:

The true-up amount to the 2017 Flow-through deferral account additions is detailed in the table below.

Line No.	Description	Approved	Actual	Variance	Projected Variance	Change in Variance
1	Revenue	$ (362.128)	$ (364.854)	$ (2.726)	$ 1.736	$ (4.462)
2						
3	Power Purchase Expense	136.216	133.214	(3.002)	(5.779)	2.777
4						
5	Wheeling	4.928	5.124	0.196	0.089	0.107
6						
7	Water Fees	10.328	10.316	(0.012)	0.001	(0.013)
8						
9	O&M Tracked Outside of Formula					
10	Insurance Premiums	1.327	1.268	(0.059)	(0.060)	0.001
11	Advanced Metering Infrastructure Project	(1.126)	(1.246)	(0.120)	-	(0.120)
12	Mandatory Reliability Standards Incremental O&M	0.050	0.053	0.003	-	0.003
13	Upper Bonnington Unit 3 Annual Inspection	(0.040)	(0.040)	-	-	-
14						
15	Property Tax	16.052	15.723	(0.329)	(0.164)	(0.165)
16						
17	Depreciation and Amortization	55.657	55.618	(0.039)	0.062	(0.101)
18						
19	Other Revenue	(8.056)	(9.724)	(1.668)	(0.924)	(0.744)
20						
21	Interest Expense	40.191	38.127	(2.064)	(1.739)	(0.325)
22						
23	Income Tax	10.849	12.201	1.352	1.455	(0.103)
24						
25	Working Capital Adjustment for AMI - booked in 2018		-		(0.006)	0.006
26						
27	Duplication of 2016 Flow-Through True-Up				(0.886)	0.886
28						
29	2018 After-Tax Flow-Through Addition to Deferral Account			(8.470)	(6.215)	(2.254)

37.1.1 Please provide an explanation for any significant variances identified in the table provided in response to IR No. 37.1 above.

Response:

The variance in revenue between the projected ending 2017 Flow-Through deferral account balance embedded in 2018 rates and the actual ending 2017 deferral account balance is primarily the net result of higher sales revenue net of power purchase expense due to weather-related increases in load, in addition to higher savings on market purchases of power.

The increase in Other Revenue is due to higher than forecast pole attachment revenue as a result of issuing final invoices in the last half of the year, higher connection charges resulting from customer growth, and higher than forecast other recoveries from construction work for a third party.

Interest expense was lower than projected mainly due to the later than projected issuance of $75 million in long term debt.

FBC inadvertently duplicated the true-up of the 2016 Flow-through account in the deferred charges schedule for 2018 rates[9] and is correcting this error through the true-up of the 2017 Flow-through account, at Line 27 in the table in response to BCUC IR 1.37.1.

[9] In its response to BCUC IR 1.23.1 in Annual Review for 2018 rates, Line 5 of Schedule 12 showed 2017 gross additions to the Flow-through deferral account of $(6.215) million, which was comprised of the projected 2017 Flow-through amount of $(5.329) million plus the 2016 Flow-through true-up of $(0.886) million (Table 12-5 in the Annual Review for 2018 Rates). The addition of the 2016 true-up to the deferral account for rate setting was an error, because the opening balance of the account was based on year-end actuals as filed in FBC's 2016 Annual Report to the BCUC, and already included the true-up amount of $(0.886) million.

I. SERVICE QUALITY INDICATORS

38.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Application, Section 13.2.1, p. 123

All Injury Frequency Rate (AIFR)

On page 123 of the Application, FBC provides information related to the AIFR for 2017 and 2018 year-to-date (YTD) and states;

> The June 30, 2018 YTD AIFR is 2.56. As of June 30, 2018, there were 2 Medical Treatment and 4 Lost Time injuries. Four of these six events occurred in January. If the recent improving trend in performance continues, FBC expects the 2018 AIFR to improve over the course of the year.

38.1 Please provide further information regarding the four safety events which occurred in January. How were these safety events related in terms of work site or scope of work and what actions has FBC undertaken to mitigate similar safety risks in the future?

Response:

Three of the four January safety events occurred during work activities as a result of sudden inclement weather conditions with significant snow fall. Please refer to the table below.

