Diane Roy
Vice President, Regulatory Affairs

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

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

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

August 10, 2017

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

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

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-138-14 (the PBR Plan)

Annual Review for 2018 Rates

In accordance with the PBR Plan and Commission Order G-116-17 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2018 Rates Application materials.

Should further information be required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to FBC's Annual Review for 2017 Rates Proceeding

FortisBC Inc.

Multi-Year Performance Based Ratemaking Plan

for 2014 through 2019

Annual Review for 2018 Rates

Volume 1 - Application

August 10, 2017

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1. APPROVALS SOUGHT, OVERVIEW OF APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (the Commission) Order G-139-14, which approved a Performance Based Ratemaking Plan (PBR Plan) for FBC for the years 2014 to 2019. In accordance with the PBR Plan, an annual review process is required to set rates for each year of the PBR Plan. With the filing of this Application, FBC seeks to commence the fourth annual review of the PBR Plan and set FBC's rates for 2018.

The PBR Plan approved by the Decision attached to Order G-139-14 (PBR Decision) increases FBC's incentives to seek out savings while maintaining service quality.[1] Pursuant to the earnings sharing approved by the Commission, savings in formula-driven O&M and capital expenditures achieved by the Company are shared equally with customers, as discussed in Section 10 of the Application.

Under the PBR Plan, FBC projects savings in 2017 due to a continuation of its ongoing productivity focus, including a broad-based Company-wide effort to seek alternate solutions to the filling of vacancies and a number of initiatives that result in net O&M and capital savings. Overall, FBC proposes to distribute $0.831[2] million in earnings sharing to customers in 2018. FBC has achieved these savings while maintaining a high level of service quality as indicated by meeting the Service Quality Indicators (SQIs) approved in the PBR Decision.

The proposed rates for 2018 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 0.11 percent increase over 2017 rates. This equates to an increase of $0.13 to the monthly bill for an average residential customer.[3]

In the subsections below, FBC sets out the approvals it is seeking, provides an overview of the requirements for the annual review process, and provides an evaluation of the PBR Plan for 2017. This is followed by a summary of FBC's proposed revenue requirement and rate changes for 2018 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

With this Application, FBC requests approval for the following pursuant to sections 59 to 61 of the Utilities Commission Act:

[1] PBR Decision, p. 134.
[2] This amount is pre-tax and includes both the 2017 estimated earnings sharing and adjustments related to 2016 actuals.
[3] Based on a Residential customer using approximately 11,000 KWh per year.

1. Permanent rates for all customers effective January 1, 2018, resulting in a general increase of 0.11 percent compared to 2017 rates, to be applied to all components of rates for all customer classes.

2. The creation of five non-rate base deferral accounts, as described in Section 12.4.1 of the Application:

   - Multi-Year DSM Expenditure Schedule, to be financed at the Company's weighted average cost of debt (WACD);
   - Community Solar Pilot Project application, to be financed at the Company's short term interest (STI) rate;
   - Tariff Applications, to be financed at the Company's STI rate;
   - 2020 Revenue Requirements application, to be financed at the Company's WACD; and
   - 2018 Joint Use Pole Audit, to be financed at the Company's WACD.

3. Z-factor treatment for the 2018 incremental O&M and capital expenditures related to the Mandatory Reliability Standards (MRS) Assessment Reports No. 8 and No. 10, as described in Section 12.2 of the Application.

A draft order is included in Appendix F.

1.3 REQUIREMENTS FOR THE ANNUAL REVIEW

On pages 179 and 180 of the PBR Decision, the Commission set out its expectations for the Annual Review component of the PBR Plan, with one further directive (number 8 in the table below) provided on page 17 of Order G-120-15 in the Capital Exclusion Criteria compliance filing. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application:

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns.	Section 1.4
2	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 2(a) to 2(g) below
2(a)	Customer growth, volumes and revenues;	Section 3

Item	Description	Response or Reference
2(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
2(c)	Expenses (determined by the PBR formula plus flow-through items);	Section 6
2(d)	Capital expenditures (as determined by the PBR formula plus flow-through items);	Section 7
2(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;	Sections 7 and 12
2(f)	Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and	Section 10
2(g)	Any proposals for funding of incremental resources in support of customer service and load growth initiatives.	FBC does not have any proposals at this time
3	Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives.	FBC has not identified any efficiency investments with a payback beyond the end of the PBR period that it is not pursuing
4	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers.	Sections 6.3.4, 7.2.2 and 12.2
5	Review of the Companies' performance with respect to SQIs. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service.	Section 13
6	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs.	FBC does not have any recommendations for new SQIs or the discontinuation of SQIs at this time
7	Assess and make recommendations to the Commission on the scope for future Annual Reviews.	FBC does not have any recommendations at this time
8	Where the dead band is exceeded for any year, FEI and FBC are directed in the next Annual Review filing to include recommendations as to any adjustment to base capital other than those driven by the 1-X mechanism.	Dead band is forecast to be exceeded for 2017. See section 1.4.3

1.4 EVALUATION OF THE PBR PLAN

FBC has continued its productivity focus in 2017 and initiated additional projects to enhance the customer experience and improve productivity, in addition to the continuing initiatives from prior years. As a result of this focus and these initiatives, FBC was able to realize savings in O&M

expenditures above those embedded in the formula. FBC continues to be challenged to meet growth and maintain the system within the capital formula amount. Overall, the savings achieved result in $0.831 million of earnings sharing that will be returned to customers in 2018, serving to reduce overall rates for FBC's customers. FBC's performance with respect to SQIs, as reported in Section 13 of the Application, demonstrates that FBC achieved these savings while maintaining a high level of service quality.

1.4.1 Overview of O&M Savings

In 2017, FBC is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $1.2 million lower than the formula amount. Table 1-2 below shows the formula O&M savings for each year of the PBR Plan and the cumulative to date. The table also show the embedded Productivity Improvement Factor (PIF) savings for the same years. The table shows that in addition to the cumulative formula O&M savings of approximately $4.8 million to the end of 2017 which are shared with customers, the cumulative PIF savings to the benefit of customers total to approximately $2.2 million.

Table 1-2: Formula O&M Savings 2014 to 2017 ($ 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	52.9	54.1	1.2	0.6
Cumulative Savings			$ 4.8	$ 2.2

* 2017 is Projected

The 2017 projected O&M savings of $1.2 million have been achieved with the Company's continued broad-based focus on productivity. While some of the savings are one-time in nature, some of the savings are the result of efficiencies which are expected to continue into the future, recognizing that cost pressures in the future may offset such savings. Upcoming costs related to cyber security are an example of such cost pressures.

The cyber security landscape is changing at a rapid pace, contributing to incremental cost pressures as the Company responds to the evolving risks. While causing only moderate pressure in 2017, O&M costs for cyber security are expected to increase in 2018 by approximately $0.2 million, along with additional and related capital expenditures. The incremental O&M funding is for third party services and additional headcount required to protect the Company's systems.

Cyber security is a collection of technologies, processes, practices and controls designed to protect networks, computers and data from attack, theft, damage or unauthorized access. FBC focuses on securing its systems and educating users on identifying different types of cyber-attacks. In order to ensure cyber security controls are adequate, there are annual cyber security audits and assessments on the overall system architecture, user awareness, as well as project specific vulnerability testing.

The use of technology, and particularly mobile technology, in every business area is increasing. This drives the need to continually review and update security practices and procedures. The cyber security environment is changing at a rapid pace and it is unknown what the next vulnerability will be. Ransomware has become a billion-dollar industry which requires awareness training to be constantly updated to match this trend and the techniques used by criminals seeking to take advantage of IT system vulnerabilities. New tools, training and tests need to be built and executed to keep our employees informed and aware.

FBC takes a risk-based approach to cyber security, using industry proven methodologies and technologies to ensure an appropriate balance between cost and effective protection.

1.4.2 Initiatives Undertaken

The following is a discussion of some efficiency and cost savings initiatives that FBC has undertaken or ongoing in 2017.

1. ***Sharing of Gas and Electric Contact Centre Staff***

   In 2017, FBC continued to leverage gas and electric contact centre staff to achieve three goals: to reduce operating costs, to maintain or improve service levels to customers, and to provide learning and development opportunities for staff.

   In total, the integration of activities is forecast to produce annual savings for FBC of approximately $0.300 million.[4]

2. ***Interactive Voice Response Enhancements***

   In 2017, new functionality will be introduced into the Interactive Voice Response (IVR) in support of self-service channel options for customers. Basic transactions including obtaining the due date and the balance due as well as the amount and date of last payment will be available for customers 24 hours a day, 7 days a week without the need to speak to a representative. Not only will this new channel be more convenient for customers, but it is also expected to reduce operating costs in the contact centre starting in 2018 with estimated annual savings of approximately $0.075 million.

3. ***SAP Integration***

   SAP Integration is an initiative to integrate the FBC and FortisBC Energy Inc. (FEI) SAP systems, moving towards a common SAP platform for both companies. It will primarily include the integration of the Human Resources, Supply Chain, and Finance systems in

[4] This may fluctuate slightly year to year depending on the number of electric calls answered by representatives in Prince George.

SAP. The benefits will include a simplified support model, alignment of processes, simpler business processes (i.e. employee expense processing and single sign-on), reduced licensing costs and integrated payroll. Reduction in support costs will be achieved through reduced annual contractor costs because internal resources will be able to displace the contractor support due to the simplified support requirements.

The project has started with completion expected in the third quarter of 2018. The total cost of the project is estimated at $4.5 million. Based on the number of employees between the two companies (75% FEI, 25% FBC), approximately $3.4 million of the implementation costs will be allocated to FEI with the remaining $1.1 million to FBC. 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 savings will be realized beginning in 2019.

4. Advanced Distribution Management System

This project is to implement an Outage Management System (OMS) and to replace the existing Dispatch system with a Mobile Workforce Management System (MWM). This will enable the Company 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. Customers will be provided access to an outage map that will be updated automatically from the OMS. The project is currently underway and expected to be complete in 2017. The project benefits include streamlining of the manual outage management processes and the manual dispatch processes, with estimated annual savings of $0.2 million starting in 2018.

1.4.3 Overview of Capital Expenditures

FBC is projecting that capital expenditures will be above the formula in 2017.

1.4.3.1 Capital Spending Results

FBC's capital spending has been above the formula amount in each year of the PBR term to date, and this is expected to continue. Table 1-2 below shows the capital spending from 2014 to 2017.

Table 1-2: Capital Expenditures 2014 to 2017 ($ millions)

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 42.665	$ 42.193	$ 0.472	$ 44.791	$ 42.384	$ 2.407	$ 45.838	$ 42.874	$ 2.964
Pension/OPEB	6.396	6.396	-	4.253	4.253	-	3.674	3.674	-
Total	$ 49.061	$ 48.589	$ 0.472	$ 49.043	$ 46.637	$ 2.408	$ 49.512	$ 46.548	$ 2.965
Variance			0.97%			5.16%			6.37%

	2017			Cumulative		
	Forecast	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 58.560	$ 43.254	$ 15.306	$ 191.854	$ 170.705	$ 21.149
Pension/OPEB	3.539	3.539	-	17.862	17.862	-
Total	$ 62.099	$ 46.793	$ 15.306	$ 209.716	$ 188.567	$ 21.149
Variance			32.71%			11.22%

As shown in Table 1-2, Projected 2017 capital expenditures excluding items forecast outside of the PBR formula, are $15.306 million higher than the formula amount. There are a number of contributing factors which are discussed below.

One set of contributing factors consists of reductions to the capital formula envelope. Specifically, in the Commission's PBR Decision, the approved PBR capital formula included the following decreases to the allowed spending as compared to what had been proposed:

1. The growth factor for net customer additions (for the other capital) was reduced by one-half,[5] resulting in an impact of $0.3 million in 2017 and $1.0 million cumulative; and
2. The X factor was increased by 0.53 percent (from 0.5 percent to 1.03 percent), resulting in an impact of $0.3 million in 2017 and $1.2 million cumulative.

In addition to the formula-related capital pressures noted above, FBC is experiencing capital cost pressures in 2017 due to work that had been re-prioritized from previous years of the PBR term into 2017, to manage unforeseen urgent and higher priority activities in 2017. The main pressures in 2017 are described below.

1. System improvements to accommodate customer growth;
2. Forced relocation of transmission and distribution infrastructure due to the widening of Highway 97 near Kelowna by the Ministry of Transportation and Infrastructure;
3. Customer-driven modifications at RG Anderson Terminal associated with the City of Penticton's distribution voltage conversion project; and
4. Increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate.

The Highway 97 forced relocation and customer-driven modifications at RG Anderson Terminal projects contribute $4.2 million to formula capital expenditures in 2017. Both projects are

[5] In addition, the lag in timing of when customer growth is reflected in the formula as compared to when customers are actually added causes pressure on the formula in years of higher customer growth.

customer-funded, and are therefore offset by Contributions in Aid of Construction (CIAC). However, as recognized during the Annual Review for 2017 Rates[6], the CIAC for customer-funded projects, while a reduction to rate base, is excluded from the capital expenditure formula envelope under FBC's PBR Plan.

FBC has sought to mitigate the impact of the above factors through a combination of seeking out efficiencies in capital spending and re-prioritizing projects for further evaluation. Examples of efficiency initiatives undertaken to date include comprehensive pre-construction planning, combining transmission and distribution sustainment work into larger programs and resourcing through a competitive bid process, and a focus on reducing design costs across various information system applications. For 2017, FBC is continuing its capital productivity focus on a number of projects, by commencing engineering and procurement sooner than in previous years in order to better assess and schedule resourcing requirements for design and construction. This will allow FBC to effectively schedule construction with internal and external resources and execute earlier in the calendar year to allow for more flexible and efficient capital spending.

FBC manages its capital investment plan to maintain a safe and reliable electric system with an acceptable risk profile, to optimize resources and spending, and to achieve efficiencies and cost savings. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some flexibility in timing. This is done with the understanding that conditions change and the plan must be capable of adapting. This plan flexibility allows FBC to manage and execute typically expected levels of unforeseen urgent work that come up throughout the year within the resource and budget constraints of the capital plan. Apart from this routine capital plan management, FBC would not consider deferring any significant capital spending to after the PBR period. FBC believes that deferring any significant capital spending to after the PBR period would result in increased risk exposure to the system and would ultimately result in higher costs to execute the work. Furthermore, deferral of projects to after the PBR period could lead to an accumulation of work that could exceed FBC's ability to execute in a timely manner.

FBC has been successful in mitigating some of the cost pressures through efficiencies and work prioritization. However, the cost pressures have exceeded the Company's ability to re-prioritize further work within the formula capital spending envelope without incurring more risk to the system. As well, previous work that was delayed is now considered essential or mandatory work and cannot be deferred further. To mitigate this risk exposure, FBC has increased its planned sustainment activities in 2017.

Despite the pressures described above, the capital efficiency focus and the prioritization process undertaken by FBC have enabled FBC to manage its capital spending within the 10 percent one year capital dead band in each year of the PBR term until 2017. In 2017, FBC will be over both the one year capital dead band and the two-year cumulative 15 percent dead band.

[6] Annual Review for 2017 Rates, Response to BCUC IR 1.5.1 (Exhibit B-3).

FBC has carefully reviewed the dead band that was initially approved by the Commission and also the further guidance the Commission has provided on the functioning of the dead band, and provides the following regulatory history.

1.4.3.2 Capital Dead Band Regulatory History

In the PBR Application, FBC proposed a capital dead band of 10 percent with limited rebasing to occur "if annual capital expenditures are above or below the formula-based amount by more than 10 percent".[7] The rebasing mechanism was described in FEI's application as follows:

> *FEI has proposed a capital expenditure deadband outside of which rebasing would occur during the PBR term. That is, if total regular capital expenditures vary by more than 10 percent above or below the total formula-based capital expenditures in any year, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the 10 percent deadband from the formula-based amount. This will limit the impact of any capital savings during the PBR Period that would be shared between the customer and Company, and limit the amount of rebasing that would occur after the PBR Period[8].*

Further, in response to an information request,[9] FBC provided the following example of the functioning of the dead band:

> *<u>Question:</u>*
>
> *Regarding the section of the table on Controllable Expenses – Capital, provide a numerical example to show how this capital expenditure deadband of 10 percent would work.*
>
> *<u>Response:</u>*
>
> *The total capital spending under PBR for 2014 of $72.758 million, as set out in Exhibit B-1, Figure B6-3 on page 59 is used for illustrative purposes. It is also assumed for ease of illustration that no cost driver adjustments for actual customer count and service line installations are required.*
>
> *If actual capital spending is below 90 percent of $72.758 million (i.e. $65.482 million) an adjustment would be applied to the formula-based capital expenditures spending level in the year.*
>
> *Assume for this example that actual capital spending is at 85 percent of the capital spending level under PBR, or $61.844 million.*

[7] FBC 2014-2018 PBR Application, page 2, Table A1-1.
[8] FEI 2014-2018 PBR Application, Appendix D4, page 3, lines 19-34.
[9] FBC 2014-2018 PBR Application, BCUC IR 1.58.1.

> *The difference between 90 percent and 85 percent ($65.482 million - $61.844 million = $3.638 million) is deducted from the formula-based capital expenditure additions for 2014 and are incorporated in the rate base to establish revenue requirement calculations for future years; that is, the opening rate base for the following year will reflect the lower amount. The calculation of the formula-allowed capital spending amount for rate calculations in future years is unaffected by this adjustment*
>
> *The adjustment of $3.638 million would be deducted from the capital accounts (for ratemaking) in the same proportions as included in the $7.758 million before the adjustment.*

In the PBR Decision, the Commission stated:

> *Fortis states that "limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%" (FEI Exhibit B-1, p. 8; FBC Exhibit B-1, p. 40).*
>
> *To this, BCSPO points out that "the proposed deadband does not take into account the fact that capital is cumulative and that, if there is a consistent under spending of 9.5% per year, this will result in capital expenditures that are 46% lower than one year's capital. As such, in addition to the annual threshold of 10% for capital rebasing, BCPSO submits there should be a cumulative threshold that reflects the cumulative nature of capital." (BCSPO PBR Final Argument, p. 10)*[10]
>
> *There are two provisions in the PBR mechanism that mitigate the impact of this and thereby protect ratepayers in this eventuality. The first is Fortis' proposed dead-band around the actual capital spend relative to the spending envelope, which would be triggered if the under-spend was of sufficient magnitude and/or duration.* ***The Panel finds this an appropriate mitigation, providing the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula.*** [11]
>
> ***Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for****.*
>
> *In making this determination, we are mindful of the concerns of Interveners and are of the view that a two year cumulative dead band is appropriate and considers 15 percent over or underspend an appropriate setting for a two year cumulative dead-band. Accordingly, the Commission Panel directs, in addition to the one year 10*

[10] PBR Decision, pages 162-163.
[11] PBR Decision, page 172.

> *percent dead-band previously approved, a two year cumulative 15 percent dead-band for all Fortis' formulaic capital spending.* [12]

Finally, in the decision accompanying Order G-120-15 that addressed FBC's Capital Exclusion Criteria under PBR, the Commission stated[13]:

> *As noted, the PBR Decisions provided direction on the setting of dead band parameters but provided no definitive direction with respect to the process to deal with rebasing future base capital amounts in the event that the dead band parameters are exceeded. This is addressed below.*
>
> *The Panel accepts there are a number of reasons why a capital expenditure level may be higher or lower than the threshold. Some of these may support and justify raising or lowering base capital while others may demonstrate a particular result to be an anomaly, not necessarily requiring rebasing. Because of this, the Panel determines that the full circumstances of any variance from the dead-band must be examined in a transparent manner at the annual review process.* ***Where the dead band is exceeded for any year, FEI and FBC are directed in the next Annual Review filing to include recommendations as to any adjustment to base capital other than those driven by the I-X mechanism****. This will provide interveners the opportunity to review and comment on any such proposed changes prior to the Commission making its determination.*

1.4.3.3 Treatment of Capital Spending outside of the Dead Band

Based on the regulatory history discussed above, the functioning of the approved capital dead band is summarized below.

- The capital dead band places a limit on the extent to which there is earning sharing on variances from (either above or below) the capital formula amount;
- The threshold for the capital dead band is a one year 10% variance or a two-year cumulative 15% variance from the capital formula amount;
- If the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the dead band from the formula-based amount, and the capital expenditure level utilized in calculating the earnings sharing is adjusted up or down by the same amount;
- The result of exceeding the capital dead band is that there is no earnings sharing for amounts outside of the dead band;

[12] PBR Decision, page 175.
[13] G-120-15, page 17.

- If the capital dead band is exceeded, FBC will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year.

This treatment was summarized by FEI with regard to its capital expenditures in excess of the dead band in its Annual Review for 2017 Rates, and approved by Order G-182-16[14]:

> ***The Panel approves FEI's proposal to remove the amount of formula capital which has exceeded the cumulative dead-band from the earnings sharing calculation, and to add the amount of capital in excess of the dead-band to FEI's opening 2017 plant additions balance.***

Order G-182-16 also agreed with FEI that its formula capital expenditures should not be re-based at the time:

> *The Panel does not consider it necessary at this time to undertake a detailed evaluation of FEI's approved formula capital spending envelope in the form of a re-basing hearing. The Panel notes that 2016 is the first instance of FEI exceeding the capital dead-band, and based on FEI's projected 2016 capital expenditures FEI expects to be within the annual 10 percent dead-band but in excess of the cumulative 15 percent dead-band. Further, the capital amount projected to exceed the cumulative dead-band is $6.118 million, which in the Panel's view is not significant enough to warrant the regulatory cost of a re-basing hearing.*

Similarly, FBC is not recommending an increase to the annual capital formula amount for the remaining years of the PBR term. FBC does not believe that a lengthy process to review which capital items should be added into the capital formula is an efficient solution to the ongoing capital issues. By not adjusting the capital formula amount, the incentive properties of the PBR Plan remain intact and will remain consistent throughout the remainder of the PBR term. While FBC expects to continue to experience capital cost pressures, the dead band mechanism remains a reasonable way to deal with capital cost pressures by ensuring no sharing of negative earnings impacts with customers for capital expenditures in excess of 10 percent of the formula amount or 15 percent over two years.

To calculate the 2017 dead band adjustment, FBC notes that its actual 2016 capital exceeded the formula by approximately 6.37 percent. FBC is further expecting to exceed the 2017 formula by 32.71 percent as shown in Table 1-2. Therefore, the cumulative amount over the capital formula for calculating the two-year dead band adjustment is 39.08 percent. FBC must exclude from the Earnings Sharing calculation the greater of:

[14] G-182-16, page 16.

- The one-year capital dead band difference between the projected capital spending overage of 32.71 percent and the one year dead band limit of 10 percent, for a net adjustment of 22.71 percent; or
- The two-year capital dead band difference between the cumulative projected capital spending overage of 39.08 percent and the two year cumulative dead band limit of 15 percent, for a net adjustment of 24.08 percent.

Accordingly, FBC has added $11.268 million[15] to its opening plant in service for 2018 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 ($11.268 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.

1.4.3.4 Conclusion on Capital Spending

FBC has evaluated its alternatives and believes that it is in the best long-term interest of customers to pursue the capital spending program it has planned that will result in the dead band being exceeded, not only in 2017, but in the remaining years of the PBR term. It is clear that the capital spending is required and it is the right thing to do to limit increasing risk exposure in the system, and avoid unplanned and urgent capital work that reduces productivity and drives up project costs by reducing FBC's ability to plan and execute the work.

1.4.4 Summary

In summary, FBC's experience in 2014 through 2017 has resulted in the realization of earnings sharing on O&M. The first four years of PBR have also shown the challenges of the capital formula that are expected to continue and impact the remainder of the PBR term.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2018

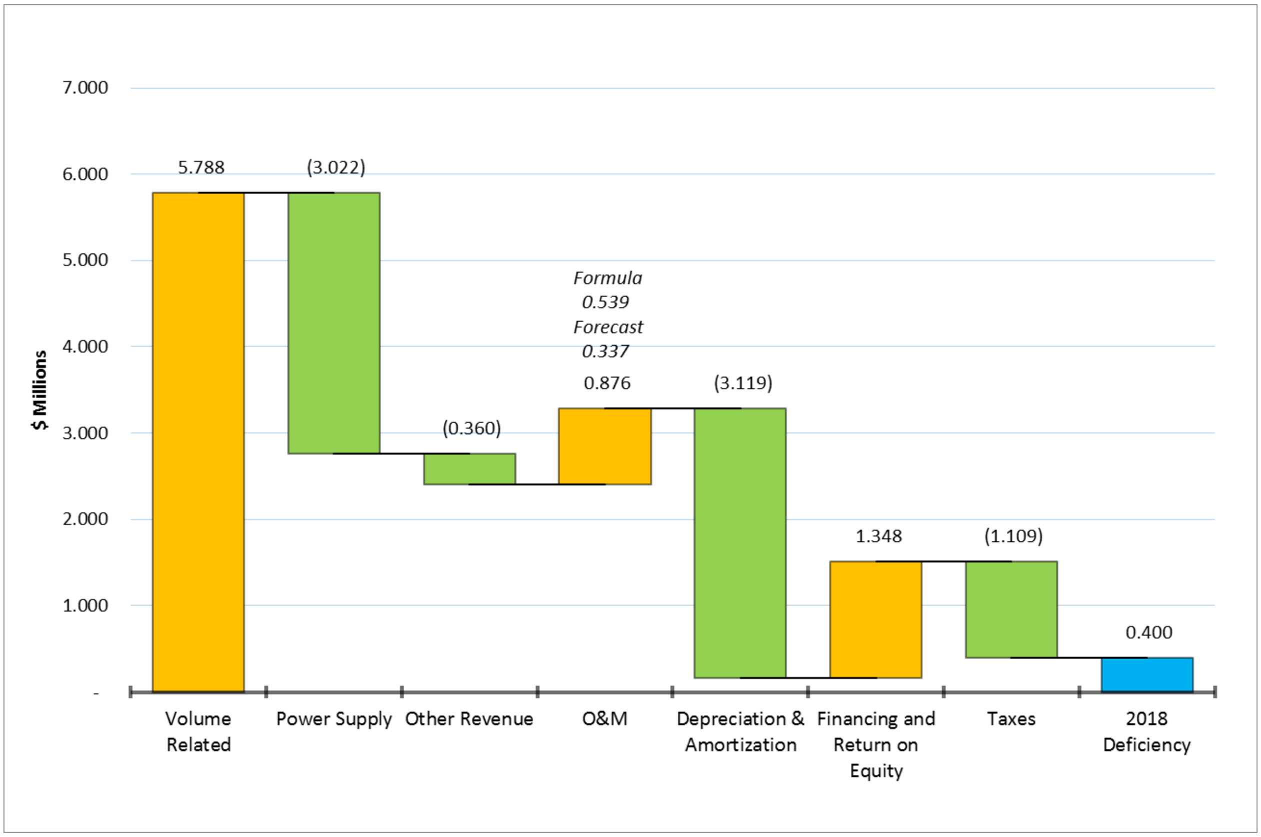
The Company is requesting a rate increase of 0.11 percent for 2018 compared to 2017 rates. The rate increase results from a revenue deficiency of $0.400 million. The revenue deficiency is due to revenue at existing rates being lower than the forecast cost of service. The forecast cost of service is impacted by both items calculated under the PBR Plan formula (controllable O&M and capital expenditures), and items that are forecast on a cost of service basis.

The following chart summarizes the items that contribute to the 2018 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the

[15] 24.08% times 2017 formula of $46.793 = $11.268 million. 2017 Actual expenditure of $62.099 - $11.268 million = $50.831 million. This results in a revised capital spending variance of 8.63% over one year and 15% over two years.

deficiency in green. The total deficiency is then the sum of all of the previous bars, and is shown at the end of the chart in blue.

Figure 1-1: 2018 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Load Forecast (Section 3)

In 2018, sales load is forecast to decrease by 74 GWh from 2017 due to lower residential usage on a per customer basis and to lower industrial loads, partially offset by an increase in commercial loads. Based on 2017 rates, FBC's 2018 revenue forecast at existing rates is $356.340 million.

1.5.2 Power Supply (Section 4)

Power Supply expense is forecast to decrease in 2018 by $3.022 million, primarily due to a lower gross load, reduced purchases under the Company's power purchase agreement with BC Hydro, combined with increased savings due to market purchases.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase in 2018 by approximately $0.360 million, primarily due to income earned on construction work performed for a third party, in addition to higher apparatus and facilities rentals and connection charges .

1.5.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the bulk of its O&M costs by formula during the PBR term. For 2018, the formula incorporates an inflation factor (I Factor) of 1.679 percent, a productivity improvement factor (X Factor) of 1.03 percent and a customer growth factor of 0.629 percent for a total increase in formula O&M of 1.282 percent. O&M forecast outside of the formula is $0.337 million higher than Approved 2017. Overall the increase in Gross O&M Expense from 2017 to 2018 is 1.790 percent. The increase in net O&M expense is $0.876 million.

1.5.5 Depreciation and Amortization (Section 7)

Depreciation expense has increased by $2.430 million as a result of additions to rate base. Amortization expense decreased by $5.549 million, primarily due to amortization of 2017 Flow-through deferral account, partially offset by the impact of the remaining credit balance in the 2014 Interim Rate Variance deferral account and the Celgar Interim Period Billing Adjustment, both of which were fully amortized in 2017. In total, the 2018 Forecast depreciation and amortization expense is lower than 2017 Approved by $3.119 million.

1.5.6 Financing and Return on Equity (Section 8)

FBC has forecast an issuance of long-term debt of $75 million during September 2017, at a forecast rate of 3.8 percent for a term of 30 years, which has been embedded into the long-term 2018 interest expense forecast. FBC is forecasting a short-term debt rate for 2018 of 3.45 percent, a decrease from the 7.45 percent rate embedded in the 2017 approved rates due to a higher forecast balance of draws on credit facilities. Overall, interest expense is forecast to increase from 2017 approved by $0.015 million.

Increases in rate base increase the equity return by $1.332 million. In calculating 2018 rates, FBC has utilized its 2018 approved capital structure and return on equity of 40 percent and 9.15 percent, respectively.

1.5.7 Taxes (Section 9)

Property taxes are forecast to increase 3.9 percent or $0.632 million from 2017 Approved. Increases are driven by changes in property tax rates and assessed values and changes in revenues to calculate grants in lieu of taxes.

There has been no change in the income tax rate of 26 percent from 2017. Income taxes are forecast to decrease in 2018 by $1.741 million, primarily due to a decrease in amortization expense driven by deferral accounts, in particular the Celgar Interim Billing Adjustment account which was fully amortized in 2017, and an increase in deductible temporary differences associated with pensions and OPEBs, partly offset by an overall increase in revenues.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC's 2016 and June 2017 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2016, for those SQIs with benchmarks, seven performed at or better than the approved benchmarks with one performing better than the threshold and within the performance range. In 2017 June year-to-date, performance is similar to 2016, with seven of the eight SQIs with benchmarks performing better than the threshold and the one remaining performing better than the threshold and within the performance range. For the three SQIs that are informational only, performance generally remains at a level consistent with prior years. Details of the SQIs are included in Section 13.

2. FORMULA DRIVERS

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factors used for calculating the 2018 O&M and Capital formula amounts according to the PBR formula.

In the PBR Decision and Commission Order G-163-14, the Commission approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting, and a growth factor of 50 percent of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as [1 + ((AC_{t-1} – AC_{t-2})/ AC_{t-2}) x 50%)].

Further guidance on how to calculate the Inflation and Growth factors was provided in Commission Order G-182-14, which states:

> 1. FortisBC Inc. is approved to use inflation data from the most recent 12-month period (July through June) for the 2014 rate change calculations and future annual reviews.
> 2. FortisBC Inc. is approved to use Statistics Canada CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC.

The Inflation Factor and Growth Factor calculations utilize these inputs, but as applied to 2018. FBC has used July 2015 through June 2017 inflation data for the 2018 rate change calculations using the CANSIM tables noted above, which are included in Appendix A1 of the Application.

As discussed below, the 2018 inflation factor based on prior year's BC-CPI and BC-AWE is 1.679 percent, and the AC Growth Factor is 0.629 percent.

2.1 *INFLATION FACTOR CALCULATION SUMMARY*

In the PBR Decision, the Commission approved an inflation factor (I-Factor) using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting. Consistent with Commission Order G-182-14 regarding FBC's PBR Compliance Filing, FBC uses inflation data from July through June and CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC. The supporting Statistics Canada CANSIM Tables 326-0020 and 281-0063 are provided as Appendix A1. The latest available month of May 2017 has been used as a placeholder for the month of June 2017 for AWE-BC, as results for June have not been released by Statistics Canada. Once results for that period are available, the placeholder will be replaced with actuals and included in an Evidentiary Update.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing CPI-BC of 1.979 percent and AWE-BC of 1.433 percent. Applying the 55 percent labour weighting, the calculation of the I-Factor is (1.979 percent x 45 percent) + (1.433 percent x 55 percent) = 1.679 percent.

Table 2-1: I-Factor Calculation

	CANSIM 326-0020 2002=100	*CANSIM 281-0063*	12-Month Average		Year over Year % Change			
	BC CPI Index	BC AWE $	CPI Index	AWE $	CPI %	AWE %	I-Factor %	PBR Year
Jul-15	120.8	914.85						
Aug-15	121.0	907.74						
Sep-15	121.0	912.59						
Oct-15	120.6	915.24						
Nov-15	120.8	910.21						
Dec-15	120.4	918.18						
Jan-16	120.7	906.99						
Feb-16	120.8	913.20						
Mar-16	121.8	915.42						
Apr-16	121.8	920.95						
May-16	122.7	917.48						
Jun-16	123.1	927.60	121.3	915.04				
Jul-16	123.3	911.54						
Aug-16	123.4	920.30						
Sep-16	123.2	919.84						
Oct-16	123.1	917.50						
Nov-16	122.7	927.86						
Dec-16	122.7	931.43						
Jan-17	123.5	931.06						
Feb-17	123.6	928.94						
Mar-17	124.2	934.30						
Apr-17	124.4	935.01						
May-17	125.0	939.99						
Jun-17	125.2	939.99	123.7	928.15	1.979%	1.433%	1.679%	2018

2.2 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the Commission approved for FBC a growth factor of 50 percent of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as [1 + ((AC_{t-1} – AC_{t-2})/ AC_{t-2}) x 50%)].

The calculation for the Average Customer growth factor is provided in Table 2-2 below:

Table 2-2: Average Customer (AC) Growth Factor Calculation

	Customer Count	12 Month Average Customers	AC Factor @50%	PBR Year
Jul-15	130,846			
Aug-15	130,795			
Sep-15	131,131			
Oct-15	131,209			
Nov-15	131,754			
Dec-15	131,883			
Jan-16	132,080			
Feb-16	132,202			
Mar-16	132,041			
Apr-16	131,955			
May-16	131,952			
Jun-16	132,097	131,662		
Jul-16	132,421			
Aug-16	132,618			
Sep-16	132,682			
Oct-16	133,019			
Nov-16	133,140			
Dec-16	133,550			
Jan-17	133,452			
Feb-17	133,582			
Mar-17	133,543			
Apr-17	133,785			
May-17	133,862			
Jun-17	134,152	133,317	0.629%	2018

2.3 INFLATION AND GROWTH CALCULATION SUMMARY

Using the I-Factor and Growth Factor as calculated above, and the approved X-Factor of 1.03 percent, a summary of the factors used in the PBR formula for 2018 is provided in Table 2-3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2018
1	Cost Drivers	
2		
3	Customer Growth Factor @ 50%	0.629%
4		
5	Escalators	
6		
7	CPI	1.979%
8	AWE	1.433%
9		
10	Non Labour	45%
11	Labour	55%
12		
13	CPI/AWE Inflation	1.679%
14		
15	Productivity Factor	-1.030%
16		
17	Net Inflation Factor	0.649%

In summary, the formula factor for O&M and capital for 2017 is 101.282 percent, calculated as (1+0.629 percent) x (1+0.649 percent).

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FBC's forecast of gross system energy load. The gross system load is a combination of residential, commercial, wholesale, industrial, street lighting and irrigation loads and system losses. The forecast of gross system load includes the impacts of forecast energy savings, which include Demand Side Management (DSM) savings, and the impacts of the Residential Conservation Rate (RCR), the Customer Information Portal (CIP)[16], the Advanced Metering Infrastructure (AMI) program and future rate changes. These savings are further explained in Section 3.3 – Demand Side Management and Other Savings.

FBC's load forecast methods, described below, are consistent with those used in prior years and accepted by the Load Forecast Technical Committee in 2011[17]. FBC is forecasting a decrease in consumption in 2018 when compared to the 2017 Approved forecast. The total normalized gross load is forecast to be approximately 3,485 GWh which is a 74 GWh decrease compared to the 2017 Approved gross load. The decrease in 2018 is due to decreased loads in the residential and industrial classes which are partially offset by increased commercial loads. Based on the 2017 rates for each customer class, FBC's 2018 revenue forecast is $356.340 million.

3.2 *OVERVIEW OF FORECAST METHODS*

FBC's forecast of customers and load relies on the following components:

- Residential and commercial customer count forecasts;
- Residential average use per customer (UPC) forecast;
- Commercial, lighting and irrigation load forecasts; and
- Industrial and wholesale survey forecasts.

The load forecast for residential customers is based on forecasts for customer count and UPC, consistent with past practice. Specifically, the UPC is forecast and is then multiplied by the corresponding forecast of the number of customers to derive the load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, while the lighting and irrigation forecasts are based on trend analysis and a 5-year average, respectively. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

[16] CIP savings refer to potential savings due to the implementation of the Customer Information Portal, which allows customer to view historic billing and consumption data. The CIP was implemented in June, 2017.

[17] The report of the Load Forecast Technical Committee is found in Exhibit B-16, FBC 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan.

More detail on FBC's forecasting methods can be found in Appendix A3 of this filing.

In the figures provided below, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For the 2018 Annual Review the latest calendar year for which full actual data exists is 2016.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2018 is the Forecast Year (2018F).
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available[18], and will be different than the original forecast for that year in the previous year's revenue requirements. For example, for this Application the Seed Year is 2017 (2017S) and the Seed Year forecast is based on the latest actual years, including 2016.

Also included in the figures in this section are the prior year's seed year (2016S) and forecast year (2017F) as presented in the Annual Review for 2017 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures in this section.

3.3 *DEMAND SIDE MANAGEMENT AND OTHER SAVINGS*

DSM savings and other savings are forecast on an incremental basis (to savings embedded in historical loads to 2016).

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. The residential load is further reduced by other savings from the RCR and CIP, but increased by recovered sales from the AMI-based revenue protection programs. Rate-driven reductions in load due to price elasticity are also taken into account and deducted from the before-saving loads for all classes. All forecast values in this section are shown after being reduced by DSM and other savings unless explicitly stated otherwise.

The forecast DSM and other savings for 2018 are summarized in Table 3-1 below. Historical DSM and other savings can be found in Appendix A2.

[18] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast 2018 DSM and Other Savings (GWh)

Line No.	Description	DSM	AMI	CIP	RCR	Rate-Driven	Total
1	Residential	(14)	9	(4)	(4)	(1)	(13)
2	Commercial	(17)				(1)	(18)
3	Wholesale	(2)				(1)	(2)
4	Industrial	(2)					(2)
5	Lighting	(1)					(1)
6	Irrigation	(0)					
7	Net	(37)	9	(4)	(4)	(3)	(38)
8	Losses	(3)	(7)				(10)
9	Gross Load	(40)	2	(4)	(4)	(3)	(48)

3.4 RESIDENTIAL AND COMMERCIAL CUSTOMER FORECAST

Table 3-2 shows the year-end customer count for FBC.

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

The forecast commercial customer count is determined by a regression of the year-end customer accounts on the provincial GDP forecast from the CBOC, which is included in Appendix A1.

No additions are forecast for other rate classes.

Table 3-2: Year-End Direct Customer Count

Line No.	Description	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
1	Residential	93,647	95,502	96,565	97,883	98,795	99,228	111,862	113,431	114,166	115,772	116,657	117,774
2	Commercial	11,010	11,216	11,308	11,419	11,525	11,811	13,662	14,363	14,976	15,073	15,748	16,122
3	Wholesale	7	7	7	7	7	7	6	6	6	6	6	6
4	Industrial	38	36	33	35	36	39	47	49	50	50	50	50
5	Lighting	1,992	1,910	1,874	1,830	1,803	1,739	1,644	1,620	1,590	1,559	1,559	1,559
6	Irrigation	1,030	1,048	1,066	1,075	1,092	1,091	1,097	1,103	1,095	1,090	1,090	1,090
7	**Total**	107,724	109,719	110,853	112,249	113,258	113,915	128,318	130,572	131,883	133,550	135,109	136,602

3.5 LOAD FORECAST

A discussion of the forecast for each customer class is provided in Sections 3.5.1 through 3.5.6; system losses and the peak demand forecast are discussed in Sections 3.5.7 and 3.5.8.

As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,213 GWh in 2018, up 4 GWh from 2017S.

Figure 3-1: Total Net Load (GWh)

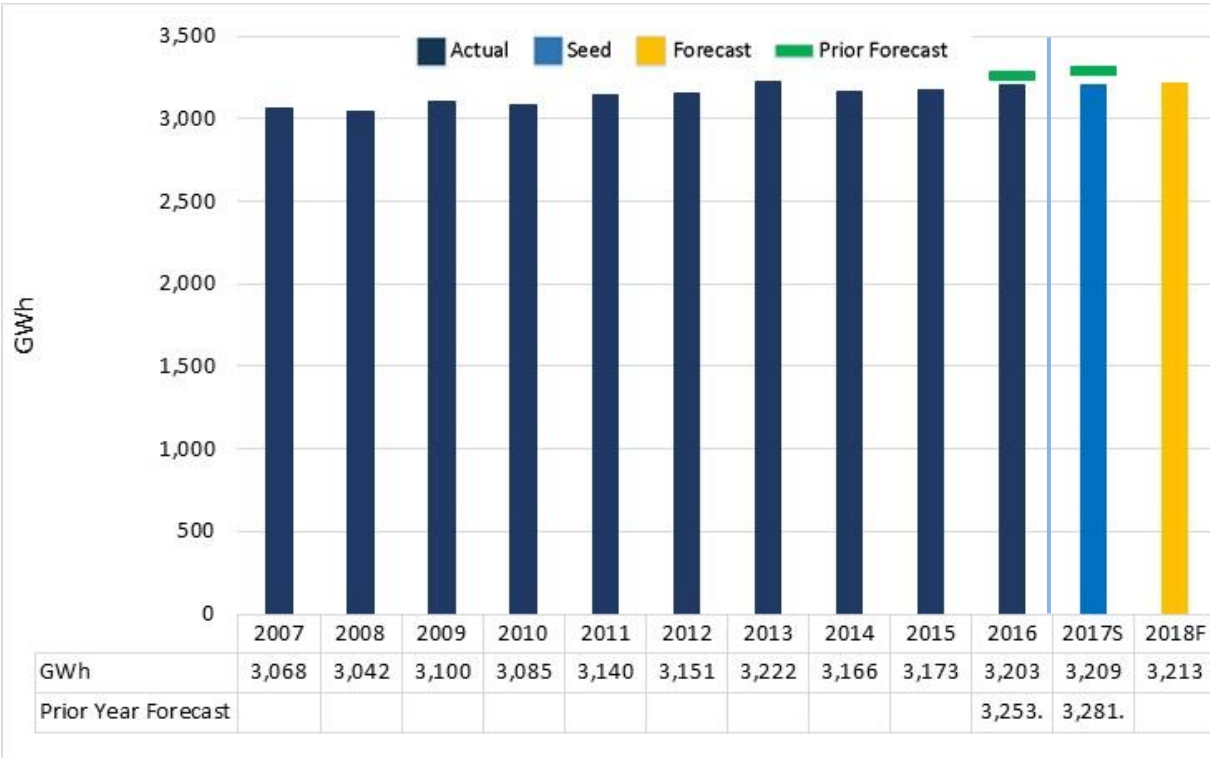


Table 3-3 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2018 the residential customer class is forecast to account for 37 percent of the normalized after-savings gross load.

Table 3-3: Normalized After-Savings Gross Load and System Peak

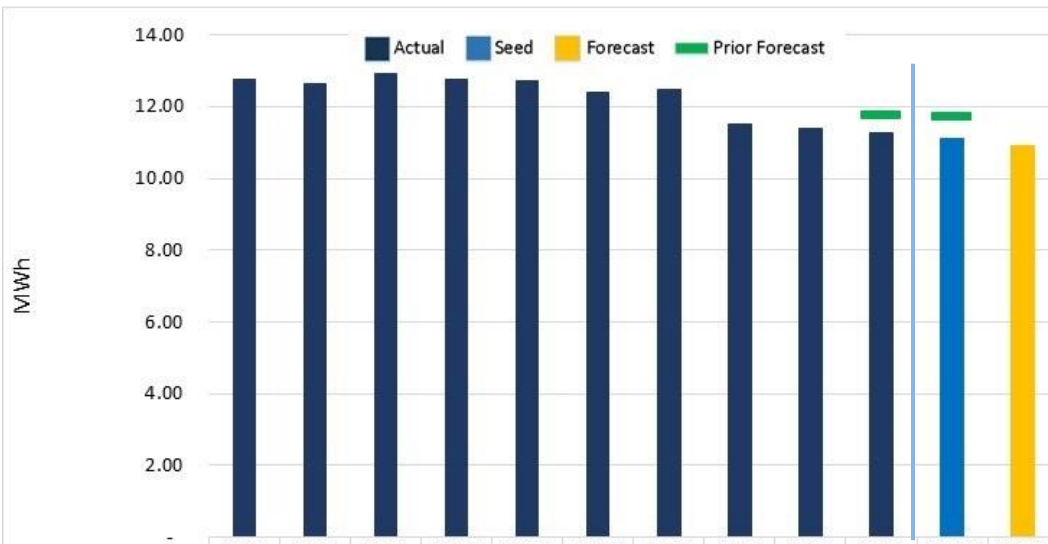
No.	Description	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
	Energy (GWh)												
1	Residential	1,165	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,290	1,280
2	Commercial	650	661	675	660	657	681	788	866	853	901	908	912
3	Wholesale	878	908	908	895	910	899	675	567	580	574	585	586
4	Industrial	314	218	216	234	271	291	352	381	380	373	370	379
5	Lighting	13	13	13	14	13	13	13	16	16	16	16	15
6	Irrigation	48	46	49	40	40	38	40	40	46	42	41	41
7	Net Load	3,068	3,042	3,100	3,085	3,140	3,151	3,222	3,166	3,173	3,203	3,209	3,213
8	Losses	346	309	315	284	307	271	278	270	272	274	275	272
9	Gross Load	3,414	3,351	3,416	3,369	3,447	3,422	3,500	3,436	3,446	3,477	3,484	3,485
10													
11	System Peak (MW)												
12	Winter Peak	704	707	704	726	702	723	698	693	685	724	710	712
13	Summer Peak	520	502	496	566	537	589	600	620	611	593	580	581

3.5.1 Residential

3.5.1.1 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a three-year trend to the most recent three years' normalized historical UPCs (2014, 2015, and 2016). The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM and other savings, which are incremental savings (that is, savings incremental to those embedded in the historical data to 2016), are then deducted from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average customer count. As shown in Figure 3-2 below, the residential after-savings UPC is forecast to decrease by 0.18 MWh during 2018.

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

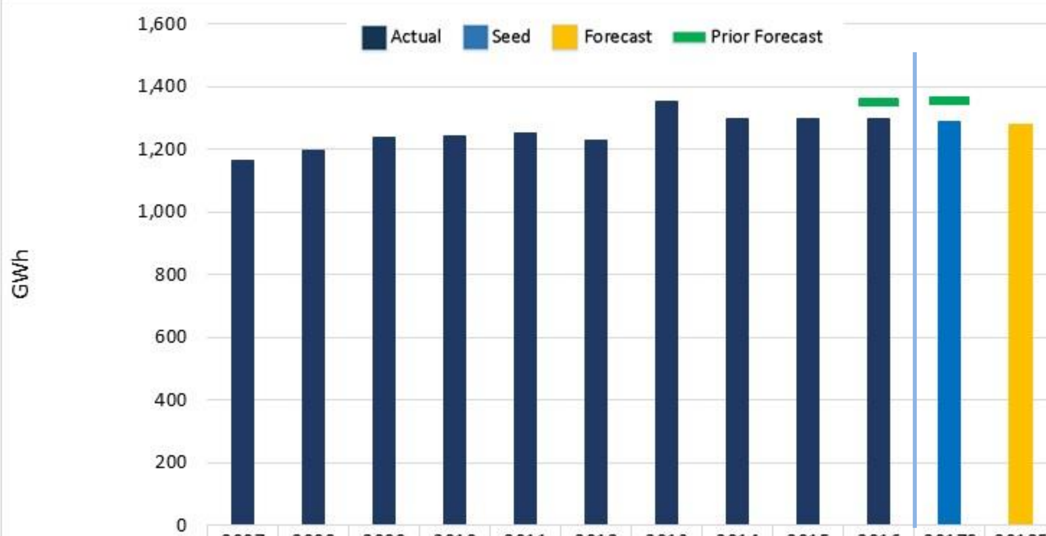


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
MWh	12.74	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.10	10.92
Prior Year Forecast										11.76	11.71	

3.5.1.2 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before savings load and then subtracting DSM and other savings. As shown in Figure 3-3 below, residential after-savings load is forecast to decrease by 10 GWh in 2018 compared to the 2017S. The decline in residential after-savings load is due to a decreasing UPC, and to DSM and other savings, which account for a 3 GWh and a 13 GWh decline in load, respectively. This decline is partially offset by an increase in the customer count, which increases load by 6 GWh.

Figure 3-3: Normalized After-Savings Residential Load (GWh)

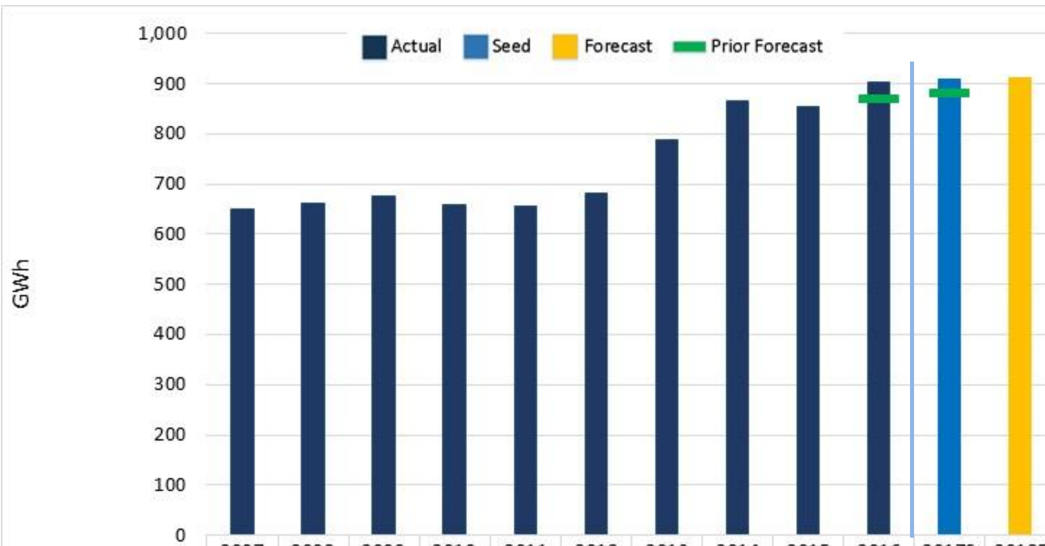


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
GWh	1,165	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,290	1,280
Prior Year Forecast										1,348.	1,353.	

3.5.2 Commercial

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. As shown in Figure 3-4 below, Commercial after-savings load is forecast to increase by 4 GWh in 2018 compared to the 2017S.

Figure 3-4: After-Savings Commercial Load (GWh)



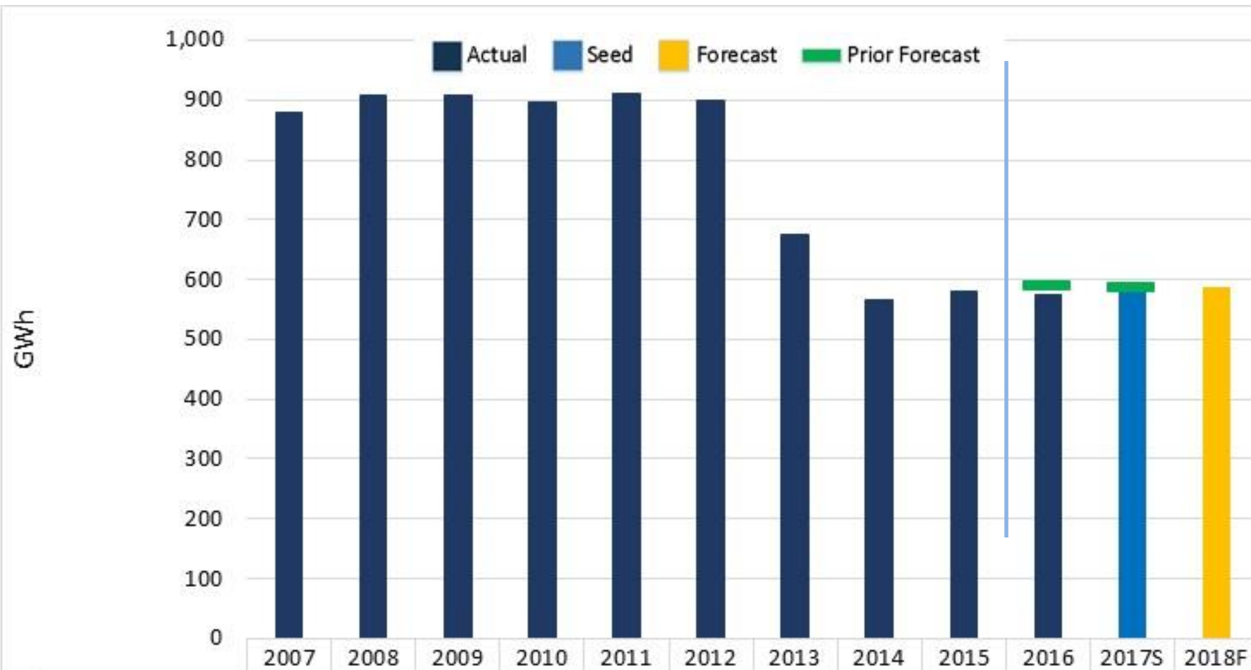
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
GWh	650	661	675	660	657	681	788	866	853	901	908	912
Prior Year Forecast										868	879	

3.5.3 Wholesale

FBC sells wholesale power to municipalities within its service territory that own and operate their own electrical distribution systems and to BC Hydro for service to certain of its customers adjacent to FBC's territory. These wholesale customers' load composition is a combination of residential, commercial, industrial and street lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers. FBC believes that the individual wholesale customers are best able to forecast their future load growth. All of the wholesale customers responded with their load forecast projections. As shown in Figure 3-5 below, after-savings wholesale load is forecast to increase by 11 GWh in 2017 and 1 GWh in 2018. The increase in 2017 is mostly due to large property developments within certain wholesale customers' territories.

Figure 3-5: Normalized After-Savings Wholesale Load (GWh)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
GWh	878	908	908	895	910	899	675	567	580	574	585	586
Prior Year Forecast										587	587	

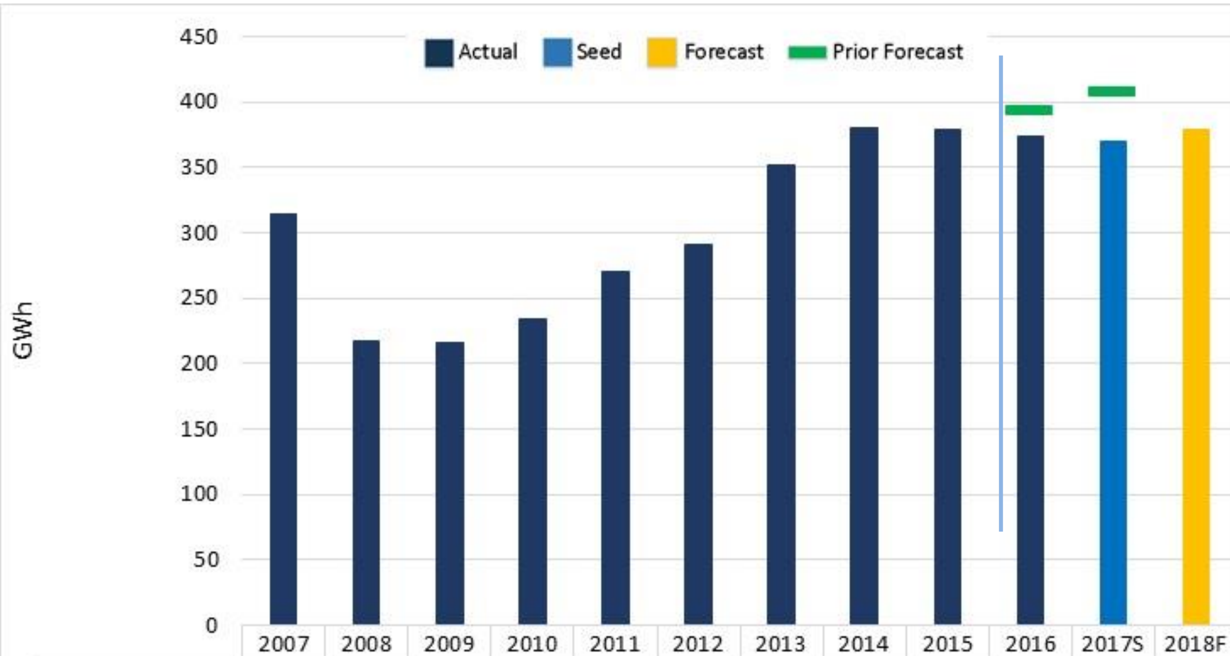
3.5.4 Industrial

Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

FBC sends all industrial customers a load survey that requests the customer's anticipated use for the next 5 years. A survey is used because individual industrial customers have the best understanding of what their future energy usage will be. This year FBC received a response from 80 percent (40 of 50) of the surveys sent out. The responding customers represent approximately 89 percent of the total industrial load.

As shown in Figure 3-6 below, after-savings industrial load is forecast to increase by 9 GWh in 2018 compared to the 2017S.

Figure 3-6: After-Savings Industrial Load (GWh)

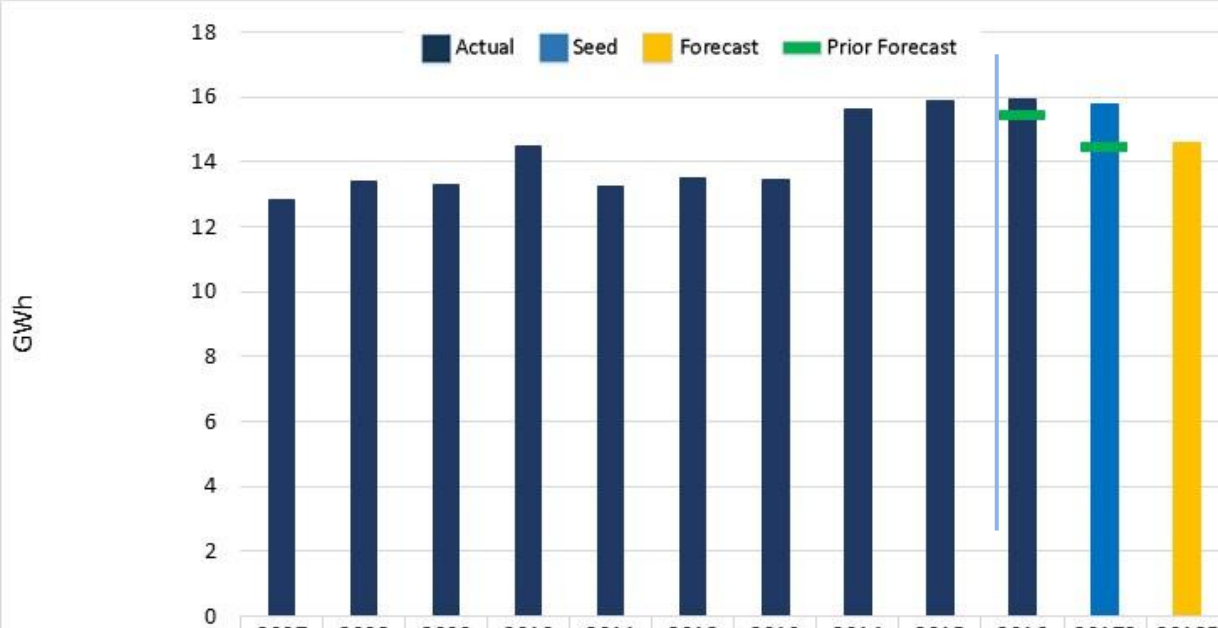


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
GWh	314	218	216	234	271	291	352	381	380	373	370	379
Prior Year Forecast										393	407	

3.5.5 Lighting

Consistent with past practice FBC checks for trends in the historical load data. There is a statistically significant trend for the most recent five-year period, which was used to forecast load for this class. As shown in Figure 3-7 below, after-savings lighting load is forecast to decrease by 1 GWh in 2018 compared to 2017S.

Figure 3-7: After-Savings Lighting Load (GWh)

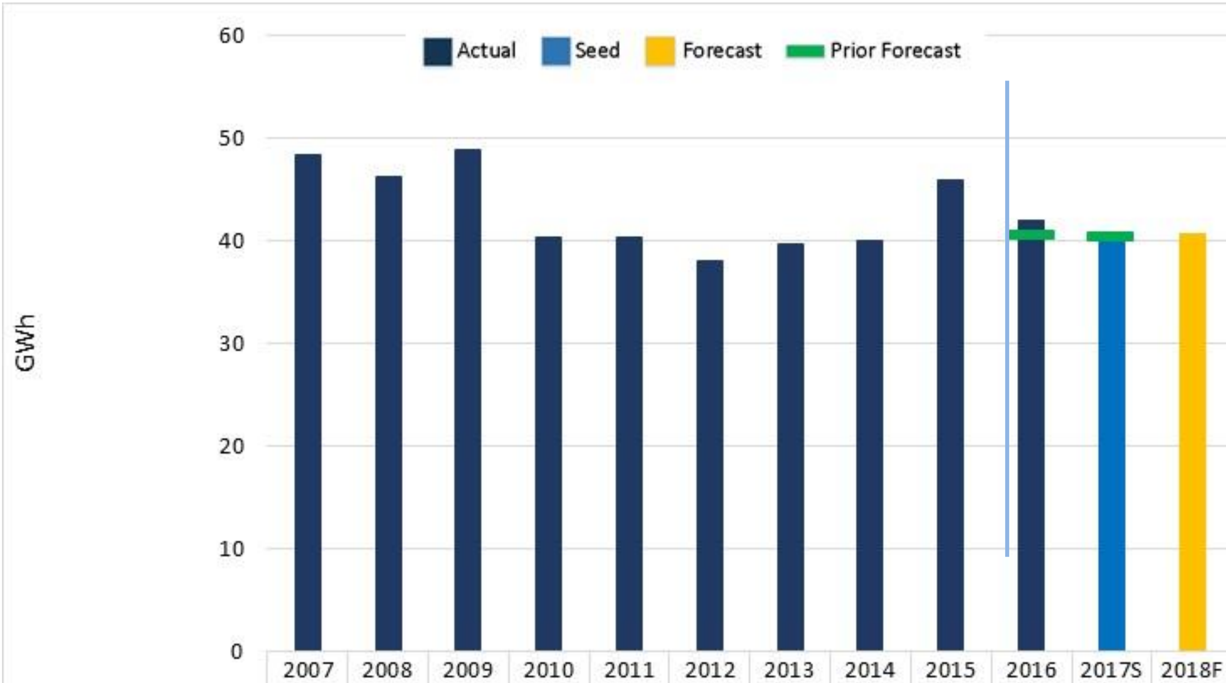


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
GWh	13	13	13	14	13	13	13	16	16	16	16	15
Prior Year Forecast										15	14	

3.5.6 Irrigation

Consistent with past practice FBC checks for trends in the historical load data. No statistically significant trend was found for this class therefore an average of the most recent five-year period was used to forecast load. As shown in Figure 3-8 below, after-savings irrigation load is forecast remain constant in 2018.

Figure 3-8: After-Savings Irrigation Load (GWh)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
After-Savings Growth	48	46	49	40	40	38	40	40	46	42	41	41
Prior Year Forecast										41	40	

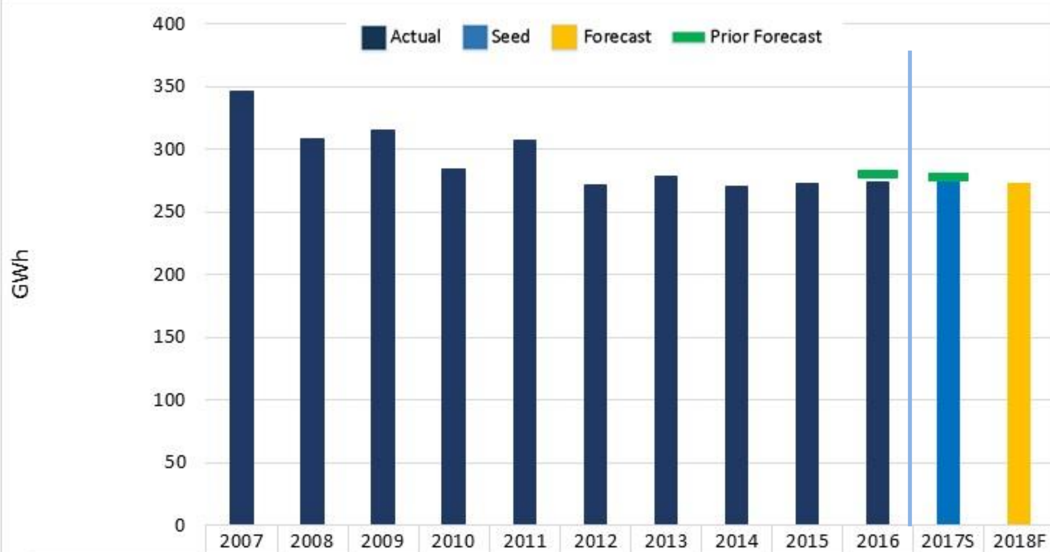
3.5.7 Losses

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. The 8 percent loss rate was based on a loss study that was conducted in 2012, which is still in line with the loss rate that FBC is seeing on an annual basis (averaging 7.88 percent over the previous three years, after DSM and AMI impacts). AMI loss reduction is expected to further reduce the losses in the future. As shown in Figure 3-9 below, after-savings energy losses are forecast to decrease by 3 GWh in 2018.

Figure 3-9: Normalized After-Savings Losses (GWh)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
GWh	346	309	315	284	307	271	278	270	272	274	275	272
Prior Year Forecast										280	278	

3.5.7.1 Advanced Metering Infrastructure (AMI) Impact on Losses

FBC's implementation of AMI (approved by Order C-7-13) is expected to positively impact losses (unaccounted-for energy) by deterring theft of power, mainly for indoor marijuana grow sites. In Order G-107-15 in FBC's Annual Review for 2015 Rates, FBC was directed to include in its next and subsequent Annual Review materials the impact of AMI on losses through theft deterrence, including:

(i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and

(ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.[19]

The following information on GWh theft reduction, costs and activities reducing electricity theft and regulatory treatment is provided in response to this directive.

The projected GWh theft reduction for the test year and subsequent years is unchanged from the estimated GWh theft reduction assumed in the AMI decision, which includes the impact of the Commission's determination to limit the number of assumed marijuana grow cycles to three per year, reducing the assumed annual energy losses downward to 113,000 kWh annually per theft site.

[19] Order G-107-15, page 15.

Current forecast loss reductions remain unchanged from those provided as part of the AMI CPCN application. Table 3-4 below provides details of the normalized losses for 2012 – 2016, as well as the forecast losses (both with and without the AMI impact) for 2017 – 2019. The 2016 AMI impact to losses related to theft detection and deterrence is 2.7 GWh, which is consistent with the original forecast. The 2016 loss figures are embedded in the 2017 – 2019 loss figures noted in Table 3-4.

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

		Before AMI				After AMI	
Line No.	Year	Actuals and Before-Savings Gross Load (GWh)	% of Gross Load	Normalized Actual and Forecast Losses (GWh)	Incremental AMI Impact (GWh)	% of Gross Load	Losses (GWh)
1	2012 Actual	3,421.7	7.92%	271.1			
2	2013 Actual	3,500.0	7.95%	278.1			
3	2014 Actual	3,436.0	7.86%	270.1			
4	2015 Actual	3,445.8	7.91%	272.4			
5	2016 Actual	3,476.6	7.87%	273.8			
6	2017 Seed	3,506.3	7.95%	278.9	(3.9)	7.84%	275.0
7	2018 Forecast	3,533.8	7.90%	279.1	(7.0)	7.70%	272.1

Note: The AMI impacts are incremental to the losses before AMI in each year, and are incorporated into the forecast for the following year (the 2018 forecast includes a 2017 forecast reduction of 3.9 GWh plus a 2018 forecast reduction of 3.0 GWh).

FBC is beginning to leverage the tamper detection functionality of the AMI system for theft identification and has also begun to implement its energy balancing program.

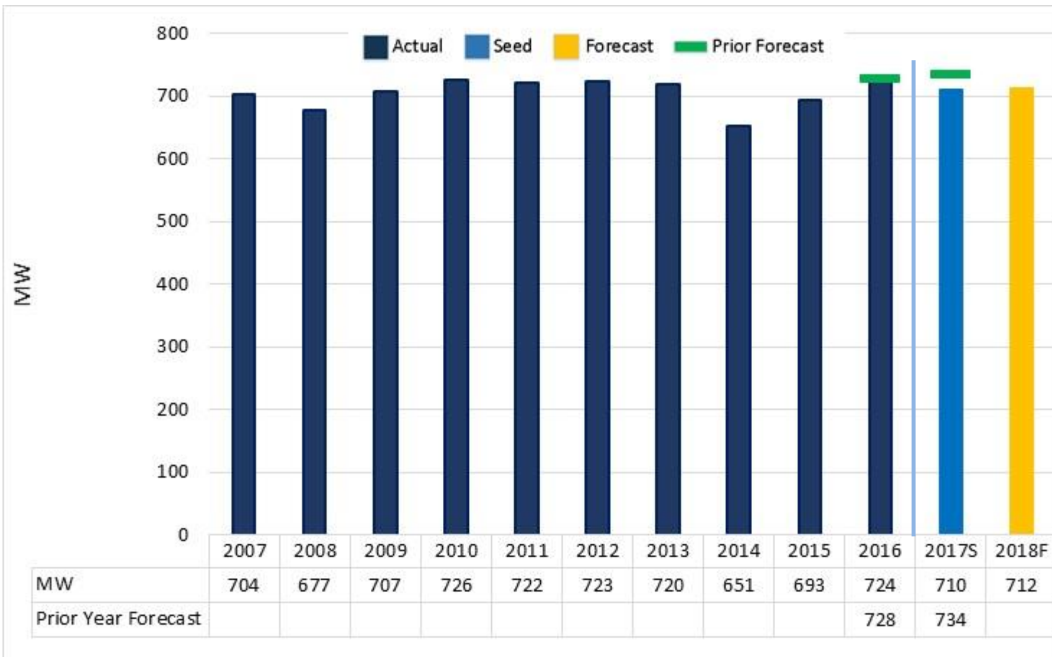
The following discussion of AMI-related O&M costs incurred in reducing electricity theft, i.e. related to the AMI-enabled revenue protection program, and their regulatory treatment is provided in this section in response to the directive cited above. The O&M expenditures incurred in reducing electricity theft that are incremental to those included in Base O&M. They relate primarily to the addition of a Revenue Protection Analyst for managing the development and operation of the AMI-enabled energy-balancing program, as well as the necessary field resources for the periodic deployment and relocation of the feeder metering devices as required. The incremental costs related to the Revenue Protection Analyst and field resources include 2018 O&M expenditures of $0.25 million.

The AMI costs associated with FBC's Revenue Protection Program that are incremental to the Revenue Protection program costs included in formula O&M are forecast, and tracked, outside of the PBR formula. Any variances from forecast are recovered from, or returned to, customers in the following year, by way of the Flow-through deferral account, as discussed in section 6.3.

3.5.8 Peak Demand

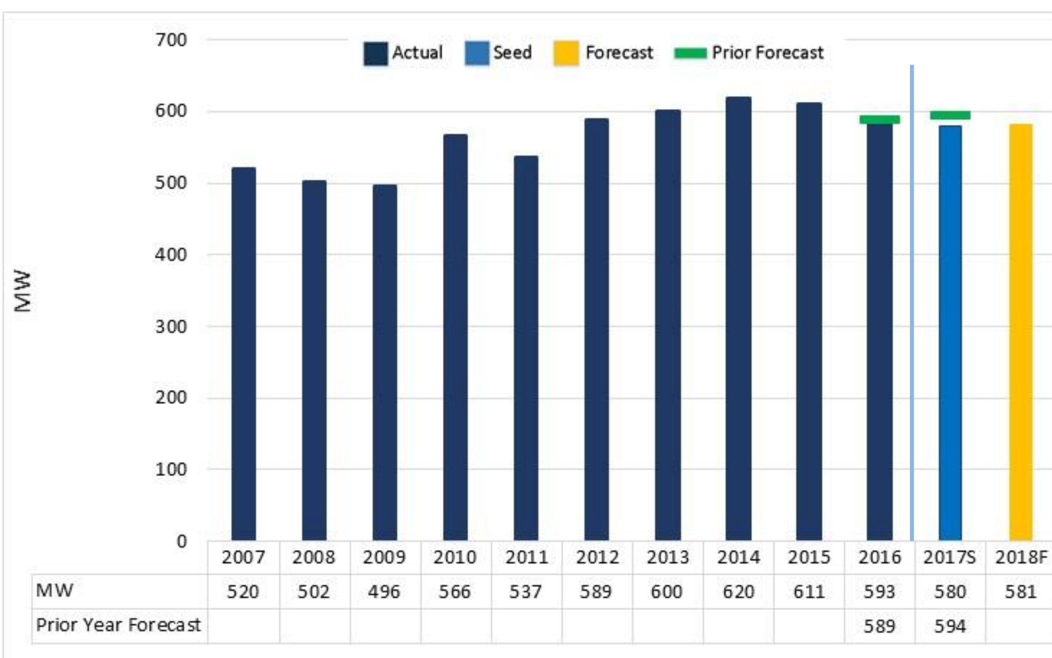
The peak demand forecast is produced using the ten-year average of historical peaks. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Normalized after-savings winter and summer peaks for 2007-2016 are shown below along with the 2017 and 2018 forecast.

Figure 3-10: After-Savings Winter Peaks (MW)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
MW	704	677	707	726	722	723	720	651	693	724	710	712
Prior Year Forecast										728	734	

Figure 3-11: After-Savings Summer Peaks (MW)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
MW	520	502	496	566	537	589	600	620	611	593	580	581
Prior Year Forecast										589	594	

3.6 *REVENUE FORECAST*

The forecast of revenues has been developed by applying approved 2017 rates to the forecast billing determinants for each customer class. Table 3-5 below summarizes the approved, projected and forecast revenue for 2017 and 2018.