Date	Location	Occupancy	Affiliation	Injury's nature	Preventive/ Corrective actions
1/5/2018	Trail	Customer Service Representative	MoveUP	Overexertion	• Increase work observations and promote regular MoveSafe warm up and stretching breaks. • Employee was advised to immediately seek First Aid • Discuss importance of stretching/ warm up exercises as a part of MoveSafe Program Request OHS department to deliver a presentation focusing on Ergonomic Hazard in Office environment to increase awareness
1/18/2018	South Interior	Crew Leader (PLT)	IBEW	Overexertion	• Discussion about self-awareness, limitations, rushing and communication to form part of the SSWP documentation prior to beginning work. Supervisor to follow-up with crew observations • SSWP group exercise to enhance the employee's ability to identify hazards associated with particular tasks. Review the identified hazards to verify consistency. • Consider the use of snow shoes if the conditions are appropriate for the work to be completed. • Consider the use of the side by side with tracks to pack down a trail.
1/10/2018	Kootenay	Customer Service Person	IBEW	Fall	*Review with Meter department on how update location details and warnings on spreadsheet. Eliminate old codes from CIS. *Ensure updates on new potential hazards are being documented on Meter Reader Spreadsheet and entered into SSWP. Supervisor to follow up on future Crew Visits. *Lessons Learned: Diccussion and review
1/8/2018	Kelowna	Power Line Technician	IBEW	Repetitive motions	• Lessons learned: discussion with employee physical limitations and importance of Warm up performs stretches before doing any physical task to help prevent MSI.• PLT discusses the use of pin finder to reduce the amount of shoveling required to locate hidden facilities underneath the snow. PLT to demonstrate.

38.2 Please explain why FBC expects the 2018 AIFR to improve over the course of the year (e.g. actions undertaken to improve safety, other). Please also discuss FBC's expectations as it relates to achieving the three-year rolling benchmark for the AIFR in 2018.

Response:

FBC continues to emphasize continual improvement in injury and incident reduction through employee engagement with the Occupational Health and Safety team spending additional time in the field with crews, engaging them in safety best practice conversations and at the same time recognizing and sharing proactive safety messages.

The YTD 2018 AIFR has improved since June with August 31 at 1.96 compared to the June 30 results at 2.56, resulting in a three year rolling average of 1.41, which is better than the

1 benchmark. If the recent improving trend in performance continues, FBC expects the 2018
2 AIFR to improve over the remainder of the year.

3

39.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Application, Section 13.2.2, p. 129

Telephone abandon rate

On page 129 of the Application, FBC provides Table 13.10 showing historical telephone abandon rates:

Table 13-10: Historical Telephone Abandon Rates

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	2.2%	1.9%	1.7%	1.9%	2.0%	12.4%	2.7%	3.9%	4.7%	5.0%
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

FBC states that it "attributes the increase in the abandon rate in recent years to an increase in customers using the self-serving option through the interactive voice response messages during power outages."

39.1 Please provide support for why FBC attributes the increase in the telephone abandon rate in recent years to customers using the self-serving option through the interactive voice response messages during power outages (e.g. data on self-serving options selected, telephone abandon rates during/after power outages, calls received during/after power outages, etc.).

Response:

FBC is not able to determine with certainty the reasons that a customer abandons a specific call. The abandon rate can vary depending on the frequency and nature of large outages often caused by storms. The increase may also reflect an increase in customers self-serving through the interactive voice response (IVR) messages during power outages and/or an increase in customer-related abandons (hanging up prior to entering a queue). The Abandon Rate would be expected to increase during outage periods to the extent that IVR messages provide the customer with the information about the outage that they are looking for.

As shown in the response to CEC IR 1.32.1, because the average speed of answer has remained relatively consistent and the Telephone Service Factor benchmarks have been met, FBC believes that it is reasonable to largely attribute the increase in Abandon Rate over this period to the use of IVR messages during outages.

39.2 Other than customers using the self-serving option through the interactive voice response messages during power outage, please provide other factors (if any) which may explain the increase in telephone abandon rates since 2015.

Response:

Please refer to the response to BCUC IR 1.39.1.

40.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Application, Section 13.2.3, pp. 121, 130–133

System Average Interruption Duration Index (SAIDI) – Normalized

On page 120 of the Application, FBC states that both 2017 and 2018 year-to-date SAIDI results performed poorer than the threshold, primarily due to the implementation of the OMS, which automated the tracking of outage data. Further, FBC states "the 2017 SAIDI results were impacted by wildfires. Specifically, wildfires in the Princeton and Joe Rich areas of the Okanagan accounted for approximately 78,000 customer hours or 15 percent of the annual SAIDI." For 2018, in addition to the OMS, FBC states the main contributor for higher SAIDI was the reliability of the transmission system due to adverse weather related outages/large snow fall events. Additionally, FBC states "On January 17, [2018] a forestry worker near a transmission line right of way caused an outage that resulted in 27,000 customer hours."