Table 3-5: Forecast Sales Revenue at 2017 Approved Rates ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Residential	$ 187.578	$ 179.346	$ 178.976
2	Commercial	86.254	91.946	90.669
3	Wholesale	48.498	50.903	48.565
4	Industrial	33.501	31.645	31.712
5	Lighting	2.873	3.306	2.903
6	Irrigation	3.424	3.246	3.515
7	Total	$ 362.128	$ 360.392	$ 356.340

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.7 *SUMMARY*

FBC's forecast of load is based upon methods that are consistent with those used in prior years and conform to the recommendations of the 2011 Load Forecast Technical Committee. The normalized after-savings gross load forecast is 3,485 GWh. Based on net load of 3,213 GWh at the approved 2017 rates, FBC's 2018 revenue forecast is $356.340 million.

When comparing the 2018 forecast to the 2017 Approved there in a decrease in gross load of 74 GWh. This decrease is due to lower residential and industrial loads, and is partially offset by increased commercial load.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2017 Projected and 2018 Forecast power purchase expense (PPE), wheeling expense and water fees.

As shown in Table 4-1 below, the 2018 Forecast power supply cost of $148.450 million represents a decrease of 2 percent or $3.022 million compared to the 2017 Approved cost of $151.472 million. The decrease in the 2018 Forecast Power Supply cost is due to reduced gross load and reduced purchases under the Company's power purchase agreement with BC Hydro, combined with increased savings due to market purchases. The increase in 2018 Forecast wheeling expense is due to increases in the wheeling nominations and annual increases to contractual wheeling rates. 2018 Forecast water fees have decreased slightly compared with 2017 Approved, as a result of a reduction in FBC's entitlement usage in the previous year. Any variances to forecast in these items are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Power Purchase Expense	$ 136.216	$ 130.437	$ 133.071
2	Wheeling Expense	4.928	5.017	5.171
3	Water Fees	10.328	10.329	10.208
4	Total Power Supply Cost	$ 151.472	$ 145.783	$ 148.450
5				
6	Gross Load (GWh)	3,559	3,542	3,485

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply and market purchases to meet its load requirements. The Company's firm resources consist of:

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year to year timing differences in the entitlement energy storage under the CPA;

2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade power (Letter L-57-00) and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro Rate Schedule 3808 (Order G-60-14);
4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);
5. A number of small Independent Power Producer (IPP) contracts; and
6. A number of market purchase arrangements.

4.3 *PORTFOLIO OPTIMIZATION*

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply all of its 2018 forecast annual energy and capacity requirements. The nature of FBC's contracted resources, in particular the BC Hydro PPA, provides the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is greater than FBC's current capacity requirements in most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by the Commission in Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by the Commission in Order E-10-15.

4.4 *FBC 2017/18 ANNUAL ELECTRIC CONTRACTING PLAN*

On March 27, 2017, FBC filed its 2017/18 Annual Electric Contracting Plan (AECP) with the Commission. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and annual energy requirements for the operating year commencing October 1, 2017 and ending September 30, 2018, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to displace PPA purchases with lower cost resources or to manage annual loads that are below forecast. Therefore, real-time opportunities are restricted to a maximum of 25 percent of the PPA nominated energy but, depending on system conditions, could be less.[20] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over the short term. FBC's forecasts of PPE for the remainder of 2017 and for 2018 are based on the plan detailed in the 2017/18 AECP, which was generally accepted by the Commission on April 27, 2017, by way of Letter L-6-17[21].

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2017/18 contract year equal to 758 GWh, less any firm market contracts that FBC could enter into, as described in section 5 of the 2017/18 AECP.

During June of 2017, FBC entered into energy supply contracts (June 2017 ESCs) with Powerex under the terms of the CEPSA which provide FBC with 71 GWh of incremental market energy during the winter of 2017/18, 71 GWh during the winter of 2018/19, and 24 GWh during the winter of 2019/2020, all at a lower cost than if supplied under the PPA. The June 2017 ESCs were submitted for BCUC approval on July 28, 2017, and FBC has prepared its forecast under the assumption that they will be accepted as filed. The June 2017 ESCs and associated savings are included in the 2017 Projected PPE and 2018 Forecast PPE. As a result of these contracts, and changes to the forecast gross load, the Company submitted a PPA nomination for the 2017/18 contract year of 642 GWh on June 27, 2017, as confirmed in a letter to BCUC on July 28, 2017.

4.5 REVIEW OF 2017 POWER PURCHASE EXPENSE

As shown in Table 4-2 below, FBC's 2017 gross load (after taking into account demand side management and other customer savings) is expected to be 17 GWh below the 2017 Approved value, while PPE is projected to be below the 2017 Approved value by $5.776 million. The reduction in 2017 projected power purchase expense is primarily due to additional market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost, reduced Waneta Expansion costs resulting from increased mitigation revenue, as well as reduced load.

[20] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh

[21] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-6-17.

Table 4-2: 2017 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Difference
1	Brilliant	$ 39.373	$ 39.362	$ (0.011)
2	BC Hydro PPA	46.968	38.806	(8.162)
3	Waneta Expansion	38.330	37.248	(1.082)
4	Market and Contracted Purchases	11.341	16.013	4.672
5	Independent Power Producers	0.204	0.087	(0.117)
6	Self-Generators	-	0.071	0.071
7	CPA Balancing Pool	-	(1.155)	(1.155)
8	Special and Accounting Adjustments	-	0.005	0.005
9	Total	$ 136.216	$ 130.437	$ (5.779)
10				
11	Gross Load (GWh)	3,559	3,542	(17)

4.6 *2018 POWER PURCHASE EXPENSE FORECAST*

As shown in Table 4-3 below, the 2018 Forecast PPE is approximately $2.634 million greater than the 2017 Projected. The forecast increase from $130.437 million in 2017 to $133.071 million in 2018 is a result of a reduction in market and contracted purchases and correspondingly a greater reliance on relatively higher cost energy supplied by BC Hydro, as well as increases to BC Hydro, Waneta Expansion, and Brilliant contract rates.

Table 4-3 shows a comparison of the 2017 Projected PPE and the 2018 Forecast PPE. Reasons for significant variances from the 2017 Projected PPE are discussed below.

Table 4-3: 2017 and 2018 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2017	Forecast 2018	Difference
1	Brilliant	$ 39.362	$ 39.632	$ 0.270
2	BC Hydro PPA	38.806	44.906	6.100
3	Waneta Expansion	37.248	37.437	0.188
4	Market and Contracted Purchases	16.013	10.951	(5.062)
5	Independent Power Producers	0.087	0.080	(0.007)
6	Self-Generators	0.071	0.066	(0.006)
7	CPA Balancing Pool	(1.155)	-	1.155
8	Special and Accounting Adjustments	0.005	-	(0.005)
9	Total	$ 130.437	$ 133.071	$ 2.634
10				
11	Gross Load (GWh)	3,542	3,485	(57)

The 57 GWh decrease in gross load is due to a reduced load forecast in 2018.

The $0.270 million increase from 2017 Projected to 2018 Forecast in the Brilliant expense is due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

BC Hydro PPA expense increased by $6.100 million in the 2018 forecast compared to the 2017 Projected. A forecast BC Hydro rate increase of 3.0 percent on April 1, 2018[22] accounts for $1.636 million, whereas higher purchased volume (84 GWh) increases the 2018 Forecast expense by $6.464 million. For the 2018 Forecast, and consistent with the 2017 Approved, FBC has included a $2.000 million reduction to the forecast BC Hydro expense to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases using the flexibility provided under the BC Hydro PPA. Additional market savings are possible for 2018 but will depend on actual system and market conditions at the time. For 2017, actual system and market conditions have resulted in the Company exceeding the $2.000 million planned savings for 2017. For the 2017 Projection, FBC has included an additional $1.356 million in net savings (above the $2.000 million planned savings) for actual PPE through May 31, 2017, as well as savings associated with the June 2017 ESCs and a forecast of savings for the rest of the year. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

The $0.188 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, as well as a $0.229 million decrease in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of capacity FBC releases to Powerex and to the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. FBC's forecast of Mid-C forward market prices is based on contracts that have been traded and/or bids and offers from forward contracts on the Intercontinental Exchange Inc. (ICE), which is a global exchange, clearing, financial data and, technology company. More electric power is traded on ICE than any other electronic marketplace in the world. The method used to forecast market prices and calculate surplus sales is the same as in the Annual Review for 2017 Rates. Overall, the forecast of market prices has a relatively small effect on the overall PPE. The forecast of surplus capacity sales revenue in 2018, which is included (in line 3) of Table 4-3, is approximately $9.273 million.

The $5.062 million reduction in Market and Contracted Purchases is due to a forecast reduction in the volume purchased in 2018. Market and Contracted Purchases for 2017 include fixed price contracted purchases, and real-time market purchases made using the 25 percent flexibility of the PPA. All of the market purchases included in the 2018 Forecast are based on fixed price contracts executed by the Company. As discussed above, there may be opportunities for additional real-time market purchases in 2018 using the flexibility of the PPA purchases and FBC has reduced its expected purchases under the BC Hydro PPA by $2.000 million to account for this, consistent with the 2017 Approved PPE.

[22] BC Hydro filed its F2017-F2019 Revenue Requirements application on July 28, 2016, requesting a rate increase of 3.0 percent effective April 1, 2018. (BC Hydro F2017 – F2019 Revenue Requirements, Exhibit B-1-1).

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA, and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2017 Projected PPE, FBC has stored a net total of 24 GWh of entitlement energy, valued at $1.155 million. For the 2018 Forecast, FBC does not forecast any net use or storage of entitlement energy.

4.7 *WHEELING EXPENSE*

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (OATT) as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's Rate Schedule 21.

Wheeling expense is forecast using the same method as in the Annual Review for 2017 Rates. Table 4-4 below shows FBC's Wheeling Expense for 2017 and 2018.

Table 4-4: Wheeling Expense ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,430	2,430	2,490
3	Creston	432	432	444
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.374	$ 4.390	$ 4.590
7	Creston	0.507	0.508	0.534
8	Other	0.048	0.119	0.048
9	Total Wheeling Expense	$ 4.928	$ 5.017	$ 5.171

In 2017 and 2018, ARWA costs are forecast to account for all of FBC's wheeling expense, except for $0.119 million and $0.048 million of OATT and Teck wheeling in 2017 and 2018 respectively. Increased use of OATT wheeling to displace PPA purchases in early 2017 caused the 2017 Projected OATT wheeling expenses to exceed Approved.

As shown in Table 4-4 above, 2018 wheeling expense is forecast to increase by $0.154 million over 2017 Projected. This is a result of anticipated ARWA rate increases on October 1 of both 2017 and 2018, as well as increases to the Okanagan and Creston Wheeling nominations starting in October 2017 and October 2018 respectively. The AWRA annual rate increases are based on forecast BC CPI.

4.8 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC CPI.

As shown in Table 4-5 below, the 2018 Forecast water fees are decreasing by $0.121 million over 2017 Projected due to reduced entitlement use in the previous year. Water fees are forecast using the same method as in the Annual Review for 2017 Rates.

Table 4-5 below shows FBC's Water Fees for 2017 and 2018.

Table 4-5: Water Fees ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Previous Year Entitlement Use (GWh)	1,617	1,619	1,568
2				
3	Water Fees	$ 10.328	$ 10.329	$ 10.208

4.9 SUMMARY

FBC's forecast of power purchase expense is based on FBC's firm resources in place at the time of filing and is consistent with the 2017/18 AECP. FBC will continue to work toward optimizing its power purchase portfolio. Any variances in the costs of power supply, including any power purchase expense decrease due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

5. OTHER REVENUE

As shown in the table below, FBC is forecasting other revenue for 2018 to be $0.360 million higher than the amounts approved for 2017. The main driver of this increase is Other Recoveries, which reflects income earned on construction work performed for a third party that that will be recognized in 2017 and 2018. This income, which is expected to be $1.072 million with approximately 80% earned in 2017 and the remaining 20% earned in 2018, is also responsible for the increase in the 2017 Projected compared to the approved value.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Apparatus and Facilities Rental	$ 4.576	$ 4.598	$ 4.736
2	Contract Revenue	1.865	1.726	1.769
3	Transmission Access Revenue	1.179	1.179	1.170
4	Interest Income	0.024	0.022	0.016
5	Connection Charges	0.270	0.456	0.368
6	Other Recoveries	0.142	0.999	0.356
7	Total	$ 8.056	$ 8.980	$ 8.416

In the following sections, FBC summarizes its forecasts for each of the line items included in the table above.

5.1 APPARATUS AND FACILITIES RENTAL

Apparatus and facilities rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. The 2017 Projected is expected to be in line with 2017 Approved. 2018 revenue is forecast to be higher than 2017 Approved due to escalations in unit rental rates.

5.2 CONTRACT REVENUE

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third party work, and the associated management fees earned, fluctuate from year to year based on customer requirements which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing

Policy[23] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2017 Projected is expected to be lower than 2017 Approved due to less contract activity performed based on customer requirements. FBC's 2018 revenue is forecast to be slightly higher than 2017 Projected due to labour and material cost escalations.

5.3 TRANSMISSION ACCESS REVENUE

Transmission access revenue represents charges to customers for transmitting power over the FBC system. Three customers are expected to be using the transmission system in 2017 and 2018. The 2017 Projected is expected to be in line with 2017 Approved, while the 2018 Forecast is expected to decrease marginally due to a lower nomination of power to transmit in that year by one of the customers.

5.4 INTEREST INCOME

Interest income is primarily comprised of DSM loan interest income. The Company is continuing to experience a decline in the number of DSM loans, and as a result a corresponding drop in interest income is expected as loans mature.

5.5 CONNECTION CHARGES

Connection Charges are calculated based on the connection charges specified in FBC's rate schedules applied to the projected or forecast number of new customers. The 2017 Projected connection charge revenues are expected to be higher than 2017 Approved due to a higher number of customer connections. The 2018 Forecast is expected to be lower than the 2017 Projected due to lower connections expected.

5.6 OTHER RECOVERIES

Other recoveries are primarily comprised of the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities. The 2017 Projected and 2018 Forecast are expected to be higher than 2017 Approved due to management fees that will be earned in 2017 and 2018 on construction work for a third party. This income is expected to be $1.072 million, with approximately 80% earned in 2017 and the remaining 20% earned in 2018.

5.7 SUMMARY

FBC has forecast the other revenue components for 2018 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the

[23] As approved by Order G-5-10A.

variable components. Variances in other revenue are recorded in the Flow-through deferral account.

6. O&M EXPENSE

6.1 *INTRODUCTION AND OVERVIEW*

Under the PBR Plan, FBC's O&M expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis. In 2018, the formula O&M is $54.764 million, representing a 1.282 percent increase from the 2017 formula O&M, entirely due to the formula drivers. O&M expenses forecast outside the formula are $3.815 million, representing an approximate 9.689 percent increase from the amount approved for 2017. Overall, the increase in Gross O&M Expense from 2017 Approved to 2018 Forecast is approximately 1.790 percent.

The components of 2018 O&M expense are shown in Table 6-1 below.

Table 6-1: 2018 O&M Expense

Line No.	Description	2018	Reference
1	Formula O&M	$ 54.764	Table 6.2 Line 6
2	Forecast O&M	3.815	Table 6.3 Line 6
3	Total Gross O&M	58.579	
4	Capitalized Overhead (15%)	(8.787)	Section 11, Sch. 20
5	Net O&M	$ 49.792	

In the subsections below, FBC provides further details on its formula and forecast O&M expenses for 2018.

6.2 *FORMULA O&M EXPENSE*

The formula-driven portion of Base O&M starts from a base of the 2017 Approved formula O&M for FBC, escalated by the prior year's inflation less a productivity improvement factor of 1.03 percent, and one-half of the prior year's growth in average customers. As calculated in Section 2, the 2018 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.649 percent and one-half of the prior year's customer growth is 0.629 percent.

For 2018, the annual operating and maintenance expense under the formula is calculated as:

2017 Approved formula O&M x [1 + (I Factor – X Factor)] x [1 + (0.5 x customer growth)]

Table 6-2 below shows the calculation of the 2018 Formula O&M.

Table 6-2: Calculation of 2018 Formula O&M

Line No.	Description			Reference
1	2017 Approved Formula O&M	$	54.071	FBC 2017 Rates Evidentiary Update Filing Sch 21
2				
3	Net Inflation Factor		0.649%	Section 2 Table 2-3
4	Customer Growth Factor		0.629%	Section 2 Table 2-2
5				
6	2018 Formula O&M	$	54.764	Line 1 x (1 + Line 3) x (1 + Line 4)

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

The Formula O&M is then adjusted to add in pension and OPEB expense, insurance premiums, the net costs and savings of FBC's AMI Project, and any exogenous factor items (Mandatory Reliability Standards for 2017 and 2018). FBC has also included in 2017 and 2018 a reduction to O&M due to lower annual inspection costs, which was due to capital refurbishment of two of its generating units. The 2018 amounts are shown in Table 6-3 below along with a comparison to 2017.

Table 6-3: 2018 Forecast O&M ($ millions)

Line No.	Description		Approved 2017		Projected 2017		Forecast 2018
1	Pension/OPEB (O&M Portion)	$	3.267	$	3.267	$	2.659
2	Insurance Premiums		1.327		1.267		1.265
3	Advanced Metering Infrastructure Project		(1.126)		(1.126)		(1.139)
4	Mandatory Reliability Standards Incremental O&M		0.050		0.050		1.070
5	Upper Bonnington Units 3 and 4 Annual Inspection		(0.040)		(0.040)		(0.040)
6	Forecast O&M	$	3.478	$	3.418	$	3.815

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expenses are captured in the Pension and OPEB Variance deferral account. Variances in insurance premiums, AMI, and the incremental Mandatory Reliability Standards (MRS) expenses are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expenses for 2018 are based upon recent actuarial estimates using a range of assumptions at December 31, 2016 provided by the Company's actuary, Willis Towers Watson. Pension and OPEB expense is broken into O&M and capital categories as shown in Table 6-4.

Table 6-4: 2017 – 2018 Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2017	Forecast 2018
1	O&M	$ 3.267	$ 2.659
2	Capital	3.539	3.630
3	Total Pension & OPEB Expense	$ 6.806	$ 6.289

Overall, pension and OPEB expense for 2018 is forecast to be $0.517 million lower than what was approved for 2017. This decrease is primarily due to lower amortization of net actuarial losses from prior years, and higher expected return on assets partially offset by the higher service cost and interest cost.

The 2017 variance between approved and actual pension and OPEB expense and any 2018 variance between these amounts is captured in the Pension and OPEB Variance deferral account and amortized into rates over a three year period as approved in by the Commission in Order G-139-14.

As described in Section 12.3.1.2, FBC has included in Table 6-4 above the impact of adopting the accounting guidance in ASU 2017-07 related to pension and OPEB expense, which results in a decrease in O&M and offsetting increase in capital expenditures of $0.360 million. The details are set out in Table 12-2.

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of the PBR formula relates to insurance premium expense allocated to FBC by Fortis Inc.

The 2018 insurance premiums are forecast at $1.265 million, a decrease of $0.062 million or 4.7 percent from what was approved for 2017. The 2018 Forecast is calculated by taking the known annual insurance premium of $1.102 which is applicable to the first six months of 2018 and escalating that amount by five percent for the remaining six months.[24] The five percent escalation is based on a combination of historical increases in premiums, increases in the value of assets year over year and the expectations of Fortis Inc.'s insurance broker on future premiums.

6.3.3 AMI Project

Incremental O&M costs related to the implementation of the AMI project are being offset by post-implementation savings, resulting in a net decrease to O&M expense during the PBR period. Because of the high variability of AMI costs and savings during the implementation

[24] $1.102 million/2 = $0.551 million x 1.05 = $0.579 million. $0.551 million + $0.579 million + $0.135 million annual firefighting premium = $1.265 million.

period, net AMI costs, including the costs of AMI-enabled billing options, are forecast and tracked outside of the PBR formula.

Table 6-5 below compares 2014 through 2018 net AMI savings to the net savings forecast in the AMI CPCN application.

Table 6-5: AMI Costs and Savings ($ millions)

Line No.		2014-2016			2017			2018	
1		Actual	Approved	CPCN(1)	Projected	Approved	CPCN(1)	Forecast	CPCN(1)
2		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
3									
4	AMI Costs	3.330	3.822	4.867	1.992	1.992	1.925	2.015	1.960
5	AMI Savings	(4.019)	(4.570)	(6.469)	(3.118)	(3.118)	(3.970)	(3.153)	(4.424)
6	Net AMI Costs/(Savings)	(0.689)	(0.748)	(1.602)	(1.126)	(1.126)	(2.045)	(1.138)	(2.464)
7									
8	(1) CPCN estimates adjusted to include reclassification of software from capital pursuant to Order G-13-14								

As reported previously, AMI-related costs and savings from 2014 to 2016 lag those estimated in the AMI CPCN primarily due to delayed project timing following an extensive CPCN review process and the Commission's directive to file for approval of an opt-out program prior to meter installation. The AMI project was substantially completed during 2016, such that 2017 will be the first year of fully realized costs and savings for the AMI project.

As shown in Table 6-5 above, the 2018 forecast costs are approximately as forecast in the CPCN application.

As also shown in Table 6-5 above, the 2018 forecast savings of $3.153 million are approximately $1.271 million lower than the CPCN forecast of $4.424 million. This variance is driven by meter reading, Measurement Canada compliance savings, and other smaller factors as explained below.

Meter Reading

The CPCN forecast was a comparison of the savings that would be achieved with the AMI project to the costs that would otherwise be incurred to support the continuation of a manual meter reading program. As such, the AMI CPCN forecast savings required a cost forecast of continuing with manual meter reading. The manual meter reading cost forecasts used in the CPCN for 2013 and 2014 (the last full years of manual meter reading) were higher than the costs actually experienced in those years. These savings resulted largely from efficiencies found in absorbing the City of Kelowna manual meter reading work. As a result, the savings potential was diminished in 2015 and beyond.

CPCN forecast costs for meter reading were also based in part on the forecast number of customers. This CPCN forecast averaged 1.9% per per year between 2014 and 2016, which was higher than the 1.3% actually experienced. The 2018 forecast customer count in the CPCN application (who would have required manual meter reading in the absence of AMI) is expected to be higher by about 6,000 customers than the actual number of customers based on experience to mid-2017.

In total, the meter reading savings contribute approximately $0.750 million of the total AMI savings variance in 2018.

Measurement Canada Compliance

One of the benefits of replacing the majority of the meter fleet with AMI meters was a reduction in Measurement Canada compliance costs. As with meter reading, forecasting these savings required a forecast of the cost of meter exchanges that would have been required in the absence of AMI. The CPCN application forecast the number of Measurement Canada compliance meter exchanges to double in 2018 over 2017 levels (in the absence of AMI), increasing avoided costs by approximately $0.250 million over 2017. This avoided cost does not result in a reduction to 2018 O&M costs, but will still result in lower rates for customers than in the absence of AMI.

Other Factors

Other factors contributing to the $1.271 million AMI Savings variance include:

- Approximately $0.100 million lower savings due to higher post-AMI manual disconnect and reconnect costs than forecast. 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.
- Approximately $0.100 million lower savings due to lower pre-AMI Measurement Canada compliance exchange costs than forecast. As with the lower pre-AMI meter reading costs discussed above, this reduced the post-AMI savings potential.

6.3.4 MRS Incremental Operating Expense

FBC forecasts that it will incur $1.070 million in incremental O&M expense in 2018 related to the adoption of new and revised standards in addition to a scheduled compliance audit, as summarized in Table 6-6 and described below.

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

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Assessment Report No. 8	$ 0.050	$ 0.050	$ 0.540
2	Assessment Report No. 10	-	-	0.180
3	2018 Compliance Audit	-	-	0.350
4	Forecast O&M	$ 0.050	$ 0.050	$ 1.070

6.3.4.1 Assessment Report No. 8

In 2016 FBC began to incur incremental O&M and capital costs for MRS in compliance with Order R-38-15 dated July 24, 2015. In Order R-38-15, the Commission adopted 34 reliability standards and the NERC (North American Electric Reliability Corporation) Glossary of Terms as recommended for adoption by BC Hydro in its MRS Assessment Report No. 8.

As explained in Section 12.2.2, the incremental costs in 2018 for MRS compliance qualify for exogenous factor treatment. This treatment is consistent with the Commission's determination in Orders G-202-15 and G-8-17 that FBC's 2016 and 2017 forecast costs required for the adoption of MRS pursuant to Order R-38-15 met the criteria for an exogenous event under the PBR Plan.

FBC is continuing to track the incremental O&M and capital costs associated with compliance with Order R-38-15 and flowing them through to rates outside of the formulas.

FBC's 2017 projection of incremental O&M expenses is $0.050 million which is equal to the Approved. The 2017 expenses include certain tasks related to Critical Infrastructure Protection (CIP) version 5 (V5) standards as well as specific training as part of Personnel Performance, Training and Qualifications standard PER-005-2.

The forecast expenditures for 2018 of $0.540 million will be utilized to maintain processes and systems that address physical and cyber security controls, continuous monitoring, change management, patch management and vulnerability assessments. The effort is primarily labour and annual licensing fees required to maintain compliance with CIP V5. These costs will continue in future years.

6.3.4.2 Assessment Report No. 10

BC Hydro issued Assessment Report No. 10 (AR10)[25] on May 1, 2017 recommending adoption of 35 of the 38 standards and 40 of the 43 terms from the NERC Glossary of Terms (NERC Glossary) that were assessed. The Commission issued Order R-39-17 on July 26, 2017 which adopted and determined the effective dates for the recommended 35 of the 38 standards. Of the 38 standards and respective NERC Glossary terms assessed by FBC, approximately 15 percent of the standards have associated costs.

FBC does not expect to incur O&M costs associated with AR10 in 2017.

O&M expenditures associated with AR10 for 2018 are forecast to be $0.180 million. The expenditures are primarily required for assessing and determining the strategy and detailed scope required to comply with the revised standards, which include: performing real-time pre- and post-contingency assessments every 30 minutes; meeting outage coordination

[25] The Commission adopted 15 Revised Standards and 10 NERC Glossary Terms addressed in BC Hydro's Assessment Report No. 9 by (AR9) Order R-32-16A on November 9, 2016. Incremental costs for FBC to achieve and maintain compliance with standards resulting from AR9 did not meet the financial threshold for Z-factor treatment.

requirements, implementing outage scheduling timelines and next day studies, and development of an operating plan to address all the above tasks. These expenditures also include fault level and breaker rating studies as well as testing of pressure relief devices and close functionality.

As noted above, in 2018 FBC will evaluate and determine how to best achieve compliance with AR10. Future expenditures associated with AR10 will be addressed in future filings.

6.3.4.3 2018 Compliance Audit

FBC's triennial MRS audit is scheduled to occur in 2018. This audit will be performed by the administrator of the BC MRS Program, Western Electricity Coordinating Council (WECC) and will include a review, at a minimum, of all applicable reliability standards identified in the Actively Monitored List to be issued in November 2017. This will include CIP and Operations and Planning (O&P) standards. The audit will be conducted by WECC auditors over a two week period where the first week will be off-site and the second week will be on-site at FBC facilities in order to perform interviews and visit specific critical sites. Preparation of evidence and the coordination of as many as ten to fifteen on-site WECC auditors and observers will take several months to complete. Audit preparation will impact various business groups including human resources, facilities, security, information systems, system control, operations, generation, engineering and planning (transmission/resource), which will be called upon and required to provide evidence to demonstrate compliance. In Order G-139-14 the Commission confirmed that as a non-recurring expenditure, MRS audits should not be included in Base O&M[26].

The Company continues to work towards maintaining MRS compliance and forecasts the costs related to the 2018 audit to be $0.350 million.

6.3.5 Annual Inspection Costs for Upper Bonnington Unit 4

The Upper Bonnington (UBO) Old Units Refurbishment project commenced in 2017. UBO Unit 3 is being refurbished in 2017, and the refurbishment of Unit 4 will be conducted in 2018. The Company will not carry out the annual inspections on the units while out of service for refurbishment. This results in an estimated savings of $0.040 million per unit.

The O&M reduction related to the annual unit inspections is a one-time reduction to O&M Expense in the year that a unit is refurbished. A unit will once again undergo annual inspections following refurbishment. Therefore, the level of Base O&M expenditures is not impacted on an ongoing basis. For this reason, the O&M reduction is outside of the formula O&M amount. Because these are avoided costs, there will not be a future true-up of this value.

6.3.6 Generation Unit Inspections

As directed by the Commission in Order G-139-14, FBC provides in this section a review of its actual expenses for generation major unit inspections in the Annual Review.

[26] PBR Decision, page 238.

The costs related to generation major unit inspections are included within formula Base O&M. These costs are for periodic major inspections of FBC's generating units, which have been the subject of upgrades and/or life extensions beginning in 1998. The inspections are expected to cost approximately $0.350 million per unit, depending on unit condition. The majority of FBC's generating units have similar characteristics and, as such, the estimate of $0.350 million is based on typical equipment in average operating condition. FBC expects to undertake one major unit inspection per year.

The Commission indicated on page 197 of the PBR Decision that the actual expenditures related to generation unit inspections should be monitored through the Annual Review process:

> Given the background and assurances provided by FBC, the Commission Panel finds that the proposal to include the $350,000 within the Base O&M is reasonable and is not persuaded there is a need to make it a flow through item at this time. However, in consideration of the concerns raised and the magnitude of the estimate, actual expenditures should be monitored through the Annual Review process.

As the inspection on Lower Bonnington Unit 1 had not been completed at the time of the Annual Review for 2017 Rates, a description of the work undertaken in 2016 is provided.

FBC completed its major unit inspection on Lower Bonnington Unit 1 on December 3, 2016 at a cost of $0.326 million. The scope of the inspection included dismantling of the unit to the shaft coupling, removing the rotor, performing overhauls on otherwise inaccessible systems such as the guide bearing, thrust bearing and brakes, performing in-depth mechanical and electrical inspections, and cleaning.

Unit inspections provide FBC with the opportunity to perform maintenance and condition assessment on components that are not accessible in normal operation. This allows FBC to address condition deterioration causes to ensure that the generating unit continues to be operated in a safe and efficient manner and that design life expectancy is achieved. These continued inspections enable the generating units to remain a reliable source of generation for FBC customers.

FBC plans to perform a unit inspection on Upper Bonnington Unit 5 in Q4 of 2017 at an estimated cost of $0.350 million.

6.4 *NET O&M EXPENSE*

Net O&M expense is Gross O&M less capitalized overhead. As approved by the Commission in Order G-139-14, the capitalized overhead rate is 15 percent for FBC. After capitalized overhead, the net O&M expense is $49.792 million.

6.5 SUMMARY

Overall the increase in Gross O&M Expense from Approved 2017 to 2018 is approximately 1.790 percent. The formula-driven O&M is increasing at a rate of 1.282 percent, and forecast O&M is 9.689 percent higher than Approved 2017. The capitalized overhead rate remains unchanged from 2017.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

The 2018 Rate Base for FBC is forecast to be $1.322 billion. Rate Base is composed of mid-year net plant in service, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital and the generation plant acquisition adjustment[27].

The 2018 Rate Base of FBC includes the full-year impacts of the 2017 closing projected plant balances as well as the mid-year impact of the following amounts:

- Capital additions resulting from regular capital expenditures, net of Contributions in Aid of Construction (CIAC) additions, of $42.472 million;
- Capital additions of $25.287 million resulting from completion of the Kootenay Operations Centre and the first of four generating units completed under the Upper Bonnington Old Units Rehabilitation Project; and
- Plant depreciation, net of CIAC amortization, of $39.531 million.

The capital formula dead band adjustment of $11.268 million, discussed in Section 1.4.3, is also included as an opening balance adjustment.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $40.580 million.

Details of the 2018 forecast plant balances can be found in Section 11 Schedules 5 through 9.

7.2 2018 REGULAR CAPITAL EXPENDITURES

Under the PBR Plan, FBC's regular capital expenditures are primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis. In 2018, the formula capital is $43.809 million, representing a 1.282 percent increase from 2017, entirely due to the formula drivers. Regular capital expenditures forecast outside the formula are $3.945 million, representing a 25.524 percent decrease from 2017, primarily due to lower incremental capital expenditures for MRS capital and AMI sustainment capital. Overall regular capital expenditures are forecast to decrease from 2017 to 2018 by 1.643 percent. The components of 2018 regular capital expenditures are shown in Table 7-1 below.

[27] The utility plant acquisition adjustment relates to the 1982 purchase of plants 2, 3, and 4 and is being amortized over a period of 64 years.

Table 7-1: 2018 Regular Capital Expenditures ($millions)

Line No.	Description			Reference
1	Formula Capital Expenditures	$	43.809	Table 7.2 Line 6
2	Forecast Capital Expenditures		3.945	Table 7.3 Line 4
3	Total Regular Capital Expenditures	$	47.754	

In the subsections below, FBC provides further details on its formula and forecast capital expenditures for 2018.

7.2.1 Formula Capital Expenditures

The formula-driven portion of regular capital expenditures starts from a base of the 2017 approved formula capital, escalated by the prior year's inflation less a productivity improvement factor of 1.03 percent, and one-half of the prior year's growth in average customers. As calculated in Section 2, the 2018 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.649 percent, and one-half of the prior year's average customer growth is 0.629 percent. In accordance with Order G-139-14, regular capital expenditure amounts will not be rebased to actual amounts during the PBR term, except that if the capital dead band is exceeded, FBC will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year.

For 2018, the annual capital expenditures under the formula are initially calculated as:

$$2018\text{ Capital} = 2017\text{ Capital} \times [(1 + (\text{I Factor} - \text{X Factor})] \times [1 + \text{customer growth}]$$

Table 7-2 below shows the calculation of the resulting 2018 formula capital expenditures.

Table 7-2: Calculation of 2018 Formula Capital Expenditures

Line No.	Description			Reference
1	2017 Approved Formula Capital Expenditures	$	43.254	FBC 2017 Rates Evidentiary Update Filing Sch. 4
2				
3	Net Inflation Factor		0.649%	Section 2 Table 2-3
4	Customer Growth Factor		0.629%	Section 2 Table 2-2
5				
6	2018 Formula Capital	$	43.809	Line 1 x (1 + Line 3) x (1 + Line 4)

7.2.2 Regular Capital Expenditures Forecast Outside the Formula

To calculate total regular capital expenditures, the formula capital expenditures are adjusted to add in pension and OPEB expense, AMI sustainment capital and MRS incremental capital expenditures related to BC Hydro's Assessment Reports No. 8 and No. 10, which qualify for exogenous treatment as discussed in Section 12.2 of the Application. These amounts are shown in Table 7-3 below along with a comparison to 2017.

Table 7-3: 2018 Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Pension/OPEB (Capital Portion)	$ 3.539	$ 3.539	$ 3.630
2	AMI Sustainment Capital	0.408	0.408	0.265
3	Mandatory Reliability Standards Incremental Capital	1.350	1.349	0.050
4	Forecast Capital Expenditures	$ 5.297	$ 5.296	$ 3.945

Each of the items forecast outside of the formula is described further below.

- The Pension and OPEB forecast of $3.630 million represents the forecast capital portion of the total Pension and OPEB costs for 2018. These amounts are described in Section 6.3.1.
- AMI Sustainment Capital of $0.265 million represents the costs of new sustainment capital associated with IT hardware, licensing, and support. These sustainment capital requirements result from the addition of new software required by the AMI project, such as the meter data management system, the head end system and network management system, and ongoing software licensing and support requirements.
- FBC forecasts that it will incur $0.050 million in incremental capital related to the adoption of new and revised MRS standards. The treatment of this amount as an exogenous factor is discussed in Section 12.2.1. The 2018 capital expenditure is related to Assessment Report No. 8 and is required for annual software upgrades for maintaining support and avoiding potential security, productivity and reliability issues, as well as making new functionality and features available that the vendors have developed through continued investment in their products.

7.3 CPCN AND SPECIAL PROJECTS CAPITAL EXPENDITURES

Also forecast outside of the formula are any capital expenditures related to approved CPCNs and other projects which were determined by Order G-80-16 to be outside of the formula capital expenditures and eligible for flow-through treatment.

For 2018, FBC is forecasting capital expenditures related to the Ruckles Substation Rebuild Project, the UBO Project, and the Corra Linn Dam Spillway Gate Replacement Project. Of these projects, only the portion of the UBO Project attributable to the refurbishment of Unit 3 will be included in rate base in 2018. Additionally, the Kootenay Operations Centre, which is expected to be completed in 2017, will be included in rate base in 2018.

Each of these projects is described further below[28].

- The Ruckles Substation Rebuild Project was approved by Order G-8-17 and involves rebuilding the existing substation in Grand Forks. The project will be completed during 2018 and is estimated to cost $8.038 million of which $2.644 million will be incurred in 2018. The Ruckles Substation Rebuild Project Status Report is included as Appendix C.
- The UBO Project was approved by Order G-8-17 and involves the refurbishment of the more than 100 year old generating Units 1 – 4 (the Old Units), over four years at an estimated cost of $31.783 million of which $7.447 million will be incurred in 2018. The UBO Project Status Report is included as Appendix D.
- The Corra Linn Dam Spillway Gate Replacement Project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. The project is expected to be completed in 2021 at a cost of $62.694 million with $21.968 million of this amount incurred in 2018.
- Order C-2-16 granted a CPCN for the construction of a new Kootenay Operations Centre located in the Castlegar area. The total project is expected to cost $21.098 million, less than the CPCN-approved forecast of $22.355 million. The expected in-service date is in the fall of 2017.

7.4 *2017 PLANT ADDITIONS*

The 2018 Plant Additions are comprised of FBC's 2018 regular capital expenditures from section 7.2 above, the Kootenay Operations Centre, Unit 3 of the UBO Project, the change in work in progress which adjusts for capital expenditures for projects such as those listed in Section 7.2 that are in progress at year end, AFUDC and overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Schedule 5 in Section 11.

[28] Costs inclusive of AFUDC and cost of removal.

Table 7-5: Reconciliation of Capital Expenditures to Plant Additions ($millions)

Line No.	Description		Reference
1	Formula Capital Expenditures	$ 43.809	Table 7-2
2	Forecast Capital Expenditures	3.945	Table 7-3
3	Total Regular Capital Expenditures	$ 47.754	
4			
5	Capitalized Overhead	8.787	Table 6-1
6	Direct Overhead	5.000	Section 11, Sch. 5, Line 20
7	AFUDC	0.692	Section 11, Sch. 5, Line 21
8	Cost of Removal charged to Accumulated Depreciation	(2.577)	Section 11, Sch. 5, Line 22
9	Total Regular Additions to Plant	59.656	
10			
11	Special Projects and CPCN Capital Expenditures	29.945	Section 11, Sch. 5, Line 28
12	Special Projects and CPCN AFUDC	2.114	Section 11, Sch. 5, Line 29
13	Special Projects and CPCN Cost of Removal	(1.381)	Section 11, Sch. 5, Line 30
14	Change in Special Projects and CPCN Work in Progress	(5.391)	Section 11, Sch. 5, Line 32
15	Special Projects and CPCN Additions to Plant	25.287	
16			
17	2018 Plant Additions	$ 84.943	

7.5 *CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)*

Rate base is reduced by CIAC. Gross CIAC is composed of opening contributions plus additions during the year. 2018 CIAC additions are forecast at $6.120 million. The year-end CIAC balances net of accumulated amortization are $118.894 million in 2017 (projected) and $121.101 million forecast in 2018.

7.6 *ACCUMULATED DEPRECIATION*

The rate base of FBC includes the accumulated depreciation of plant in service, which is increased through depreciation expense, and decreased through retirements.

The depreciation rates used for 2018 are the rates that have been approved by Orders G-202-15 and C-7-13 and include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved in Commission Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2018 depreciation expense is calculated as $58.476 million.

7.7 RATE BASE DEFERRED CHARGES

The forecast mid-year balance of unamortized deferred charges in rate base for FBC is approximately $11.942 million in 2018 and this balance is driven largely by the balances in deferral accounts for DSM, Pension and OPEB funding liability, deferred debt issue expense and unamortized meter costs arising from the AMI project, which were deferred pursuant to Order C-7-13. FBC is not proposing any new rate base deferral accounts for 2018.

Based on amortizing the opening deferral account balances using the approved amortization periods, the 2018 amortization expense for rate base deferral accounts is calculated as $4.982 million.[29]

7.8 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

7.8.1 Cash Working Capital

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag).

FBC's revenue lag for each customer class is the sum (weighted by the relative proportion of monthly- to bimonthly-billed customers in the class) of:

- The consumption lag, which is the number of days between the consumption of energy and the date the customer's meter is read or estimated;
- The processing lag, which is period between the date the customer meter is read or estimated and the date the bill to the customer is prepared; and
- The clearing lag, which is the period between the customer billing date and the when the funds are received from the customer.

The revenue lag associated with sales revenue is primarily a function of the frequency of billing. The majority of residential and commercial customers are currently being billed on a bi-monthly basis which corresponds with the bi-monthly manual meter reading schedule. Following the completion of FBC's AMI project, the Company is offering a new billing option to provide customers with monthly billing based on verified meter reads. Depending on the number of customers choosing this option, the revenue lag component of working capital may be reduced. In its Decision and Order G-16-14 approving FBC's proposed AMI-Enabled Billing Options, the Commission directed that FBC must flow through any incremental working capital benefits to customers by way of the Flow-through deferral account approved in Order G-139-14.

[29] Section 11, Schedule 11 Line 16 Column 6.

7.8.1.1 AMI Working Capital Impact

The impact on working capital due to the AMI Project results from changes in the proportion of monthly-billed to bi-monthly-billed customers. For this purpose, the proportion of customers billed monthly and bi-monthly as of June 2015 (prior to AMI implementation) was used in the determination of cash working capital for 2016 approved rates, and used as a baseline against which to identify future changes. Beginning in 2016, customers were able to choose the monthly billing option identified in FBC's AMI-Enabled Billing Options Application. Based on the change in the proportion of monthly-billed customers annually at December 31 of each year, FBC will quantify the impact on working capital and will record the variance in the Flow-through deferral account. In 2016, the impact of AMI on cash working capital resulted in a notional decrease of $0.006 million to revenue requirements, which will be returned to customers in 2018. The calculation of the revenue requirements impact is provided below.

From a comparison of columns c and f in Table 7-6 below it can be seen that the two largest customer classes, residential and commercial, experienced increases in the proportion of customers receiving monthly bills compared to bi-monthly bills. The periods between taking service and meter reading, and between billing and collection are shorter for customers on a monthly billing cycle. Hence, the total revenue lag days is lower than calculated in the approved cash working capital calculation.

Table 7-6: Calculation of 2016 Revenue Lag

Line No.	Customer Class	Service Period to Meter Read: Monthly	Service Period to Meter Read: Bimonthly	Approved Proportion Billed: Monthly	Approved Proportion Billed: Bimonthly	Approved Consumption Lag	Actual Proportion Billed: Monthly	Actual Proportion Billed: Bimonthly	Actual Consumption Lag	Meter Read to Billing Processing Lag
		a	b	c	d	e=a*c+b*d	f	g	h=a*f+b*g	i
1	Residential	15.2	30.4	13.5%	86.5%	28.3	14.6%	85.4%	28.2	1.0
2	Commercial	15.2	30.4	18.9%	81.1%	27.5	19.6%	80.4%	27.4	1.0
3	Wholesale	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0
4	Industrial	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0
5	Lighting	15.2	30.4	16.7%	83.3%	27.9	16.2%	83.8%	27.9	1.0
6	Irrigation	15.2	30.4	42.7%	57.3%	23.9	40.3%	59.7%	24.3	1.0
7										
8										

Line No.	Customer Class	Billing to Collection: Monthly	Billing to Collection: Bimonthly	Approved Proportion Billed: Monthly	Approved Proportion Billed: Bimonthly	Approved Clearing Lag	Actual Proportion Billed: Monthly	Actual Proportion Billed: Bimonthly	Actual Clearing Lag	Approved Total Lag Days	Actual Total Lag Days
12		j	k	l=c	m=d	n=j*l+k*m	o=f	p=g	q=j*o+k*p	r=e+i+n	s=h+i+q
13	Residential	17	22	13.5%	86.5%	21.3	14.6%	85.4%	21.3	50.7	50.5
14	Commercial	17	22	18.9%	81.1%	21.1	19.6%	80.4%	21.0	49.6	49.4
15	Wholesale	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2	33.2
16	Industrial	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2	33.2
17	Lighting	17	22	16.7%	83.3%	21.2	16.2%	83.8%	21.2	50.0	50.1
18	Irrigation	17	22	42.7%	57.3%	19.9	40.3%	59.7%	20.0	44.8	45.3

Table 7-7 below recalculates 2016 cash working capital assuming the revenue lags as of December 31, 2016. Cash working capital is reduced by $0.071 million, therefore reducing rate base by the same amount.

Table 7-7: AMI Adjustment to Cash Working Capital ($ million)

Line No.	Particulars	2016 at Revised Rates	Lag (Lead) Days	Extended	Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 184.048	50.5	$ 9.286		
4	Commercial Tariff Revenue	82.385	49.4	4.073		
5	Wholesale Tariff Revenue	46.940	33.2	1.558		
6	Industrial Tariff Revenue	31.020	33.2	1.030		
7	Lighting Tariff Revenue	2.417	50.1	0.121		
8	Irrigation Tariff Revenue	3.782	45.3	0.171		
9						
10	**Other Revenue**	8.177		0.249		2016 Rates Compliance Filing, Section 11, Schedule 14, Lines 10 - 14
11						
12	Total	$ 359		$ 16	46.0	
13						
14	**EXPENSES**	$ 260.017		$ 260.017	(38.6)	2016 Rates Compliance Filing, Section 11, Schedule 14, Line 34
15						
16	Net Lag (Lead) Days				7.4	
17						
18	Total Expenses				$ 260.017	
19						
20	Cash Working Capital, Revised Lag Days				$ 5.272	
21						
22	Cash Working Capital in 2016 Rates				$ 5.343	2016 Rates Compliance Filing, Section 11, Schedule 14, Line 40
23						
24	Reduction in Cash Working Capital				$ (0.071)	

Finally, Table 7-8 calculates the notional revenue requirements impact of the $0.071 million reduction in rate base, which is the pre-tax weighted average cost of capital. The adjustment is included in the additions to the Flow-through deferral account, as shown in Section 12, Table 12-3 at line 25.

Table 7-8: Revenue Requirements Impact of AMI Adjustment to Cash Working Capital ($ million)

Line No.	Description	Weight	Pre-Tax Rate	Adjustment for Cash Working Capital	Reference (2016 Rates Compliance Filing)
1	Long Term Debt	53.20%	5.35%	$ (0.002)	Section 11, Schedule 26, Line 1
2	Short Term Debt	6.80%	2.65%	(0.000)	Section 11, Schedule 26, Line 2
3	Common Equity	40.00%	12.36%	(0.004)	Note 1
4					
5					
6	Weighted Average	100.00%	7.97%	$ (0.006)	Column 2 x Column 3 x $0.071 million
7					
8	Reduction in Cash Working Capital				
9					
10	Note 1: Pre-tax value = approved ROE of 9.15%/(1-26%)= 12.36%				

FBC will similarly calculate any impact on 2017 cash working capital in its Annual Review for 2019 rates.

7.8.2 Other Working Capital

Other working capital includes the monthly averages of uncollectible accounts, inventory of materials and supplies, and DSM and employee loans, less customer deposits and sales taxes. Forecast values for these items, except for customer loans for DSM projects which are forecast separately, are generally based on the average of the actual amounts in the two prior years.

On page 30 of Order G-8-17, the Commission provided the following directive regarding uncollectible accounts:

> The Panel…**directs FBC to provide additional information regarding the monthly average of uncollectible accounts, increases and decreases to the monthly average of uncollectible accounts and FBC's efforts to manage uncollectible accounts as part of its annual review for 2018 rates application.**

The directive was in response to uncollectible accounts being identified as the largest contributor to the 2017 Forecast of working capital being $0.823 million higher than 2016 Approved. Although not identified in the proceeding to review 2017 rates, the 2016 forecast was lower than usual due to an error when certain uncollectible account balance provisions in the general ledger were omitted from the forecast. This resulted in a 2016 Approved amount that was lower than it should have been.

Table 7-9 below shows the trend of uncollectible account adjustments from 2012 to 2017, and shows that the 2016 uncollectible account provision forecast was miscalculated.

Table 7-9: Uncollectible Accounts in Working Capital ($ million)

Line		Projected	Actual				
No.	Description	2017	2016	2015	2014	2013	2012
1	Decision	1.520	0.697	1.224	1.124	0.937	0.930
2	Projected/Actual	1.700	1.653	1.504	1.247	1.124	1.011
3							
4	Sales Revenue	360.392	335.186	323.375	317.330	308.532	282.943
5	Uncollectible Accounts as % of Revenue	0.47%	0.49%	0.47%	0.39%	0.36%	0.36%

The uncollectible accounts in working capital for rate-setting purposes are based on the allowance for doubtful account (AFDA) provision that is booked for accounting purposes. FBC recognizes AFDA based on a budgeted percentage of sales being uncollectible, net of a budgeted percentage of recoveries. Each year the balance is also assessed against the balance of invoices greater than 90 days old, as well as the total value of accounts receivable, and adjusted if necessary.

AFDA is generally increasing due to increasing sales revenue. In addition:

- In 2014 an adjustment was made due to the acquisition of approximately 15,000 direct customers from the City of Kelowna. Acquiring these customers included the credit risk associated with the customers and therefore an increase in the uncollectible account provision.
- Also in 2014, a second general ledger account used to record provisions for uncollectible accounts that historically had been used by FBC to provide for uncollectible miscellaneous invoicing, including revenue protection, was added to the working capital adjustment balance. This second account relates to amounts that flow through Other Revenue in the Cash Working Capital determination and therefore should be included in the balance of uncollectible accounts used to adjust working capital. Because the adjustments to working capital in Schedule 13 are based on the average of the prior two

years, there was a lag in recognizing the appropriate level of uncollectible account provisions in this schedule.

FBC continues to monitor uncollectible accounts the same way it always has, through monthly internal reporting, trend analysis, account risk analytics, and a dedicated collections team with assistance from collection agencies when necessary. Some additional changes that have been made in the last few years to ensure potential uncollectible accounts are identified in a timely manner. These include shortening the timeline for sending payment reminder notices, using reminder calls on overdue payments more frequently, and the implementation of AMI meters with the ability to remotely disconnect and reconnect meters. These changes have all resulted in an improvement to collection timelines. It should also be noted that FBC has security deposits in place for all customers with lack of credit history, which could be applied against accounts if determined to be uncollectible.

7.9 *SUMMARY*

FBC's rate base includes the impact of both formula-driven capital expenditures and those capital expenditures that are forecast outside of the formula and CPCNs and Special Projects, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its rate base deferral accounts in its financial schedules in Section 11. Finally, the rate base includes other working capital, composed of customer deposits and loans and other smaller components.

8. FINANCING AND RETURN ON EQUITY

8.1 *INTRODUCTION AND OVERVIEW*

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent as approved by Orders G-75-13 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. The 2018 forecast for financing costs, including the interest expense on issued long and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC Rate for 2018 (which is equal to its after-tax weighted average cost of capital) is 5.91 percent. Variances in the interest expense recovered in rates will be recorded in the Flow-through deferral account for return to or recovery from customers in the following year.

8.2 *CAPITAL STRUCTURE AND RETURN ON EQUITY*

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the Commission from time to time. Order G-47-14 approved a capital structure for FBC of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE, which was set at 8.75 percent by Order G-129-16.

FBC has therefore prepared this Application using an ROE of 9.15 percent and a common equity percentage of 40 percent.

8.3 *FINANCING COSTS*

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long-term debt and short-term (unfunded) debt.

8.3.1 Long-term Debt

FBC is a public issuer of long-term debt. As reflected in the financial schedules, FBC plans to issue additional long-term debt of approximately $75 million in 2017. The Application assumes the issuance occurs in September 2017 at a rate of 3.80 percent and for a term of 30 years. The proceeds of this issuance are expected to be used to repay existing indebtedness. Unfunded debt was used to repay the $25 million Series H debenture with a coupon rate of 8.77 percent that matured in February 2016. The exact timing, amount and rate of the issuance will depend on market conditions at the time of issuance and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuance of the debt or the rate at which it is issued will be captured in the Flow-through deferral account.

8.3.2 Short-term Debt

FBC obtains short-term funding primarily through the issuance of Bankers' Acceptances or prime lending rate margin loans, both drawn on its $150 million operating credit facility, which matures in May 2022. The operating credit facility, along with a $10 million overdraft facility, provide FBC with required liquidity should there be constraints issuing debt to fund FBC's capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on forecast long-term debt issuances are based on current indicative rates, on the assumption that FBC's credit ratings of FBC are maintained and that credit spreads will remain at current levels in the future. As discussed above, FBC currently expects to issue long term debt in 2017 for the repayment of debt that matured in 2016, as well as for other capital requirements. The forecast issue rate is approximately 3.80 percent based on a 30-year GOC rate of 2.30 percent and an indicative spread of 1.50 percent.

FBC's short-term borrowing rate is based on the rate at which it issues Bankers' Acceptances (or the Canadian Dealer Offered Rate or CDOR) plus an Acceptance Fee Rate, and on the Prime Lending Rate. Since CDOR is not forecast by economists, a forecast needs to be derived by FBC. Therefore, the Company must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. The Company then adds the Acceptance Fee Rate of 1.0 percent, based on the pricing in the Company's operating credit facility agreement based on its current credit ratings.

The forecast weighted average short-term rate, prior to including standby fees and financing fees, has increased from the 2017 projected rate of 2.09 percent to a 2018 forecast rate of 2.61 percent.

The short-term interest rate forecasts are shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast[30]

Line No.	Description	Projected 2017	Forecast 2018
1	3 month T-Bills[1]	0.69%	1.22%
2	Spread to CDOR	0.39%	0.39%
3	Acceptance Fee Rate	1.00%	1.00%
4	Bankers' Acceptance Rate	2.09%	2.61%
5			
6	add: Standby Fee on Undrawn Credit[2]	0.12%	0.36%
7	Short-term Interest Rate applied to debt balance	2.21%	2.97%
8	add: Financing fees[3]	0.28%	0.50%
9	FBC Short-term Interest Rate	2.50%	3.45%

Notes:

[1] 3 month T-Bill and prime rate for 2017 based on a composite of actual historical rates up to June 15, 2017 and forecast rates for the remainder of the year.

[2] Amounts undrawn on the credit facility are subject to a Standby fee, which is estimated to be 20 basis points in 2017 and 2018. In order to incorporate the standby fee into the short-term interest rate, the Standby Fee as shown reflects the amount payable had it been converted to a rate to be applied to the amount of operating credit facilities which has not been drawn upon through BAs and prime loans.

[3] Also included in the total interest expense forecast are financing fees which are of a more fixed nature. These financing fees consist of banking agreement renewal fees, annual lender and agency fees, demand line interest and other minor interest charges such as interest due to customers on outstanding security deposits.

Although the Bankers' Acceptance rate is forecast to increase in 2018, the increase in the all-in short-term interest rate is also impacted by a higher expected balance of draws on the credit facilities (short-term debt) in 2017 Projected as compared to 2018 Forecast. Included in short-term interest expense are standby fees and financing fees, which do not directly correspond with the amount of short-term debt issued. As the average short-term debt balance is expected to be lower in 2018 Forecast compared to 2017 Projected, when the absolute dollar amount of standby fees and financing fees are converted into a 2018 short-term interest rate, the overall rate increases compared to 2017 as a result of dividing these fees over the lower forecast balance of 2018 short-term debt.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long-term debt and short-term debt.

[30] The 2017 approved short term rate for FBC was 7.45%, inclusive of standby fees and financing fees.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance and then adding financing fees. Long-term debt interest expense is determined using the straight line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2018 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

FBC's Flow-through deferral account captures the variances in interest expense for return to or recovery from customers in the following year.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than 3 months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC Rate for 2018 (which is equal to its after-tax weighted average cost of capital) is 5.91 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2018

Line No.	Description	Weight	Pre-Tax Rate	After-Tax Rate
1	Short Term Debt	4.39%	3.45%	2.55%
2	Long Term Debt	55.61%	5.20%	3.85%
3	Common Equity	40.00%	12.36%	9.15%
4				
5	Weighted Average	100.00%	7.99%	5.91%

8.4 SUMMARY

FBC's capital structure and ROE have been forecast for 2018 at the same percentages as approved for 2017. FBC's financing costs on rate base are primarily determined by embedded rates on long-term debt with one forecast debt issuance in 2017. While the calculated short-term debt rate is forecast to increase in 2018, this increase primarily reflects the mechanics of the calculation, with standby fees and fixed financing fees being applied to a lower forecast balance of short term debt in 2018, and not a material change in the underlying cost drivers.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis that is consistent with prior years. In 2018, property taxes are forecast to increase 3.9 percent from 2017 Approved, while income tax is forecast to decrease by 16.0 percent compared to 2017 Approved. Any variances from the forecast of property taxes and income tax included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.2 PROPERTY TAXES

Property taxes for 2018 of $16.684 million incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Forecast 2018
1	Generating Plant	$ 3.113	$ 3.009	$ 3.080
2	Transmission and Distribution	6.328	6.499	6.672
3	Substation Equipment	3.806	3.650	3.731
4	Land and Buildings	0.729	0.770	1.192
5	In-Lieu	2.076	1.960	2.009
6	Total Property Taxes	$ 16.052	$ 15.888	$ 16.684
7				
8	Forecast Change from Approved 2017			3.9%
9	Forecast Change from Projected 2017			5.0%

As shown in the table above, in 2018 property taxes are forecast to increase by 3.9 percent from 2017 Approved, and to increase 5.0 percent compared to 2017 Projected. In general, the increase from 2017 Projected is primarily due to the following:

3. **Changes in Tax Rates.** Tax rates are based on FBC's average annual change in the tax rate applicable to FBC since 2012. On average:

   a) Municipal rates are expected to increase by 1.0 percent;

   b) School rates are expected to decrease by 0.7 percent;

   c) Rural rates are expected to decrease by 1.0 percent;

   d) Tax rates on First Nations are expected to increase 0.75 percent; and

   e) Other rates are expected to increase by 2.0 percent.

4. ***Changes in Revenues to Calculate Grants In Lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 2.5 percent over Projected based on actual revenues to be reported. As grants in-lieu of taxes are based on a fixed percentage of revenues, the overall increase in revenues reported to municipalities increases the grants in-lieu of taxes due.
5. ***Changes in Assessed Values***. Forecast changes in the assessed values of FBC's property are based on anticipated increases by BC Assessment at the time the forecast was developed. These include:
   a) A 2.0 percent increase in assessed values for distribution lines and transmission lines;
   b) A 1.0 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;
   c) A 1.5 percent increase in assessed values for substations calculated using legislated cost manuals for valuing substations; and
   d) Land value changes which are expected to range from a 3.0 percent increase in the assessed value for right of ways to a 2.0 percent increase in the market value for properties owned in fee simple.

Any variances from the forecast of property taxes included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.3 *INCOME TAX*

FBC is subject to corporate income taxes imposed by the federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with Commission-approved past practice, at the corporate tax rate of 26 percent for 2017, which is unchanged from 2016. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and will be updated each year as part of the annual rate setting process.

Income tax is forecast to decrease in 2018 by $1.741 million or 16.0 percent compared to 2017 Approved. This decrease is primarily due to a decrease in amortization expense driven by deferral accounts, in particular the Celgar Interim Billing Adjustment account which was fully amortized in 2017, and an increase in deductible temporary differences associated with pensions and OPEBs, partly offset by an overall increase in revenues.

Any variances from the forecast of income taxes included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.4 SUMMARY

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

The PBR Decision (at pages 120-121) stated that the inclusion of symmetric earnings sharing is beneficial to both FBC and its customers and approved an earnings sharing mechanism where gains and losses are shared equally between FBC and customers. For 2018, FBC is proposing to distribute a $0.831 million pre-tax credit ($0.615 million after tax) as shown in Table 10-1 below. This amount is composed of:

- 2017 projected sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth; and
- The true-up of the 2016 projected earnings sharing to actual.

Table 10-1: Summary of Earnings Sharing to be Returned in 2018 ($ millions)

Line No.	Description		After-tax Amount	Reference
1	2017 Projected Sharing	$	(0.263)	Table 10-2, Line 46
2	Actual Customer Growth Adjustment		0.004	Table 10-3, Line 18
3	2016 Projected vs. Actual Ending Balance True-Up		(0.356)	Table 10-4, Line 3
4				
5	2017 After-Tax Amount Returned to Customers	$	(0.615)	
6	2017 Pre-Tax Amount Returned to Customers	$	(0.831)	

Each of these items is discussed in the sections below.

10.1 *2017 PROJECTED SHARING*

As set out in FBC's letter dated November 7, 2014 in response to Order G-163-14 and as approved by Order G-107-15 for FBC's Annual Review for 2015 Rates, the earnings sharing is calculated each year as one-half of the pre-tax earnings impact of the variances in the formula-driven gross O&M and cumulative capital expenditures, as follows:

Formula-driven O&M less actual base O&M[31] x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[32]) x equity percentage x approved return on equity x 50%) divided by (1 – the tax rate)

As discussed in Section 1.4, FBC is projecting 2017 formula-driven O&M savings at $1.200 million, and 2017 capital expenditures in excess of the formula by $15.306 million. The $15.306

[31] Excluding items that are reforecast outside of the formula.
[32] Ibid .

million excess 2017 capital expenditures will exceed the dead band by $11.268 million, such that FBC has removed the $11.268 million amount above the dead band in the calculation of 2017 earnings sharing, as shown in Line 26 of Table 10-2 below.

Table 10-2: Calculation of 2017 Projected Earnings Sharing ($ millions)

Line No.	Description						Reference
1	Approved Formula O&M	$ 54.071					G-139-14
2							
3	Actual/Projected Gross O&M	56.688					
4							
5	Less: O&M Tracked Outside of Formula						
6	Pension/OPEB (O&M Portion)	3.391					
7	Insurance Premiums	1.305					
8	Advanced Metering/Infrastructure Costs/Savings	(1.335)					
9	MRS Incremental O&M	0.455					
10	Total	3.816					Sum of Lines 6 - 9
11							
12	Actual/Projected Base O&M	52.872					Line 3 - Line 10
13							
14	O&M Subject to Sharing	(1.200)					Line 12 - Line 1
15			Annual Capital Expenditures				
16			2014	2015	2016	2017	
17							
18	Cumulative Formula Capital Expenditures	170.705	42.193	42.384	42.874	43.254	G-139-14
19							
20	Cumulative Total Regular Capital Expenditures	209.715	49.061	49.043	49.512	62.099	Note 1
21							
22	Less: Capital Expenditures Tracked Outside of Formula						
23	Cumulative Pension and OPEB	17.862	6.396	4.253	3.674	3.539	
24							
25	Actual/Projected Base Capital Expenditures	191.853	42.665	44.791	45.839	58.560	Line 20 - Line 23
26	Deadband Adjustment	(11.268)	-	-		(11.268)	Adjustment to stay within deadband
27	Actual/Projected Base Capital Expenditures for ESM Calculation	180.585	42.665	44.791	45.839	47.292	Line 25 + Line 26
28							
29	Actual/Projected Cumulative Base Capital Expenditure Variance	9.880	0.472	2.408	2.965	4.038	Line 27 - Line 18
30							
31	Single Year Deadband % Variance (After Adjustment)		0.97%	5.16%	6.37%	8.63%	Line 29 / (Line 18 + Line 23)
32	Two Year Cumulative Deadband % Variance (After Adjustment)			6.13%	11.53%	15.00%	Line 31, sum of two years
33							
34	Equity Component of Rate Base	40.00%					G-139-14
35	Approved Return on Equity	9.15%					G-75-13/G-47-14
36	After Tax Capital Expenditures Subject to Sharing	0.362					Product of Lines 29, 34 & 35
37							
38	Tax Rate	26.00%					G-139-14
39							
40	Before Tax Capital Expenditures Subject to Sharing	0.489					Line 36 ÷ (1 - Line 38)
41							
42	Total Before Tax Sharing Account	(0.712)					Line 14 + Line 40
43	Sharing Percentage	50.00%					G-139-14
44							
45	2017 Projected Earnings Sharing (Pre-Tax)	$ (0.356)					Line 42 x Line 43
46	2017 Projected Earnings Sharing (After-Tax)	$ (0.263)					Line 45 x (1- Line 38)
47							
48	Note 1: 2014 through 2016 are actual results from BCUC Annual Report. 2014 Regular Capital Expenditures restated to correct treatment of capitalized inventory and transfer of land purchased for the Kootenay Operations Centre to CPCN-related capital upon approval of the project. 2017 is Projected result.						

10.2 *ACTUAL CUSTOMER GROWTH ADJUSTMENT*

Order G-15-15 stated the following in relation to formula capital expenditures:

> FEI and FBC are approved to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the actual customer additions. This positive or negative variance in earned return resulting from the Growth

Term shall be recovered from or returned to customers in the subsequent year through the earnings sharing mechanism.

FBC has calculated the resulting adjustment of $0.005 million debit ($0.004 million debit after tax) for 2016 as shown in Table 10-3 below based on its actual customer additions.

Table 10-3: Calculation of Earnings Sharing Adjustment for Actual Customer Growth ($ millions)

Line No.	Description		Reference
1	Average Customers 2016	132,480	
2	Average Customers 2015	131,016	
3	Growth in Average Customers	1,463	Line 1 - Line 2
4	Average Customer Growth	1.117%	Line 3 / Line 2
5		50%	G-139-14
6	Average Customer Growth to be recast in Formula	0.558%	
7	2016 Net Inflation Factor	0.539%	G-11-17 Evidentiary Update (October 5, 2016) Section 11, Schedule 3, Line 9, Column 5
8	2015 Reforecast Formulaic Capital	$ 42.567	Annual Review for 2017 Rates, Table 10-3, Line 9
9	2016 Reforecast Formulaic Capital	$ 43.035	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2016 Year Formulaic Capital	$ 42.874	G-11-17 Evidentiary Update (October 5, 2016) Section 11, Schedule 4, Line 11, Column 4
11			
12	Increase in Capital Requirements from Actual Growth	$ 0.161	Line 9 - Line 10
13	Mid-Year	$ 0.081	Line 12 / 2
14			
15	Equity Cost Component	3.66%	G-139-14
16	Debt Cost Component	3.03%	G-139-14
17	Earned Return on Incremental Capital Requirements (Pre-Tax)	$ 0.005	Line 13 x (line 15 + Line 16)
18	Earned Return on Incremental Capital Requirements (After-Tax)	$ 0.004	Line 17 x 0.74

10.3 *TRUE-UP FOR 2016 ACTUAL EARNINGS SHARING*

In FBC's 2016 Annual Report to the Commission, FBC calculated the final 2016 earnings sharing based on the final 2016 results. The final amount of earnings sharing for 2015 was $0.610 million (after-tax), which was $0.356 million higher than the $0.254 million projected for 2016 as shown in Table 10-4 below. As a result, FBC is increasing its 2018 earnings sharing by the after-tax amount of $0.356 million as shown in Table 10-1 above.

Table 10-4: Calculation of 2016 Actual Earnings Sharing True-Up ($ millions)

Line No.	Description	After-tax Amount	Reference
1	2016 Actual Earnings Sharing Account Ending Balance	$ (0.610)	2016 Annual Report to BCUC
2	2016 Projected Earnings Sharing Account Ending Balance	(0.254)	FBC Annual Review for 2017 Rates Compliance Filing Schedule 12, Line 21, Column 2
3	2016 Earnings Sharing Account True-Up	$ (0.356)	

10.4 *SUMMARY OF EARNINGS SHARING*

After calculating the 2017 projected earnings sharing and including the adjustments described above, FBC proposes to distribute $0.831 million to customers in 2018 as a reduction in 2018 revenue requirements through amortization of the projected 2018 opening after-tax balance of $0.615 million in the Earnings Sharing deferral account.

As part of the Annual Review for 2019 Rates, the earnings sharing for 2017 will be subject to similar true-ups to those described above, which account for the actual O&M and capital expenditure amounts for 2017, as well as impacts, if any, associated with non-performance of Service Quality Indicators, based on final 2017 results.

11. FINANCIAL SCHEDULES

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SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000,000s)

Line No.	Particulars	2018 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	5.788		
3	Change in Other Revenue	(0.360)	5.428	
4				
5	**POWER SUPPLY**			
6	Power Purchases (net of customer growth and volume)	(3.145)		
7	Wheeling	0.243		
8	Water Fees	(0.120)	(3.022)	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	1.030		
12	Capitalized Overhead Change	(0.155)	0.876	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions	2.430	2.430	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.224)		
19	Deferrals	(5.325)	(5.549)	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	(1.166)		
23	Financing Ratio Changes	0.044		
24	Rate Base Growth	2.471	1.348	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes Changes	0.632		
28	Other Income Taxes Changes	(1.741)	(1.109)	
29				
30				
31	Revenue Deficiency (Surplus)		$ 0.400	Schedule 16, Line 6, Column 4
32				
33	Revenue at Existing Rates		356.340	Schedule 16, Line 5, Column 3
34	Rate Change		0.11%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 2

Line No.	Particulars	2017 Approved	2018 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 1,912,643	$ 1,966,584	$ 53,941	Schedule 6.1, Line 14, Column 3
2	Opening Balance Adjustment	-	11,268	11,268	Schedule 6.1, Line 14, Column 4
3	Net Additions	61,107	73,879	12,772	Schedule 6.1, Line 14, Columns 5+6+7
4	Plant in Service, Ending	1,973,750	2,051,731	77,981	
5					
6	Accumulated Depreciation Beginning	$ (553,121)	$ (591,854)	$ (38,733)	Schedule 7.1, Line 14, Column 5
7	Opening Balance Adjustment	-	-	-	
8	Net Additions	(48,305)	(43,454)	4,851	Schedule 7.1, Line 14, Columns 6+7+8+9
9	Accumulated Depreciation Ending	(601,426)	(635,308)	(33,882)	
10					
11	CIAC, Beginning	$ (176,357)	$ (187,217)	$ (10,860)	Schedule 9, Line 1, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(6,027)	(6,120)	(93)	Schedule 9, Line 1, Column 4
14	CIAC, Ending	(182,384)	(193,337)	(10,953)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 64,660	$ 68,323	$ 3,664	Schedule 9, Line 3, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	3,689	3,913	224	Schedule 9, Line 3, Column 4
19	Accumulated Amortization Ending - CIAC	68,349	72,236	3,887	
20					
21	Net Plant in Service, Mid-Year	$ 1,253,056	$ 1,281,213	$ 28,157	
22					
23	Adjustment for timing of Capital additions	$ 2,987	$ 12,644	$ 9,657	
24	Capital Work in Progress, No AFUDC	8,387	8,921	534	
25	Unamortized Deferred Charges	12,392	11,942	(450)	Schedule 11, Line 12, Column 8
26	Working Capital	2,906	1,580	(1,326)	Schedule 13, Line 15, Column 3
27	Utility Plant Acquistion Adjustment	5,679	5,493	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,285,408	$ 1,321,793	$ 36,386	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 3

Line No.	Particulars	Reference	2014	2015	2016	2017	2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Cost Drivers for Formulaic Capital and O&M**							
2	CPI		0.473%	0.879%	0.980%	1.627%	1.979%	
3	AWE		2.277%	1.646%	2.050%	1.250%	1.433%	
4	Labour Split							
5	Non Labour		45.000%	45.000%	45.000%	45.000%	45.000%	
6	Labour		55.000%	55.000%	55.000%	55.000%	55.000%	
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	1.465%	1.301%	1.569%	1.420%	1.679%	
8	Productivity Factor		-1.030%	-1.030%	-1.030%	-1.030%	-1.030%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.435%	0.271%	0.539%	0.390%	0.649%	
10								
11	Average Customer Growth		0.326%	0.181%	0.613%	0.494%	0.629%	
12	Inflation Factor	(1 + Line 9) x (1 + Line 11)	100.758%	100.452%	101.155%	100.886%	101.282%	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 4

Line No.	Particulars	CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base	$ 41,875			
3	**2014**				
4	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
5	Formula Capex	42,193			
6	**2015**				
7	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
8	Formula Capex	42,384			
9	**2016**				
10	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
11	Formula Capex	$ 42,874			
12	**2017**				
13	Net Inflation Factor	100.886%			Schedule 3, Line 12, Column 6
14	Formula Capex	$ 43,254			
15	**2018**				
16	Net Inflation Factor	101.282%			Schedule 3, Line 12, Column 7
17	Formula Capex	$ 43,809		$ 43,809	
18					
19					
20	**Capital Tracked Outside of Formula**				
21	Pension & OPEB (Capital Portion)		$ 3,630		
22	Mandatory Reliability Standards Incremental Capital		50		
23	AMI Sustainment Capital		265		
24	Corra Linn Spillway Gate Replacement		20,615		
25	Ruckles Substation Rebuild		2,238		
26	Upper Bonnington Old Units Refurbishment		7,092		
27	Total		$ 33,890	$ 33,890	
28					
29	**Total Capital Expenditures before CIAC**			$ 77,699	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION Schedule 5
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars		2018	Cross Reference
	(1)		(2)	(3)
1	**CAPITAL EXPENDITURES**			
2				
3	Formula Capital Expenditures	$	43,809	Schedule 4, Line 17, Column 4
4	Forecast Capital Expenditures		3,945	Schedule 4, Lines 21 to 23, Column 3
5	Total Regular Capital Expenditures	$	47,754	
6				
7	**CPCN and Special Projects**			
8	Corra Linn Spillway Gate Replacement		20,615	Schedule 4, Line 24, Column 3
9	Ruckles Substation Rebuild		2,238	Schedule 4, Line 25, Column 3
10	Upper Bonnington Old Units Refurbishment		7,092	Schedule 4, Line 26, Column 3
11	Total CPCN and Special Projects	$	29,945	
12				
13	**Total Capital Expenditures**	$	77,699	
14				
15				
16	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
17				
18	Regular Capital Expenditures	$	47,754	
19	Add - Capitalized Overheads		8,787	Schedule 20, Line 31, Column 4
20	Add - Direct Overheads		5,000	
21	Add - AFUDC		692	
22	Less: Removal costs		(2,577)	Schedule 7.1, Line 14, Column 8 - Row 30
23	Gross Capital Expenditures	$	59,656	
24	Change in Work in Progress		-	
25	**Total Additions to Plant**	$	59,656	
26				
27				
28	**CPCN and Special Projects**	$	29,945	
29	Add - AFUDC		2,114	
30	Less: Removal costs		(1,381)	
31	Gross Capital Expenditures		30,678	
32	Change in Work in Progress		(5,391)	
33	**Total Additions to Plant**	$	25,287	
34				
35	**Grand Total Additions to Plant**	$	84,943	Schedule 6.1, Line 14 , Columns 5+6