FBC shows the 2009 to 2017 and 2018 year-to-date results in Table 13-11 on page 131 of the Application, as copied below:

Table 13-11: Historical SAIDI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Three year rolling average results	2.40	2.51	2.33	2.22	1.94	2.09	2.15	2.18	2.76	3.26
Benchmark	n/a	n/a	n/a	n/a	n/a	2.22	2.22	2.22	2.22	2.22
Threshold	n/a	n/a	n/a	n/a	n/a	2.62	2.62	2.62	2.62	2.62

Further, on pages 130 and 131 of the Application, FBC states:

> With the change to the OMS and a different definition to the Outage Start Time, the reported outage times have increased, causing the SAIDI values reported to increase, even though there has been no change in the company's operating practices. FBC estimates the increase in reported values for SAIDI as the result of the OMS to be in the 15 to 30 percent range, consistent with other utilities' experience who has replaced their manual systems with an OMS. As recorded on page 7 of the November 21, 2014 minutes for the SQI [Service Quality Indicator] Workshop, FBC stated that "with AMI [Advanced Metering Infrastructure], the company many need to assess the impact on the SAIDI measure as the company would be notified of outages earlier than previously. [Emphasis added]

FBC also states on page 131, "If SAIDI were normalized for the estimated impact of the OMS, FBC's three-year rolling average SAID results for 2017 would be better than the threshold."

40.1 Please clarify when (i.e. month/year) FBC implemented the OMS.

Response:

The OMS was implemented in January of 2017.

40.2 Please provide SAIDI results for 2017 annual and 2018 year-to-date, which have been normalized for the estimated impact of the OMS, and compare to the benchmark and threshold.

Response:

Reliability results, including SAIDI, are impacted by both the transmission and distribution system reliability. The ADMS project has only impacted the accuracy of the distribution system reporting. From a transmission reliability reporting perspective, FBC's processes have not changed with the introduction of the OMS.

In 2017, both the Transmission and Distribution SAIDI values were considerably higher than in 2015 and 2016 due to an increase in adverse weather, foreign interference (e.g. vehicle accidents), and the impact of forest fires, all of which are outside the control of FBC, in addition to the impact of OMS.

Since OMS was only implemented twenty months ago and during a year impacted by increased weather-related outages, the exact impact on SAIDI cannot be quantified. One area where the OMS likely had a significant impact is in the identification of and accounting for major adverse weather-related outages. Prior to OMS, FBC relied on individual customers to notify the utility of a power outage. During these widespread events impacting both the transmission and distribution systems, call handling and field resources could quickly become backlogged. This led to challenges in fully understanding the scope and scale of system damage and the extent of all the outages on the system. Given the limitations of the previous systems, it would take significantly longer to fully and accurately account for all outages.

Other utilities implementing an ADMS have experienced an impact to SAIDI of approximately 15 percent to 30 percent. FBC does not have any reason to believe that its own experience would fall outside of this range.

40.2.1 Does FBC consider that its SAIDI performance should be assessed on a normalized basis? Please explain why or why not.

Response:

FBC is not proposing that SAIDI performance should be normalized for the effect of OMS as it is difficult to assess what the exact impact has been with a high degree of accuracy. Instead, FBC is explaining why SAIDI performance is higher than the threshold and that the SAIDI performance is appropriate given the circumstances and should not be considered a degradation of service quality.

40.3 Please discuss how the implementation of the OMS and AMI impacts FBC's ability to set a future SAIDI measure.

Response:

FBC does not anticipate any issues in setting a benchmark for SAIDI in the future as part of the next PBR Plan.

For example, with the start of the next PBR Plan expected to be 2020, FBC will have three full years of SAIDI results available (i.e. 2017, 2018 and 2019) incorporating the impact of the OMS. Similar to the current three-year average methodology used today, the proposed benchmark could then be based on the average of the 2017, 2018 and 2019 results.

40.4 Please provide a summary discussion of the causes, if known, of the wildfires in 2017. Specifically, please indicate the number of wildfires caused by (or potentially caused by) downed power lines, if this information is available.