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	12/31/17	Opening Bal. Adjustment	CPCNs	Additions	Retirements	12/31/18	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	15,711	66	36	349	(15)	16,147	
4	332	Reservoirs, Dams & Waterways	33,805	161	175	852	(50)	34,943	
5	333	Water Wheels, Turbines and Gen.	95,943	8	3,548	44	(553)	98,990	
6	334	Accessory Equipment	42,956	74	1,477	393	(456)	44,444	
7	335	Other Power Plant Equipment	45,832	103	-	546	(19)	46,462	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 236,495	$ 412	$ 5,237	$ 2,183	$ (1,093)	$ 243,235	
10		**Transmission Plant**							
11	350	Land Rights-R/W	$ 9,673	$ 38	$ -	$ 202	$ -	$ 9,912	
12	350.1	Land Rights-Clearing	8,903	38	-	202	-	9,142	
13	353	Station Equipment	233,834	2,551	175	13,503	(227)	249,836	
14	355	Poles Towers & Fixtures	108,798	647	-	3,426	(301)	112,571	
15	356	Conductors and Devices	104,147	533	-	2,822	(332)	107,170	
16	359	Roads and Trails	1,121	-	-	-	-	1,121	
17			$ 466,476	$ 3,807	$ 175	$ 20,154	$ (860)	$ 489,751	
18		**Distribution Plant**						-	
19	360	Land Rights-R/W	$ 3,604	$ -	$ -	$ -	$ -	$ 3,604	
20	360.1	Land Rights-Clearing	10,330	-	-	-	-	10,330	
21	362	Station Equipment	255,248	-	-	-	(423)	254,825	
22	364	Poles Towers & Fixtures	257,381	3,653	-	19,338	(484)	279,887	
23	365	Conductors and Devices	293,544	1,090	-	5,772	(786)	299,620	
24	368	Line Transformers	132,655	545	-	2,886	(1,461)	134,626	
25	369	Services	9,521	-	-	-	-	9,521	
26	370	Meters	415	-	-	-	(20)	395	
27	370.1	AMI Meters	38,755	164	-	866	-	39,784	
28	371	Installation on Customers' Premises	938	-	-	-	-	938	
29	373	Street Lighting and Signal System	11,921	-	-	-	(57)	11,864	
30			$ 1,014,311	$ 5,452	$ -	$ 28,862	$ (3,231)	$ 1,045,394	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	12/31/17	Opening Bal. Adjustment	CPCNs	Additions	Retirements	12/31/18	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**General Plant**							
2	389	Land	$ 10,993	$ -	$ -	$ -	$ -	$ 10,993	
3	390	Structures - Frame & Iron	337	-	-	-	-	337	
4	390.1	Structures - Masonry	45,884	138	19,875	733	-	66,630	
5	391	Office Furniture & Equipment	6,368	30	-	161	(521)	6,039	
6	391.1	Computer Equipment	99,059	800	-	4,235	(2,600)	101,494	
7	391.2	AMI Software	10,353	60	-	315	-	10,728	
8	392	Transportation Equipment	27,595	380	-	2,011	(1,749)	28,238	
9	394	Tools and Work Equipment	15,385	141	-	748	(495)	15,780	
10	397	Communication Structures & Equipment	27,792	47	-	250	(515)	27,574	
11	397.1	AMI Communications Structure & Equipment	5,535	-	-	3	-	5,537	
12			$ 249,302	$ 1,597	$ 19,875	$ 8,456	$ (5,880)	$ 273,350	
13									
14		**Total Plant in Service**	$ 1,966,584	$ 11,268	$ 25,287	$ 59,656	$ (11,064)	$ 2,051,731	
15									
16		Cross Reference			Schedule 5 Line 33 Column 2	Schedule 5 Line 25 Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/17	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/18	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**Hydraulic Production Plant**									
2	330	Land Rights	$ 962	2.60%	$ (463)	$ 25	$ -	$ -	$ -	$ (438)	
3	331	Structures and Improvements	15,813	1.29%	5,759	204	(15)	(36)	-	5,912	
4	332	Reservoirs, Dams & Waterways	34,141	1.78%	7,020	608	(50)	(899)	-	6,679	
5	333	Water Wheels, Turbines and Gen.	99,499	1.79%	16,250	1,781	(553)	(118)	-	17,360	
6	334	Accessory Equipment	44,507	2.28%	11,073	1,015	(456)	(57)	-	11,574	
7	335	Other Power Plant Equipment	45,935	2.05%	15,057	942	(19)	(25)	-	15,954	
8	336	Roads, Railroads and Bridges	1,287	1.47%	219	19	-	-	-	237	
9			$ 242,144		$ 54,914	$ 4,593	$ (1,093)	$ (1,135)	$ -	$ 57,278	
10		**Transmission Plant**									
11	350	Land Rights-R/W	$ 9,711	0.00%	$ (231)	$ -	$ -	$ -	$ -	$ (231)	
12	350.1	Land Rights-Clearing	8,941	1.23%	2,103	110	-	-	-	2,213	
13	353	Station Equipment	236,560	2.45%	71,459	5,796	(227)	(1,215)	-	75,813	
14	355	Poles Towers & Fixtures	109,445	2.53%	28,777	2,769	(301)	(214)	-	31,031	
15	356	Conductors and Devices	104,680	2.52%	22,153	2,638	(332)	(177)	-	24,283	
16	359	Roads and Trails	1,121	2.88%	305	32	-	-	-	338	
17			$ 470,457		$ 124,567	$ 11,345	$ (860)	$ (1,606)	$ -	$ 133,446	
18		**Distribution Plant**									
19	360	Land Rights-R/W	$ 3,604	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
20	360.1	Land Rights-Clearing	10,330	1.23%	2,202	127	-	-	-	2,329	
21	362	Station Equipment	255,248	2.57%	66,598	6,560	(423)	-	-	72,735	
22	364	Poles Towers & Fixtures	261,033	2.67%	57,337	6,970	(484)	(744)	-	63,080	
23	365	Conductors and Devices	294,634	2.89%	95,607	8,515	(786)	(222)	-	103,114	
24	368	Line Transformers	133,200	2.74%	33,177	3,650	(1,461)	(111)	-	35,254	
25	369	Services	9,521	0.50%	6,695	48	-	-	-	6,743	
26	370	Meters	415	6.68%	(314)	28	(20)	-	-	(306)	
27	370.1	AMI Meters	38,918	5.00%	1,459	1,946	-	(33)	-	3,372	
28	371	Installation on Customers' Premises	938	0.00%	938	-	-	-	-	938	
29	373	Street Lighting and Signal System	11,921	4.65%	3,664	554	(57)	-	-	4,161	
30			$ 1,019,763		$ 267,364	$ 28,397	$ (3,231)	$ (1,110)	$ -	$ 291,419	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/17	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/18	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**General Plant**									
2	389	Land	$ 10,993	0.00%	$ (12)	$ -	$ -	$ -	$ -	$ (12)	
3	390	Structures - Frame & Iron	337	0.56%	4	2	-	-	-	6	
4	390.1	Structures - Masonry	65,898	2.77%	19,273	1,825	-	(10)	-	21,089	
5	391	Office Furniture & Equipment	6,399	1.68%	5,186	108	(521)	(2)	-	4,770	
6	391.1	Computer Equipment	99,859	7.21%	79,997	7,200	(2,600)	(56)	-	84,541	
7	391.2	AMI Software	10,413	10.00%	2,433	1,041	-	-	-	3,474	
8	392	Transportation Equipment	27,975	6.01%	6,541	1,681	(1,749)	(27)	-	6,447	
9	394	Tools and Work Equipment	15,526	2.49%	10,248	387	(495)	(10)	-	10,130	
10	397	Communication Structures & Equipment	27,839	5.49%	20,603	1,528	(515)	(3)	-	21,612	
11	397.2	AMI Communications Structure & Equipment	5,535	6.67%	737	369	-	-	-	1,106	
12			$ 270,774		$ 145,010	$ 14,141	$ (5,880)	$ (107)	$ -	$ 153,164	
13											
14	108	Total Accumulated Depreciation	$ 2,003,138		$ 591,854	$ 58,476	$ (11,064)	$ (3,958)	$ -	$ 635,308	
15											
16		Cross Reference	Schedule 6.1								
17			Line 14								
18			Columns 3+4+5								

SCHEDULE NOT APPLICABLE

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/17	Adjustment	Additions	Retirements	12/31/18	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**	$ 187,217	$ -	$ 6,120	$ -	$ 193,337	
2							
3	**Amortization**	(68,323)	-	(3,913)	-	(72,236)	
4							
5	**Net CIAC**	$ 118,894	$ -	$ 2,207	$ -	$ 121,101	

SCHEDULE NOT APPLICABLE

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

Schedule 11

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	Benefits Matching Accounts								
2	Demand Side Management	$ 22,595	$ -	$ 7,900	$ (2,054)	$ (3,711)	$ 24,730	$ 23,662	
3	Deferred Debt Issue Costs	3,889	-	-	-	-	3,889	3,889	
4	Preliminary and Investigative Charges[1]	165	-	-	-	(17)	149	157	Note 1
5	Right of Way Reclamation (Pine Beetle Kill)	173	-	-	-	(173)	-	87	
6	Accounting Treatment of non-AMI Meters	2,163	-	-	-	(1,082)	1,082	1,623	
7		$ 28,986	$ -	$ 7,900	$ (2,054)	$ (4,982)	$ 29,849	$ 29,417	
8	Other Accounts								
9	Pension and OPEB Liability	(17,541)	-	132	-	-	(17,409)	(17,475)	
10		$ (17,541)	$ -	$ 132	$ -	$ -	$ (17,409)	$ (17,475)	
11									
12	**Total Rate Base Deferral Accounts**	$ 11,445	$ -	$ 8,032	$ (2,054)	$ (4,982)	$ 12,440	$ 11,942	
13									

14 Note 1: Gross additions for Preliminary and Investigative Charges are net of transfers to Construction Work in Progress. Additions of $350,000 - transfers of $350,000 = $0.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
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	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	Forecast Variance Accounts								
4	Revenue and Power Supply[1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Flow-Through Accounts	(7,102)	-	-	-	7,102	-	(3,551)	
6	Pension & Other Post Retirement Benefits (OPEB) Variance	(369)	-	-	-	289	(80)	(224)	
7		$ (7,470)	$ -	$ -	$ -	$ 7,391	$ (80)	$ (3,775)	
8	Benefit Matching Accounts								
9	2014-2019 Performance Based Ratemaking Application	493	-	-	-	(246)	246	369	
10	Annual Reviews for 2015-2019 Rates	102	-	150	(39)	(102)	111	107	
11	Self-Generation Policy Application, Stage II	(18)	-	25	(7)	(0)	-	(9)	
12	Net Metering Program Tariff Update	41	-	-	-	(69)	(28)	6	
13	BCUC Residential Inclining Block Rate Report	(34)	-	-	-	34	-	(17)	
14	2017 Demand Side Management Expenditure Schedule Application	5	-	-	-	(5)	-	3	
15	BC Hydro Application for Power Purchase Agreement with FBC	(7)	-	-	-	7	-	(3)	
16	Community Solar Pilot Project	93	-	-	-	(93)	-	46	
17	Tariff Applications	-	-	-	-	-	-	-	
18		$ 675	$ -	$ 175	$ (46)	$ (475)	$ 329	$ 502	
19	Other Accounts								
20	2014-2019 Earnings Sharing Account	$ (615)	$ -	$ -	$ -	$ 615	$ -	$ (307)	
21		$ (615)	$ -	$ -	$ -	$ 615	$ -	$ (307)	
22									
23	**Total Deferral Accounts at Short Term Interest**	$ (7,410)	$ -	$ 175	$ (46)	$ 7,531	$ 250	$ (3,580)	
24									
25	Financing Costs at STI	$ (362)	$ -	$ (98)		$ 362	$ (98)	$ (230)	
26									
27	Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term.								

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd Schedule 12.1
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	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	Benefit Matching Accounts								
4	CPCN Projects Preliminary Engineering	$ 231	$ -	$ 130	$ -	$ -	$ 361	$ 296	
5	2016 Long Term Electric Resource Plan	704	-	-	-	(141)	563	633	
6	2017 Rate Design Application	74	-	600	(156)	-	518	296	
7	Transmission Customer Rate Design	2	-	-	-	(2)	-	1	
8	2020 Revenue Requirements	22	-	70	(39)	-	53	38	
9	Multi-Year DSM Expenditure Schedule	93	-	125	(33)	(37)	148	120	
10	2018 Joint Pole Use Audit	-	-	200	(52)	(30)	118	59	
11		$ 1,126	$ -	$ 1,125	$ (280)	$ (209)	$ 1,762	$ 1,444	
12									
13	Other Accounts								
14	US GAAP Pension and OPEB Transitional Obligation	$ 2,728	$ -	$ (827)	$ (195)	$ -	$ 1,706	$ 2,217	
15	Advanced Metering Infrastructure Radio-Off Shortfall	127	-	120	(31)	-	216	171	
16		$ 2,855	$ -	$ (707)	$ (226)	$ -	$ 1,922	$ 2,388	
17									
18									
19	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ 3,981	$ -	$ 418	$ (506)	$ (209)	$ 3,684	$ 3,832	
20									
21	Financing Costs at WACD	$ 488	$ -	$ 207		$ (488)	$ 207	$ 347	
22									
23	**Deferral Accounts Financed at AFUDC**								
24									
25	Benefit Matching Accounts								
26	On Bill Financing (OBF) Participant Loans	$ 8	$ -	$ (5)	$ -	$ -	$ 4	$ 6	
27									
28	**Total Deferral Accounts at AFUDC**	$ 8	$ -	$ (5)	$ -	$ -	$ 4	$ 6	
29									
30	Financing Costs at AFUDC	$ 1	$ -	$ 1		$ (1)	$ 1	$ 1	
31									
32	**Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
33									
34	**Total Non Rate Base Deferral Accounts (including financing)**	$ (3,244)	$ -	$ 698	$ (551)	$ 7,194	$ 4,096	$ 426	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 5,496	$ 4,850	$ (646)	Schedule 14, Line 41, Column 5
3					
4	Add: Funds Unavailable				
5	Customer Loans	800	430	(370)	
6	Employee Loans	310	310	-	
7	Uncollectible Accounts	1,520	1,700	180	
8	Inventory (average monthly investment)	580	680	100	
9					
10	Less: Funds Available				
11	Average Customer Deposits	(4,440)	(5,150)	(710)	
12	Average Provincial Sales Tax	(710)	(690)	20	
13	Average Goods and Services Tax	(650)	(550)	100	
14					
15	Total	$ 2,905	$ 1,580	$ (1,326)	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2018 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 179,177	50.5	$ 9,048		
4	Commercial Tariff Revenue	90,771	49.4	4,484		
5	Wholesale Tariff Revenue	48,620	33.2	1,614		
6	Industrial Tariff Revenue	31,748	33.2	1,054		
7	Lighting Tariff Revenue	2,906	50.1	146		
8	Irrigation Tariff Revenue	3,519	45.3	159		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	4,736	27.4	130		
12	Contract Revenue	1,769	43.6	77		
13	Transmission Revenue	1,170	15.2	18		
14	Interest Income	16	15.2	0		
15	Other Utility Income	725	44.7	32		
16						
17	Total	$ 365,156		$ 16,763	45.9	
18						
19	**EXPENSES**					
20	Power Purchases	$ 133,071	41.7	5,549		
21	Wheeling	5,171	40.2	208		
22	Water Fees	10,208	(1.0)	(10)		
23	Operating Labour					
24	Salaries and Wages	16,627	5.3	88		
25	Employee Benefits	10,104	13.2	133		
26	Contracted Labour	12,690	50.6	642		
27	Rental of T&D Facilities	3,345	48.6	163		
28	Office Lease	569	(15.2)	(9)		
29	Materials	5,192	45.6	237		
30	Insurance	1,265	(182.5)	(231)		
31	Interest	40,206	85.2	3,426		
32	Property Taxes	16,684	1.4	23		
33	Income Tax	9,108	15.2	138		
34						
35	Total	$ 264,240		$ 10,358	(39.2)	
36						
37	Net Lag (Lead) Days				6.7	
38						
39	Total Expenses				$ 264,240	
40						
41	Cash Working Capital				$ 4,850	

SCHEDULE NOT APPLICABLE

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast at Existing Rates	2018 Forecast Revised Revenue	2018 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,282	3,213		3,213	(69)	Schedule 17, Line 9, Column 3
3							
4	**REVENUE**						
5	Sales	$ 352,389	$ 356,340	$ -	$ 356,340	$ 3,951	Schedule 17, Line 19, Column 3
6	Deficiency (Surplus)	9,739	-	400	400	(9,339)	
7	Total	362,128	356,340	400	356,740	(5,388)	Schedule 18, Line 8, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	151,472	148,450	-	148,450	(3,022)	Schedule 19, Line 29, Column 3
11	O&M Expense (net)	48,917	49,792	-	49,792	876	Schedule 20, Line 32, Column 4
12	Depreciation & Amortization	55,657	52,538	-	52,538	(3,119)	Schedule 21, Line 11, Column 3
13	Property Taxes	16,052	16,684	-	16,684	632	Schedule 22, Line 7, Column 3
14	Other Revenue	(8,056)	(8,416)	-	(8,416)	(360)	Schedule 23, Line 8, Column 3
15	Utility Income Before Income Taxes	98,086	97,292	400	97,692	(394)	
16							
17	Income Taxes	10,849	9,004	104	9,108	(1,741)	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 87,237	$ 88,288	$ 296	$ 88,584	$ 1,347	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,285,408	$ 1,321,793		$ 1,321,793	$ 36,386	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.79%	6.68%		6.70%	-0.08%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,353	1,280	(73)	
3	Commercial	879	912	33	
4	Wholesale	587	586	(1)	
5	Industrial	407	379	(28)	
6	Lighting	14	15	1	
7	Irrigation	40	41	1	
8					
9	Total	3,282	3,213	(69)	
10					
11	**REVENUE AT EXISTING RATES**				
12	Residential	$ 187,578	$ 178,976	$ (8,602)	
13	Commercial	86,254	90,669	4,415	
14	Wholesale	48,498	48,565	67	
15	Industrial	33,501	31,712	(1,788)	
16	Lighting	2,873	2,903	30	
17	Irrigation	3,424	3,515	90	
18					
19	Total	$ 362,128	$ 356,340	$ (5,788)	

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved Revenue	2018 Forecast Revenue at Existing Rates	2018 Forecast Effective Increase	2018 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 187,578	$ 178,976	$ 201	$ 179,177	117,216	1,280	
2	Commercial	86,254	90,669	102	90,771	15,935	912	
3	Wholesale	48,498	48,565	55	48,620	6	586	
4	Industrial	33,501	31,712	36	31,748	50	379	
5	Lighting	2,873	2,903	3	2,906	1,559	15	
6	Irrigation	3,424	3,515	4	3,519	1,090	41	
7								
8	Total	$ 362,128	$ 356,340	$ 400	$ 356,740	135,855	3,213	
9								
10	**Effective Increase**				0.11%			

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 19

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,559	3,485	(74)	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 39,373	$ 39,632	$ 259	
6	BC Hydro PPA	46,968	44,906	(2,062)	
7	Waneta Expansion	38,330	37,437	(893)	
8	Independent Power Producers	204	80	(124)	
9	Market and Contracted Producers	11,341	11,016	(325)	
10	Balancing Pool	-	-	-	
11	Total	$ 136,216	$ 133,071	$ (3,145)	
12					
13	**WHEELING**				
14	**Wheeling Nomination (MW months)**				
15	Okanagan Point of Interconnection	2,430	2,490	60	
16	Creston	432	444	12	
17					
18	**Wheeling Expense**				
19	Okanagan Point of Interconnect	$ 4,374	$ 4,590	$ 216	
20	Creston	507	534	27	
21	Other	48	48	-	
22	Total	$ 4,928	$ 5,171	$ 243	
23					
24	**WATER FEES**				
25	Plant Entitlement Use in previous year (GWh)	1,617	1,568	(49)	
26					
27	Water Fees	$ 10,328	$ 10,208	$ (120)	
28					
29	Total	$ 151,472	$ 148,450	$ (3,022)	

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 20

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base O&M	$ 60,159			
3	Less: O&M tracked outside of Formula	(7,810)			
4	O&M Subject to Formula	52,349			
5	**2014**				
6	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
7	Formula O&M	52,746			
8	**2015**				
9	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
10	Formula O&M	52,984			
11	**2016**				
12	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
13	Formula O&M	$ 53,596			
14	**2017**				
15	Net Inflation Factor	100.886%			Schedule 3, Line 12, Column 6
16	Formula Capex	$ 54,071			
17	**2018**				
18	Net Inflation Factor	101.282%			Schedule 3, Line 12, Column 7
19	Formula Capex	$ 54,764		$ 54,764	
20					
21	**O&M Tracked Outside of Formula**				
22	Pension & OPEB (O&M Portion)		$ 2,659		
23	Insurance Premiums		1,265		
24	Advanced Metering Infrastructure Costs/Savings		(1,139)		
25	Mandatory Reliability Standards Incremental O&M		1,070		
26	Upper Bonnington Unit 4 Annual Inspection		(40)		
27	Total		$ 3,815	3,815	
28					
29	**Total Gross O&M**			$ 58,579	
30					
31	Capitalized Overhead - 15% of Total Gross O&M			(8,787)	
32	**Net O&M Expense**			$ 49,792	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 56,046	$ 58,476	$ 2,430	Schedule 7.1, Line 14, Column 6
3					
4	**Amortization**				
5	Rate Base deferrals	$ 4,714	$ 4,982	$ 268	Schedule 11, Line 12, Column 6
6	Non-Rate Base deferrals	(1,600)	(7,194)	(5,594)	Schedule 12.1, Line 34, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(3,689)	(3,913)	(224)	Schedule 9, Line 3, Column 4
9		(389)	(5,938)	(5,549)	
10					
11	Total	$ 55,657	$ 52,538	$ (3,119)	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,113	$ 3,080	$ (33)	
2	Transmission and Distribution	6,328	6,672	344	
3	Substation Equipment	3,806	3,731	(75)	
4	Land and Buildings	729	1,192	463	
5	1% In-Lieu of Municipal Taxes	2,076	2,009	(67)	
6					
7	Total	$ 16,052	$ 16,684	$ 632	

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 4,576	$ 4,736	$ 160	
2	Contract Revenue	1,865	1,769	(96)	
3	Transmission Access Revenue	1,179	1,170	(9)	
4	Interest Income	24	16	(8)	
5	Connection Charge	270	368	98	
6	Other Recoveries	142	356	214	
7					
8	Total	$ 8,056	$ 8,416	$ 360	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 87,237	$ 88,584	$ 1,347	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(40,191)	(40,206)	(15)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(16,167)	(22,455)	(6,288)	Schedule 24, Line 29, Column 3
4	Accounting Income After Tax	$ 30,878	$ 25,923	$ (4,956)	
5					
6	1 - Current Income Tax Rate	74.00%	74.00%	0.00%	
7	Taxable Income	$ 41,728	$ 35,030	$ (6,697)	
8					
9	Current Income Tax Rate	26.00%	26.00%	0.00%	
10	Income Tax - Current	$ 10,849	$ 9,108	$ (1,741)	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 10,849	$ 9,108	$ (1,741)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 56,046	$ 58,476	$ 2,430	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	3,114	(2,211)	(5,325)	Schedule 21, Lines 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension & OPEB Expense	6,806	6,289	(517)	
22					
23	Deductions:				
24	Capital Cost Allowance	(64,246)	(66,522)	(2,276)	Schedule 25, Line 19, Column 6
25	CIAC Amortization	(3,689)	(3,913)	(224)	Schedule 21, Line 8, Column 3
26	Pension & OPEB Contributions	(5,433)	(5,594)	(161)	
27	Overheads Capitalized Expensed for Tax Purposes	(8,632)	(8,787)	(155)	Schedule 20, Line 31, Column 4
28	All Other	(319)	(379)	(60)	
29	Total	$ (16,167)	$ (22,455)	$ (6,288)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 25

Line No.	Class	CCA Rate	31/12/2017 UCC Balance	Adjustments	2018 Additions	2018 CCA	31/12/2018 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 189,093	$ -	$ -	$ 7,564	$ 181,529
2	1(b)	6%	28,851	-	598	1,749	27,700
3	2	6%	15,538	-	-	932	14,606
4	3	5%	979	-	-	49	930
5	6	10%	4	-	-	0	3
6	8	20%	2,958	-	731	665	3,024
7	9	25%	-		-	-	-
8	10	30%	4,994	-	1,660	1,747	4,907
9	12	100%	-	-	-	-	-
10	13	manual	117	-	-	-	117
11	14.1	5%	-		164	4	160
12	17	8%	110,110	-	29,336	9,982	129,463
13	42	12%	4,732	-	199	580	4,351
14	45	45%	9	-	-	4	5
15	46	30%	7,195	-	-	2,158	5,036
16	47	8%	444,926	-	39,958	37,192	447,691
17	50	55%	5,197	-	3,769	3,895	5,071
18							
19	Total		$ 814,702	$ -	$ 76,414	$ 66,522	$ 824,594

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved Earned Return	2018 Amount	2018 Ratio	2018 Average Embedded Cost	2018 Cost Component	2018 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 39,353	$ 735,000	55.61%	5.20%	2.89%	$ 38,203	$ (1,150)	Schedule 27, Line 9, Column 6
2	Short Term Debt	838	58,076	4.39%	3.45%	0.15%	2,004	1,165	
3	Common Equity	47,046	528,717	40.00%	9.15%	3.66%	48,378	1,332	
4									
5	Total	$ 87,237	$ 1,321,793	100.00%		6.70%	$ 88,584	$ 1,348	
6									
7	Cross Reference		Schedule 2 Line 29 Column 3						

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Series G	28/08/1993	28/08/2023	$ 25,000	8.800%	$ 2,200	
2	Series I	01/12/1997	01/12/2021	25,000	7.810%	1,953	
3	Series 1 - 05	09/11/2005	09/11/2035	100,000	5.600%	5,600	
4	Series 1 - 07	04/07/2007	04/07/2047	105,000	5.900%	6,195	
5	MTN - 09	02/06/2009	02/06/2039	105,000	6.100%	6,405	
6	MTN - 10	24/11/2010	24/11/2050	100,000	5.000%	5,000	
7	MTN - 14	28/10/2014	28/10/2044	200,000	4.000%	8,000	
8	MTN - 17 (forecast)	01/09/2017	01/09/2047	75,000	3.800%	2,850	
9	Total			$ 735,000		$ 38,203	
10							
11	Average Embedded Cost				5.20%		

12. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

12.1 *INTRODUCTION AND OVERVIEW*

In this section, FBC discusses “Exogenous Factors” under its PBR Plan (updating one exogenous factor previously approved), emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC requests approval of five new deferral accounts. FBC also reports on two of its existing deferral accounts in this section.

12.2 *EXOGENOUS (Z) FACTORS*

FBC is permitted to adjust the cost of service for “Exogenous Factors” under its PBR Plan. The following criteria have been established for evaluating whether the impact of an event qualifies for exogenous factor treatment:

6. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
7. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
8. The impact of the event was unforeseen;
9. The costs must be prudently incurred; and
10. The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.301 million, as approved by Commission Order G-184-14.

FBC provides updated costs for the exogenous factor which was approved for 2016 and 2017, as described below.

12.2.1 Mandatory Reliability Standards

FBC will continue to incur incremental O&M and capital requirements in 2018 and future years related to complying with the changes to BC’s MRS program approved by Order R-38-15 and R-39-17. Consistent with Orders G-202-15 and G-8-17 for the costs associated with Assessment Report No 8, the 2018 costs qualify for exogenous factor treatment under the PBR Plan. The MRS costs identified in this Application for exogenous factor treatment in 2018 are for ongoing costs related to Assessment Report No. 8 and for new costs related to Assessment Report No. 10.

FBC's 2016 and 2017 incremental costs to comply with the changes to BC's MRS program were approved for Z-factor treatment by Orders G-202-15 and G-8-17. The incremental MRS compliance requirements were described in FBC's Annual Review for 2016 Rates as follows:

> In Section 6.3.6, FBC identified incremental O&M Expense in 2016 and future years (and incremental capital expenditures in 2017) related to MRS that qualify as exogenous events. By Order R-38-15 dated July 24, 2015, the Commission adopted 34 reliability standards and the NERC (North American Electric Reliability Corporation) Glossary of Terms as recommended for adoption by BC Hydro in MRS Assessment Report No. 8. In that Order, the Commission also identified that one standard is pending and two standards are held in abeyance. The Commission accepted BC Hydro's recommendation of adoption given that the major portion of costs identified by the entities relate to the implementation of new cyber security requirements, new modelling and testing requirements for generators and synchronous condensers, and an overhaul of the protection system maintenance program requirements.
>
> This event and the costs required as a result of the adoption of the reliability standards meet the exogenous factor criteria identified above.
>
> - The costs are entirely attributed to complying with the changes to BC's MRS program approved by Order R-38-15, which is an event outside the control of FBC. These changes were developed by regulatory bodies in the U.S., assessed for adoption by BC Hydro and then adopted by the BCUC. FBC is legally obligated to comply with the new reliability standards.
> - As described in section 6.3.6, the costs are directly and solely attributable to complying with the changes to the BC MRS program approved on July 24, 2015. These costs have not been previously incurred and were not known at the time the 2013 base O&M was determined and therefore were not included in the 2013 base O&M used to determine the O&M expense included in the PBR formula.
> - The costs to comply with the reliability standards that were approved by Order R-38-15 could not have been foreseen at the time the 2013 base was set as the new standards were either non-existent or under preliminary development at the time.
> - FBC will manage its costs to comply with the reliability standards in a prudent manner and the Commission will have the opportunity to review the costs in subsequent annual reviews.

- The forecast O&M costs of $0.4445 million in 2016, $0.500 million in 2017, and $0.425 million in 2018 and beyond, and the forecast capital expenditures of $0.445 million in 2017 exceed the materiality threshold of $0.301 million.

In Appendix A to Order G-202-15, the Commission stated:

> **The Panel approves for Z-factor treatment the forecast O&M costs of $0.445 million in 2016 relating to its compliance with the changes to BC's MRS program.**
>
> FBC has provided sufficient evidence and justification to satisfy the Z-factor Criteria in their entirety as relating to these forecast expenditures.

Further, in appendix A to Order G-8-17, the Commission stated:

> **The Panel approves Z-factor treatment for the 2017 incremental O&M and capital expenses related to the MRS Assessment Report No. 8.** The Panel considers these costs to be outside the control of FBC as changes to the MRS program are determined by an external regulatory body and FBC is legally obligated to comply with the reliability standards. Further, the Panel agrees with FBC that these incremental costs were not known at the time of the establishment of FBC's Base O&M and the forecast 2017 costs exceed the materiality threshold for Z-factor treatment. Thus, it is appropriate to account for these costs outside of FBC's formula-driven O&M spending. The Panel also notes that all variances between forecast and actual MRS costs are captured in FBC's Flow-through deferral account; thus, FBC is ultimately recovering the actual costs incurred from ratepayers, not the forecast costs.

As described in sections 6.3.4 and 7.2.1 of the Application, FBC will continue to incur costs in 2018 to achieve and maintain compliance with the new and revised standards adopted as a result of Assessment Reports No. 8 and No. 10.

For 2018, the incremental MRS costs that qualify for exogenous factor treatment are forecast to be $0.770 million, comprised of $0.720 million in incremental O&M expense and an incremental $0.050 million in capital expenditures. These costs continue to exceed the Commission-defined materiality threshold of $0.301 million and satisfy the other Z-factor criteria on the same basis as accepted by the Commission in Orders G-202-15 and G-8-17. FBC has therefore forecast these costs outside of the O&M and capital formulas as described in Sections 6.3.4 and 7.2.2 of the Application.

12.3 *ACCOUNTING MATTERS*

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging US GAAP Accounting Guidance

In the PBR Decision, the Commission directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." FBC discusses three US GAAP accounting standards with the impacts set out below:

- ASU 2014-09 ASC Topic 606 Revenue Recognition - not expected to affect future rates but is still being assessed;
- ASU 2017-07 ASC Topic 715 Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost - results in a small decrease to 2018 rates; and
- For ASU 2016-02 ASC Topic 842 Leases - the assessment will conclude in 2018.

12.3.1.1 Revenue Recognition

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, and the amendments in this update created Accounting Standard Codification (ASC) Topic 606 *Revenue from Contracts with Customers*. This standard completes a joint effort by FASB and the International Accounting Standards Board (IASB) to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards (IFRS) that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. In 2016, a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017.

The majority of FBC's revenue is generated from electricity sales to customers based on published tariff rates, as approved by the BCUC, and is considered to be in scope of ASU No. 2014-09. FBC does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from electric sales to customers, or on its remaining material revenue streams.

However, FBC's conclusions on the recognition of its revenue under the new standard is still subject to final review by the Company's external auditors and could be affected by certain industry specific interpretative issues which remain outstanding. If conclusions reached either by the industry or external auditors is different than current practice or preliminary conclusions reached by FBC, it could impact the Corporation's consolidated financial statements and related disclosures beginning January 1, 2018.

Should the final conclusions ultimately result in a difference between how FBC recognizes revenue for rate-setting purposes with how it is required to recognize that same revenue for external accounting purposes, FBC will apply to capture that difference in a deferral account. The request for such a deferral account would provide greater certainty around the existence of a deferred charge asset or liability for external reporting purposes. Any such difference would be expected to affect the revenue recognized for external financial reporting purposes, with the offset recognized in a deferral account and as such would not be expected to affect revenue requirements.

12.3.1.2 Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, FASB issued ASU No. 2017-07, Compensation-Retirement Benefit (Topic 715) - *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*.

Current US GAAP does not contain explicit guidance on where the amount of pension and OPEB expense, also referred to as net benefit cost, should be presented in the income statement and does not require an employer to disclose the amount of net benefit costs included in each line item in the income statement or capitalized in assets. The amendments in ASU 2017-07 Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost is intended to provide greater transparency around presentation of defined benefit cost in financial statements. The amendments in this update require that companies disaggregate the service cost component from the other components of pension and other post-retirement benefits (OPEB) expenses in the income statement and allow only the service cost component of pension and OPEB expenses to be eligible for capitalization. The amendments will be effective for annual and interim periods beginning on or after December 15, 2017, which is January 1, 2018 for FBC.

In prior applications, FBC treated all components of pension and OPEB expenses as eligible to be allocated between O&M and capital. For 2017, this allocation resulted in $3.267 million of pension and OPEB expense residing in O&M and the remaining balance of $3.539 million allocated to capital expenditures.

For this Application, FBC's 2018 Forecast is prepared consistent with ASU 2017-07 under which only the service cost of pension and OPEB expense as eligible for capitalization. The remaining non-service cost components (including interest cost, expected return on assets and amortization of net actuarial loss and prior service credit) will remain in the income statement as they are not eligible for capitalization. For the 2018 Forecast, $2.659 million or approximate 42 percent of pension and OPEB expense is recognized in O&M and $3.630 million or approximate 58 percent of pension and OPEB expense has been recognized in capital expenditures.

To assist with understanding the effects of this new guidance, the following table shows the 2017 Approved as compared to the 2018 Forecast pension and OPEB expenses disaggregated into the various components.

Table 12-1: Components of Pension and OPEB Expense

Line No.	Description	Approved 2017	Forecast 2018	Variance
1	Service cost	$ 6.846	$ 6.981	$ 0.135
2	Interest cost	9.330	9.667	0.337
3	Expected return on assets	(10.936)	(11.588)	(0.652)
4	Amortization:			
5	Net actuarial (gain) loss	1.650	1.313	(0.337)
6	Prior service cost (credit)	(0.911)	(0.911)	-
7	US GAAP transitional obligation	0.827	0.827	-
8	Total Pension & OPEB Expense	$ 6.806	$ 6.289	$ (0.517)

Table 12-2 below represents the allocation to capital and O&M of FBC's pension and OPEB expenses for 2017 Approved, 2018 Forecast using the past practice (existing guidance) and 2018 Forecast using the new guidance. As shown in Table 12-2, the new guidance results in an increase of $0.360 million in the pension and OPEB costs allocated to capital and a net decrease of $0.360 million in the net benefit costs recognized in O&M. An alternative comparison is that under past practice, approximately 48 per cent of total pension and OPEB expense was recognized in O&M and the remaining 52 per cent allocated to capital, as compared to the new guidance which would require 42 per cent of total pension and OPEB expense to be recognized in O&M and the remaining 58 per cent allocated to capital.

This change in methodology to align with the new guidance has minimal impact, resulting in a 0.01% decrease to 2018 rates. While fewer components of pension and OPEB expense are eligible to be capitalized under ASU 2017-07, there is a slight increase in capitalization primarily due to the expected return on assets component, which is a credit to pension expense, now recognized in O&M.

Table 12-2: Allocation of Pension Expense under New Guidance

Line No.	Description	Approved 2017	2018 Forecast per Existing Guidance	2018 Forecast per New Guidance	2018 Variance the Existing Guidance vs New Guidance
1	O&M	3.267	3.019	2.659	(0.360)
2	Capital	3.539	3.270	3.630	0.360
3	Total Pension & OPEB Expense	$ 6.806	$ 6.289	$ 6.289	$ -

12.3.1.3 Leases

In February 2016, FASB issued ASU No. 2016-02, *Leases (Topic 842*) which supersedes lease requirements in ASC Topic 840, *Leases*. This standard increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This standard is effective for FBC for annual and interim periods beginning on January 1, 2019. The main provision of Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current US GAAP.

The new guidance will result in operating leases being recognized as assets and liabilities on the balance sheet. The new standard either classifies lease costs as interest and depreciation or as a rent expense, depending on the type of classification under this new lease standard. FBC will be assessing its arrangements that qualify as leases which could potentially be recorded as assets and liabilities on the balance sheet for external financial reporting purposes. Final assessments on the impact of this standard on FBC's external financial statements and revenue requirements, if any, will not be determined until 2018. Any updates will be incorporated into the Annual Review for 2019 Rates.

12.4 *NON RATE BASE DEFERRAL ACCOUNTS*

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the Commission. The forecast mid-year balance of unamortized non rate base deferred charges is a debit balance of approximately $0.426 million in 2018.

On May 3, 2017, the Commission issued is Regulatory Account Filing Checklist[33]. The purpose of this checklist is to facilitate an efficient review of applications for deferral accounts.

The checklist classifies deferral accounts as either: (a) forecast variance accounts; (b) rate smoothing accounts; (c) benefit matching accounts; (d) retroactive expense accounts; or (e) other. FBC has reclassified its existing non rate base deferral accounts in accordance with the guidelines in Section 11, Schedules 12 and 12.1

[33] Log No. 53608, Appendix B.

In the following sections, FBC requests approval of five new deferral accounts, four of which are related to regulatory requirements. FBC also provides additional information for its previously approved AMI Radio-Off Shortfall and Flow-through deferral accounts.

12.4.1 New Deferral Accounts

FBC seeks approval for five new deferral accounts, four of which are related to current or future regulatory proceedings. Table 12-3 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to deferral accounts for regulatory proceedings.

Consistent with the Commission's decision in the 2012-2013 RRA and the PBR Decision, FBC has followed the practice of new deferral accounts being financed using either the short term interest (STI) rate where recovery is over a one-year period; or the weighted average cost of debt (WACD) for longer-term deferrals.

Specific proposals for financing and disposition of the accounts are included in the relevant sections describing the individual accounts.

Table 12-3: Deferral Account Filing Considerations

Item	Consideration	Regulatory Proceeding Costs	2018 Joint Pole Use Audit
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The four regulatory proceeding cost accounts are new deferral accounts, consistent with the existing regulatory proceeding deferral accounts.	The 2018 Joint Pole Use Audit is a new deferral account, consistent with past treatment of joint pole use audits in previous years.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested accounts are regulatory proceeding cost accounts, which are routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.	Discussed below.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of each account encompasses the preparation and filing of the relevant regulatory application and its review by the Commission.	The audit will be completed in 2018.

Item	Consideration	Regulatory Proceeding Costs	2018 Joint Pole Use Audit
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the PBR formula O&M since regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report on.	In the absence of a deferral account, the costs of the audit would have to be forecast as an O&M expense (outside of the PBR formula O&M since the 2013 audit costs were deferred and excluded from Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers a deferral account to be the more appropriate treatment since it permits the amortization of costs over the five-year period between audits.

Item	Consideration	Regulatory Proceeding Costs	2018 Joint Pole Use Audit
IV	Address:		
a)	whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the Commission and the degree of involvement of interveners.	An audit of joint use poles is required at five year intervals as a condition of FBC's agreements with the counter parties and is therefore outside of FBC's direct control.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FBC forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	FBC forecasts audit costs based on past experience. Actual costs are recorded in the account so that the actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the PBR Plan. See sections 12.4.1.1 through 12.4.1.6.	See section 12.4.1.7.
d)	any impact on intergenerational equity	Generally FBC recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. See sections 12.4.1.1 through 12.4.1.6.	FBC proposes to recover the deferred costs over the five year period between the required audits, which serves to match the costs and benefits.

Item	Consideration	Regulatory Proceeding Costs	2018 Joint Pole Use Audit
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.	FBC classifies this account as a benefit matching account since the costs are recovered over the period between audits.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.	The joint use pole audit account is a cash account.
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the Commission's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M Expense. See sections 12.4.1.1 through 12.4.1.6	Costs include incremental labour, vehicle, and staff expense in addition to FBC's share of common costs such as data input costs. See section 12.4.1.7.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally FBC amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. See sections 12.4.1.1 through 12.4.1.6.	FBC proposes to recover the deferred costs over the five year period between the required audits.

Item	Consideration	Regulatory Proceeding Costs	2018 Joint Pole Use Audit
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Consistent with the Commission's decision in the 2012-2013 RRA and the PBR Decision, FBC has followed the practice of new deferral accounts being financed using either the short term interest (STI) rate where recovery is over a one-year period, or the weighted average cost of debt (WACD) for longer-term deferrals. See sections 12.4.1.1 through 12.4.1.5.	Consistent with the Commission's decision in the 2012-2013 RRA and the PBR Decision, FBC proposes a WACD rate for the five year term of the deferral account.
XI.	Outline a recommended regulatory process for the Commission's review of the application.	Deferral account approvals and disposition are determined in revenue requirements proceedings.	The approval and disposition of this account will be determined in the Annual Review for 2018 Rates.

12.4.1.1 Multi-Year Demand Side Management Expenditure Schedule Application

FBC intends to file an application for approval of a DSM Expenditure Schedule for 2018 and future years by the first Quarter of 2018. A written public hearing is anticipated for the review of this application; FBC estimates the costs at $0.250 million ($0.185 million after tax).

FBC is seeking approval of a deferral account attracting a WACD return, to capture costs related to the multi-year DSM Expenditure Schedule application. FBC will propose the disposition of this account in a future application.

12.4.1.1 Community Solar Pilot Project Application

On April 26, 2017, FBC applied to the Commission for an order authorizing FBC to implement new rate schedules, and to construct a Community Solar Pilot Project. The Company is proposing to build a 240 kW community solar array in Kelowna that will allow a limited number of FBC customers the opportunity to voluntarily subscribe to the generation output. The application is currently under review.

FBC is seeking approval of a deferral account attracting a STI return, to capture an estimated $0.125 million ($0.093 million after tax) related to this tariff application. FBC proposes to amortize the costs over one year, in 2018.

12.4.1.2 Tariff Applications

FBC is seeking approval of a deferral account to capture the costs of applications for new tariffs or for tariff revisions (excluding rate design applications).

In 2017, FBC intends to file an application for revisions to Rate Schedule 50 – Lighting, including the establishment of a new rate for Type III Company-owned, Company-maintained Light Emitting Diode (LED) lights. The Company also intends to file a Transmission Tariff Update application to update the portions of its Point-to-Point (PTP) Transmission rate schedules (Rate Schedules 101 102) to clarify the treatment of a customers using the transmission systems of both FBC and BC Hydro.

The deferral of the costs related to the Transmission Tariff Update application were approved in Order G-8-17; FBC proposes to include the costs of this and future tariff-related applications in a single deferral account in order to reduce the number of individual deferral account requests. The forecast expenditures in 2017, assuming written public hearing processes for the review of these two applications, are $0.100 million ($0.076 million after tax)[34].

[34] The Tariff Applications deferral account is found at Line 17 in Section 11, Schedule 12. Order G-8-17 approved expenditures of $0.100 million ($0.074 million after tax) and amortization of the same amount in 2017 for the Transmission Tariff Update application. FBC's current forecast is for aggregate expenditures in 2017 of $0.100

The Company proposes to finance this account at its STI rate and to amortize each year's expenditures in the following year.

12.4.1.3 2020 Revenue Requirements Application

FBC's portion of the costs related to the next revenue requirement application following the end of the current PBR term will include the costs of the benchmarking study discussed below.

In its order approving the 2014-2019 PBR Plan, the Commission's review of the appropriate stretch factor (X Factor) included the following observation and directive:

> A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed **prior to the application for the next phase of the PBR**. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.**[35]

Further, the Commission directed[36]

> **that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study.** As a result of this consultation, the Panel expects that agreement be reach on the broad terms and parameters of the study. **Fortis is directed to report the results of this consultation to the Commission prior to starting the study.**

FBC and FEI jointly began the consultation with interveners in 2017 and anticipate completing the benchmarking study by year end 2018 at an estimated cost of $0.030 million in 2017 and $0.070 million in 2018 for each utility, for a combined total cost of $0.200 million for both utilities. The benchmarking study will inform the 2020 revenue requirements and/or next generation PBR filing which will be submitted in 2019. Forecast costs for the remainder of the application and its regulatory review will be updated at a later time.

FBC is seeking approval of a deferral account attracting a WACD return, to capture costs related to the next generation PBR application. FBC will propose the disposition of this account in a future application.

million ($0.074 million after tax) for both applications in the Tariff Update deferral account, therefore the balance in the account will be $0 at December 31, 2017.

[35] Order G-139-14, pages 79-80.

[36] Order G-139-14, page 80.

12.4.1.4 2018 Joint Use Pole Audit

Under the provisions of the Company's various joint pole use agreements, the parties are required to perform an audit of the joint use pole contacts once every five years. The last audit was in 2013.

Consistent with the treatment of the 2013 Joint Use Pole Audit, FBC is seeking approval of a deferral account attracting a WACD return, to capture estimated costs of $0.200 million ($0.148 million after tax), and to amortize the costs over a five year period beginning in 2018.

12.4.2 Existing Deferral Accounts

Below, FBC provides information on two of its approved deferral accounts.

12.4.2.1 AMI Radio-Off Shortfall Deferral Account

Pursuant to Order G-202-15, FBC records the shortfall between the costs of reading radio-off AMI meters and the fees charged for manually reading these meters under Rate Schedule 81 (RS 81) in a deferral account. On September 30, 2016, FBC filed its Report on Radio-off AMI Meter Participation and Costs (the Radio-Off Report), the purpose of which was to determine whether or not a revision to the radio-off meter reading fee is required to restore matching of cost and causation for manual reading of radio-off meters. In Order G-8-17, the Commission directed FBC to file the September 30, 2016 AMI Radio-Off Report as part of its Annual Review for 2018 rates and to address the disposition of the AMI Radio-Off Shortfall deferral account in that application. The Radio-Off Report is attached as Appendix E.

The Radio-Off Report, based on the Company's experience between June 2016 and August 2016, concluded that the shortfall between radio-off costs and revenues should be minimal and that no revision to RS 81 was required. Since the completion of the Radio-Off Report, however, the shortfall has grown to an estimated $0.120 million on an annual basis. FBC therefore intends to address RS 81 and to propose the disposition of the deferral account in its upcoming Rate Design Application.

12.4.2.2 Flow-Through Deferral Account

As approved by Commission Order G-163-14, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are included in rates on a forecast basis and which do not have a previously approved deferral account. The specific items included in the Flow-through account were set out in Table 1, which was included in FBC's letter Response to Orders G-162-14 and G-163-14 filed with the Commission on November 7, 2014 reproduced below.

Table 12-4: Variances Captured in the Flow-through Deferral Account[37]

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power purchase variances	N/A	Flow-through deferral
Water fees variances	N/A	Flow-through deferral
Gross O&M:		
Formula driven O&M variances	Earnings sharing	Earnings sharing
BCUC fees variances	BCUC Variances deferral	Flow-through deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances *	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	N/A - no variance	N/A - no variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Depreciation and Amortization:		
Depreciation variances	Flow-through deferral	Flow-through deferral
Amortization of deferrals	N/A - no variance	N/A - no variance
Other Revenues (FEI)/Other Income (FBC):		
SCP Mitigation Revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
All other other revenue/income variances	Flow-through deferral	Flow-through deferral
Wheeling (FBC)/Transportation costs (FEI):		
Transportation and wheeling variances	Flow-through deferral	Flow-through deferral
Income Tax:		
Income tax variances	Flow-through deferral	Flow-through deferral
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas Storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
All other interest variances	Flow-through deferral	Flow-through deferral

* Including items re-forecast outside of the formula such as insurance premiums, AMI, NGT stations, Biomethane, RS46 O&M

In accordance with the method set out in the table above, the calculation of the 2017 projected Flow-through amount of $6.215 million credit is shown in Table 12-5 below. To calculate the amount to be distributed to customers, FBC has also included an adjustment for the difference between the projected ending 2016 deferral account debit balance of $3.078 million embedded in 2017 rates and the actual ending 2016 deferral account debit balance of $2.191 million, a credit difference of $0.886 million. FBC notes that the financing return on this account is

[37] FBC notes an error in the table that was filed. Although for FEI the BCUC fee variances are recorded in a separate deferral account, for FBC these fees are included in formula O&M. As such, for FBC, any variance in these fees between the formula-driven amount and the actuals will be subject to earnings sharing, and not to flow-through treatment.

included in the aggregate financing of deferral accounts financed at the STI rate at Section 11, Schedule 12.1, Line 25.

Table 12-5: 2017 Flow-through Deferral Account Additions ($ millions)

Line No.	Description	Approved 2017	Projected 2017	Variance
1	Revenue	$ (362.128)	$ (360.392)	$ 1.736
2				
3	Power Purchase Expense	136.216	130.437	(5.779)
4				
5	Wheeling	4.928	5.017	0.089
6				
7	Water Fees	10.328	10.329	0.001
8				
9	O&M Tracked Outside of Formula			
10	Insurance Premiums	1.327	1.267	(0.060)
11	Advanced Metering Infrastructure Project	(1.126)	(1.126)	-
12	Mandatory Reliability Standards Incremental O&M	0.050	0.050	-
13	Upper Bonnington Unit 3 Annual Inspection	(0.040)	(0.040)	-
14				
15	Property Tax	16.052	15.888	(0.164)
16				
17	Depreciation and Amortization	55.657	55.719	0.062
18				
19	Other Revenue	(8.056)	(8.980)	(0.924)
20				
21	Interest Expense	40.191	38.452	(1.739)
22				
23	Income Tax	10.849	12.304	1.455
24				
25	Working Capital Adjustment for AMI			(0.006)
26				
27	2015 After-Tax Flow-Through Addition to Deferral Account			(5.329)
28				
29	2015 Ending Deferral Account Balance True-Up			$ (0.886)
30	2017 After-Tax Amortization			$ (6.215)

The variance in revenue is due to loads being lower than approved for the wholesale, industrial and residential classes, partially offset by higher commercial load. The variance in power purchase is primarily due to higher market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost, reduced WAX CAPA costs, and the lower load. Variances in wheeling and water fees are shown in Section 4, other revenue are shown in Section 5, O&M tracked outside of formula are shown in Section 6, Property Taxes are shown in Section 9. Depreciation and amortization expense is close to the approved value. The variance in interest expense is due to the timing of issuing and a lower volume of long-term debt issuance, partially offset by higher short-term debt balance associated with the long-term debt issuance delay. Finally, the variance in income taxes is due to the income tax impacts of each of the aforementioned items, the variance between the projected and approved tax timing differences, partially offset by an adjustment between the prior year's tax provision and the actual tax return.

A true-up of $0.886 million between the projected ending 2016 Flow-Through deferral account balance embedded in 2017 rates and the actual ending 2016 deferral account balance is the result of higher revenue on construction work performed for a third party in addition to lower loads in the last half of 2016 due to warmer than normal weather and reduced residential and industrial loads. Similarly, an adjustment to include the difference between the projected and final actual amounts for 2017 subject to flow-through will be recorded in the deferral account in 2018 and amortized in 2019 rates.

12.5 *SUMMARY*

FBC has updated the costs associated with the MRS exogenous event(s) which affect rates in 2018 and proved updates on certain accounting related matters. In this section, FBC has also requested approval of five non-rate base deferral accounts and included information on two existing deferral accounts.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

SQIs form the basis of determining a utility's quality of service and represent a broad range of business processes that are important elements to the customer experience. Under a PBR Plan, SQIs are used to monitor the utility's performance to ensure that any cost reductions by the utility as a result of implementing productivity initiatives do not result in serious degradation of the quality of service to customers during the PBR period.

The Commission approved a balanced set of SQIs covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level, as outlined in the Consensus Recommendation approved by the Commission in Order G-14-15. Three of the SQIs are for information only, and as such do not have benchmarks or performance ranges.

In 2016, the Commission issued its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing. The Commission determined that it was appropriate to review FBC's service quality for a year in the following year's annual review. The Commission stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid- year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

In the subsections below, FBC reports on its 2016 and June 2017 year-to-date performance as measured against the SQI benchmarks and thresholds. Both 2016 and June 2017 year-to-date SQI results indicate that the Company's overall performance is meeting service quality standards. In 2016, for the eight SQIs with benchmarks, seven performed at or better than the approved benchmarks with the remaining one, the All Injury Frequency Rate (AIFR) performing better than the threshold. For the three SQIs that are informational only, performance is generally consistent with recent years' performance.

June 2017 year-to-date performance is similar to 2016, with seven of the eight SQIs with benchmarks performing at or better than the approved benchmarks and the one remaining SQI, System Interruption Duration Index (SAIDI) performing better than the threshold.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FBC's 2016 and June year-to-date performance for 2017 to the Commission-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation that was approved by the Commission. Actual 2016 and June year-to-date results for 2017 are also provided for the three informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2016 Results	2017 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	93%	90.6%	97%	93%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64	2.39	1.97	1.34
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	72%	79%	79%
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.57	0.15
Meter Reading Accuracy	Number of scheduled meters that were read	97%	94%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	70%	70%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.2	8.1
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	3.9%	4.4%
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) - Normalized	3 year average of SAIDI (average of cumulative customer outage time)	2.22	2.62	2.18	2.36

Performance Measure	Description	Benchmark	Threshold	2016 Results	2017 June YTD Results
System Average Interruption Frequency Index (SAIFI) - Normalized	3 year average of SAIFI (average customer outage)	1.64	2.50	1.51	1.47
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.8%	0.9%

In the following sections, FBC reviews each SQI's individual performance in 2016 and 2017. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time including conditions such as time of day (during business hours or after business hours), number and type of events (i.e. widespread outages), available resources and location (travel times and traffic congestion) and weather conditions.

The 2016 result was 97 percent which was better than the benchmark of 93 percent. The June 2017 year-to-date result is 93 percent, which meets the benchmark level set at 93 percent. The 2017 year-to-date performance has been impacted by two major events: a heavy snowfall on February 6, and a windstorm on May 24. During these two outage events, the high number of trouble calls has contributed to the lower 2017 year-to-date performance versus the same period in 2016.

The Company's 2009 to 2016 annual and 2017 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the types of outage described above and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Results	92%	95%	92%	91%	94%	91%	92%	97%	93%
Benchmark	n/a	n/a	n/a	n/a	n/a	93%	93%	93%	93%
Threshold	n/a	n/a	n/a	n/a	n/a	90.6%	90.6%	90.6%	90.6%

All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e. one or more days missed from work) and medical treatments (i.e. medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three year rolling average of the annual results.

The 2016 annual (calendar year) AIFR result was 1.15, resulting in a three-year rolling average of 1.97 in 2016, which is between the threshold and the benchmark. In 2016, there was an improved trend in the annual result with 5 recordable incidents occurring. This annual result demonstrates a continued improvement which has continued into 2017. The June 30, 2017 YTD AIFR annual result is 1.33. As of June 30, 2017, there were 3 Medical Treatment and no Lost Time injuries. The three-year rolling average of annual results including 2017 June year-to-date results is 1.34, which is better than the benchmark of 1.64. The recent AIFR results are reflective of FBC's continuing focus on safety.

Safety continues to be a core value for FBC and prevention of injury remains a key focus. FBC continues to focus on and reinforce the fundamentals of safety through effective safe work planning identifying hazards and mitigating risks, detailed work observations and thorough event analysis capturing learnings and identifying opportunities for continued improvement. FBC has a robust Safety Management System that addresses the hazard and risk requirements of a safe workplace and identifies opportunities for improvement in the Company's safety culture. FBC continues to maintain the Certificate of Recognition (COR) through audits performed annually, providing validation of the effectiveness of the Company's safety programs. The COR, administered by the Partners in Injury and Disability Prevention Program of WorkSafeBC, is a voluntary initiative that recognizes and rewards employers who meet the requirements of the Occupational Health and Safety Regulations.

Target Zero is the continual improvement program which was launched in January 2016. This program focuses on a number of key elements designed to enhance the existing safety management system and engage employees at all levels in safety as well as promote an interdependent safety environment. The Company believes this program has contributed to the positive safety trend experienced.

The Company's 2009 to 2016 and 2017 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	1.41	1.72	1.48	1.72	2.82	3.21	1.54	1.15	1.33
Three year rolling average	2.00	2.00	1.54	1.64	2.01	2.58	2.52	1.97	1.34
Benchmark	n/a	n/a	n/a	n/a	n/a	1.64	1.64	1.64	1.64
Threshold	n/a	n/a	n/a	n/a	n/a	2.39	2.39	2.39	2.39

The annual results in Table 13-3 support the conclusion that the higher AIFR results in 2013 and 2014 are anomalous in nature. As seen in the historical results, FBC's 2015, 2016 and June 2017 year-to-date annual AIFR results are materially improved as compared to 2013 and 2014 and have returned to pre-2013 levels.

FBC remains committed to maintaining its focus on safety. FBC believes that its actions to increase the focus on safety supported by increase funding to its safety program are appropriate in the circumstances and that the year-to-date results are an encouraging sign that the program is working as anticipated.

13.2.2 Responsiveness to Customer Needs

First Contact Resolution

First Call Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2016 result was 79 percent and better than the benchmark at 78 percent. June 2017 year-to-date performance is 79 percent and also better than the benchmark.

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	n/a	n/a	n/a	n/a	73%	73%	76%	79%	79%
Benchmark	n/a	n/a	n/a	n/a	n/a	78%	78%	78%	78%
Threshold	n/a	n/a	n/a	n/a	n/a	72%	72%	72%	72%

Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date):
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

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

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

The 2016 result was 0.57 which was better than the benchmark of 5.0. The June 2017 year-to-date performance is 0.15 which is also better than the benchmark. No significant billing issues have arisen in 2017.

The 2016 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2016 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	100.00%	If (PA ≥99.9%,5000*(1 - PA),1.05-PA))	=5000*(1-1)	0.60
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	98.82%	(100%-PA)*100	=(100%-98.82%)*100	1.12
Billing Service Quality Indicator; Target < 5.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0+0+1.18) /3	**0.57**

The Company's 2014 to 2016 annual and 2017 year-to-date results are provided below. As tracking of this SQI began part way through 2013, the 2013 results do not reflect a full year.

Table 13-6: Historical Billing Index Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	n/a	n/a	n/a	n/a	0.10	2.34	0.39	0.57	0.15
Benchmark	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0	5.0
Threshold	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0	5.0

Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2016 result was 99 percent, better than the benchmark. The June 2017 YTD result is 99 percent, also better than benchmark

The Company's 2009 to 2016 and 2017 year-to-date results are provided below. Historically, there has been little variation in performance other than in 2013, which saw a significant drop in performance (to 51 percent) as the result of the six-month IBEW labour disruption.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	98%	98%	98%	98%	51%	98%	96%	99%	99%
Benchmark	n/a	n/a	n/a	n/a	n/a	97%	97%	97%	97%
Threshold	n/a	n/a	n/a	n/a	n/a	94%	94%	94%	94%

Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2016 result was 70 percent, which met the benchmark of 70 percent. The June 2017 year-to-date performance is also at 70 percent which meets the benchmark.

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by the events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	70%	70%	70%	70%	70%	48%	71%	70%	70%
Benchmark	n/a	n/a	n/a	n/a	n/a	70%	70%	70%	70%
Threshold	n/a	n/a	n/a	n/a	n/a	68%	68%	68%	68%

Customer Satisfaction Index

The Customer Satisfaction Index (CSI), an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The Index includes feedback from both residential and commercial customers. The survey is conducted quarterly and results are presented as a score out of ten.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage. Over the last several years, customer concerns about tiered electricity prices, collection policies and advanced metering have contributed to an overall erosion of CSI scores as evident in Table 13-9 below. Recent years' index scores have stabilized.

The 2016 year-end result was 8.2, slightly higher than the 8.1 score in 2015. The June 2017 year-to-date average index score was 8.1, slightly lower than the 8.2 score for the same period last year. Of the five measures that make up the overall score, results were lower in three, higher in one and static in one category. Customer attitudes about the Company's contact centre increased by two points from 8.1 for June 2016 year-to-date to 8.3 for June 2017 year-to-date. Small decreases in the scores were seen for overall satisfaction, the accuracy of meter reading and field services satisfaction. On a year-to-date basis, overall satisfaction decreased from 8.0 for June 2016 year-to-date to 7.9 for June 2017 year-to-date. The accuracy of meter reading and field services satisfaction scores decreased from 7.7 to 7.5 and 9.1 to 8.8 from June 2016 year-to-date to June 2017 year-to-date, respectively. The score for the energy conservation metric remained static at 7.2.

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	8.6	8.8	8.7	8.4	8.0	8.1	8.1	8.2	8.1
Benchmark	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

Telephone Abandon Rate

The Telephone Abandon Rate, an informational indicator, measures the percent of calls abandoned by the customer before speaking to a customer service representative. Abandon rates can be due to waiting times, or due to customers receiving their required information through informational messages in the Company's Interactive Voice Response (IVR) system such that the customer no longer needs to speak to an agent.

The 2016 result was 3.9 percent and the June 2017 year-to-date result is 4.4 percent.

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below. As discussed in the 2015 Annual Review, the 2014 result of 12.4 percent was negatively impacted by high call volumes resulting from the first verified meter readings occurring after the IBEW labour disruption ended in December of 2013, the introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-10: Historical Telephone Abandon Rates

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	2.2%	1.9%	1.7%	1.9%	2.0%	12.4%	2.7%	3.9%	4.4%
Benchmark	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

In August of 2016, FortisBC implemented a new feature where customers can retain their place in the telephone queue by entering their phone number and requesting a call back. As soon as it is their turn in line, the system dials the recorded number and connects the customer with a Customer Service Representative (CSR).

In Appendix A to Order G-8-17, the Commission Panel directed FBC to include in its Annual Review for 2018 Rates a discussion of the impact, if any, that the new call back option has had on the Telephone Abandon Rate Service Quality Indicator and to discuss whether there are other measures, such as “Time Until Call Back is Received,” which may provide additional value to FBC’s existing informational indictors. FBC provides the requested information below.

So far in 2017, the new call back option has been selected approximately 1,290 times, representing approximately 2 percent of the customers who called each month. It is not possible to distinguish between the average wait-time for customers utilizing the call-back feature from the wait time of those not using the feature. The requested measurement of “Time Until Call Back is Received” is therefore not available. As described above, there are many other reasons a call may be abandoned other than waiting time, the most frequent being the use of avoidance messages on the IVR during outages. Since the number and size of outages are variable from year to year, it is impossible to determine the impact that the call-back feature alone had on the abandon rate.

13.2.3 Reliability

FBC measures transmission and distribution system reliability as adjusted by the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding “major events”. Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the “2.5 Beta” adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Major event days in the FBC service territory have been caused by mudslides, windstorms and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e. the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2016 result was 2.18, which is better than the benchmark of 2.22. In addition, the June 2017 year-to-date result is 2.36, which is better than the threshold of 2.62.

During the first six months of 2017, FBC experienced two major events. The first event was an outage on February 6, 2017 caused by a heaving snowfall, which affected approximately 6,500 customers in the Kootenay area for a total of 37,000 customer hours. The second major event was an outage on May 24, 2017 caused by a windstorm, which affected 7,900 customers for a total of 48,000 customer hours.

FBC's January to June 2017 SAIDI performance was higher than the historical three-year average, while the SAIFI performance remains similar to the historical three-year average performance. The main contributor for higher SAIDI was the reliability of the transmission system in the first quarter of 2017. The normalized transmission system customer hours related to outages was over four times higher than the previous three year average mainly due to adverse weather related outages. Significant transmission outages during this time include outages in the Kootenays on February 9 that contributed 34,000 customer hours and an outage on March 18 for 20,000 customer hours. These outages did not qualify as major events.

The Company's 2009 to 2016 and 2017 year-to-date results are provided below. From 2009 to 2016, performance has generally been stable and improving. However, the results can be influenced by uncontrollable events such as storms that occur in a year.

Table 13-11: Historical SAIDI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Three year rolling average results	2.40	2.51	2.33	2.22	1.94	2.09	2.15	2.18	2.36
Benchmark	n/a	n/a	n/a	n/a	n/a	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

System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e. the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

For the purposes of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2016 result was 1.51, which is better than the benchmark of 1.64. The June 2017 year-to-date result is 1.47, which is also better than the benchmark.

The Company's 2009 to 2016 and 2017 year-to-date results are provided below. From 2009 to 2016, performance has generally been stable and improving. However, the results can be influenced by uncontrollable events such as storms that occur in a year.

Table 13-12: Historical SAIFI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Three year rolling average results	1.87	1.96	1.71	1.64	1.31	1.39	1.49	1.51	1.47
Benchmark	n/a	n/a	n/a	n/a	n/a	1.64	1.64	1.64	1.64
Threshold	n/a	n/a	n/a	n/a	n/a	2.50	2.50	2.50	2.50

Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X 100}$$

The 2016 result for GFOR was 0.9 percent and is mainly attributable to the failure of the over one hundred-year-old Upper Bonnington Unit 3 transformer. This transformer was not repairable and was replaced. The replacement took just under a month to complete. The GFOR for 2017 year-to-date is 0.9 percent and is mainly attributable to various equipment failures at the Upper Bonnington plant.

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below. The 2013 and 2014 results are higher than the other years due to forced outages arising from fires at the Corra Linn and South Slocan generating plants. Also shown is the comparable data from CEA, demonstrating that FBC's results, other than 2013, have been much lower than the industry average.

Table 13-13: Historical Generator Forced Outages

	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
FBC	0.9%	0.1%	0.1%	0.5%	5.2%	1.7%	0.1%	0.9%	0.9%
CEA	1.8%	3.9%	5.0%	4.9%	4.9%	6.3%	6.2%	n/a[38]	

13.3 *REVIEW OF 2016 PERFORMANCE OF SERVICE QUALITY INDICATORS*

In summary, FBC's 2016 results and June 2017 year-to-date SQI results indicate that the Company's overall performance meets service quality standards. In 2016, for the eight SQIs with benchmarks, seven performed at or better than the approved benchmarks with one performing better than the threshold. For the three SQIs that are informational only, performance is generally consistent with recent years' performance.

[38] The final CEA report is generally available in the third quarter of the following year.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Appendix A-1

Statistics Canada and Conference Board of Canada Reports

Table A1-1: CANSIM Table 326-0020

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Table 326-0020 [2, 9]

Consumer Price Index

monthly (2002=100)

Data table | Add/Remove data | Manipulate | Download | Related information | Help

The data below is a part of CANSIM table 326-0020. Use the Add/Remove data tab to customize your table.

Selected items [Add/Remove data]

Geography = British Columbia

Products and product groups [18]	All-items	Food [17]	Shelter [18]	Household operations, furnishings and equipment	Clothing and footwear	Transportation	Gasoline	Health and personal care	Recreation, education and reading	Alcoholic beverages and tobacco products
2015 July	120.8	134.8	113.9	115.3	99.6	128.4	182.1	113.7	119.9	137.3
2015 August	121.0	134.6	114.1	115.1	102.2	127.8	178.9	113.8	120.6	137.9
2015 September	121.0	135.6	114.0	115.4	108.0	125.2	162.1	114.4	119.6	139.5
2015 October	120.6	135.2	114.4	114.9	108.2	125.6	160.0	114.0	116.4	137.6
2015 November	120.8	136.2	114.5	113.7	106.5	127.2	167.4	114.7	115.3	139.0
2015 December	120.4	137.0	114.6	114.1	101.8	126.6	162.5	113.9	115.1	137.8
2016 January	120.7	139.5	114.4	114.7	101.4	125.9	148.0	114.6	114.6	140.1
2016 February	120.8	137.9	114.4	115.8	103.4	125.0	140.3	115.1	116.0	140.2
2016 March	121.8	138.1	114.7	117.1	106.0	126.9	150.8	114.9	117.8	141.1
2016 April	121.8	137.3	115.0	117.2	105.3	127.7	153.8	115.9	116.7	141.2
2016 May	122.7	137.7	115.3	117.3	105.3	130.3	161.4	115.5	119.6	140.9
2016 June	123.1	137.0	115.8	117.3	103.6	131.7	166.9	116.4	120.9	141.1
2016 July	123.3	137.8	115.7	116.9	103.2	131.1	166.4	115.9	123.5	141.8
2016 August	123.4	137.5	116.0	117.9	103.7	130.0	162.4	116.7	123.5	141.7
2016 September	123.2	135.4	115.9	117.0	106.9	130.5	167.9	115.9	123.0	141.9
2016 October	123.1	134.1	116.8	117.5	107.3	131.3	171.5	116.7	120.0	142.4
2016 November	122.7	135.0	117.1	117.3	106.1	129.3	160.9	116.3	118.4	142.7
2016 December	122.7	135.7	117.1	116.8	104.3	130.2	162.9	116.1	118.2	141.7
2017 January	123.5	136.1	117.1	117.1	102.2	133.3	174.6	117.4	119.3	143.2
2017 February	123.6	136.6	117.0	117.1	103.7	132.6	168.0	116.2	120.6	143.9
2017 March	124.2	136.6	117.2	116.9	106.5	133.4	176.6	116.5	123.0	144.3
2017 April	124.4	137.1	117.7	117.8	105.1	134.1	183.1	117.8	120.7	144.1
2017 May	125.0	138.1	117.8	118.4	105.9	133.6	177.8	118.2	123.5	144.5
2017 June	125.2	138.5	118.3	118.7	103.9	133.5	172.7	118.3	123.9	144.9

Table A1-2: CANSIM Table 281-0063

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Table 281-0063 [1, 11, 12, 13, 14]

Survey of Employment, Payrolls and Hours (SEPH), employment and average weekly earnings (including overt employees by North American Industry Classification System (NAICS), seasonally adjusted
monthly

Data table | Add/Remove data | Manipulate | Download | Related information | Help

The data below is a part of CANSIM table 281-0063. Use the Add/Remove data tab to customize your table.

Selected items [Add/Remove data]
Geography = British Columbia
Estimate = Average weekly earnings including overtime for all employees (dollars) [3]

North American Industry Classification System (NAICS) [14]	Industrial aggregate excluding unclassified businesses [11-91N] [3, 5]	Goods producing industries [11-33N] [5]	Forestry, logging and support [11N] [5]	Mining, quarrying, and oil and gas extraction [21]	Utilities [22]	Construction [23]	Manufacturing [31-33]	Servic produci industr [41-91 [5]
2015 July	914.85[A]	1,154.64[A]	1,173.48[A]	1,715.72[A]	1,653.21[A]	1,143.70[A]	1,032.94[A]	869.28[A]
2015 August	907.74[A]	1,130.30[A]	1,204.64[A]	1,725.43[A]	1,700.13[A]	1,127.50[A]	1,014.75[A]	863.98[A]
2015 September	912.59[A]	1,145.27[A]	1,239.12[A]	1,701.82[A]	1,577.58[A]	1,129.88[A]	1,041.00[A]	866.89[A]
2015 October	915.24[A]	1,154.93[A]	1,286.28[A]	1,751.60[A]	1,614.48[A]	1,113.44[A]	1,077.46[A]	868.22[A]
2015 November	910.21[A]	1,156.57[A]	1,287.80[A]	1,803.49[A]	1,605.43[A]	1,115.07[A]	1,057.17[A]	862.10[A]
2015 December	918.18[A]	1,158.77[A]	1,315.59[A]	1,768.22[A]	1,567.11[A]	1,109.84[A]	1,055.00[A]	879.28[A]
2016 January	906.99[A]	1,147.60[A]	1,283.82[A]	1,871.30[A]	1,694.18[A]	1,118.98[A]	1,050.69[A]	859.40[A]
2016 February	913.20[A]	1,145.25[A]	1,320.52[A]	1,831.69[A]	1,645.40[A]	1,111.67[A]	1,046.51[A]	869.82[A]
2016 March	915.42[A]	1,152.16[A]	1,248.83[A]	1,879.29[A]	1,822.15[A]	1,115.96[A]	1,044.59[A]	869.44[A]
2016 April	920.95[A]	1,157.69[A]	1,278.97[A]	1,757.12[A]	1,860.00[A]	1,126.00[A]	1,093.66[A]	874.58[A]
2016 May	917.48[A]	1,145.12[A]	1,236.77[A]	1,717.18[A]	1,781.26[A]	1,116.80[A]	1,049.74[A]	872.66[A]
2016 June	927.60[A]	1,158.69[A]	1,135.29[A]	1,715.00[A]	1,707.11[B]	1,147.66[A]	1,042.45[A]	884.26[A]
2016 July	911.54[A]	1,147.71[A]	1,217.51[A]	1,759.44[B]	1,605.27[A]	1,121.33[A]	1,054.20[A]	868.16[A]
2016 August	920.30[A]	1,164.08[A]	1,266.57[A]	1,791.15[A]	1,730.02[A]	1,142.26[A]	1,062.10[A]	872.73[A]
2016 September	919.84[A]	1,161.59[A]	1,276.31[A]	1,838.00[A]	1,658.94[A]	1,102.77[A]	1,072.55[A]	873.40[A]
2016 October	917.50[A]	1,148.26[A]	1,199.22[A]	1,749.57[A]	1,727.95[A]	1,123.73[A]	1,061.91[A]	872.88[A]
2016 November	927.86[A]	1,169.90[A]	1,111.49[A]	1,789.40[A]	1,794.96[A]	1,143.97[A]	1,082.22[A]	880.20[A]
2016 December	931.43[A]	1,191.28[A]	1,268.40[A]	1,840.48[A]	1,804.00[A]	1,154.03[A]	1,080.56[A]	890.24[A]
2017 January	931.06[A]	1,185.70[A]	1,205.23[A]	1,840.33[A]	1,726.37[A]	1,148.97[A]	1,097.60[A]	879.56[A]
2017 February	928.94[A]	1,193.15[A]	1,229.89[A]	1,747.09[A]	1,975.76[A]	1,151.79[A]	1,114.58[A]	878.00[A]
2017 March	934.30[A]	1,193.89[A]	1,271.42[A]	1,896.04[A]	1,721.37[A]	1,147.06[A]	1,115.54[A]	884.07[A]
2017 April	935.01[A]	1,160.82[A]	1,253.20[A]	1,792.34[A]	1,662.37[A]	1,121.94[A]	1,093.56[A]	889.97[A]
2017 May	939.99[A]	1,176.34[A]	1,186.44[B]	1,859.52[A]	1,778.63[A]	1,127.34[A]	1,091.63[A]	894.20[A]

Table A1-3: CBOC Conference Board of Canada Forecast Gross Domestic Product, Spring 2017

Table 1a

Key Economic Indicators: British Columbia, 2016–18

(forecast completed May 4, 2017)

	2016 Q1	2016 Q2	2016 Q3	2016 Q4	2017 Q1	2017 Q2	2017 Q3	2017 Q4	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2016	2017	2018
GDP at market prices ($ millions)	258,626	257,764	262,006	268,865	270,061	269,755	271,577	273,299	276,356	279,264	281,764	284,259	261,815	271,173	280,411
	2.8	*–0.3*	*1.6*	*2.6*	*0.4*	*–0.1*	*0.7*	*0.6*	*1.1*	*1.1*	*0.9*	*0.9*	*4.7*	*3.6*	*3.4*
GDP at market prices (2007 $ millions)	237,826	240,419	242,192	241,794	244,339	246,230	247,463	248,639	249,717	250,991	252,152	253,312	240,558	246,668	251,543
	1.6	*1.1*	*0.7*	*–0.2*	*1.1*	*0.8*	*0.5*	*0.5*	*0.4*	*0.5*	*0.5*	*0.5*	*4.0*	*2.5*	*2.0*
GDP at basic prices (2007 $ millions)	216,243	218,546	220,337	219,895	222,005	223,685	224,831	225,944	227,210	228,406	229,478	230,569	218,755	224,116	228,916
	1.4	*1.1*	*0.8*	*–0.2*	*1.0*	*0.8*	*0.5*	*0.5*	*0.6*	*0.5*	*0.5*	*0.5*	*3.7*	*2.5*	*2.1*
Consumer price index (2002 = 1.0)	1.211	1.225	1.233	1.228	1.236	1.242	1.249	1.255	1.261	1.268	1.274	1.281	1.224	1.245	1.271
	0.4	*1.2*	*0.6*	*–0.4*	*0.7*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*1.9*	*1.7*	*2.1*
Implicit price deflator—GDP at market prices (2007 = 1.0)	1.087	1.072	1.082	1.112	1.105	1.096	1.097	1.099	1.107	1.113	1.117	1.122	1.088	1.099	1.115
	1.2	*–1.4*	*0.9*	*2.8*	*–0.6*	*–0.9*	*0.2*	*0.2*	*0.7*	*0.5*	*0.4*	*0.4*	*0.7*	*1.0*	*1.4*
Wages and salary per employee ($ 000s)	46	46	47	47	47	47	48	48	48	49	49	49	47	47	49
	0.5	*0.5*	*0.3*	*0.7*	*0.2*	*0.8*	*0.6*	*0.7*	*0.6*	*0.6*	*0.7*	*0.7*	*1.2*	*2.0*	*2.6*
Primary household income ($ millions)	183,663	186,442	188,674	190,373	192,696	194,193	195,560	197,462	199,805	202,060	204,296	206,421	187,288	194,977	203,145
	0.0	*1.5*	*1.2*	*0.9*	*1.2*	*0.8*	*0.7*	*1.0*	*1.2*	*1.1*	*1.1*	*1.0*	*4.2*	*4.1*	*4.2*
Household disposable income ($ millions)	158,389	160,606	163,862	166,259	168,172	169,473	170,497	171,988	173,991	175,837	177,645	179,376	162,279	170,033	176,712
	–0.3	*1.4*	*2.0*	*1.5*	*1.2*	*0.8*	*0.6*	*0.9*	*1.2*	*1.1*	*1.0*	*1.0*	*4.8*	*4.8*	*3.9*
Household net savings rate (per cent)	–1.3	–1.5	–0.5	0.5	0.7	0.5	0.3	0.2	0.1	0.1	0.0	0.0	–0.7	0.4	0.0
Population (000s)	4,716	4,730	4,752	4,773	4,777	4,795	4,809	4,823	4,837	4,852	4,866	4,880	4,743	4,801	4,859
	0.0	*0.3*	*0.5*	*0.5*	*0.1*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.1*	*1.2*	*1.2*
Employment (000s)	2,351	2,375	2,390	2,402	2,434	2,433	2,432	2,437	2,450	2,461	2,471	2,479	2,379	2,434	2,465
	0.4	*1.0*	*0.6*	*0.5*	*1.3*	*0.0*	*0.0*	*0.2*	*0.5*	*0.5*	*0.4*	*0.3*	*3.1*	*2.3*	*1.3*
Labour force (000s)	2,514	2,524	2,532	2,555	2,571	2,576	2,575	2,577	2,590	2,602	2,611	2,618	2,531	2,575	2,605
	0.5	*0.4*	*0.3*	*0.9*	*0.6*	*0.2*	*0.0*	*0.1*	*0.5*	*0.5*	*0.3*	*0.3*	*2.9*	*1.7*	*1.2*
Labour force participation rate (per cent)	64.3	64.3	64.3	64.7	64.9	64.9	64.7	64.6	64.7	64.8	64.8	64.8	64.4	64.8	64.8
Unemployment rate (per cent)	6.5	5.9	5.6	6.0	5.4	5.5	5.5	5.5	5.4	5.4	5.3	5.3	6.0	5.5	5.4

(continued ...)