Response:

The Princeton and Joe Rich fires were both believed to have been caused by lightning.

40.5 Please discuss whether wildfires in 2018 are expected to impact 2018 annual SAIDI performance.

Response:

Currently, the 2018 wildfires have not had a significant impact on SAIDI performance. There have been short outages required on both the transmission and distribution system required to support firefighting efforts. The impact to FBC infrastructure has been minimal due to these fires.

40.5.1 If possible, please provide updated 2018 year-to-date SAIDI results at the time of filing this IR response.

Response:

The 2018 YTD SAIDI result as of the end of August is 2.50.

40.6 Please provide the historical number of snowfall events and snowfall-related outages experienced from 2015 to 2018 year-to-date.

Response:

FBC is not able to specifically report on all snowfall related events as the outages are commonly coded to other factors. For example, during a heavy snowstorm there may be widespread outages due to trees contacting power lines from snow loading. This event would be classified as a tree contact in the outage database.

However, FBC can confirm that snow events have been the cause of four major events that qualified for normalization since 2015.

40.7 Given the January 17, 2018 incident, please discuss the measures (if any) which FBC has taken to mitigate similar future events.

Response:

WorkSafe BC has procedures in place to ensure the safety of workers near energized power lines (OHS Regulations Part 19). Had these procedures been followed, it is likely that this event could have been avoided. While FBC does not have direct authority over these third parties, it participated in the event investigation which was led by WorkSafe BC. FBC is not aware of what, if any, corrective measures followed this investigation.

FBC states on page 131 of the Application that 2017 annual SAIDI performance was 4.05.

40.8 Please add an additional row to Table 13-11 on page 131 of the Application, showing FBC's annual historical and 2018 year-to-date SAIDI results.

Response:

The requested version of Table 13-11 is provided below.

Historical SAIDI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	August 2018 YTD
Three year rolling average results	2.40	2.51	2.33	2.22	1.94	2.09	2.15	2.18	2.76	3.13
Annual result	2.28	2.84	1.86	2.00	2.01	2.32	2.13	2.10	4.05	3.24
Benchmark	n/a	n/a	n/a	n/a	n/a	2.22	2.22	2.22	2.22	2.22
Threshold	n/a	n/a	n/a	n/a	n/a	2.62	2.62	2.62	2.62	2.62

41.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Application, Section 13.2.3, p. 132

Generator Forced Outage Rate (GFOR)

On page 132 of the Application, FBC states

> The 2017 result for GFOR was 0.6 percent and is mainly attributable to equipment failures at Upper Bonnington and Corra Linn plants. The failures included UBO Unit 1 outages caused by governor issues in April and an oil leak in June and an outage on COR Unit 3 on November 17th caused by a Potential Transformer failure.

41.1 Please provide a table explaining the origin/cause, cost and mitigating solutions undertaken by FBC to address the equipment failures (e.g. governor failure, oil leak and potential transformer failures) at Upper Bonnington and Corra Linn plants.

Response:

The table below explains the origin/cause, cost and mitigating solutions undertaken by FBC to address the equipment failures reported on Exhibit B-2, Application, Section 13.2.3, p. 132.

Plant/Unit	Failure Description	Date of failure	Cause of failure	Cost of failure	Mitigation solutions
UBO/Unit 1	Governor mechanical failure	April 3, 2017	Failure of the Unit 1 governor due to normal wear and tear due to its age	$21,666	Governor was temporary repaired with spare parts from the Unit 3 governor, which was replaced in 2017 as part of the UBO Refurbishment project. The Governor on Unit 1 will be replaced in 2019.
UBO/Unit 1	An oil spill was detected on Unit 1 upper guide bearing and the Unit was shut down to contain the oil spill	June 26, 2017	The oil spill was due to the deficient design of the original installation.	-	The guide bearing oil system on all units will be upgraded as part of the UBO Refurbishment project and will be including a system that will alarm when the oil levels could cause an oil spill. The Unit 1 system will be upgraded in 2019.
COR/Unit 3	Potential transformer failure caused Unit 3 protection to trip Unit 3	November 17, 2017	The design of the potential transformer did not include protection against ferro - resonance. When Unit 3 was taken offline, a small instability resulted in a ferro - resonance condition in the bus leading to overvoltage and protection operation.	$26,891	A damping resistor and a dual secondary potential transformer will be installed in 2019 to avoid trips due to ferro-resonance conditions.

41.2 Please clarify whether the costs form part of FBC's formula O&M expenditures, regular capital expenditures, or CPCN capital expenditures for the Upper Bonnington Old Units Refurbishment (UBO)/Corra Linn Dam Spillway Gate Replacement projects.

Response:

The costs to address the failures were part of FBC's formula O&M expenditures and regular capital expenditures.

J. UPPER BONNINGTON OLD UNITS REFURBISHMENT PROJECT STATUS REPORT

42.0 Reference: UPPER BONNINGTON OLD UNITS REFURBISHMENT PROJECT
Exhibit B-2, Application, Appendix C, pp. 4, 9, 14, 20
Project contingency

On page 20 of Appendix C of the Application, FBC provides Table C-2 which shows the Upper Bonnington Refurbishment project expenditures to June 30, 2018 and the forecast project expenditures to completion.

42.1 Please confirm, or explain otherwise, that there is a mathematical error in the "Spent to Date" column as it relates to the calculation of the total project cost.

Response:

Confirmed. An updated table is provided in response to BCUC IR 1.42.1.1. FBC has also provided the corrected table in the Errata filed concurrently with these IR responses.

42.1.1 If confirmed, please provide a revised Table C-2 with corrected total project cost amounts for all columns.

Response:

A revised Table C-2 has been provided below. FBC has also provided the corrected table in the Errata filed concurrently with these IR responses.

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)
	($000s)				(%)	
Unit 3	4,079	6,128	86	6,214	52%	150%
Unit 4	6,634	5,027	2,393	7,419	12%	76%
Unit 1	8,050	668	6,805	7,473	-7%	8%
Unit 2	5,641	438	5,035	5,473	-3%	8%
Common	860	397	342	739	-14%	46%
Subtotal - Construction	**25,264**	**12,657**	**14,660**	**27,318**	**8%**	**50%**
Cost of Removal	1,880	826	670	1,496	-20%	44%
Project Contingency	3,771	(see Note 1)	1,781	1,781	-53%	0%
Subtotal-Construction	**30,916**	**13,483**	**17,112**	**30,585**	**-1%**	**44%**

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
& Removal						
AFUDC	867	314	874	1,188	37%	36%
Total Project Cost	**31,783**	**13,797**	**17,986**	**31,783**	**0%**	**43%**

Note: (1) Approximately $1.99 million of contingency has been allocated to Units 3, 4 and 1. This is reflected in the "Spent to Date" column for Units 3 and 4, and in the "Estimate to Complete" column for Unit 1 as described in the response to BCUC IR 1.43.2.

In the "Variance Explanations" column in Table C-2, FBC states "(the project c contingency has been reduced by $2.0 million to reflect significant proportion of engineering/procurement/construction complete)."

42.2 Please explain how FBC determined that reducing the project contingency by $2.0 million is appropriate at this time, with reference to the remaining scope of work, cost and mitigated risks of the Upper Bonnington Refurbishment project. Please include a breakdown of the $2.0 million reduced project contingency by contributing factors, if possible.

Response:

Contingency of approximately $2.0 million was re-allocated to other project line items to largely account for the following risks that materialized:

- Higher than anticipated generator rewind costs ($1.3 million); and
- Unforeseen turbine runner seal repairs for Unit 4 ($0.25 million).

The remainder (approximately $0.45 million) was used to address other risks that materialized, such as:

- the new high pressure governor system – the installation and commissioning of the new high pressure governor system required additional effort driven by the interfacing of modern equipment with an antiquated design;
- the new braking system – additional effort was required to confirm the feasibility of the new braking system installation;
- the new trash racks – the as-found condition of the trash rack support beams was worse than anticipated and replacement was required; and

- the generator rewind – the generator rewind scope of work was increased to account for the replacement of the pole to pole connectors and for the refurbishment of the rotor fans, which was required due to worse than anticipated as-found condition of these components.

Other cost pressures resulting from risks that materialized were offset by savings elsewhere.

Referencing Table C-2 Cost Summary, the Estimate to Complete for New Construction and Cost of Removal is approximately $15.330 million. The remaining contingency ($1.781 million) therefore represents a contingency of approximately 11.6 percent on future spend. The contingency is approximately 14.4 percent as a percentage of future spend if existing commitments (approximately $3.0 million) are removed.

FBC believes the contingency remaining is appropriate given the significant amount of engineering, procurement and construction that has been completed. The remaining project risks are largely related to the unknown condition of the mechanical components for Units 1 and 2.

On page 4 of Appendix C of the Application, FBC states "One exception is the generator stator and rotor rewind contract which is approximately $1.3 million over the estimate cost. This is partially offset by reduction in contingency and removal costs."

On page 9, FBC states "[it] encountered some challenges throughout construction related to as-found conditions being worse than anticipated… The impact of these challenges were offset by savings elsewhere or were absorbed using contingency."

Finally, on page 14, FBC states "The repair for the seals for Unit 4 is approximately $250,000 over the estimated cost. This additional cost is offset by reductions in contingency."

42.3 Please clarify and explain why the amount in the project contingency "Spent to Date" column in Table C-2 is zero. For clarity, please explain how each of the additional costs noted in the preamble above are reflected in Table C-2.

Please discuss what actions FBC has undertaken to mitigate future budget variances.

Response:

The "Spent to Date" column for contingency in Table C-2 is zero as contingency used to offset the financial impact of materialized risks is reflected in the "Spent to Date" column and the "Estimate to Complete" for Units 3, 4, 1 and 2.

Once a risk materializes, "Contingency" is used to offset the financial impact. The financial impact will be reflected in either the "Spent to Date" column or the "Estimate to Complete" column, depending on whether the item is completed, for the respective unit impacted by the materialized risk. For example, as discussed in the Application[10], the agreement for the stator and rotor rewind was approximately $1.3 million over budget, which is approximately $0.44 million per unit. Contingency of $1.3 million was, therefore, allocated to the line items driving the variance. The $0.44 million variance for the Unit 3 rewind and the $0.44 million variance for the Unit 4 rewind is reflected in the Unit 3 and Unit 4 "Spent to Date" columns, respectively, since these items have been completed. The $0.44 million variance for the Unit 1 rewind is reflected in the Unit 1 "Estimate to Complete" column, since the Unit 1 rewind is scheduled for 2019 and has not yet occurred.

If FBC were to include this $0.44 million variance for Unit 1 rewind under the "Contingency – Spent to Date", it would increase the "Total Project Cost – Spent to Date" value. This would be misleading since the funds have not yet been spent. In this case, it is more accurate to show the variance under the "Estimate to Complete" column. It would also be misleading if FBC were to include the $0.44 million variance for Unit 1 rewind under "Contingency – Estimate to Complete". The remaining project contingency is meant to address risks that have not yet materialized. In this particular case, the $0.44 million variance for Unit 1 rewind is already certain. Including the $0.44 million variance for Unit 1 in "Contingency – Estimate to Complete" would therefore overstate the remaining contingency and would not distinguish between contingency remaining for risks that have yet to materialize and contingency committed for risks that have materialized.

In short, where contingency has been used to offset the financial impact of materialized risks, the financial impact is embedded in the "Spent to Date" column or the "Estimate to Complete" column for the respective units impacted. This avoids overstating "Total Project Cost – Spent to Date" and avoids overstating the remaining project contingency. As stated in the Application[11], FBC continues to make efforts to reduce the risk profile of the project through the use of lump sum contracts and the use of condition assessments, where possible. To date, FBC has completed a significant amount of procurement for the project which mitigates future budget variances.

Additionally, lessons learned throughout unit dismantle, construction, reassembly and commissioning are applied to future units which will result in efficiencies moving forward. For

[10] Appendix C, Section 3, Page 21, Lines 2-3.
[11] Appendix C, Section 4, Pages 22 to 23.

example, as discussed in the Application[12], FBC had difficulty interfacing the new high pressure governor system with the units antiquated design. While this resulted in a greater level of effort than anticipated, these learnings have since been applied to Units 4, 1 and 2.

With respect to the mechanical components for Units 1 and 2, due to the unit design, it is not possible to assess the condition of mechanical components prior to dismantling and therefore it is not possible to say prior to dismantling which components can be refurbished and which components require replacement. Nonetheless, FBC continues to evaluate its vendors for the machining and fabrication work to ensure the vendors are cost competitive and continues to work collaboratively with these machine shops to reduce the potential for cost and schedule impacts.

[12] Appendix C, Section 3, Page 21, Lines 9 to 11.

K. RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

43.0 Reference: RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT
Exhibit B-2, Application, Appendix D, Section 1.4.3, p. 4
Emergency flood response

On page 4 of Appendix D of the Application, FBC states that additional emergency flood response from flooding in May 2018 resulted in approximately $70 thousand of additional costs to the project, but no significant schedule delays.

43.1 Please explain why it is appropriate to consider the additional emergency flood response in May 2018 as a cost of the Ruckles Substation Rebuild project. Would it be appropriate to record the $70 thousand of costs as O&M? Please explain why or why not.

Response:

The original forecast amount for the flood response was $70 thousand. The actual mitigation cost that was incurred was $30 thousand. Replacement of lost construction material, fence repairs, and other small costs were incurred due to the flood. Given the nature of the costs, their materiality, and that they were incurred directly in support of the construction of a capital asset, it is appropriate that they be included in the capital cost of the project.

44.0 Reference: RUCKLES SUBSTATION REBUILD PROJECT

Exhibit B-2, Application, Appendix D, Section 2.3, 3 and 4, pp. 10, 12

Project contingency

On page 12 of Appendix D of the Application, FBC provides an update of the Ruckles Substation Rebuild project contingency budget:

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percent Budget Spent	Variance Explanation
Project Contingency	805	0	314	314	-61%	0%	Identified potential risks did not materialize

FBC further states on page 12 of Appendix D that the remaining project risks relate to schedule, cost and environment.

44.1 Please explain what the "identified potential risks [that did] not materialize" are and the associated cost which reduced the project contingency budget from $805,000 to $314,000.

Response:

Contingency was originally calculated each month based on the forecast expenditures. Contingency was then released once it was determined that additional scope or unforeseen material or labour would not be required. This resulted in the release of $0.311 million. The major risks that did not transpire resulted in an additional release of $0.180 thousand of contingency.

The identified major risks that did not transpire were:

Risk Description	Likelihood rating	Cost impact
Ruckles T1 transformer leak repairs prior to relocation	high	$48 thousand
Ruckles T1/T2 transformers PCB contamination	high	$90 thousand
4 kV to 13 kV conversion delays	medium	$42 thousand

44.2 Please explain and provide a detailed breakdown of the remaining $314,000 project contingency into the identified schedule, cost and environmental risks.

Response:

The $314 thousand of project contingency contained $244 thousand in contingency allowance for scope changes and deficiencies, and $70,000 for major risks listed in the table below.

Risk Description	Likelihood rating	Cost impact
Additional excavation/soil disposal from oil leaks	medium	$44 thousand
Contaminated soil and material disposal from flood	high	$24 thousand
Grounding deficiencies	medium	$2 thousand

The Ruckles Substation Rebuild is now substantially complete and potential major risks did not materialize; consequently, the project contingency has been reduced to $10 thousand for the remaining project closeout/engineering activities. As a result, the forecast total to complete the project is reduced from $6.913 million to $6.438 million.

On page 10 of Appendix D, FBC states that project completion for the Ruckles Substation Rebuild project is still scheduled for August 2018.

44.3 Please provide an update on the current project timeline for the completion of the Ruckles Substation Rebuild project.

Response:

The Ruckles Substation Rebuild project is scheduled to be substantially completed by the end of September 2018. Project close out and engineering documentation will be finalized by November 2018.

Based on updated construction costs and the release of contingency as explained in the response to BCUC IR 1.44.2, the revised project forecast is reduced by $0.475 million compared to Appendix D, Table D-2, to $6.438 million, as shown in the table below.

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)
	($000s)				(%)	
Line Work	241	259	0	259	7	107
Civil & Site	1,688	1,526	146	1,672	(1)	90
Buildings	191	203	10	213	11	106
Structures & Buswork	427	481	23	505	18	113
Station Equipment & Apparatus	2,602	1,769	8	1,776	(32)	68
Communications & SCADA	32	33	0	33	6	106
Protection, Control & Metering	270	246	0	246	(9)	91
Design	627	673	22	695	11	107
Commissioning	132	122	0	122	(7)	93
Project Management	544	279	42	320	(41)	51
Subtotal - Construction	6,754	5,591	251	5,842	(13)	83
Cost of Removal	301	168	15	184	(39)	56
Project Contingency	805	0	10	10	(99)	0
Subtotal- Construction & Removal	7,860	5,760	276	6,036	(23)	73
AFUDC	428	287	116	403	(6)	67
Total Project Cost	8,288	6,046	392	6,438	(22)	73

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