Appendix A-2

Load Forecast Tables

Table of Contents

1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. Tables 2.1 to 5.2 show ten years of historical data and the before-savings and after-savings forecast for 2017 and 2018. Table 5.3 shows the DSM and Other-Savings that were deducted from the before-savings forecast to provide the after-savings forecast for 2018. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2011 to 2016 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2011. Finally Table 6.4 shows the system load factor from the years 2011 to 2016 and the forecast load factor for 2017 and 2018.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and all other savings (RCR[1], CIP[2], AMI[3], and rate-driven impacts);
- after-savings – the load after DSM and all other savings (RCR, CIP, AMI, and rate-driven impacts).

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2007	362,696	318,187	300,725	251,383	254,740	238,900	280,425	261,986	228,445	261,607	298,971	356,106	3,414,170
2008	351,478	312,547	288,943	248,550	243,211	235,861	276,961	258,486	223,859	260,879	300,150	349,985	3,350,908
2009	357,560	302,739	305,539	244,978	242,249	242,735	276,801	262,866	234,668	269,945	315,009	360,679	3,415,766
2010	358,574	304,251	288,022	253,247	237,451	232,285	274,190	265,937	227,770	258,133	303,172	365,668	3,368,701
2011	374,096	313,764	312,059	254,039	235,722	242,276	268,421	273,732	242,593	260,877	307,093	362,607	3,447,280
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,245	306,420	303,949	253,146	241,945	242,396	285,626	270,799	229,532	256,624	301,612	380,684	3,435,977
2015	364,636	317,325	299,476	250,366	249,815	247,921	287,307	276,774	233,611	256,959	300,534	361,093	3,445,816
2016	362,417	311,090	292,322	268,567	248,286	243,400	287,329	280,865	234,850	266,011	328,783	352,683	3,476,603
Before-Savings													
2017S	366,699	316,499	300,955	264,357	248,375	248,923	289,465	282,563	238,738	262,884	317,408	369,427	3,506,289
2018F	369,158	318,896	303,266	266,567	250,648	251,174	291,738	284,782	240,921	265,041	319,642	371,954	3,533,786
After-Savings													
2017S	365,643	315,402	299,698	263,080	246,982	247,355	287,580	280,513	236,632	260,480	314,651	366,329	3,484,343
2018F	365,745	315,478	299,746	263,116	247,146	247,509	287,715	280,555	236,629	260,403	314,596	366,523	3,485,161

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2007	319,345	281,021	269,786	228,457	231,883	218,021	253,178	237,923	209,218	237,608	267,532	314,154	3,068,127
2008	313,562	279,252	262,392	227,860	223,882	217,082	252,395	236,852	206,815	238,874	270,905	312,359	3,042,230
2009	318,969	271,732	276,533	225,115	223,331	223,208	252,599	240,861	216,326	246,835	283,506	321,479	3,100,494
2010	322,764	275,389	264,054	233,827	220,707	215,751	252,308	245,260	211,831	238,568	276,095	328,561	3,085,116
2011	333,975	282,076	283,208	233,733	218,542	223,679	246,555	251,059	223,951	240,135	278,304	324,686	3,139,902
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	329,517	279,546	279,656	235,365	226,070	226,002	263,980	251,199	214,732	238,897	276,987	343,940	3,165,892
2015	330,474	288,500	275,700	232,842	232,855	230,716	265,292	256,237	218,219	239,080	275,925	327,535	3,173,373
2016	328,972	283,576	269,823	248,799	231,696	226,952	265,539	259,978	219,469	247,136	300,036	320,866	3,202,843
Before-Savings													
2017S	332,274	287,888	277,026	245,015	231,644	231,636	267,203	261,278	222,751	244,278	290,263	334,532	3,225,786
2018F	334,530	290,070	279,153	247,051	233,742	233,709	269,297	263,326	224,767	246,274	292,319	336,845	3,251,084
After-Savings													
2017S	331,669	287,172	276,171	244,081	230,625	230,481	265,871	259,770	221,066	242,347	288,060	332,053	3,209,367
2018F	332,022	287,433	276,440	244,306	230,995	230,865	266,335	260,135	221,279	242,508	288,268	332,493	3,213,078

[1] FBC's Residential Conservation Rate
[2] Customer Information Portal
[3] Advanced Metering Infrastructure

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2007	133,283	110,758	109,301	80,854	84,765	70,147	92,330	83,263	69,225	90,062	107,143	133,921	1,165,052
2008	136,053	115,157	109,364	89,438	80,721	72,251	97,949	85,591	74,307	91,773	109,092	133,820	1,195,516
2009	138,654	111,321	124,105	89,024	87,454	83,579	97,792	88,147	71,111	92,827	114,789	140,106	1,238,909
2010	144,415	116,176	112,135	94,505	85,285	75,333	96,222	91,300	72,613	94,047	110,964	148,667	1,241,663
2011	150,580	112,169	121,527	98,312	80,093	79,957	85,233	91,744	76,608	88,720	117,345	146,806	1,249,094
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
Before-Savings													
2017S	148,243	121,332	121,046	92,220	83,008	82,583	105,571	98,748	74,672	96,992	125,003	146,960	1,296,377
2018F	147,911	121,060	120,775	92,013	82,822	82,398	105,335	98,527	74,504	96,775	124,723	146,631	1,293,476
After-Savings													
2017S	147,911	120,979	120,643	91,829	82,622	82,170	105,110	98,224	74,055	96,232	124,100	145,919	1,289,795
2018F	146,966	120,063	119,759	91,015	81,881	81,464	104,430	97,534	73,310	95,421	123,231	144,993	1,280,067

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2007	57,625	54,282	51,787	50,427	52,321	55,372	55,996	53,312	51,185	52,063	55,272	60,163	649,803
2008	60,679	56,323	52,557	51,300	52,601	55,870	56,404	52,930	51,191	52,238	56,934	61,945	660,971
2009	60,319	57,143	55,134	52,468	52,802	56,015	57,628	55,929	54,675	55,551	57,688	60,004	675,356
2010	58,527	55,666	53,799	51,561	52,546	56,272	56,380	52,416	51,844	54,570	57,594	58,382	659,556
2011	57,742	59,980	55,524	50,675	51,759	55,477	59,401	55,911	50,918	50,637	53,116	55,779	656,918
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,354	73,607	69,309	70,566	73,342	72,255	76,262	75,406	66,710	60,531	66,112	81,292	865,746
2015	80,156	72,259	68,665	64,591	71,392	74,678	72,149	71,980	68,558	62,811	67,227	78,701	853,168
2016	81,888	75,253	71,663	71,537	69,950	67,264	75,224	78,198	68,802	70,075	79,061	92,524	901,438
Before-Savings													
2017S	84,606	77,179	73,171	72,144	74,933	74,763	78,057	78,737	71,228	67,510	74,135	88,138	914,602
2018F	86,061	78,506	74,430	73,385	76,221	76,048	79,400	80,091	72,453	68,671	75,410	89,654	930,330
After-Savings													
2017S	84,447	76,943	72,862	71,765	74,484	74,242	77,454	78,045	70,455	66,644	73,165	87,057	907,562
2018F	84,895	77,282	73,166	72,091	74,894	74,667	77,936	78,531	70,807	66,923	73,549	87,677	912,417

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2007	97,305	84,118	78,385	66,546	61,822	58,282	72,200	64,135	54,997	65,136	77,393	97,674	877,994
2008	95,009	83,999	79,094	66,892	69,677	66,114	71,212	70,951	57,242	70,540	82,793	94,718	908,240
2009	95,727	81,925	76,294	64,159	63,412	59,985	72,433	70,682	64,375	73,304	87,106	98,864	908,266
2010	98,545	83,945	77,442	67,108	59,780	59,833	72,144	70,068	60,545	64,123	82,201	99,603	895,337
2011	100,725	84,225	82,112	65,996	58,766	60,441	68,427	71,106	64,187	70,871	84,304	98,386	909,548
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
Before-Savings													
2017S	66,293	55,930	52,008	43,192	38,621	36,135	46,595	44,228	38,660	43,320	56,302	65,221	586,505
2018F	66,520	56,122	52,187	43,340	38,753	36,258	46,755	44,380	38,792	43,468	56,495	65,445	588,517
After-Savings													
2017S	66,226	55,864	51,938	43,123	38,549	36,058	46,502	44,128	38,556	43,202	56,163	65,065	585,373
2018F	66,353	55,957	52,020	43,178	38,590	36,092	46,571	44,187	38,594	43,255	56,258	65,189	586,243

2.6 *INDUSTRIAL (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2007	29,351	30,288	28,555	28,792	28,203	25,897	22,857	25,798	23,811	24,761	24,910	20,828	314,051
2008	19,981	22,004	19,570	18,082	16,331	16,765	16,700	15,303	15,758	18,412	18,815	20,129	217,849
2009	22,496	19,712	19,195	17,101	15,353	13,975	14,634	15,213	17,528	18,602	21,176	20,726	215,710
2010	19,449	17,896	18,991	18,389	18,616	18,603	18,551	20,146	19,259	21,495	22,097	20,207	233,699
2011	23,160	24,129	21,555	17,261	24,902	22,812	25,671	21,690	22,374	24,978	20,262	21,971	270,764
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
Before-Savings													
2017S	30,907	31,315	28,551	34,134	29,711	31,005	28,706	30,748	31,132	31,435	31,564	31,878	371,087
2018F	31,812	32,250	29,513	34,989	30,574	31,853	29,534	31,511	31,958	32,338	32,432	32,780	381,546
After-Savings													
2017S	30,870	31,266	28,496	34,065	29,637	30,921	28,614	30,643	31,016	31,306	31,423	31,725	369,983
2018F	31,647	32,075	29,334	34,800	30,385	31,655	29,327	31,289	31,723	32,088	32,168	32,501	378,993

2.7 *LIGHTING (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2007	1,056	1,041	1,121	1,040	1,073	1,057	1,080	1,057	1,064	1,129	1,056	1,062	12,835
2008	1,168	1,104	1,151	1,128	1,111	1,055	1,196	1,094	1,111	1,140	1,083	1,066	13,406
2009	1,097	1,044	1,133	1,024	1,163	1,154	1,112	1,136	1,089	1,153	1,077	1,114	13,297
2010	1,132	1,100	1,172	1,047	1,184	1,513	1,767	1,246	1,123	1,111	1,045	1,041	14,480
2011	1,114	1,027	1,674	582	1,092	1,098	1,086	1,113	1,615	560	1,121	1,153	13,233
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
Before-Savings													
2017S	1,301	1,344	1,303	1,351	1,374	1,374	1,364	1,388	1,285	1,284	1,287	1,397	16,052
2018F	1,301	1,344	1,303	1,351	1,374	1,374	1,364	1,388	1,285	1,284	1,287	1,397	16,052
After-Savings													
2017S	1,296	1,336	1,292	1,336	1,356	1,353	1,340	1,360	1,253	1,248	1,247	1,352	15,768
2018F	1,243	1,274	1,223	1,261	1,275	1,264	1,242	1,252	1,135	1,119	1,106	1,200	14,593

2.8 *IRRIGATION (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2007	726	534	637	800	3,699	7,265	8,715	10,359	8,937	4,456	1,758	507	48,393
2008	672	666	656	1,019	3,441	5,028	8,933	10,984	7,206	4,771	2,190	682	46,248
2009	675	588	673	1,340	3,147	8,501	9,000	9,754	7,548	5,399	1,669	664	48,957
2010	698	605	514	1,217	3,296	4,198	7,243	10,085	6,448	3,223	2,194	660	40,381
2011	654	545	816	908	1,931	3,894	6,737	9,495	8,249	4,369	2,156	590	40,345
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
Before-Savings													
2017S	923	788	945	1,973	3,998	5,777	6,909	7,428	5,774	3,737	1,971	938	41,163
2018F	923	788	945	1,973	3,998	5,777	6,909	7,428	5,774	3,737	1,971	938	41,163
After-Savings													
2017S	918	783	940	1,964	3,977	5,738	6,853	7,370	5,732	3,715	1,962	935	40,887
2018F	917	782	938	1,961	3,970	5,723	6,829	7,343	5,710	3,702	1,956	933	40,765

2.9 *SYSTEM PEAK (MW)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2007	676	644	555	514	540	393	520	487	471	535	627	704	704	520
2008	660	660	543	535	476	380	502	494	443	504	666	677	677	502
2009	707	643	624	507	481	415	496	446	564	514	660	704	707	496
2010	683	629	536	499	486	420	566	554	448	487	652	726	726	566
2011	722	666	593	516	472	448	529	537	509	508	632	691	722	537
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	720	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	651	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	693	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	724	593
Before-Savings														
2017S	668	608	559	485	428	490	575	567	448	497	608	680	714	582
2018F	673	613	564	489	431	494	580	572	451	501	612	685	719	586
After-Savings														
2017S	667	608	559	484	427	488	574	565	446	495	605	676	710	580
2018F	669	609	560	485	427	489	575	566	446	495	606	678	712	581

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential	93,647	95,502	96,565	97,883	98,795	99,228	111,862	113,431	114,166	115,772	116,657	117,774
Commercial	11,010	11,216	11,308	11,419	11,525	11,811	13,662	14,363	14,976	15,073	15,748	16,122
Wholesale	7	7	7	7	7	7	6	6	6	6	6	6
Industrial	38	36	33	35	36	39	47	49	50	50	50	50
Lighting	1,992	1,910	1,874	1,830	1,803	1,739	1,644	1,620	1,590	1,559	1,559	1,559
Irrigation	1,030	1,048	1,066	1,075	1,092	1,091	1,097	1,103	1,095	1,090	1,090	1,090
Total Direct	107,724	109,719	110,853	112,249	113,258	113,915	128,318	130,572	131,883	133,550	135,109	136,602

3.2 CUSTOMER ADDITIONS

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential	4,466	1,855	1,063	1,318	912	433	12,634	1,569	735	1,606	885	1,118
Commercial	725	206	92	111	106	286	1,851	701	613	97	675	375
Wholesale	(1)	-	-	-	-	-	(1)	-	-	-	-	-
Industrial	1	(2)	(3)	2	1	3	8	2	1	-	-	-
Lighting	87	(82)	(36)	(44)	(27)	(64)	(95)	(24)	(30)	(31)	-	-
Irrigation	33	18	18	9	17	(1)	6	6	(8)	(5)	-	-
Total Direct	5,311	1,995	1,134	1,396	1,009	657	14,403	2,254	1,311	1,667	1,559	1,493

4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential	12.74	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.10	10.92

5. ENERGY

5.1 NORMALIZED AFTER-SAVINGS ENERGY

Energy (GWh)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential	1,165	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,290	1,280
Commercial	650	661	675	660	657	681	788	866	853	901	908	912
Wholesale	878	908	908	895	910	899	675	567	580	574	585	586
Industrial	314	218	216	234	271	291	352	381	380	373	370	379
Lighting	13	13	13	14	13	13	13	16	16	16	16	15
Irrigation	48	46	49	40	40	38	40	40	46	42	41	41
Net	3,068	3,042	3,100	3,085	3,140	3,151	3,222	3,166	3,173	3,203	3,209	3,213
Losses	346	309	315	284	307	271	278	270	272	274	275	272
Gross	3,414	3,351	3,416	3,369	3,447	3,422	3,500	3,436	3,446	3,477	3,484	3,485
System Peak (MWh)												
Winter Peak	704	677	707	726	722	723	720	651	693	724	710	712
Summer Peak	520	502	496	566	537	589	600	620	611	593	580	581

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE ENERGY

Wholesale (GWh)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
BCH Lardeau	9	7	6	10	8	6	6	6	6	6	7	7
BCH Kingsgate	3	3	4	3	3	5	5	5	5	5	6	6
City of Grand Forks	41	41	41	41	41	41	41	39	41	41	40	39
City of Nelson	86	107	109	90	88	80	83	81	83	80	83	80
City of Penticton	348	346	346	341	344	341	348	342	348	345	356	357
District of Summerland	98	92	78	97	96	95	98	94	97	98	94	97
City of Kelowna	293	312	324	314	329	332	94	-	-	-	-	-
City of Princeton	-	-	-	-	-	-	-	-	-	-	-	-
Total	878	908	908	895	910	899	675	567	580	574	585	586

5.3 DSM AND OTHER SAVINGS (GWH) WITHOUT LOSSES[4]

Energy (GWh)	2012	2013	2014	2015	2016	2017S	2018F
Demsnd Side Management	(30)	(28)	(14)	(12)	(11)	(23)	(37)
Advanced Metering	-	2	3	4	4	5	9
Customer Information Portal (CIP)	-	-	-	-	-	(2)	(4)
Residential Conservation Rate	(8)	(14)	(14)	(4)	(4)	(4)	(4)
Rate-Driven	-	-	(5)	(5)	(3)	(3)	(3)
Total Net	(38)	(40)	(30)	(17)	(14)	(27)	(38)

4 See Section 3 of the Application for the impact of AMI on losses.

6. VARIANCES TO FORECAST

6.1 *CUSTOMER COUNT VARIANCE*

Customer Count	2011	2012	2013	2014	2015	2016
Actual						
Residential	98,795	99,228	98,906	113,431	114,166	115,772
Commercial	11,525	11,811	12,077	14,363	14,976	15,073
Wholesale	7	7	6	6	6	6
Industrial	36	39	39	49	50	50
Lighting	1,803	1,739	1,641	1,620	1,590	1,559
Irrigation	1,092	1,091	1,097	1,103	1,095	1,090
Total	113,258	113,915	113,766	130,572	131,883	133,550
Forecast						
Residential	99,663	101,320	103,279	113,229	114,855	115,758
Commercial	11,714	11,837	12,130	13,739	14,531	15,042
Wholesale	7	7	7	6	6	6
Industrial	35	36	36	48	49	49
Lighting	1,836	1,830	1,830	1,742	1,620	1,620
Irrigation	1,081	1,075	1,075	1,091	1,103	1,103
Total	114,336	116,105	118,357	129,855	132,164	133,578
Variance (customers)						
Residential	(868)	(2,092)	(4,373)	202	(689)	14
Commercial	(189)	(26)	(53)	624	445	31
Wholesale	-	-	(1)	-	-	-
Industrial	1	3	3	1	1	1
Lighting	(33)	(91)	(189)	(122)	(30)	(61)
Irrigation	11	16	22	12	(8)	(13)
Total	(1,078)	(2,190)	(4,591)	717	(281)	(28)
Variance (%)						
Residential	-0.9%	-2.1%	-4.4%	0.2%	-0.6%	0.0%
Commercial	-1.6%	-0.2%	-0.4%	4.3%	3.0%	0.2%
Wholesale	0.0%	0.0%	-16.7%	0.0%	0.0%	0.0%
Industrial	2.8%	7.7%	7.7%	2.0%	2.0%	2.0%
Lighting	-1.8%	-5.2%	-11.5%	-7.5%	-1.9%	-3.9%
Irrigation	1.0%	1.5%	2.0%	1.1%	-0.7%	-1.2%
Total	-1.0%	-1.9%	-4.0%	0.5%	-0.2%	0.0%

Note: The 2013 forecast included the CoK as a single (wholesale) customer since at the time of the 2012- 2013 Revenue Requirements the application for the acquisition of the CoK was not yet filed.

6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Energy (GWh)	2011	2012	2013	2014	2015	2016
Normalized						
Residential	1,249	1,229	1,274	1,296	1,298	1,296
Commercial	657	681	699	866	853	901
Wholesale	910	899	904	567	580	574
Industrial	271	291	291	381	380	373
Lighting	13	13	13	16	16	16
Irrigation	40	38	40	40	46	42
Net	3,140	3,151	3,222	3,166	3,173	3,203
Gross	3,447	3,422	3,500	3,436	3,446	3,477
Forecast						
Residential	1,261	1,264	1,276	1,402	1,397	1,367
Commercial	671	696	709	813	808	871
Wholesale	940	926	935	581	593	579
Industrial	233	250	255	389	371	393
Lighting	12	14	14	13	14	13
Irrigation	45	44	43	42	40	39
Net	3,162	3,193	3,233	3,240	3,224	3,262
Gross	3,472	3,502	3,543	3,519	3,499	3,540
Variance (GWh)						
Residential	(12)	(35)	(3)	(106)	(99)	(71)
Commercial	(14)	(16)	(10)	53	45	31
Wholesale	(30)	(27)	(31)	(14)	(13)	(5)
Industrial	38	41	36	(9)	9	(20)
Lighting	1	(0)	(0)	3	2	3
Irrigation	(4)	(6)	(3)	(2)	6	3
Net	(22)	(43)	(11)	(75)	(51)	(59)
Gross	(25)	(81)	(43)	(83)	(53)	(63)
Variance (%)						
Residential	-1.0%	-2.9%	-0.2%	-8.2%	-7.6%	-5.5%
Commercial	-2.1%	-2.3%	-1.4%	6.1%	5.3%	3.4%
Wholesale	-3.4%	-3.0%	-3.4%	-2.5%	-2.2%	-0.8%
Industrial	13.9%	14.1%	12.4%	-2.2%	2.3%	-5.3%
Lighting	10.4%	-3.5%	-1.5%	18.2%	12.7%	16.3%
Irrigation	-10.8%	-14.9%	-8.7%	-4.9%	12.1%	7.7%
Net	-0.7%	-1.4%	-0.3%	-2.4%	-1.6%	-1.8%
Gross	-0.7%	-2.4%	-1.2%	-2.4%	-1.5%	-1.8%

Note: The 2013 forecast included the CoK as a single (wholesale) customer since at the time of the 2012- 2013 Revenue Requirements the application for the acquisition of the CoK was not yet filed.

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential	1,249	1,229	1,353	1,296	1,298	1,296	1,290	1,280
Commercial	657	681	788	866	853	901	908	912
Wholesale	910	899	675	567	580	574	585	586
Industrial	271	291	352	381	380	373	370	379
Lighting	13	13	13	16	16	16	16	15
Irrigation	40	38	40	40	46	42	41	41
Net	3,140	3,151	3,222	3,166	3,173	3,203	3,209	3,213
Losses	307	271	278	270	272	274	275	272
Gross	3,447	3,422	3,500	3,436	3,446	3,477	3,484	3,485
System Peak								
Winter Peak (MW)	722	723	720	651	693	724	710	712
Summer Peak (MW)	537	589	600	620	611	593	580	581

Growth Year over Year	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential		-2%	10%	-4%	0%	0%	0%	-1%
Commercial		4%	16%	10%	-1%	6%	1%	1%
Wholesale		-1%	-25%	-16%	2%	-1%	2%	0%
Industrial		7%	21%	8%	0%	-2%	-1%	2%
Lighting		2%	0%	16%	2%	0%	-1%	-7%
Irrigation		-6%	4%	1%	15%	-9%	-3%	0%
Net		0%	2%	-2%	0%	1%	0%	0%
Losses		-12%	3%	-3%	1%	0%	0%	-1%
Gross		-1%	2%	-2%	0%	1%	0%	0%

Customer Count	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential	98,795	99,228	111,862	113,431	114,166	115,772	116,657	117,774
Commercial	11,525	11,811	13,662	14,363	14,976	15,073	15,748	16,122
Wholesale	7	7	6	6	6	6	6	6
Industrial	36	39	47	49	50	50	50	50
Lighting	1,803	1,739	1,644	1,620	1,590	1,559	1,559	1,559
Irrigation	1,092	1,091	1,097	1,103	1,095	1,090	1,090	1,090
Total Direct	113,258	113,915	128,318	130,572	131,883	133,550	135,109	136,602

Growth Year over Year	2011	2012	2013	2014	2015	2016	2017S	2018F
Residential		0%	13%	1%	1%	1%	1%	1%
Commercial		2%	16%	5%	4%	1%	4%	2%
Wholesale		0%	-14%	0%	0%	0%	0%	0%
Industrial		8%	21%	4%	2%	0%	0%	0%
Lighting		-4%	-5%	-1%	-2%	-2%	0%	0%
Irrigation		0%	1%	1%	-1%	0%	0%	0%
Total Direct		1%	13%	2%	1%	1%	1%	1%

6.4 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross energy, peak load and load factor. The annual load factor is calculated as annual energy ÷ peak hourly load x number of hours in a year (8,760).

Year	Energy (MWh)	Peak (MW)	Load Factor
2011	3,447,280	722	0.55
2012	3,421,657	723	0.54
2013	3,525,953	720	0.56
2014	3,436,514	651	0.60
2015	3,445,816	693	0.57
2016	3,476,603	724	0.55
2017S	3,484,343	710	0.56
2018F	3,485,162	712	0.56

Appendix A-3

Load Forecast Methods

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1. LOAD FORECAST METHODS

In the figures provided the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2018 Annual Review the latest calendar year for which full actual data exists is 2016.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2018 is the Forecast Year (2018F).
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous year's revenue requirements. For example, for this Application the Seed Year is 2017 (2017S) and the Seed Year forecast is based on the latest actual years, including 2016.

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, energy requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

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 regression results show significant results with high R^2 values for these load classes. The commercial class data started being normalized in 2017 since a correlation presented itself in 2016, therefore there is no historical normalized data for that class at this time. .

Results of the normalization regressions are provided in the tables below.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	30,865	62,933	70,093	64,165
Slope HDD	184	122	-	97
Slope CDD	-	-	207	-
Adjusted R^2	0.80	0.75	0.83	0.89

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	51,393	53,494	60,565	57,990
Slope HDD	78	61	-	42
Slope CDD	-	-	93	-
Adjusted R^2	0.63	0.73	0.63	0.58

Table A3-2: Commerical Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	68,240	52,933	53,278	53,531
Slope HDD	16	1	-	(4)
Slope CDD	-	-	31	-
Adjusted R^2	0.62	0.84	0.86	0.85

Table A3-2: Irrgation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	2,566	4,801	5,618	7,413
Slope HDD	(3)	(11)	-	(11)
Slope CDD	-	-	21	-
Adjusted R^2	0.15	0.74	0.21	0.35

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[2] and Cooling Degree Days (CDD)[3] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential and wholesale classes, regress energy on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring (March to May), summer (June to August) and fall (September to October). All monthly

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[2] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[3] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

energy and degree day data for each season is used and four separate regressions are calculated for each class. Princeton and the City of Kelowna (CoK) event variables were included in the regressions to recognize the integration of Princeton Light and Power Inc. (PLP) in 2007 and CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2016:
   (a) obtain the month's HDD (or CDD) information from Environment Canada;
   (b) calculate the deviation from the 10-year average (2007-2016) HDD (CDD) as found in Step 2;
   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and
   (d) add the normalization adder to the month's load (residential or wholesale).

The general equation to normalize energy requirements in month t is shown below.

$$Normalized\ Energy_t = Energy_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

where HDD is Heating Degree Days and $t = \text{Spring, Fall and Winter}$

and

$$Normalized\ Energy_t = Energy_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

where CDD is Cooling Degree Days and $t = \text{Summer}$

1.2 ENERGY FORECAST

This section discusses the before-savings forecast energy requirements for different load classes. Savings is defined as the sum of DSM and other savings, which include the Residential Conservation Rate (RCR), Customer Information Portal (CIP), Advanced Metering Infrastructure Project (AMI), and rate-driven impacts. Note that the RCR and CIP forecasts are only available for the residential class. A general formula for an after-savings load in year *t* is

$$After\ Savings\ Load_t = Before\ Savings\ Load_t - Savings_t$$

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

The before-savings UPC forecast was based on a trend analysis of historic annual UPC values from 2014 to 2016. FBC reviews the forecast methods on an annual basis and found that a trend was evident in the most recent three years of UPC data.

Table A3-3: Results of UPC Trend Analysis

Regression	UPC
Start Year	2014
End Year	2016
R^2	0.99
Adjusted R^2	0.98
df	2
Intercept	253
Slope UPC	-0.12

Next, the average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = 0.5 \times (Year\ End\ Customer\ Count_{t-1} + Year\ End\ Customer\ Count_t)$$

The year-end customer count in year (*t-1)* is the prior year actual:

$$Year\ End\ Customer\ Count_{t-1} = Prior\ Year\ Actual$$

The year-end customer count in year *t* is based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population forecast supplied by BC Stats that is customized to the Company's direct service area.

Table A3-4: Results of Residential Regression

Regression	Residential
Start Year	2012
End Year	2016
R^2	0.94
Adjusted R^2	0.88
df	4
Intercept	19,297
Slope Population	0.39

1.2.2 Commercial

The expected before-savings commercial load in year t was forecast based on the provincial GDP supplied by the CBOC[4]. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = b_0 + b_1 \times GDP_t + b_2 \times Princeton\ Event_t + b_3 \times CoK\ Event_t$$

Princeton Event_t is a binary variable for the Princeton Light and Power (PLP) integration event in 2007. CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1, b2, and b3 are obtained from an ordinary least squares (OLS) regression analysis on the 2002 to 2016 data.

Table A3-5: Results of Commercial Regression

Regression	GEN
Start Year	2002
End Year	2016
R^2	0.99
Adjusted R^2	0.99
df	14
Intercept	15,152
Slope GDP	3.97
Slope PLP Event	39,210
Slope CoK Event	125,843

1.2.3 Wholesale

The Company forecasts its wholesale load based on load surveys from all wholesale customers. For this update, the response rate was 100 percent. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated energy requirements, etc.

1.2.4 Industrial

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in. The majority of the FBC industrial customers responded to the surveys (80 percent of customers accounting for 89 percent of 2016 load).

Consistent with past practice, FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. The lead time for new

[4] The CBOC GDP forecast is included in Appendix A-1.

industrial customers is much longer than the lead time for the typical residential and commercial customer, and FBC staff work with industrial customers well in advance of the date they are added to the system. Given the significant impact and variability in demand from individual customers in the industrial load class, the industrial addition forecast cannot be reliably undertaken through a forecasting process based on historical additions.

1.2.5 Irrigation

The before-savings irrigation load for 2018F was developed using a 5-year average of actual loads in 2012-2016.

1.2.6 Lighting

The before-savings street lighting forecast for 2018F was based on a trend analysis of lighting loads from 2012 to 2016.

Table A3-6: Results of UPC Trend Analysis

Regression	UPC
Start Year	2012
End Year	2016
R^2	0.82
Adjusted R^2	0.75
df	4
Intercept	-1,473,819
Slope UPC	739.18

1.2.7 DSM and Other Savings

FBC forecasts load reductions resulting primarily from its DSM programs. In addition to DSM programs the Company also has or anticipates other savings from the RCR, AMI, CIP, and the impact of future rate increases. Each of these items is discussed below.

- The forecast of DSM savings is consistent with the Company's approved 2017 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.
- The RCR forecast is a result of analysis performed for the Residential Conservation Rate Information Report submitted to the Commission in November 2014.
- AMI savings are the incremental sales that occur due to an increase in paying marijuana grow operations that are offset by loss reductions due to closing illegal marijuana grow sites. The estimates and forecasts of incremental savings are based on the theft

reduction information provided as part of the AMI CPCN Application as adjusted by the Commission determination provided in Order C-7-13.

- CIP savings refer to potential savings due to the implementation of the Customer Information Portal, which allows customers to view historic billing and consumption data.
- Rate-Driven impacts are price elasticity savings given as a percentage of the before-savings loads. The current price elasticity estimate of -0.05 is consistent the elasticity used by BC Hydro.

RCR and CIP are forecast for the residential class only while AMI is forecast for the residential class and system losses. RCR, CIP, and rate-driven impacts are calculated as a percentage of the corresponding before-savings load. The rate-driven impact savings is independent of the RCR savings and applied to all rate classes.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the ten year average (2007-2016) of historic peak data. The historic 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. Self-Generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. A separate forecast of 16 MW a month was completed for those customers and was then added to the forecast. Seasonal peaks were used for both the winter and the summer. The twelve monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-139-14 – FBC MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
1.	80	29, 30, 31	***Benchmarking Study:*** The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018. In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	Consultation underway. Study will be filed in 2018.	N/A
2.	212	98	***Accounting Changes*** The Panel directs FBC to communicate any accounting policy changes/updates to the Commission and other stakeholders as part of its Annual Review process during the PBR period.	Ongoing during term of PBR	Section 12.3
G-169-14 – FBC ADVANCED METERING INFRASTRUCTURE (AMI) ENABLED BILLING OPTIONS FOR CUSTOMERS					
3.	6	3	***AMI Deferral Account*** FBC must flow through any incremental O&M costs and/or benefits to customers as part of the Advanced Metering Infrastructure project deferral account.	Ongoing. Incremental costs/benefits are included in the Flow-through deferral account	Section 12.4.2
4.	6	4	FBC must flow through any incremental working capital benefits to customers as part of the new flow through deferral account, approved in Order G-163-14, or another appropriate flow through account.	Ongoing	Section 7.8.1
5.	n/a	5	FBC must report these incremental costs and savings in each of the annual reviews during the Performance Based Ratemaking term.	Ongoing during term of PBR	Section 6.3.3

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-107-15 – FBC ANNUAL REVIEW FOR 2015 RATES					
6.	15	n/a	***Advanced Metering Infrastructure (AMI) Theft Reduction*** The Commission Panel directs FBC to include, in its next and subsequent annual PBR reports, the impact of AMI on losses through theft deterrence. This directive will improve regulatory efficiency in the review of FBC's proposed actions (and FBC's incentives to undertake these actions while under PBR) related to the reduction of theft related costs. The information to be submitted should include: (i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and (ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.	Ongoing during term of PBR	Section 3.5.7.1
G-120-15 – FEI-FBC PBR CAPITAL EXCLUSION CRITERIA					
7.	17	4	***Capital Expenditures Exceeding the Deadband*** Should the dead-band for annual capital expenditures approved in the PBR Plans be exceeded FBC or FEI are directed to include in its next Annual Review filing, recommendations as to any adjustment to base capital (re-basing) for Commission approval.	Capital expenditures are forecast to exceed the deadband	Section 1.4.3
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES					
8.	15	5	***Ruckles Substation Rebuild Project:*** The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the Ruckles Substation Rebuild project: • The status of the Ruckles project, including a comparison of the project timeline provided in the current Application to the updated project timeline, as at the time of filing each annual review application. • Updated cost estimates and scope descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the Ruckles project as at the time of filing each annual review application. • The final actual project cost, including a description of the scope of work completed relative to the cost estimate and scope description provided in the Application, with explanations for any variances.	Ongoing during term of PBR	Section 7.3 and Appendix C

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
9.	21	6	***Upper Bonnington Old Units Refurbishment Project:*** The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Ongoing during term of PBR	Section 7.3 and Appendix D
10.	28	7	***Telephone Abandon Rate:*** The Panel directs FBC to include in its annual review for 2018 rates application a discussion of the impact, if any, that the new call back option has had on the Telephone Abandon Rate Service Quality Indicator and to discuss whether there are other measures, such as “Time Until Call Back is Received,” which may provide additional value to FBC’s existing informational indictors.	Completed	Section 13.2.2
11.	30	8	***Uncollectible Accounts:*** The Panel directs FBC to provide additional information regarding the monthly average of uncollectible accounts, increases and decreases to the monthly average of uncollectible accounts and FBC’s efforts to manage uncollectible accounts as part of its annual review for 2018 rates application.	Completed	Section 7.8
12.	31	9	***Advanced Metering Infrastructure Radio-Off Report:*** The Panel directs FBC to file the September 30, 2016 AMI Radio-Off Report as part of its annual review for 2018 rates application and to address the disposition of the AMI Radio-Off Shortfall deferral account in that application.	Completed	Section 12.4.2 and Appendix E

Appendix C

RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

Appendix C

FortisBC Inc.

Ruckles Substation Rebuild Project

Status Report

August 2017

1. PROJECT STATUS

1.1 PROJECT BACKGROUND

On January 20, 2017, the Commission approved capital expenditures related to the Ruckles Substation Rebuild project (Ruckles project) by Order G-8-17. The Commission directed FBC to provide the following information about the progress of the project as part of its annual review applications.

- The status of the Ruckles project, including a comparison of the project timeline provided in the [Annual Review for 2017 Rates] Application to the updated project timeline, as at the time of filing each annual review application.
- Updated cost estimates and scope descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or project scope.
- Actual costs incurred to date on the Ruckles project as at the time of filing each annual review application.
- The final actual project cost, including a description of the scope of work completed relative to the cost estimate and scope description provided in the [Annual Review for 2017 Rates] Application, with explanations for any variances.1

The Ruckles project involves rebuilding the existing Ruckles Substation, together with the necessary transmission and distribution modifications, primarily to address issues of age and the substation's location in the flood zone of the Kettle River, in order to continue to safely supply electricity to the City of Grand Forks (CoGF) municipal electric utility and surrounding area. FBC submits the following report in compliance with Directive 5 of Commission Order G-8-17, including costs to June 30, 2017.

1.2 GENERAL PROJECT STATUS

The project commenced on schedule as originally provided in the Annual Review for 2017 Rates. Engineering and Design and some pre-construction activities are well underway. FBC does not anticipate any significant delays to the project and plans to advance some work from 2018 into 2017.

The Ruckles project had a Class 3 capital cost estimate of $8.288 million in as-spent dollars (including $0.428 million of AFUDC and $0.301 million of removal costs). Project expenditures

[1] G-8-17, Appendix A, page 15.

to June 30, 2017 are approximately $0.779 million. Final project costs are currently estimated at $8.038 million, or $0.250 million lower than estimated, primarily due to savings associated with 13 kV to 4 kV step-down equipment which is no longer necessary (discussed further below).

FBC does not anticipate any significant variances to the original schedule provided in the business case. Pre-construction activity has commenced and project completion is scheduled for September 2018. Some minor delays in the civil component are expected due to the high water levels during the 2017 spring freshet. The Company plans to accelerate civil and physical construction upon award of the contract to offset this pressure.

The Ruckles project to date has mainly focused on engineering and design, procurement, and scheduling. In preparation for the upcoming construction, secondary site access and reconfiguration of the existing 63 kV interconnection is under construction to allow for better clearance and for a safe work zone to be created.

In the first quarter of 2017, the Engineering group commenced the civil and site design aspects of the project. The design package was completed in the second quarter along with an Electrical/Civil Tender package. FBC has completed the Civil Issued for Construction (IFC) package and is currently focusing on the Electrical IFC package. FBC expects to outsource the majority of the construction through a competitive bidding process.

1.3 MAJOR ACCOMPLISHMENTS, WORK COMPLETED AND KEY DECISIONS MADE

1.3.1 Project Engineering

The existing Ruckles Substation station is supplied by two FBC transmission lines and provides a distribution supply source to direct residential, irrigation and commercial customers of FBC (at 13 kV), the electrical utility of the City of Grand Forks (at both 13 kV and 4 kV), and an industrial sawmill customer (at 4 kV).

Following Commission approval of the project, and to seek out project cost savings, FBC initiated discussions with the CoGF municipal electric utility to explore whether the CoGF would be willing to advance its ongoing 4 kV to 13 kV system voltage conversion project so that it would be completed by June 1, 2018. The CoGF was originally anticipating completion of the conversion project in 2018/2019. An earlier conversion allows FBC to eliminate the 4 kV infrastructure requirements associated with the CoGF supply from this project and to achieve project cost savings. In June 2017, the CoGF accepted FBC's offer to contribute a portion of the project savings in order to advance the voltage conversion.

FBC also held discussions with its industrial customer, Interfor Corporation (Interfor) to explore whether Interfor would also be willing to convert its equipment from 4 kV to 13 kV by June 1, 2018. Following initial discussions, Interfor engaged a third party to develop a scope and estimate for the conversion. FBC and Interfor have reached an agreement whereby FBC will contribute a portion of Interfor's costs of conversion.

By removing the 4 kV supply infrastructure from the Ruckles project, gross cost savings are anticipated to be approximately $0.500 million, less contributions to the CoGF and Interfor. The net cost savings are estimated at $0.250 million.

All civil and structural design was completed by Austin Engineering and IFC packages were received by the FBC Project Management Office (PMO) on April 28, 2017. The electrical tender package was issued to the PMO on May 19, 2017. This tender package was issued as part of the Request for Quotation (RFQ) to four vendors on June 6, 2017. The detailed electrical construction package is expected to be issued on September 1, 2017. To date, the Electrical IFC is approximately 10% complete.

1.3.2 Procurement

A purchase order for one 40 MVA, 63 kV/13 kV power transformer from Partner Technologies Incorporated Manitoba (PTI) has been issued and the unit is expected to arrive onsite in the last quarter of 2017.

All major equipment has been ordered and is scheduled to be received in 2017.

An RFQ for the station construction was issued to four vendors for competitive quotes on June 6, 2017. Contractor estimates have been reviewed and the contract was awarded on July 14, 2017 to Martech Electrical Systems Ltd.

1.3.3 Environmental Planning

FBC has developed a site specific Environmental Management Plan for the project. Both internal FBC crews and contractors will be expected to meet or exceed the environmental requirements.

1.3.4 Permits and Approvals

Construction commenced on July 24, 2017. A Notice of Project was filed with WorkSafeBC prior to the construction start date.

Rights-of-way for the underground 13 kV supplies to the CoGF and Interfor were surveyed and approved in July, 2017.

1.4 PROJECT CHALLENGES AND ISSUES

1.4.1 Detailed Engineering

Geotechnical and soil characterization studies were completed to verify site conditions. Surveys and historical information were also used to determine site elevations. This allowed engineering to design the project above the flood plain by reconstructing the station 2 metres above the existing grade.

1.4.2 Permits and Approvals

Interfor site induction training will be required for workers to enter Interfor properties during construction.

Any alterations required on the CoGF property will need to be approved by the CoGF prior to construction.

1.4.3 Communications and Stakeholder Engagement

Communications with the CoGF and Interfor have been ongoing. Negotiations are complete, and both parties have agreed to convert from a 4 kV to 13 kV supply. As explained in section 1.3.1, this will reduce the project capital cost, improve system reliability by reducing the amount of installed equipment, and allow FBC to achieve efficiencies by not having to maintain non-standard 4 kV equipment.

1.4.4 Construction and Commissioning

High water tables and water accumulation has resulted in some minor project delays however the overall construction schedule will not be affected. Specifically, a high water level table due to the 2017 spring freshet has delayed pole placements within the station and reconfiguration of the 63 kV interconnection was delayed to the end of June 2017 because of water accumulation within the site.

The power transformer acceptance testing and transformer placement will be completed by the vendor, and all other equipment and protection and control commissioning will be performed by FBC internal crews in Q2 2018.

2. PROJECT SCHEDULE

Major milestones have been identified in the schedule below. Milestone targets will be monitored, and variance explanations will be documented. FBC is projecting that some milestones such as Structures/Buswork and Station Equipment/Apparatus may be completed earlier than originally forecast.

Table C-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering/Procurement:	Q4-2018		In progress
9L 63 kV reconfiguration(IFC)	Q1-2017	March 31, 2017	Complete
Control room (IFT)	Q2-2017	May 11, 2017	Complete
Site/Civil (IFC)	Q2-2017	April 14, 2017	Complete
Electrical/Physical (IFT)	Q2-2017	June 5, 2017	Complete
Issue RFQ	Q2-2017	June 6, 2017	Complete
Steel (IFC)	Q2-2017	June 15, 2017	Complete
Issue Contract	Q3-2017	July 14, 2017	Complete
Major equipment delivery	Q4-2017		In progress
Construction:	Q4-2017		
Civil/site Phase 1 (pre-construction)	Q4-2017		In progress
Civil/Site Phase 2 (completion)	Q4-2018		
Buildings	Q2-2018		
Structures/Buswork	Q4-2018		
Station Equipment/Apparatus	Q3-2018		
Communication/SCADA	Q2-2018		
Protection/Control/Metering	Q2-2018		
Commissioning	Q3-2018		
Distribution Line work	Q3-2018		
Equipment removal	Q4-2018		
Project Completion	Q4-2018		

2.1 *SCHEDULE PERFORMANCE TO DATE*

Procurement and Contracts are on schedule.

2.2 SCHEDULE PROJECTION GOING FORWARD

The construction schedule was reviewed with Martech Electrical Systems on July 24, 2017. Major milestones and completion dates were reviewed and agreed to by FBC and the contractor. Changes in scope and schedule will be monitored and controlled.

2.3 SCHEDULE DIFFICULTIES AND VARIANCES

High water levels in the Grand Forks area and Ruckles substation have delayed the 63 kV reconfiguration portion of the project. FBC anticipates that this will not affect the schedule or major milestones, but costs for the 63 kV reconfiguration have increased due to vacuum truck requirements for pole placements. These minor cost increases are expected to be offset by the elimination of the 4 kV equipment in addition to 63 kV reconfiguration improvements in which improved access and clearances will allow for a more efficient work-site.

2.4 PROJECT SCOPE CHANGE SUMMARY

Successful negotiations with the CoGF and Interfor have allowed FBC to remove the 4 kV portion of the project. This will create some Civil and Electrical design changes for the project. Specifically, two padmount transformers and the associated containment systems and foundations will be removed from the scope of work.

FBC change management procedures will be used to document any scope or schedule changes that directly affects the project.

3. PROJECT COSTS

The following table outlines the project expenditures to June 30, 2017 and the forecast project expenditures to completion.

Table C-2: Cost Summary

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percent Budget Spent
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)
	($000s)				(%)	
Line Work	241	115	150	264	10%	48%
Civil & Site	1,688	27	1,611	1,638	-3%	2%
Buildings	191	1	190	191	-%	1%
Structures & Buswork	427	-	427	427	-%	-%
Station Equipment & Apparatus	2,602	87	2,315	2,402	-8%	3%
Communications & SCADA	32	14	18	32	-%	44%
Protection, Control & Metering	270	92	178	270	-%	34%
Design	627	383	226	609	-3%	61%
Commissioning	132	-	132	132	-%	-%
Project Management	544	51	380	431	-21%	9%
Subtotal - Construction	6,754	770	5,625	6,395	-5%	11%
Cost of Removal	301	-	301	301	-%	-%
Project Contingency	805	-	824	824	2%	-%
Subtotal- Construction & Removal	7,860	770	6,750	7,520	-4%	10%
AFUDC	428	9	509	518	21%	2%
Total Project Cost	8,288	779	7,259	8,038	-3%	9%

The forecast project cost is $0.250 million lower than the business case forecast, primarily as a result of eliminating the 4 kV equipment from the substation. Higher than budget AFUDC, due to the advancement of some components as identified in section 2, is offset by savings in project management.

4. PROJECT RISKS

4.1 SCHEDULE RISKS

Schedule risks remain for the project associated with the potential for future high water levels that could delay construction into the Spring of 2018. Also, a delay in the Interfor and CoGF 4KV conversion could delay the project schedule.

4.2 COST RISKS

Cost risks remaining for the project include risks associated with the occurrence of contaminated soil disposal, access or project staging issues, or archaeological finds.

4.3 ENVIRONMENTAL RISKS

Environmental risks mainly include potential equipment oil spills. This risk will be mitigated with on-site spill kits and emergency response plans.

There is also the potential for asbestos to be present in the control room, which would result in an increase in removal costs. Samples will be taken to confirm asbestos results and mitigation plans will be put in place if required.

Contaminated soil may also be present and could result in increased project costs. Any soil removed from site will be sampled and disposed of at an approved dump site.

FBC has developed a site specific EMP for the project.

5. CONCLUSION

The Ruckles project continues to track according to schedule. Project cost savings are anticipated as a result of successful negotiations with Interfor and the CoGF allowing for FBC to remove the 4 kV voltage system requirements from the project scope.

Appendix D

UPPER BONNINGTON OLD UNITS REFURBISHMENT PROJECT STATUS REPORT

Appendix D

FortisBC Inc.

Upper Bonnington Unit Refurbishment Project

Status Report

August 2017

1. PROJECT STATUS

1.1 PROJECT BACKGROUND

On January 20, 2017, the Commission approved capital expenditures related to the Upper Bonnington Old Units Refurbishment (UBO Refurbishment Project) in Order G-8-17. The Commission directed FBC to provide the following information about the progress of the project as part of its annual review applications:

- The status of both the UBO Refurbishment Project as a whole and of the individual units, including a comparison of the project timeline provided in the [Annual Review for 2017 Rates] Application to any updated project timeline as at the time of filing each annual review application.
- Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or project scope.
- Actual costs incurred to date on the UBO Refurbishment Project as a whole and on each individual unit as at the time of filing each annual review application.
- Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.[1]

The UBO Refurbishment Project involves the refurbishment of generating Units 1–4 (the Old Units), which are more than 100 years old, in order to extend their life for an additional twenty years or more. The project will also reduce the safety and environmental risks associated with failures of the aged equipment.

FBC submits the following report regarding the UBO Refurbishment Project in compliance with Directive 6 of Commission Order G-8-17, including costs to June 30, 2017.

1.2 GENERAL PROJECT STATUS

The project commenced on schedule as originally provided in the Annual Review for 2017 Rates. Engineering, Procurement and some pre-construction activities are well underway. The dismantling of Unit 3 began on schedule in late June 2017. FBC does not anticipate any significant delays to the project and plans to advance some engineering and procurement work from 2018 into 2017.

[1] G-8-17, Appendix A, page 21.

The UBO Refurbishment Project had a Class 4 capital cost estimate of $31.783 million in as-spent dollars (including $0.867 million of AFUDC and $1.880 million of removal costs). Project expenditures to June 30, 2017 are approximately $3.046 million. Final actual project costs are currently forecast to equal budget.

Over the first half of 2017, FBC's focus has largely been on engineering for plant-related systems in addition to systems relevant to Unit 3, the first of the units to be refurbished. Additionally, FBC has completed a significant amount of procurement for major materials and services, and has substantially completed the demolition of the legacy UBO switchgear structure and general preparation of the generator floor.

Engineering has largely focused on developing technical and performance specifications for the various components of Unit 3. These specifications have served as the basis for material supply contracts. As many of these specifications have now been completed, FBC has shifted its focus to system integration and developing commissioning documentation.

In terms of procurement, agreements have been concluded for all of the large material supplies and services, with the exception of the transformer supply contract for Unit 1 and the refurbishment/fabrication contract for Units 1, 2 and 4. These agreements are expected to be in place for the end of 2017.

Demolition of the old switchgear structure was required to make available additional floor space for new equipment. This demolition work was substantially completed in March 2017, with a small section (containing Unit 3 main cables) to be removed following the removal of Unit 3 from service in June 2017.

1.3 MAJOR ACCOMPLISHMENTS, WORK COMPLETED AND KEY DECISIONS MADE

1.3.1 Detailed Engineering

Engineering work completed to date includes performance specification and detailed engineering for the governor system, technical specifications for the generator stator and rotor refurbishments, performance specifications for the excitation system, generator unit and governor control system, and the generator protection and control design.

The ongoing effort leading up to Unit 3 construction is largely focused on system integration, ensuring that all the mechanical and electrical subsystems work together properly.

System integration is expected to be complete in early Q3 2017 whereas commissioning documentation will be ongoing throughout Q3 2017.

FBC will also begin engineering for Unit 4 starting in late Q3 2017. This includes updating any engineering drawings originally completed for Unit 3 for use on Unit 4, and includes any items that are relevant to the remaining units, such as machining and fabrication specifications.

1.3.2 Procurement

To date, FBC has completed a substantial amount of procurement, not only for Unit 3 but also for the subsequent units in order to realize savings by purchasing multiple components where possible. Major items procured include the generator bearing lubrication system, excitation system, high pressure governor system and unit control system, motor control centre, and generator stator and rotor rewind contract.

The contract values of most procurement items are consistent with the project estimate. The only exception is the generator stator and rotor rewind contract which is approximately $1.3 million over the estimated cost. This is offset by reductions in contingency and removal costs.

The remaining procurement items include the contracting of the major mechanical refurbishment and replacement for Units 1, 2, and 4[2], for which a request for proposal (RFP) is expected to be completed by year end 2017, and the transformer replacement for Unit 1, which will be tendered in Q3 2017.

1.3.3 Environmental Planning

FBC has developed a site specific Environmental Management Plan (EMP) for the project. Both internal FBC crews and contractors will be expected to meet or exceed the environmental requirements.

The EMP developed for the project includes background information on applicable regulations and the impact on the project, prevention measures to ensure regulatory compliance, and communication plans to ensure all on-site personnel are working cohesively towards preventing incidents which may have an environmental impact.

1.4 PROJECT CHALLENGES AND ISSUES

1.4.1 Detailed Engineering

FBC has completed a significant amount of engineering work during the first half of 2017, with no significant resulting financial or schedule impacts.

[2] Mechanical refurbishment of Unit 3 was completed in 2014.

1.4.2 Construction and Commissioning

During the demolition of the UBO switchgear structure, FBC was required to construct a containment area to manage silicia dust and asbestos. The following picture shows the asbestos and silica containment area.

Figure D-1: Asbestos Containment Area

This containment has since been dismantled.

FBC substantially removed the old switchgear structure in Q1 2017. A small section was left in place as the main cables for Unit 3 are embedded in the wall of this section. This remaining section will be removed in Q3 2017. A small containment area will be re-established to facilitate this final demolition work.

2. PROJECT SCHEDULE

Major milestones associated with Unit 3 have been identified in the milestone summary below. Construction schedules for the remaining units are described in section 2.3.4.

Table D-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering			
Governor System Performance Specification	10/02/2017	28/02/2017	Complete
Excitation System Performance Specification	27/01/2017	27/01/2017	Complete
Unit and Governor Control System Performance Specification	27/01/2017	28/02/2017	Complete
Generator Protection System Detailed Design	23/05/2017	23/05/2017	Complete
System Integration	15/07/2017	15/07/2017	Complete
Mechanical Components – Machining and Fabrication Specifications	13/10/2017		Ongoing
Procurement			
Excitation System	20/02/2017	28/02/2017	Complete
Governor System and Unit Control	07/03/2017	07/03/2017	Complete
Generator Rotor and Stator Rewind	10/05/2017	10/05/2017	Complete
Transformer	01/01/2020		Originally planned for 2020, advanced due to poor condition of transformer. Tender closed July 12, 2017. Ongoing.
Major Unit Mechanical	01/01/2018		RFP to be issued when Engineering complete.
Construction			

Milestone	Planned Completion Date	Actual Completion Date	Status
Substantial Removal of Concrete Switchgear Structure	28/03/2017	28/03/2017	Complete
Final Removal of Concrete Switchgear Structure	17/07/2017		Ongoing
Dismantle of Unit 3	07/07/2017	07/07/2017	Complete and unit handed over to Contractor for generator rewind.
Installation of new High Pressure Governor System	02/10/2017		
Installation of new Excitation System	06/10/2017		
Installation of new Unit Protection and Control	02/11/2017		
Full System Integration	13/12/2017		
Unit 3 Returned to Commercial Service	13/12/2017		

2.1 SCHEDULE PERFORMANCE TO DATE

Engineering has been progressing favourably, and is largely completed, with the exception of integration engineering and commissioning documentation. The majority of the procurement is now complete as most contracts are now in place and expected delivery dates are on-schedule. Many of the supply agreements are for all four units in order to standardize equipment.

The dismantling of Unit 3 began as scheduled at the end of June 2017. FBC prepared the unit for handover to Voith Hydro for the generator rewind. In July 2017, Voith started work on the rewind and FBC began removal of old equipment and installation of new equipment. This work is expected to be completed in early October 2017.

Demolition of the old switchgear structure was substantially completed in March 2017, with the remaining section to be demolished in Q3 2017.

2.2 SCHEDULE PROJECTION GOING FORWARD

For the remainder of 2017, engineering resources will be focused on providing construction and commissioning support for Unit 3, updating documentation from Unit 3 for use on Unit 4, finalizing the condition assessment report for Unit 4, and creating performance and technical specifications for Unit 4 that were not needed for Unit 3.

FBC expects to complete these items prior to year-end, slightly ahead of schedule.

The outstanding procurement items were identified in section 1.3.2. The procurement of the generator step-up transformer for Unit 1 is also ahead of schedule.

Construction for Unit 3 remains on target. Reassembly is expected to begin in September 2017, with unit alignment completed in early October 2017. Commissioning is expected to begin in October 2017 and be complete by mid-December 2017. FBC expects to return Unit 3 to service December 13, 2017.

Construction for the remaining units is scheduled as follows:

- Unit 4: February 2018 – November 2018
- Unit 2: February 2019 – November 2019
- Unit 1: February 2020 – November 2020
- Plant wrap-up: December 2020 – April 2021

2.3 *SCHEDULE DIFFICULTIES AND VARIANCES*

Based on progress to date, FBC has advanced the dismantling start date for the remaining units from March, as originally scheduled, to February of the respective year in order to provide additional schedule contingency. The project schedule remains on target.

2.4 *PROJECT SCOPE CHANGE SUMMARY*

Throughout detailed engineering, FBC has made minor adjustments in order to address some unforeseen challenges and issues. These adjustments do not represent significant scope deviations and do not have a major financial or schedule impact.

Any engineering deviations from the original scope are captured and documented through FBC's change management procedures.

Scope changes to date include floor modifications for removal and disposal of asbestos and other minor issues identified during demolition of the old switchgear structure, and the requirement for one additional tail race gate in order to work through high tail water during freshet, at an aggregate cost of approximately $0.115 million. The overall project schedule is not affected.

3. PROJECT COSTS

The following table outlines the project expenditures to June 30, 2017 and the forecast project expenditures to completion.

Table D-2: Cost Summary

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent	Variance Explanations
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)	
	($000s)				(%)		
Unit 3	4,079	1,710	3,689	5,399	32%	42%	Advancement of engineering effort from future years into 2017 in addition to higher than anticipated stator and rotor rewind new construction costs.
Unit 4	6,634	277	6,633	6,910	4%	4%	Completion of Unit 4 turbine assessment and higher than anticipated stator and rotor rewind costs.
Unit 2	5,641	177	5,219	5,396	-4%	3%	
Unit 1	8,050	178	7,705	7,883	-2%	2%	
Common	860	277	596	873	2%	32%	
Subtotal - Construction	25,264	2,619	23,842	26,461	5%	10%	
Cost of Removal	1,880	392	1,054	1,446	-23%	21%	Lower than anticipated removals for stator and rotor rewind, transformer containment, and engineering and construction management support during removals

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent	Variance Explanations
Project Contingency	3,771	-	2,736	2,736	-27%	0%	Contingency has been reduced by $1.04 million to reflect significant proportion of engineering/procurement complete).
Subtotal- Construction & Removal	30,916	3,011	27,632	30,643	-1%	10%	
AFUDC	867	35	1,105	1,140	31%	4%	Advancement of engineering and procurement
Total Project Cost	31,783	3,046	28,737	31,783	0%	10%	

In summary, the total project forecast remains per the original budget. While there are instances where forecast costs are higher than budgeted, they have been offset by reductions in contingency and forecast removal costs.

4. PROJECT RISKS

FBC continues to make efforts to reduce the risk profile of the UBO Refurbishment Project through the use of lump sum contracts and the use of condition assessments.

The major financial and schedule risks are related to the as-found condition of submerged turbine components (Section 4.1) and the as-found condition of the stator cores (Section 4.2). FBC continues to work towards reducing the impact of these risks by identifying them as soon as practically possible through the use of condition assessments, where possible.

Safety and environmental risks continue to be managed using FBC's safe work planning procedures.

4.1 *AS-FOUND CONDITION OF SUBMERGED TURBINE COMPONENTS*

There is a risk that the as-found condition of submerged turbine components could be worse than anticipated, resulting in a requirement for replacement rather than refurbishment.

The most significant component of this risk is associated with the turbine runners. Typically, there is a single turbine runner per generating unit. However, in the case of the units in the Upper Bonnington Old Plant, each unit has three turbine runners. For Units 1, 2 and 4, FBC included the cost of replacing two of the runners in the project, while refurbishing the remaining seven. The runners for Unit 3 were successfully refurbished in 2013/14.

Replacing turbine runners would also have a considerable schedule impact. The procurement period for the turbine runners is between six to twelve months. To mitigate this impact, FBC will be completing a detailed condition assessment of the turbine runners for each unit before unit dismantle in order to allow sufficient time to procure replacement runners.

The condition assessment of Unit 4 was completed in June 2017. The preliminary findings from the third party engineering firm Engen Services Ltd. suggests that the turbine runners of Unit 4 are repairable.

4.2 *AS-FOUND CONDITION OF STATOR CORE*

There is a risk that the as-found condition of the stator core of each unit (excluding Unit 2) could be worse than anticipated.

While recent condition assessment reports do not indicate any visible issues, non-destructive testing upon unit dismantle is required for FBC to ascertain the true condition of the stator cores.

5. CONCLUSION

The UBO Refurbishment Project continues to track according to schedule. While the forecast annual spend has changed since the submission of the project last year, due to the advancement of engineering and procurement costs, the total project forecast remains on-target. FBC continues to focus on safe execution of construction work and on reducing the risk profile of the project.

Appendix E

AMI RADIO-OFF METER OPTION ORDER G-220-13 COMPLIANCE FILING

Diane Roy
Director, Regulatory Services

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

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

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

September 30, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Ms. Ross:

Re: FortisBC Inc. (FBC)

Advanced Metering Infrastructure (AMI) Radio-Off Meter Option – British Columbia Utilities Commission (Commission) Order G-220-13 Compliance Filing

Report on Radio-Off AMI Meter Option Participation and Costs (the Report)

On December 19, 2013, the Commission issued Order G-220-13 and accompanying Reasons for Decision in FBC's Application for a Radio-Off Meter Option pursuant to Order C-7-13 granting FBC a Certificate of Public Convenience and Necessity for the AMI Project.

In Order G-220-13, the Commission made, among others, the following order:

> FortisBC must track the actual number of Radio-Off AMI Meter Option participants and the actual annual manual meter reading costs separately from other costs and submit a report on these items with the British Columbia Utilities Commission on or before September 30, 2016.

In accordance with Commission Order G-220-13, FBC respectfully submits the attached Report.

If further information is required, please contact Sarah Wagner at 250-469-6081.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachment

FortisBC Inc.

Advanced Metering Infrastructure Project

Report on Radio-off AMI Meter Option Participation and Costs

September 30, 2016

Table of Contents

1. BACKGROUND

On July 26, 2012, FortisBC Inc. (FBC or the Company) applied to the British Columbia Utilities Commission (BCUC or the Commission) for approval of the Advanced Metering Infrastructure (AMI) Project (the Project). Project components include the replacement of existing customer meters (excluding certain industrial customers with existing MV90 interval metering) with AMI enabled meters and the installation of the associated infrastructure to support the transmission of metering information from the AMI meters at customers' premises back to FBC.

Order C-7-13, dated July 23, 2013, granted FBC a Certificate of Public Convenience and Necessity (CPCN) for the Project. The approval was subject to the condition that FBC confirm in writing that it would file an application for an opt-out provision by November 1, 2013.

On August 30, 2013, FBC filed an application for a Radio-off AMI Meter Option (the Radio-off Option) setting out the rates and processes for customers who choose the Radio-off Option. Commission Order G-220-13 approved revised permanent rates for Radio-off Option customers and directed FBC to track the actual number of Radio-off Option participants and actual annual manual meter reading costs separately from other costs and provide a report to the Commission on or before September 30, 2016 (the Radio-off Report).[1]

On September 11, 2015, FBC submitted an application for its Annual Review of 2016 Rates (2016 Annual Review). In the 2016 Annual Review FBC stated that the approved Radio-off tariff fees were not sufficient to recover the costs associated with providing the Radio-off Option and estimated a shortfall of $0.168 million and $0.392 million for 2015 and 2016, respectively. The Commission directed FBC to record the shortfall amount in a deferral account for future determination. The Commission noted that more complete and detailed information available from the Radio-off Report would better equip the Commission to make a decision on establishing just and reasonable rates.[2]

The following sections set out the actual Radio-off Option participants and actual manual meter reading costs as at August 2016 and sets out FBC's proposed treatment of the amounts captured in the Radio-off deferral account.

[1] Order G-220-13, Directive 3
[2] Order G-202-15, Directive 9 and Appendix A, pages 20-21

2. RADIO-OFF OPTION

Radio-off Option customer counts, and the costs incurred to manually read radio-off meters, varied during implementation of the AMI Project from 2014 to the second quarter of 2016.

The following table sets out the monthly Radio-off Option customer counts, costs incurred to manually read the radio-off meters, and manual read fee revenue.

Table 2-1: Radio-off Advanced Meter Option: Customer Counts, Costs and Revenue

Year	Month	RO Count	RO Read Costs ($000)	RO Read Fee ($000)	Cumulative Net: Costs - Fee ($000)
2014	September	259	$0.0	$0.0	$0.0
	October	358	$0.0	$0.0	$0.0
	November	449	$0.0	$0.0	$0.0
	December	541	$0.0	$0.0	$0.0
2015	January	648	$0.0	$0.0	$0.0
	February	762	$0.0	$0.0	$0.0
	March	896	$0.0	$0.0	$0.0
	April	1072	$0.0	$0.0	$0.0
	May	1116	$0.0	$0.0	$0.0
	June	1238	$0.0	$0.0	$0.0
	July	1566	$0.0	$0.1	-$0.1
	August	1694	$0.0	$3.4	-$3.4
	September	1868	$15.3	$8.6	$6.7
	October	2112	$8.1	$9.2	-$1.1
	November	3080	$7.9	$6.7	$1.2
	December	2968	$9.0	$14.0	-$5.0
	2015 Total:		$40.3	$42.0	-$1.7
2016	January	2994	$27.9	$16.9	$11.0
	February	2991	$29.8	$12.4	$17.4
	March	2862	$32.0	$15.9	$16.1
	April	2865	$30.1	$37.5	-$7.4
	May	2857	$22.4	$22.8	-$0.4
	June	2835	$26.2	$26.9	-$0.7
	July	2827	$25.5	$23.0	$2.5
	August	2828	$25.8	$25.0	$0.8
	2016 Total:		$219.7	$180.4	$39.3

The following sections provide detail on the Radio-off Option customer counts, manual meter reading costs and read fee revenue shown in Table 1 above.

2.1 *CUSTOMERS COUNTS*

Radio-off Option customer counts rose as implementation progressed, peaking at 3,080 Radio-off Option customers in November of 2015. Since that time Radio-off Option customer counts have steadily decreased as customers elected to move off of the Radio-off Option to the standard radio-on AMI meters. The Radio-off Option customer count has stabilized over the three month period ending August 2016 at an average 2,830 customers.

2.2 *MANUAL METER READING COSTS*

Costs incurred to manually read the Radio-off Option customer meters varied during project implementation as a factor of the counts, the geography of the specific Radio-off Option customers, and as FBC personnel learned the skills necessary to manually read radio-off meters. Meter reading routes were created, and revised throughout implementation.

2015 costs to manually read the Radio-off Option customer meters were $40,300, which was less than the forecast costs provided in the FBC 2016 Annual Review of $256,600. In 2016, costs incurred to-date to manually read the Radio-off Option customer meters are $219,700. The forecast 2016 yearend total costs are approximately $322,900 which will also be less than the forecast of $604,300 provided in FBC's 2016 Annual Review.

The 2015 cost estimate was based on an estimated requirement of 3.3 FTE staff reading meters. With overheads and vehicle costs, this amounted to approximately $51,000 per month for the last five months of 2015, from which the 2015 forecast of $256,600 was derived. Costs recorded in 2015 were much lower, largely due to incomplete cost tracking due to the transfer of meter reading responsibilities to Operations.

The approximately $51,000 per month estimate was also used to derive the forecast Radio-off meter reading costs of $604,300 in 2016.

Radio-off cost tracking was fully implemented at the beginning of 2016, with actual costs incurred during the first five months of 2016 of $28,500 per month. Actual costs from June to August 2016 were approximately $25,800 per month.

The 2015 actual and 2016 forecast Radio-off Option meter reading cost variances are due to two factors:

1. More customers choosing the Radio-off Option than originally forecast, reducing drive time (and the associated costs) between reads; and
2. Efficient use of FBC Operations resources for manual meter reading. Where possible, manual meter reading work is combined with other work in remote areas. As well, manual reading routes have been optimized to further minimize travel time.

With the stabilization of Radio-off Option customer counts experienced in the three months ending in August 2016, finalized manual meter reading routes have been created to maximize efficiencies. Average monthly costs during the period of June to August 2016 were $25,800 per month.

2.3 MANUAL METER READING REVENUE

Radio-off Option manual meter read fee revenues collected under Electric Tariff Rate Schedule 81 were $42,000 in 2015 and are $180,400 to date in 2016.

During the three months ending in August 2016, total Radio-off manual meter reading fee revenue was $74,900.

3. CONCLUSION AND RECOMMENDATION

Based on the Radio-off Option customer counts over the three months ending in August 2016, FBC forecasts an average Radio-off Option customer count of 2,800 and an average cost to manually read the Radio-off Option customer meters of approximately $18 per manual read, going forward. FBC considers the June to August 2016 time period, in which costs averaged $18.26 per read, to be reflective of a stabilized environment for manual Radio-off reading and has forecast accordingly.

The existing Radio-off Option manual read fee under Rate Schedule 81 of $18 reflects with reasonable accuracy the actual costs to manually read meters as experienced by FBC during June to August 2016, therefore FBC recommends that the current Radio-off manual meter read fee under Rate Schedule 81 be maintained at $18 per read.

FBC proposes to continue recording any variances related to the Radio-off costs and revenues in the existing Radio-off Shortfall deferral account through 2017. Given the Company’s experience during June to August 2016 and its forecasts going forward, FBC expects any variances between Radio-off costs and revenues to be minimal and will make a request for the disposition of the deferral account balance in the Company’s Annual Review for 2018 Rates.

Appendix F

DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review of 2018 Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On September 15, 2014, the British Columbia Utilities Commission (Commission) issued its Decision and Order G-139-14 approving for FortisBC Inc. (FBC) a Multi-Year Performance Based Ratemaking (PBR) Plan for 2014 through 2019 (the PBR Decision). In accordance with the PBR Decision, FBC is to conduct an Annual Review process to set rates for each year;

B. By letter dated July 24, 2017, FBC proposed a regulatory timetable for its annual review for 2018 rates;

C. By Order G-116-17 dated July 27, 2017, the Commission established the Regulatory Timetable for the annual review for 2018 rates which included the anticipated date for FBC to file its annual review materials, the deadline for intervener registration, one round of information requests, a workshop, FBCs response to undertakings requested at the workshop, and written final and reply arguments;

D. On August 10, 2017, FBC submitted its Annual Review for 2018 Rates Application materials (Application);

E. The Commission has reviewed the Application and evidence filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, the Commission orders as follows:

1. FortisBC Inc.'s (FBC) application for a 0.11 percent rate increase to be applied to all components of rates for all customer classes is approved, effective January 1,2018;

2. FBC is approved to establish the following three non-rate base deferral accounts and is approved to accrue financing charges on the three non-rate base deferral accounts based on FBC's weighted average cost of debt:

    - Multi-Year DSM Expenditure Schedule regulatory proceeding, with an amortization period to be proposed in a future Annual Review;
    - 2020 Revenue Requirement regulatory proceeding, with an amortization period to be proposed in a future Annual Review; and
    - 2018 Joint Use Pole Audit with a five year amortization period beginning in 2018.

3. FBC is approved to establish the following two non-rate base deferral accounts with a one-year amortization period, and is approved to accrue financing charges on the two non-rate base deferral accounts based on FBC's short-term interest rate:

    - Community Solar Pilot Project regulatory proceeding; and
    - Tariff Applications.

4. Z-factor treatment for the 2018 incremental operations and maintenance expenses and capital expenditures related to Mandatory Reliability Standards Assessment Reports No. 8 and 10 is approved.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner