



YUKON ENERGY CORPORATION

FOLLOW-UP QUESTIONS ON YUKON ENERGY UNDERTAKINGS
2017 – 2018 GENERAL RATE APPLICATION

ATTACHMENTS

YUB-YEC 3-3 ATTACHMENT 1

YUB-YEC 3-3 ATTACHMENT 2

July 27, 2018



IN THE MATTER OF

FORTISBC INC.

**MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN
FOR 2014 THROUGH 2018**

DECISION

September 15, 2014

Before:

**D.A. Cote, Panel Chair/Commissioner
N.E. MacMurchy, Commissioner
D.M. Morton, Commissioner**

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Commission Order G-139-14

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EXECUTIVE SUMMARY

On July 5, 2013, FortisBC Inc. (FBC) applied to the British Columbia Utilities Commission (Commission) for approval of a proposed multi-year Performance Based Ratemaking (PBR) plan for the years 2014–2018 (Application). The Application is made pursuant to sections 44.2 and 59 through 61 of the *Utilities Commission Act* (UCA). FBC seeks approval of, among other things:

- PBR mechanisms and the rate stabilization mechanism for setting rates for the years 2014–2018.
- Permanent rates for all customers effective January 1, 2014 resulting in an increase of 3.3 percent over 2013 and the flow-through of any rate increase or decrease resulting from the Generic Cost of Capital (Stage 2) proceeding.
- Deferral accounts additions, changes and discontinuance as well as proposed changes in financing costs.
- Accounting policies including the allocation of executive costs, the capitalized overhead rate and direct overhead charging methodology.
- Demand-Side Management (DSM) related to 2014–2018 expenditures and amortization changes.

FBC filed this 2014–2018 PBR plan based on the following objectives:

1. To reinforce FBC's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

On July 5, 2013, FortisBC Energy Inc. (FEI) filed a similar application. Portions of each application concerned with the PBR mechanism were combined into a joint proceeding. For convenience, the joint applicants in that portion of the proceeding are referred to as Fortis.

Many of the interveners expressed concern with the FBC proposal and recommend denying the Application in favour of moving forward with additional process to resolve the issues that arose. Considering the time and money spent to conduct the proceeding and the considerable volume of evidence, the Commission Panel determines it is appropriate to move forward with the process and render a decision based on the substantial evidentiary record. The Panel considers much of the

problem among the parties is based on a lack of trust, which must be addressed if a PBR regimen is to be successful.

The Decision following the Introduction section is separated into three sections:

1. PBR Design which deals with determinations related to the PBR formula components and elements of the PBR plan including the management of Service Quality Indicators (SQIs);
2. Making the PBR Work which addresses key revenue requirement issues including Base Operating and Maintenance (O&M) and Base Capital, accounting policy proposals and a number of issues with deferral accounts; and
3. Demand-Side Management (DSM) Programs.

PBR Design

A brief summary of some of the key issues and determinations related to the PBR design components are as follows:

PBR Formula Components

- (a) **PBR Term:** Fortis' proposal is for a five-year PBR term starting in 2014. Most interveners favoured a shorter term pointing to the risk associated with a five-year term. The Commission Panel, in recognition of the timing of this Decision, determines that a six-year period ending in 2019 is optimum. In the Panel's view, the changes made to certain PBR mechanisms provide the necessary checks and balances to protect ratepayer interests.
- (b) **I-Factor:** The Commission Panel supports the use of CPI-BC and the BC-AWE indexes in the determination of the I-factor as recommended by Fortis. However, the Panel is not persuaded that relying on forecast data to determine the I-factor is appropriate. We find that a reliance on the previous year's actual index figures, while backward looking, has significant advantages and therefore have determined this method to be most appropriate.
- (c) **X-Factor:** Considering the opposing views of two expert witnesses, Dr. Overcast on behalf of Black and Veatch (B&V) and Dr. Lowry on behalf of Pacific Economic Group (PEG), the Panel does not accept the B&V study results due to methodology shortcomings and resulting errors but places considerable weight on the PEG study considering it more rigorous. The Commission Panel determines that an X-factor of 1.03 is appropriate for FBC.

PBR Plan Components

- (a) **Earnings Sharing Mechanism:** The Commission Panel determines that an Earnings Sharing Mechanism, where gains and losses are shared equally by the Company and the ratepayer, balances the interests of the customer and the utility.
- (b) **Efficiency Carry-over Mechanism:** Fortis' proposes an efficiency carry-over mechanism (ECM) to allow the utility to benefit from savings following the PBR period resulting from measures taken and costs incurred during PBR. The interveners oppose this proposal considering it one sided and favouring the utility. The Commission Panel denies the Fortis ECM request but approves a methodology to review specific requests to carry over efficiency related benefits.
- (c) **Service Quality:** Considering the evidence, the Commission Panel determines there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs. It further determines a list of SQIs and sets performance benchmarks for each. The Panel acknowledges the need for an acceptable performance range for each SQI and directs the Fortis Companies, in consultation with the stakeholders, to develop these ranges.
- (d) **Capital Expenditures:** Fortis has proposed an approach to capital which excludes CPCNs from the PBR plan. Intervenors have raised concerns with respect to inclusion of capital pointing out that even with CPCN capital excluded, the potential to underspend exists. The Commission Panel finds the Fortis proposed CPCN criteria inappropriate for determining what capital is excluded from the PBR formula and invites further submission from parties on this issue. On a temporary basis, the Panel approves the current CPCN exclusion criteria and sets a process to further examine issues related to dollar thresholds and management of capital within the PBR.
- (e) **Mid-Term and Annual Review Process:** The Commission Panel finds that an extensive Annual Review process is necessary to build trust among the stakeholders and ensure the PBR plan functions as intended. The Panel sets out a list of items, which it directs the parties to address within the Annual Review. Given this more comprehensive approach to Annual Reviews, there is no need for the proposed Mid-Term Review and it is therefore denied.

Making the PBR Work

A brief summary of some of the key issues and determinations related to FBC's Non PBR components are as follows:

Determining Base O&M and Capital

- (a) **Base O&M:** The methodology for determining Base O&M proposed by FBC is to use the 2013 Approved O&M as a starting point and make adjustments to arrive at the PBR Opening Base O&M figure. Interveners expressed concern with both the methodology and the proposed adjustments. The Commission Panel determines that 2013 Approved O&M is an appropriate starting point and determines that further adjustments to the PBR Opening O&M Base are required resulting in a minor overall reduction to FBC's proposed base.
- (b) **Base Capital:** Given that there is to be a more fulsome review of issues related to dollar thresholds and the management of capital within the PBR, the Commission Panel approves FBC's approach to formula capital and approves FBC's PBR Opening Capital Base as applied for, subject to further adjustment as directed elsewhere in this Decision.

Accounting Policies

The Commission Panel approves a number of proposed accounting changes, including discontinuance of the US GAAP to Canadian GAAP reconciliation, changes to the handling of pension and OPEB funding differences and application of the Massachusetts Formula for executive costs. The Panel directs FBC to reduce its capitalized overhead rate to 15 percent in 2014 as well as to commence expensing its annual software upgrade costs consistent with the direction provided to FEI in its current RRA Decision.

Deferral Accounts

- (a) **Deferral Account Financing:** FBC requests revisiting the Commission's 2012–2013 RRA Decision relative to the handling of financing costs. The Commission Panel considers the matter to be of sufficient importance to warrant a more fulsome review of deferral accounts and has recommended the Commission initiate such a review in the near future. The Panel considers it appropriate to maintain FBC's deferral account financing as it is currently approved pending such a review.

- (b) **RSDM Deferral Account:** The Commission Panel denies FBC's proposal to establish the Rate Stabilization Deferral Mechanism (RSDM) deferral account combining the impact of the Waneta Capacity Purchase Agreement and other PBR rate impacts.
- (c) **Deferral Accounts for Flow-Through Items:** The Panel denies the establishment of the Insurance Expense Variance deferral account, Tax Variance deferral account, Property Tax Variance deferral account and Interest Expense Variance deferral account. FBC is directed to flow-through variances between forecast and actual expenses in these accounts through the annual true-up mechanism.
- (d) **Other Deferral Accounts:** The Panel approves the addition of, changes to and discontinuance of deferral accounts as proposed by FBC with the exception of deferral accounts mentioned above. The Panel applies, where appropriate, financing costs and amortization periods as outlined in the 2012–2013 RRA Decision.

Demand-Side Management

FBC withdrew its request for the 2015–2018 Demand-Side Management (DSM) expenditures as a result of amendments to the DSM Regulations, retaining its request for approval of \$3.0 million for 2014. Given that the timing of this Decision will not meaningfully impact 2014 DSM expenditures, the Commission Panel approves FBC's \$3.0 million DSM expenditure request for 2014. In addition, the Panel denies the FBC request to increase the DSM amortization period from 10 years to 15 years.

1.0 INTRODUCTION

1.1 Background

FortisBC Inc. (FBC) is a wholly owned subsidiary of FortisBC Holdings Inc. that generates, transmits and distributes electricity to approximately 163,000 direct and indirect customers including residential, commercial and industrial users. Its service territory is located in the southern interior of British Columbia.

On July 5, 2013, FBC submitted an application seeking British Columbia Utilities Commission (Commission) approval of a multi-year performance based ratemaking (PBR) plan for the years 2014 through 2018 (PBR Plan) including approval of rates for 2014 in accordance with the PBR Plan (Application).

On July 5, 2013, FortisBC Energy Inc. (FEI) filed a similar application. Portions of each application concerned with the PBR mechanism were combined into a joint proceeding. For convenience, the joint applicants in that portion of the proceeding are referred to as Fortis.

In its Application, FBC cites the following primary objectives of the PBR Plan:

- To reinforce FBC's productivity improvement culture while ensuring safety and customer service requirements continue to be met; and
- To create an efficient regulatory process for the upcoming years allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

FBC has had two previous PBR plans in the past (1996–2004 and 2007–2011). From 2005 to 2006 and from 2012 to 2013 FBC was regulated under the Cost of Service (COS) rate setting mechanism.

1.2 Application and Approvals Sought

FBC is seeking certain approvals under section 59–61 of the *Utilities Commission Act* (UCA) in order to implement a new five-year PBR Plan. The approvals sought are broken down into several areas and are described below.

1.2.1 PBR Plan and Rate Stabilization

FBC seeks:

- Approval of the PBR mechanisms set out in Section B of the Application for setting rates for the years 2014–2018;
- Approval for the rate stabilization mechanism set out in Section B7.1 of the Application.

1.2.2 General Rate Increases

- Approval of the rates that were effective January 1, 2013 to be made permanent;
- Approval of the current interim rates, effective January 1, 2014 and reflecting a 3.3 percent increase to be made permanent; and
- Approval to flow-through during 2014 the revenue requirement impact of the decrease in return on equity (ROE) used to calculate FBC's rates effective January 1, 2013.

1.2.3 Accounting Policies Changes, effective January 1, 2014

FBC seeks:

- Approval to discontinue the reconciliation of US Generally Accepted Accounting Principles (GAAP) to Canadian GAAP in future BCUC Annual Reports as set out in Section D3.1 of the Application;
- Approval to discontinue the net-of-tax treatment for the pension and other post-employment benefits (OPEB) funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of the income tax expense as explained in Section D3.1 of the Application;
- Approval to allocate Executive costs between FortisBC Energy Inc. (FEI) and FBC effective January 1, 2014, by way of applying the Massachusetts Formula described in Section C 4.17 of the Application;
- Continued approval of FBC's capitalized rate of 20 percent as set out in Section D 3.7;

- Continued approval of FBC's direct overhead charging methodology as set out in Section D3.8 of the Application.

1.2.4 Deferral Accounts

FBC seeks approval of the following:

- Rate based treatment and financing of deferral accounts, as set out in Section D3.2 of the Application;
- Financing costs for 2013 at FBC's Weighted Average Cost of Capital (WACC) for the six deferral accounts approved by Order G-23-13 as set out in Sections D4.4 of the Application; and
- The discontinuance, modification and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, as set out in Section D4 and Appendix F4 of the Application.

1.2.5 Demand-Side Management (DSM) Expenditures

Pursuant to section 44.2(3) of the UCA and as amended by FBC's letter dated July 16, 2014, FBC seeks Commission approval for:

- DSM expenditures in the amount of \$3.0 million for 2014;
- Approval to change the amortization period of existing and future DSM expenditures from 10 years to 15 years, effective January 1, 2014; and
- Approval to discontinue semi-annual reporting on its DSM Program and to submit annual reports as of December 31, in each year, effective January 1, 2014.

1.3 Legislative Framework

FBC is seeking approval of a PBR Plan for the 2014–2018 time frame including appropriate rate increases pursuant to sections 59 to 61 of the UCA. In summary, these sections of the UCA require any Commission Panel to have due regard for setting rates that are not unjust or unreasonable in respect to services provided by the applicant. Subsection 59(5) states that a rate is 'unjust' or 'unreasonable' if it is:

- a. more than a fair and reasonable charge for service of the nature and quality provided by the utility,

- b. insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
- c. Unjust and unreasonable for any other reason.

FBC is also seeking approval of proposed DSM capital expenditures for the duration of the PBR Plan (2014–2018) pursuant to subsection 44.2(3) of the UCA.

Approval of the DSM expenditures for 2014 is sought pursuant to Subsection 44.2(3), which states:

After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6) must

- a. Accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
- b. Reject the schedule.

Subsection 44.2(4) allows the Commission to accept or reject a part of a schedule.

Subsection 44.2(5) indicates the factors which the Commission is required to consider in the review of an expenditure schedule filed by a public utility (other than the British Columbia Hydro and Power Authority). It states:

In considering whether to accept an expenditure schedule ... the Commission must consider:

- (a) The applicable of British Columbia's energy objectives,
- (b) The most recent long-term resource plan filed by the public utility under section 44.1, if any,
- (c) The extent to which the [expenditure] schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,
- (d) If the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any,

[Demand-Side Measures Regulation BC Reg. 326/2008 as amended by BC Reg. 228/2011 and BC Reg. 141/2014 is applicable]

- (e) The interests of persons in British Columbia who receive or may receive service from the public utility.

The Demand-Side Measures Regulation (BC Reg. 326/2008) (DSM Regulation) was amended by BC Reg. 228/2011 and BC Reg. 141/2014. The DSM Regulation applies to demand-side measures proposed in long-term resource plans filed under section 44.1 of the UCA as well as those proposed under section 44.2 of the UCA.

Part of the DSM Regulation defines the class composed of all demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the UCA as an expenditure portfolio.

Section 3 of the DSM Regulation sets out all the criteria that must be met for a utility's plan portfolio to be deemed 'adequate' for the purposes of subsection 44.1(8)(c) of the UCA. To meet these criteria, the plan portfolio must include:

- (a) a demand-side measure intended specifically
 - (i) to assist residents of low-income households to reduce their energy consumption, or
 - (ii) to reduce energy consumption in housing owned and operated by
 - A. a housing provider incorporated under the *Society Act* or the *Cooperative Association Act*, or
 - B. a band within the meaning of the *Indian Act* (Canada),
if the benefits of the reduction primarily accrue to
 - C. the low-income households occupying the housing,
 - D. a housing provider referred to in clause (A), or
 - E. a band referred to in clause (B) if the households in the band's housing are primarily low-income households.
- (b) a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
- (c) an education program for students enrolled in schools within the public utility's service area;

- (d) an education program for students enrolled in post-secondary institutions in the utility's service area.

Section 4 of the Demand-Side Measures Regulation provides for the calculation of the effectiveness of demand-side measures. It also prescribes how the cost-effectiveness of a demand-side measure is to be determined for demand-side measures proposed in an expenditure portfolio. The prescribed calculation is called the modified TRC (mTRC) to distinguish it from the more traditional Total Resource Cost (TRC) test.

Clean Energy Act

The Commission is required to consider British Columbia's energy objectives as laid out under the *Clean Energy Act* (CEA) in reviewing any proposed expenditure schedule. The objectives are laid out in section 2 of the CEA and relate in large measure to the use of clean energy or renewable resources, promotion of energy conservation and efficiency and the reduction of greenhouse gas emissions.

1.4 Regulatory Process

FBC filed its Application on July 5, 2013. By Order G-109-13 dated July 17, 2013, a Preliminary Regulatory Timetable, Procedural Conference and Notice of Workshop were issued. The Procedural Conference date was originally set for October 11, 2013.

There were eleven Registered Interveners, although not all fully participated in the regulatory hearing process. The Registered Interveners were:

- BC Ministry of Energy and Mines (MEM);
- Irrigation Ratepayers Group (IRG);
- British Columbia Pensioners' and Seniors' Organization (BCPSO);
- Canadian Office and Professional Employees Union Local 378 (COPE);
- British Columbia Municipal Electrical Utilities (BCMEU);
- Commercial Energy consumers of British Columbia (CEC);

- Norman Gabana;
- BC Sustainable energy Association and the Sierra Club of British Columbia (BCSEA);
- British Columbia Hydro and Power Authority (BC Hydro);
- Industrial Consumers Group (ICG);
- Henry Stanski.

There were five expert witnesses who provided evidence and actively participated in the regulatory process. Expert Witnesses and their respective parties were as follows:

- Dr. H. Edwin Overcast on behalf of Black & Veatch (FEI and FBC);
- Ms. Barbara R. Alexander (COPE);
- Mr. Russ Bell (BCPSO);
- Dr. Mark Lowry on behalf of Pacific Economic Group (CEC);
- Mr. Tony Pullman on behalf of ICG.

On June 10, 2013, FEI filed an application also seeking to implement a PBR Plan of five years duration (2014–2018). Details of the ensuing process and proceeding are summarized in Appendix A to this Decision.

1.5 Approach to this Decision

This Decision is separated into 4 Sections.

Section 1 provides background as well as an outline of the legislative framework and regulatory process for this proceeding. This section will continue with a discussion of some of the issues which arose within the context of the proceeding and provide some guidance to the determinations which follow.

Section 2 considers the PBR Methodology. This includes a discussion and determinations on key design issues such as the PBR Formula components, the PBR Plan components and the management of Service Quality.

Section 3 covers how the PBR will work. It includes key issues like setting the Base for Operating and Maintenance (O&M) and Capital, Accounting Policy Issues and the Use of Deferral Accounts.

Finally, Section 4 considers issues related to DSM.

1.6 Issues Arising

Two contextual issues arose in this Proceeding, which need to be addressed as they serve to provide guidance to determinations made in this Decision. These issues are:

- Why Performance Based Regulation; and
- A Fair Rate of Return Under PBR.

1.6.1 Why Performance Based Regulation

The fact that FBC has filed an Application for PBR is not a surprise to the Commission given that FBC has operated under PBR for much of the last two decades and has been open about its intentions. What is surprising is the position taken by interveners with respect to PBR. After what appeared to be support for a PBR, a number of interveners are calling for a rejection of the PBR Plan as proposed by FortisBC Energy Inc. and FortisBC Inc. (Fortis) and recommend moving forward with further process to resolve the matter. The issue the Commission Panel must consider is whether the objections to PBR relate to performance based ratemaking itself or whether the concerns raised are founded on a desire to circumvent the established process and embark on an undefined process more to the Interveners' liking. In considering this issue, the Panel is mindful that an alternative negotiated settlement process was considered in the Reasons for Decision attached to Order G-150-13 issued on September 12, 2013. In these Reasons, the Panel stated "[f]or the PBR mechanism review, the Panel finds that that the oral hearing which provides an opportunity to cross examine expert witnesses is the most appropriate means to obtain a complete evidentiary

record necessary to assess these complex and challenging methodologies” (Exhibit A-13, Reasons for Decision, p. 4). Having completed the regulatory process which included an oral hearing, the Panel will consider the fullness of the evidence in reaching its determination as to whether a PBR is appropriate and whether there is a need for additional process.

1.6.1.1 A Case for PBR

After two years of COS regulation, FBC has opted to file a multi-year PBR. FBC has filed this 2014–2018 PBR Plan based on the following primary objectives:

1. To reinforce FBC’s productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for the upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing cost for customers.

FBC states that its proposed PBR Plan builds on the successful components of its most recent PBR Plan, which ran from 2007 through 2011. The current Plan, like the earlier PBR, establishes a formula-driven approach to calculating O&M and also introduces a formula-driven approach to calculating capital expenditures. Fortis considers these to be areas where it has the greatest control. FBC asserts that the proposed formula will result in lower spending targets in both of these areas when compared to the five-year O&M and capital forecast prepared by the Company. This is because it is incented to invest in new efficiencies to meet targets driven by the formula. In those years where the Company achieves efficiencies greater than those driven by the formula, the financial benefits are shared with customers, as are any shortfalls. The proposed PBR Plan utilizes flow-through accounts and annual forecasts to ensure that customers pay only the actual cost in those areas where FBC has limited or no control thereby protecting customers and the Company from the impact of forecast variances. The PBR Plan also includes off-ramp mechanisms to deal with cases where financial results fall outside a band of reasonableness or where there is serious, sustained and unjustified service quality degradation.

B&V provides a study of PBR methodologies and concludes there is no one right PBR model and the adopted FBC framework should be in keeping with the Company’s circumstances. FBC’s position is

that the proposed PBR Plan, as a model, will encourage it to seek efficiencies over the term of the plan with both customers and the Company benefiting while ensuring that safe and reliable service is maintained. B&V endorses the plan as being reasonable in the circumstances but believes the “stretch” productivity factor proposed by Fortis is more aggressive than is warranted. (Exhibit B-1, pp. 1–3)

FBC states that a priority is to improve productivity and create efficiencies to allow for rates to be more effectively managed, yet maintain a customer service focus. To this end, through 2012 and 2013 “employees were asked to consider embedded practices and rethink work while maintaining appropriate service levels” (Exhibit B-1, p. 12). FBC reports that this has resulted in efficiencies being realized from streamlined processes, leveraging technology and the optimization of integration opportunities. FBC states that efficiency review activities and finding productivity gains will continue to be a focus with an emphasis on managing costs. FBC further states:

“In providing value for FBC’s customers while delivering safe and reliable service at the most reasonable cost, a productivity focus is a requirement and is ingrained into the Company. The implementation of the PBR Plan proposed in this Application will result in a continuation of this focus through the PBR Period, and in an equal sharing with customers of any resulting incremental savings above the productivity factor built into customer rates.” (Exhibit B-1, p. 14)

Intervener Submissions

In concluding its Opening Statement in the Oral Hearing, CEC states: “CEC is in support of PBR. This is not an issue. It simply does not see this proposal of the company at this time as aligned with customer interests and we will deal with how that may be improved in our final submissions and through this proceeding” (T2:188). CEC, in its Final Argument “recommends that the Commission deny the Utilities application for their proposed PBR process and direct the parties to commence discussion with respect to alternatives that may more suitably align customer interest and the Utilities interest.” A summary of CEC’s position includes the following concerns:

- The PBR formulas proposed by Fortis are overly generous and are likely to result in the utilities enjoying windfall gains.

- The PBR has incentives which could lead to losses or inappropriate gains for the customer. The build-up of expenses before entering PBR and the deferral of expenditures late in a PBR period serve as examples of such perverse incentives.
- The Fortis proposal includes numerous examples of misalignment with customer interests and has not assessed alternatives due to its failure to consult with customer groups. CEC continues by noting 178 examples of misalignment of ratepayer interest to shareholder interest it has identified and therefore, approval of such a PBR proposal does not balance interests.
- Fortis has not made a sufficient business case for regulatory efficiency.

(CEC PBR Final Argument, p. 7)

CEC continues its submissions for a total of 219 pages outlining its concerns and sharing its view as to how the various PBR components can be better aligned with customer interests.

ICG reaches a similar conclusion with respect to FBC in that the PBR proposal is not aligned with customer interests and substantial changes are necessary. However, even with these changes, ICG does not support a PBR Plan at this time. (ICG Final Argument, p. 1)

IRG acknowledges the economic basis for PBR generally but asserts that FBC has not adequately explained why a change to PBR is required. IRG asserts that FBC has not established that a PBR will result in material expansion of incremental efficiency savings or that regulatory efficiency will result if PBR is implemented. (IRG Final Argument, pp. 1, 10)

COPE, in its Final Argument provided comments on some of the strengths and weaknesses of PBRs but took no position on the Application as a whole. COPE did provide detailed submissions on Service Quality Indicators (SQIs).

BCPSO took no position on whether to deny the Application but outlined alternative positions to those of Fortis with respect to customer alignment and balance in its Final Argument.

BCMEU, in its Final Argument supports the arguments of CEC and the need for a PBR with a good balance of risk and reward.

The matter of whether to go forward with a PBR was addressed again within the context of the Oral Argument phase of the proceeding held on July, 14, 2014. The Interveners were consistent in their opposition of the PBR as proposed by Fortis. However, CEC did submit that an “improved and ongoing PBR could serve to mitigate customer concerns” (T8:1415). It continued by recommending that a BCUC supervised process be initiated immediately to develop a PBR process more aligned with customer interests.

Fortis Reply

In the view of Fortis, interveners like CEC, BCPSO and ICG pay lip service to the concept of a PBR while objecting to its fundamental elements. Fortis holds that the case in favour of PBR is compelling. It states that interveners representing customers consider COS to be the gold standard pointing to the detailed review of costs and typical rebasing every two years as the reason. This is in comparison to PBR where there are less detailed reviews of utility costs over the PBR period and a longer period (in this case five years) between rebasing. In Fortis’ view, the reason why PBR remains an accepted ratemaking model is that these two features are fundamental to the values of productivity and efficiency that the PBR delivers to utility customers. Fortis argues that:

- Extending the time before rebasing incents the utility to search for incremental efficiencies.
- The more streamlined regulatory process related to PBR increases the likelihood of achieving direct and indirect savings.
- An appropriate level of transparency can be achieved with a less intensive regulatory process in PBR.

Fortis considers much of the concern raised by interveners to be misconceptions. Some examples of these follow.

Fortis argues that some of the interveners consider PBR to be misaligned with customer interests by providing windfalls to the utility and harming customers by creating inappropriate incentives. It considers these views to be misconceived and to lack recognition of short and long-term customer benefits as commented on by both CEC’s expert witness, Dr. Lowry, and Fortis’ expert witness,

Dr. Overcast. Fortis further states that the achievement of a higher than approved ROE is a benefit because this only occurs when benefits have flowed to both parties. By comparison, under COS, 100 percent of the benefit flows to the Company and the customer obtains benefits only after rebasing.

In response to concerns raised by Interveners that the PBR Plan does not distinguish between efficiency gains and cost cutting, Fortis further states that cost cutting is efficient and beneficial. Fortis argues that the distinction is artificial as by definition efficiency occurs when the earned return equals or exceeds the allowed return under revenue cap when a positive stretch factor exists. In addition, Fortis states that the opposition of interveners to mere cost cutting seems to be based on a misconception that under-expenditures are a product of gamesmanship related to perverse incentives and are made at the expense of service quality and asset integrity. The Company points out that these types of arguments ignore the presumption of good faith and the existence of a regulator.

Fortis asserts that PBR will bring regulatory efficiency, pointing out that revenue requirements applications are 10 to 30 times more costly than the Annual Review process under PBR. In addition, it is intuitive that there is a direct benefit related to having utility employees focus on managing the business rather than the regulatory process. (Fortis PBR Final Argument, pp. 1–16)

Fortis is unequivocal in stating that there is not a need for further process. Fortis is of the view that there are fundamental differences among the parties and “that is precisely the time when the Commission needs to come in and make a decision” (T8:1474).

Commission Determination

In the words of COPE, “between the interveners in this process, there were some significant commonalities in their evaluation of the PBR, not the least of which was the universal opposition to the particular set of applications...” (T8:1456). The Commission Panel does not disagree and considers the proposals as put forward by the Fortis Companies to favour Fortis. The discussion of evidence put forward in this proceeding, which follows in Section 2.0, bears this out.

The submissions of the parties seem to suggest that the concerns of the parties are not with a PBR itself but with the specifics of the Applications put forward by the Companies. CEC made this clear in its opening statement at the Oral Hearing, noting that it would provide recommendations on how the proposed Application could be improved during the Oral Hearing and in its Final Arguments. Its lengthy Final Argument listed its many concerns with recommendations as to how they should be addressed. It thus appears that CEC's concern is not with whether a PBR should be established, but with how the PBR elements should be more balanced in the interest of all stakeholders. Of the Interveners, only ICG and IRG are firm in not wanting to move forward albeit for different reasons. Of the remaining parties who commented, all seemed to favour some form of cost of service arrangement for the short term and a process to bring the parties together to discuss some form of PBR alternative for the future.

The Commission Panel notes that considerable time and money has been spent to conduct this PBR proceeding. Over the past year, the parties and the Commission have read through the Applications, volumes of IRs and considered the evidence, both oral and written, from a number of expert witnesses. The evidentiary record on which to base a decision is substantial. Add to this the level of differences among the parties with regard to various aspects of the PBR proposal and it is questionable whether any value will result from further process. **Therefore, the Commission Panel determines that it is appropriate to render a decision based on the substantial evidence before it and not move to a further process on the design of the PBR.**

In moving forward with this PBR Decision the Panel has a number of concerns.

The Commission Panel is not looking at this Application from a short-term viewpoint. We see an opportunity to make significant change over the long term with the way regulation is conducted in this jurisdiction and the way in which revenue requirements are determined. What form this may take is at this point undecided. Standing in the way of this is the lack of trust among the parties. If moving forward with this PBR is going to work, the level of trust must be addressed and increased. For this reason, the Commission Panel has included a more lengthy discussion of the Annual Review

process in this Decision than perhaps many of the parties anticipate. We have made significant changes to the purpose, content and process for this important program element. This will be discussed further in Section 2.3.6.

Much has been said by the parties about the improved regulatory efficiency that will result from a PBR process. Fortis seems to view PBR as a period where it will be required to provide only limited information as to its activities and savings it has achieved. This is a sticking point with interveners who are outspoken in their concerns with respect to the level of scrutiny and oversight of the activities of FEI and FBC over the PBR period. The Commission Panel acknowledges that improving regulatory efficiency is a desired outcome but due to the current levels of trust, the achievement of major regulatory savings in the first few years of PBR may not be possible or even advisable.

Looking at regulatory models more broadly, the Commission Panel accepts that there is no perfect regulatory process. The COS model has been relied upon in this jurisdiction and others with some success. The interveners may take comfort in the fact that one of its advantages is that it requires more frequent rebasing and hence there is a limit on the time before any sustainable savings directly impact customer rates. However, with COS regulation, there is little incentive to make sustainable efficiency gains and even less when an investment is required. In fact, perversely, the utility may be incented to make unsustainable savings. On the other hand, the PBR model comes with its own set of inherent problems. If the wrong base is set for O&M or capital, or inappropriate I- or X-factors are set which favour either party, it can result in additional gains for that party over a longer period of time unless an off-ramp is tripped.

Regardless of the method chosen, to be successful over the longer term, the parties need to feel that their concerns are heard and where reasonable, acted upon. To facilitate this, the Commission Panel has taken steps in this Decision to ensure there is ongoing communication between the parties, which will result in greater transparency.

1.6.1.2 A Fair Rate of Return Under PBR

Fortis has relied on a number of guiding principles in developing its PBR Plan proposal. One of these states: “The PBR Plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return” (FEI Exhibit B-1, p. 43; FBC Exhibit B-1, p. 39). Whether rates are set under COS or a PBR Plan, the Commission remains tasked with setting just and reasonable rates under sections 59 to 61 of the UCA.

“As reflected in section 59(5), just and reasonable rates must represent:

- a ‘fair and reasonable charge for service of the nature and quality provided by the utility’ and
- ‘a fair and reasonable compensation for the service provided by the utility’” (Fortis PBR Final Argument, p. 17).

Fortis submits that this includes the well-established right of a utility to earn a fair return and the assessment of the PBR plan needs to be on a holistic basis as rate levels are a product of the plan elements working in tandem to yield a revenue requirement. Fortis’ expert witness, Dr. Overcast describes the concept of just and reasonable rates in a PBR context as follows:

“The need for just and reasonable rates under a PBR plan means that each element of the plan must be carefully reviewed so the expectation is that during the regulatory control period a utility operating at the industry average efficiency could expect to earn its allowed rate of return. If the utility operates below the average efficiency it could not reasonably expect to earn the allowed rate of return, but the resulting lower returns should not be so low as to be confiscatory in nature. For performance above the average efficiency, the utility should be able to earn above the allowed rate of return and beyond a reasonable level the customers should benefit directly in the success of the utility at an improved efficiency level....”
(Exhibit B-1-1, Appendix D2, p. 7)

Fortis considers Dr. Overcast’s description to be reasonable and submits that for the PBR plan to meet legislative requirements, three conditions must be present:

- An appropriate base on which to apply the PBR formula;
- A plan which has been crafted with a recognition of the extent to which costs are controllable by the utility; and

- The I-X formula applicable must realistically portray inflation impacts and other productivity factors impacting the X-Factor and the I-X formula result must be reasonably achievable.

(Fortis PBR Final Argument, pp. 17–18)

Commission Determination

The Commission Panel is in agreement with Fortis that the revenues driven by the PBR formula must provide utilities the opportunity to earn a fair return. The Panel also acknowledges that changes to individual plan components “may change the overall risk/reward profile of the PBR Plan.” The UCA addresses this in section 60(1)(a):

In setting a rate under this act

- (a) the commission must consider all matters it considers proper and relevant affecting the rate,
- (b) the commission must have due regard in the setting of a rate that
 - (i) is not unjust or unreasonable within the meaning of section 59...

Fortis has put forward a PBR plan with numerous elements. As outlined by Dr. Overcast, each of the elements needs to be scrutinized carefully. This is to ensure they are reasonable and do not favour either the Companies or the ratepayer. Determinations resulting from this evaluation need to achieve a proper balance of risks and rewards between the Companies and the ratepayer and reflect current reality.

FEI and FBC’s Applications provide forecasts for O&M and Capital for the period 2014 to 2018. The Companies compare these forecasts against outputs from their proposed PBR mechanism and show that there are similar patterns between their forecasts and the amounts generated by the proposed PBR mechanism. Fortis takes the position that this similarity of pattern or balance must be maintained with any changes that the Commission may make to the formula. The Commission Panel notes that the validity and accuracy of these forecasts has not been established. Therefore, there is no basis on which to justify this comparison between the PBR mechanism and the Fortis forecasts. While there is a need to holistically consider the effects of changes to the PBR

mechanism on the Companies' ability to earn a fair return, the Panel places no weight on the Fortis assertion that Commission changes must be balanced against what the Companies have submitted. Accordingly, the Commission Panel finds there is no requirement to balance Commission adjustments to the PBR against the revenue requirement forecasts provided by Fortis.

2.0 FORTIS PBR DESIGN

2.1 Background

2.1.1 Experience with PBR

FBC has had experience with a formula driven PBR regime operating two previous PBR plans; one in 1996–2004 and a second in 2007–2011. FBC reports that both of its previous plans were successful and building on this it has incorporated many of the elements of previous plans. In addition, it has made adjustments to these as appropriate.

FortisBC (then West Kootenay Power) states that in 1996 it received Commission approval to replace its Cost of Service plan with a PBR. FBC describes the plan as consisting “of ‘targeted’ cost categories with cost drivers, base costs escalators, productivity improvement factors (PIFs) and a sharing mechanism.” In addition, performance standards that were subject to periodic review were made part of the plan, which ran for three years but was extended on two occasions with some modification. The modifications included some of the incentive mechanisms in the original plan such as the introduction of a power purchase mechanism and market incentive mechanism as well as excluding capitalized overhead from the mechanism.

The 2007–2011 PBR plan was based on a negotiated settlement and was like the previous plan in many aspects. A key difference between the two plans was the exclusion of capital expenditures, which were not part of the 2007–2011 PBR plan and were approved by annual filing or by CPCN applications. Additionally, an Earnings Sharing Mechanism (ESM) was introduced and “replaced the previously-existing line-by-line review used to determine the level of any incentive sharing between the Company and its customers.” Further modifications included performance indicator changes.

These were designed to improve the measurement of customer satisfaction with service quality and reliability as well as the convenience of customer interactions. (Exhibit B-1, p. 31)

2.1.2 PBR Approaches

Approaches to PBR fall into two broad categories: price caps and revenue caps. Under a price cap formula, rates are a function of two factors; the previous year's rates and a formula which is applied to those rates. Typically, the formula accounts for inflation (or an I-Factor) and an efficiency factor (referred to as the X-factor) and may also include other terms to account for such things as growth, flow-through items and exogenous events. The revenue cap approach differs from this in that it is the utilities' allowed or authorized revenue that is subject to the formula.

While both of these methods serve to create incentives to reduce costs and raise efficiency, they differ in the way they treat energy demand and incremental sales volumes. Under the price cap model the utility takes on the risk for demand variations. Therefore, they are encouraged to maximize sales volumes to the point where their marginal revenue equals their marginal costs. FBC states that this method is more appropriate for utilities with a demand trend that is stable and growing. It can be problematic in those cases where there is a continuous decline in sales per customer due to exogenous factors. This makes a price cap problematic for FEI where gas usage rates are trending down. Under a revenue cap model as is proposed in this Application, allowed revenue is decoupled from demand, which provides the utility protection against such variation in demand.

Revenue Cap plans are typically further broken down into either a "building block" approach or a "total expenditure" approach based on their rate base assessment methodology and the role of the formula in establishing costs. Under the building block approach O&M and capital expenditures are assessed separately and in some cases some or all capital expenditures are handled outside of the formula. The separation of capital from O&M expenditures is a key distinction in comparing the two approaches. In contrast, the total expenditure approach combines O&M and capital expenditures under one factor. FBC states that in most cases "the majority of PBR plans end up as

hybrid systems where part of the capital expenditures (such as significant sustainment capital) is treated outside the PBR formulas and the rest of capital expenditures and O&M expenditures are determined under indexing formula and the productivity factor.” FBC further states that the removal of sustainment capital from the formula results in the large negative impact of infrastructure replacement on TFP being reduced or eliminated. (Exhibit B-1, pp. 29–30)

However, the building block approach does not allow the utility the same amount of flexibility to substitute capital expenditures for O&M, and vice-versa, as does the more traditional revenue cap model.

2.1.2.1 FBC Proposed Formulas for PBR

FBC proposes the following two formulas, one for O&M and one for capital:

O&M Formula:

$$OM_t = OM_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}} \right)$$

Where: OM =Operating and Maintenance Expense subject to formula
 AC =Average Customers
 t = Upcoming year
 I = Inflation Factor
 X = Productivity Factor

(Source: FBC Exhibit B-1, p. 52)

Capital Formula:

$$C_t = C_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}} \right)$$

Where: C =Capital Expenditures subject to formula
 AC =Average Customers
 t = Upcoming year
 I = Inflation Factor
 X = Productivity Factor

(Source: FBC Exhibit B-1, p. 57)

Note: Fortis also describes two additional components; an exogenous factor (Z) and a flow-through (Y) but does not include them in the formulas.

These formulas provide the basis for calculation of FBC's operating and maintenance expense and capital calculations over the PBR term.

Commission Discussion

There is value in FBC and FEI utilizing the same PBR approach for purposes of consistency. The revenue cap approach has been accepted as applied for by FEI and there is no evidence to suggest that this approach would not be effective for utilities with more stable and growing demand.

Accordingly, the Commission Panel accepts the revenue cap approach for FBC

The Commission Panel accepts the building block approach proposed by FBC. It is consistent with the approach taken in previous PBRs, and, as such has a track record. Further, no Intervener takes issue with it.

The Commission Panel also generally approves the formulas proposed. By this we mean that the proposed formula components: an Inflation Factor, a Productivity Factor, Exogenous and Flow-Through Items and a growth term based on average customers may be appropriate for inclusion. Further, the Panel takes no issue with the way Fortis proposes to combine the formula components.

We will examine the various proposed components in these formulas in greater detail later in this section and make determinations on each of these components. In addition, various other components of the FBC PBR proposal will be examined. These include the Earnings Sharing Mechanism, the Efficiency Carry-Over Mechanism, Service Quality Indicators, Review Processes and Off Ramps. These will be reviewed and determinations made. Collectively, these mechanisms will provide guidance and structure to the operation of the PBR over its term.

The PBR Formula Components

2.1.3 Setting the PBR Term

FEI and FBC have applied for a five-year term (2014 to 2018) for their PBRs. Fortis asserts that this is a reasonable term for the PBR Plan for the following reasons:

- It is a commonly adopted term for PBR's in North America;
- It promotes regulatory efficiency by reducing the number of comprehensive revenue requirement reviews; and
- It provides an adequate period of time to allow Fortis to realize cost savings resulting from efficiencies flowing from capital investments and other efficiency initiatives.

(FBC Exhibit B-1, p. 41; FEI Exhibit B-1, p. 45)

Fortis recognizes that a longer PBR plan poses risks to both the utility and its customers but believes that these risks are mitigated by other elements of the plan such as exogenous factors, re-openers and off ramps. It further asserts that the annual and mid-Term review processes will assure transparency and allow regular opportunities to assess the PBR plan.

In their Applications, Fortis draws attention to the B&V Report, which endorses the five-year term as being appropriate given the various elements in the plan. For example:

“While there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders. For a well developed plan that includes appropriate plan elements to preserve the fundamental regulatory compact for all stakeholders the five year period seems to be appropriate. The length of the plan must be set in conjunction with off-ramps and reopeners that protect all stakeholders. Further, the plan incentives must be symmetric and reasonable as will be discussed below. Shorter plans have a larger regulatory burden than longer plans in terms of the rate reset frequency. Longer plans have potentially lower regulatory costs but greater uncertainty of outcomes for stakeholders. The five year plan seems to be reasonable so long as other portions of the plan are reasonable.”

(FEI Exhibit B-1, pp. 45–46; FBC Exhibit B-1, pp. 41–42; Fortis Exhibit B-1-1, Appendix D1, p. 36)

Intervener Submissions

CEC's view is that the five-year term proposed by the Companies is not appropriate. CEC states:

"Theoretically, and as indicated in the AUC decision, the appropriate balance for a PBR plan lies in ensuring the term is long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues become substantially out of sync with its costs or to create considerable gains or losses for stakeholders." (CEC PBR Final Argument, p. 17)

In CEC's view, the five-year term does not strike an appropriate balance as the risks to ratepayers are significant in a five-year term. CEC raises a number of concerns including:

- The claimed 'benefits' set out by Fortis are not supportable;
- There is a benefit to stakeholders if there is more frequent rebasing;
- There is a loss of transparency when costs and revenues are not scrutinized for five years rather than after two years under cost of service regulation;
- There is a loss of some assurance that the Utilities costs and revenues are prudent; and
- The five-year term exposes the ratepayer to:
 - Increased potential for miscalibration of the PBR plan resulting in increased risk;
 - Increased forecasting and estimating uncertainty and error;
 - Increased risk to principles of fair return on capital and recovery of prudent costs; and
 - Increased risk that the costs of the PBR plan will exceed any real benefits.

(CEC PBR Final Argument, p. 17)

CEC notes that PBR terms of three or four years are not unusual, although it acknowledges that those jurisdictions presented in the application are all for five years. CEC further disputes that the cost savings resulting from less frequent revenue requirement hearings are not necessarily a benefit to ratepayers in that revenue requirements have customer benefits and should not be eliminated simply to eliminate the expense of a revenue requirement proceeding (CEC PBR Final Argument pp. 20–21). CEC further suggests that the PBR proceedings will be significantly more

expensive than an RRA proceeding and recommends the Commission carefully review the cost effectiveness of PBR relative to cost of service.

CEC challenges Fortis' claims that the longer PBR period is necessary to allow a broader set of efficiency projects to be considered for improving efficiency. CEC contends that efficiency investments may be undertaken within shorter time frames under Cost of Service if properly timed. It also asserts that Fortis has failed to give specific examples of efficiency projects that require a five year time period. CEC recommends that efficiency improvement projects could be brought forward at the Annual Review to allow them to be developed to ensure the required payback was available. This would create greater certainty for both the Companies and the ratepayer (CEC PBR Final Argument, p. 26). CEC also suggests that the issue of payback term could be better addressed through the use of deferral accounts which would not limit payback to any particular term. (CEC PBR Final Argument, p. 23).

With respect to Fortis' claim that the risks to customers and the lack of regulatory transparency under the PBR Plan is mitigated by checks and balances such as the use of exogenous factors, re-openers and off-ramps, and opportunities to review the operation of the plan throughout the term, CEC claims that there is little value to the ratepayer afforded by these checks and balances and they do not provide openness or transparency (CEC PBR Final Argument, p. 25).

CEC recommends that in the event the Commission approves a PBR, they approve at most a three-year term (CEC PBR Final Argument, p.26).

ICG believes that Fortis has not adequately justified a five-year PBR plan and recommends that if a PBR plan is approved, it should have a two-year term.

ICG concludes that:

- Efficiency investments, if any, are not as finely tuned to the regulatory regime as to justify the need for a five year PBR plan; and

- A five-year PBR plan should only be approved for a utility with rate stability closely following inflation. ICG believes this may be the case for FEI but it is not the case for FBC. (ICG Final Argument, pp. 16, 17)

Fortis Reply

Fortis refutes the CEC recommendations for the following reasons:

- Given that a decision will not be forthcoming until the second half of 2014, CEC's recommendation for a three year term is, in effect, advocating a two year term which would restrict the potential for efficiency investments to no greater than would occur under a two-year RRA;
- The shorter time period would also suggest a lower X-Factor providing customers with less upfront benefits;
- The CEC claims regarding increased forecasting and estimating uncertainty and error is erroneous in that PBR formula inputs and flow-through items will be re-forecasted annually in the fall of the preceding year, as opposed to preparing two-year forecasts in the spring before the first year of a two-year Cost of Service test period;
- The AUC 2012 PBR Decision stated:

“The Commission considers that a five-year fixed term for each of the PBR plans is reasonable. The Commission has chosen this period recognizing that some of the elements approved in the PBR plans in this decision are novel and this term is consistent with the typical term for PBR plans in North America.” (Exhibit B-1-1, Appendix D8, para 836)
- Under PBR, the benefit of embedding cost savings is not lost, it is only delayed. Furthermore, there is an opportunity under PBR to generate greater benefits.

(Fortis PBR Reply, pp. 28–30)

Fortis responds that ICG's view — that efficiency investments are not as finely tuned to the regulatory regime so as to justify a five-year PBR plan — is a backwards approach to analyzing the term. In Fortis' view the PBR is about creating opportunities to find efficiencies. The term selected should maximize these opportunities while balancing this with the need for periodic rebasing. Trying to identify the shortest term necessary to make already identified opportunities viable is not the correct approach. In Fortis' view a shorter term “reduces the power of the incentive for management to find — using economic terms — the best available combination of inputs to produce

outputs. There is an opportunity cost to customers associated with a shorter term, which ICG is ignoring.”

Fortis makes the following counter-points to ICG’s assertion:

- ICG has not cited any evidence in support of the notion that PBR cannot work in the context of a utility that has recently been experiencing rate increases higher than inflation;
- The evidence of Drs. Overcast and Lowry would suggest that the scenario envisaged by ICG merely suggests that the X-Factor for the utility will tend to be negative;
- FBC’s recent rate trajectory has been driven by investment in asset replacement and reinforcement projects and the cost of energy to meet customer demand. FBC’s proposed PBR plan accounts for such circumstances by excluding lumpy capital from the formula and by flowing through variances in power purchase expenses.

(Fortis PBR Reply, pp. 27–28)

No other Interveners took positions on the length of term of the PBR.

Commission Determination

Both CEC and Fortis agree that a major factor in determining the appropriate length of time for a PBR is to find the balance between a time period that is adequate for the companies to find and pursue opportunities for efficiencies that will benefit both the shareholder and the ratepayer and not being so long as to put either party at risk.

Fortis asserts that the design of the plan puts in place checks and balances, such as regular re-forecasting of certain elements within the PBR formula, annual and mid-term reviews providing an opportunity to assess how well the plan is working, and re-openers and off-ramps to deal with possible failings of the plan. CEC asserts that these checks and balances will be ineffective in protecting ratepayer interests and in addition there are transparency and prudence concerns.

Efficiencies that require significant upfront costs in order to deliver a stream of benefits over a period of years are, in the Panel’s view, more likely to be pursued under a PBR with a longer time period. The Panel is not persuaded by the assertions of CEC and ICG that a longer time period for

the PBR plan is of little or no value to Fortis' pursuit and implementation of efficiencies. Nor is the Panel persuaded that a five-year PBR plan can only be implemented for utilities with rate stability closely following inflation.

In the Commission Panel's view, the time frame for the PBR plan is appropriately determined by assessing the time period over which the Companies are incented to maximize input efficiencies while the ratepayer and the utility are protected from unwarranted gains or losses. In choosing the time frame for the PBR, we consider the ability of the checks and balances to provide stakeholders with appropriate protection. Elsewhere in this Decision, the Panel directs Fortis to make changes to certain mechanisms, which will strengthen Fortis' proposed checks and balances in order to adequately protect stakeholder interests.

While the Commission Panel finds that with the changes it has directed to the mechanisms that protect stakeholder interests, a five-year PBR term is appropriate, it must be recognized that a substantial portion of year one will have passed without the certainty provided by this Decision. The effect of this would be a PBR term that is only a little over four years. **In order to realize the full benefits of a five-year term, the Panel directs the term be extended through the end of 2019.** This six-year term ending in 2019 should better enable Fortis to find efficiencies that will benefit all parties.

2.1.4 Setting the I-Factor

An inflation, or I-Factor, has been included in the mechanism to provide recognition that utility costs are subject to inflationary costs occurring in the economy. In this Application, Fortis proposes to use a weighted composite I-Factor for O&M with labour at 55 percent indexed to the BC-AWE and non-labour at 45 percent indexed to the BC-CPI which reflects Fortis' current ratios of labour to non labour. These would be based on forecasts for the coming year for both indexes. For BC-CPI, the average of six forecasts is relied upon. Fortis considers the use of a composite labour and non-labour inflation index to be more reflective of Company costs, which have both labour and non-labour components, rather than relying solely on an economy based inflation measure such as CPI.

Moreover, Fortis reports that other jurisdictions have relied upon these two indexes in developing I-Factor estimates.

In selecting these inflation indexes, Fortis considered alternatives on the basis of whether they are:

- Indicative of changes in inflationary pressures that the utility expects to experience;
- Readily available and published by a reputable, independent agency;
- Transparent and easy to understand; and
- Reasonably stable.

Fortis intends to update both the BC-AWE and BC-CPI rates each year as part of the Annual Review process stating that this is more preferable to truing-up forecasts to actual because it more closely reflects the cost pressures of the utility. In explanation, Fortis argues that this methodology applies to both labour and non-labour costs. (FBC Exhibit B-1, pp. 42–44; Fortis Final Argument, pp. 62–67)

Intervener Positions

CEC states that the 55 percent to 45 percent labour/non-labour weighting places too much weight on the labour component particularly for FEI capital. CEC states that the percentage of labour to non-labour for FEI in the last five years has been consistent at “45% to 55% then reversing in 2012 to 55% to 45% and has declined from 54 percent to 46 percent in 2012.” Capital has been more inconsistent “in the 22% to 78% range ending in 2012 at 24% to 76%.” For FBC, the actual O&M labour to non-labour was 54 percent to 46 percent in 2012, with the capital labour to non-labour ratio 67 percent to 33 percent. (CEC Final Argument p. 35; FBC Exhibit B-11, BCPSO 1.26.3; FEI Exhibit B-6, BCPSO 1.13.2)

In addition, CEC raises a number of issues with the Fortis methodology for determining the I-Factor:

1. Actual vs Forecast Inflation — CEC argues that the Fortis approach results in a consistent bias toward over forecasting. Analysis of the inflation forecasts being used indicates that over the last nine years, the CPI has been over forecast on average by 0.38 percent annually and by 1.4 percent annually on a compound basis. CEC submits that the AUC approach of adopting the previous year’s actual is preferable to the Company’s approach of using

forecasts, embedding errors and compounding them over time. (CEC PBR Final Argument, pp. 29–33)

2. Impact of Forecast Timing on Adequacy – CEC takes issue with the inflation forecasts they intend to rely upon and the timing of published data. CEC argues that during this proceeding, Fortis' submission of more updated information resulted in a 10 percent reduction in the inflation forecast.
3. CPI Systemically Overestimates Inflation – CEC argues that when using CPI as a measure of inflation, there are 4 systemic biases; commodity substitution, outlet substitution, new goods and quality adjustment bias. CEC cites a number of studies that estimate the bias effect to be 0.5 to 0.6 percent. Dr. Lowry concurs with a CPI bias of close to 0.5 percent and offers the GDP IPI as a solution. CEC submits that Dr. Lowry's evidence on GDP IPI indicates it is the best macroeconomic indicator.
4. Overweighting of Labour to Non-labour – CEC contends that the labour AWE (which is typically higher than the CPI) is over weighted relative to the non-labour portion particularly when it comes to capital. Moreover, when considering the Conference Board of Canada overestimates of CPI and AWE, its estimate of AWE is 100 percent greater than the amount AWE actually exceeds CPI 0.61 to 0.31 percent. It therefore concludes that the proposed methodologies will overestimate inflation. (CEC Final Argument pp. 29–35)

PEG states that if the Commission wishes to use a macroeconomic output price index in the inflation measures for the Fortis utilities either the CPI-BC or the Gross Domestic Product Implicit Price Index times Final Domestic Demand (GDPIPIFDD) for BC is recommended. It indicates that both of these are reflective of local BC conditions. (FEI Exhibit C1-9, PEG Evidence, p. 51) PEG recommends that if the Commission is to approve escalation indexes for capital expenditure budgets, industry-specific indexes are warranted. PEG states that inflation in power and gas utility construction can deviate significantly from macroeconomic measures noting that there has been a slowdown in electricity construction inflation since 2011. In its view, the risk of overcompensation exists if the Commission is to adopt the inflation indexes proposed by Fortis to be applied to capital expenditures. PEG discusses a range of indexes to estimate Canadian construction costs and states "[it] can be seen that the summary EUCPI for power distribution did a fairly good job of tracking the trend in the CSPI for engineering structures...On the basis of this comparison, we recommend the EUCPI for power distribution as the best available measure of the trend in gas utility construction prices." Later in its evidence, PEG suggests that a 50/50 weighting between the EUCPI power distribution and power transmission indexes would be sensible for FBC. Based on a review of the Canadian non-residential building cost price indexes, PEG notes that Vancouver prices lag behind

Canada as a whole by 50 basis points annually and states that it would be reasonable to reduce EUCPI growth rates by a similar amount to reflect the local economy. (FEI Exhibit C1-9, PEG Evidence, p. 51)

With respect to the weighting of labour vs materials, PEG states that care must be taken to ensure the labour cost weighting is equal to the share of direct labour expenses and views the proposed 55 percent as being too high with reference to capital cost or total cost. (Exhibit C1-9, p. 52)

BCPSO argues that the I-Factor should be trued-up to actual because it is uncontrollable and hence, should be flowed through. It notes that if actual prices are different than forecast, the utility will either win or lose and the result will have nothing to do with a gain or a loss in efficiency. BCPSO also takes issue with the Fortis argument that its costs are based on forecast inflation rather than actual inflation due to the timing of purchases. It asserts that actual inflation differs from forecast inflation and therefore actual increases are not driven by forecasts. BCPSO takes no position on the use of a composite I-Factor relying upon the BC-CPI and the BC-AWE. (BCPSO Final Argument, para. 41–44)

ICG states that it takes no position on the I-Factor because it does not consider it to have a material impact on rates (ICG Final Argument, p. 23).

Fortis Reply

Fortis submits that the rationale for its proposal is consistent with COS and prior PBR principles and asserts that there is nothing to justify the approach proposed by Interveners. Fortis asserts that CEC has provided no evidence that the BC GDPIIFDD or BC-CPI alone is more reflective of actual Fortis labour costs than the BC-AWE and CEC's opposition to the use of BC-AWE is because labour indexes rise more quickly than corresponding macroeconomic indicators. In its view, if the Commission were to adopt a measure that reflects labour inflation to a lesser degree, it would result in a bias in favour of customers. (Fortis PBR Reply, pp. 55–56)

Fortis also takes issue with CEC's characterization of labour/non-labour weightings and argues they are more characteristic of the base year and not historical years. In support of this, Fortis points out that the increase in the O&M labour weighting occurred in 2012 when customer care was insourced. This reversed costs between the two categories. In addition, Fortis notes that CEC's percentages do not reflect the contractor labour in the non-labour category. When contractor labour is considered, the 55 percent labour weighting is supported. Fortis also points out that in spite of CEC's opposition to a labour specific inflation measure, its expert, Dr. Lowry "modified his recommended I-X formula for FEI's O&M to include a 55 percent BC-AWE weighting." (Fortis PBR Reply, pp. 56–57)

Fortis does not dispute the average annual variance of 0.38 percent between forecast and actual CPI yields. However, it does argue that the compound annual variance of 1.4 percent for BC-CPI is unsubstantiated and should be disregarded. However, Fortis provides no alternative calculation. (Fortis PBR Reply, pp. 59–60)

Fortis considers forecast inflation as reflective of the cost challenge faced by companies and arguments in favour of a true-up or reliance on the previous year flawed. It points out, in reference to BCPSO's comments, that they are overlooking the fact that the I-Factor serves as a proxy for Fortis' inflation "not the economy as a whole." With respect to CEC's reliance on the previous year actuals, Fortis states that this is just another way of forecasting "which employs a simplifying assumption that the actual experience in the prior year is predictive of the future." In the view of Fortis, relying on the previous year as a proxy for the current year introduces lag rather than being forward looking. Fortis further states that applying the previous year's actuals to future forecasts result in greater under or over estimations of inflation. It provides a graphic demonstration of this showing the two methods and the effect of inflationary changes from 2008 to 2012. (Fortis PBR Reply, pp. 57–59)

Commission Determination

There are two interrelated issues to be addressed by the Commission Panel with respect to the determination of the I-Factor. The first of these deals with the basis on which the I-Factor should

be set. Is it appropriate to use forecasts as proposed by Fortis, rely upon the previous year's actuals as argued by CEC or true-up to actual as proposed by BCPSO. The second is what indexes are most suitable to rely upon for the determination of the I-Factor. Related to this is consideration of the labour/non-labour separation. If separated, what is the appropriate weighting for each and whether the weighting ratio should be applied in the same manner for O&M and Capital expenditures?

i) Method to Determine I-Factor

From the evidence presented it is clear there is no perfect way to determine the I-Factor. Therefore, the best that can be expected is to derive a proxy that best estimates the impact of inflation on the Companies for the full PBR period.

The problem with the forecast approach proposed by Fortis is that there will almost always be a variance between forecast and actual. Fortis has not disputed this but has argued that its actual costs are very much influenced by forecast as they often make binding commitments in advance of a given year and these take into account forecasted inflation. The Commission Panel accepts that this may be the case but it is not unique to Fortis as actual inflation measures reflect this spending behaviour on a broader basis. BCPSO makes a similar point as it observes that "actual inflation differs from forecast inflation and therefore actual increases are not driven by forecasts." In the view of the Panel, a significant problem with Fortis' proposed reliance on forecast rates of inflation lies in the fact that any variances which do occur are compounded each year. This may not be too serious where there is some assurance that over time these forecast errors will balance out. However, this is not the case. Instead, it is reasonable to assume that over the PBR period future forecasts may be significantly skewed either up or down relative to actuals and, as stated by BCPSO, wins or losses may have little to do with gains or losses in efficiency. **Considering the potential for a significant impact on the I-X formula resulting from this, the Commission Panel denies Fortis' proposal to rely on forecast data in the determination of the I-Factor.**

The BCPSO approach provides the most accurate measure but suffers from the fact that an actual number is not available until the year has been completed. Both Fortis and its ratepayers require a

higher level of certainty as the year progresses and therefore the Panel does not support this approach.

While the approach, proposed by CEC, to rely on the previous year's actual index figures is backward looking and introduces lag, the Commission Panel finds this approach offers some significant advantages. It is based on actual numbers rather than a series of forecasts, none of which are trued up. This approach will ensure that over time the cumulative effect of the I-Factor will be close to actual index numbers. Given the importance of the I-factor on the I-X formula and its impact on future O&M and Capital forecasts over time, the use of actual numbers is of critical importance. While not forward looking, a reliance on the previous year's actual numbers will eliminate the impact of compounded errors that exists in the Fortis proposal. Moreover, the index numbers are available early enough in the year so as to give Fortis and its customers a level of certainty. **Given these advantages, the Commission Panel determines that the I-Factor used in the formula is the actual index results of the previous year.** The Panel notes that this methodology has been employed by the AUC in its PBR.

ii) I-Factor Indexes

The Commission Panel has reviewed the evidence and determines that the CPI-BC as calculated by Statistics Canada and BC-AWE indexes are most appropriate for use in this PBR. For non-labour expenses, the Panel notes that CPI indexes such as those proposed by Fortis (where an average of six BC-CPI forecasts were used in this proposal) are more commonly relied upon and indeed were approved by the Commission in past PBRs. Moreover, CEC has not presented sufficient evidence to support a move to the GDP-IPI and the Panel is not persuaded that a move away from the more commonly relied upon CPI based indexes is warranted. We do, however, accept that there is a distinction between labour and non-labour costs that is not satisfactorily captured in CPI indexes. Therefore, the Panel accepts the use of the BC-AWE index to capture labour costs and notes that its use seems to be supported by Dr. Lowry.

A matter causing considerable concern among Interveners is whether a 55 percent weighting to labour is appropriate. This issue is raised by CEC, which recommends a lower labour component.

The Commission Panel accepts the explanation of Fortis that FEI's O&M labour costs shifted in 2012 due to the insourcing of the customer care function, which resulted in a 55 percent labour weighting going forward. The Panel also notes that O&M labour costs for FBC have ranged from 54 percent to 58 percent since 2008, which is close to Fortis' proposed 55 percent labour component. **The Commission Panel approves a 55 percent labour weighting for use in the O&M formula for FEI and FBC.**

When applied to Capital Expenditures the matter is less clear. This is because, as Fortis points out, there is contractor labour in the non-labour line item. When included in the calculation, the inclusion of contractor labour brings the capital labour percentage up to 64 percent from 24 percent, which is higher than the proposed 55 percent for FEI. For FBC, the ratio of labour costs embedded in its capital expenditures has consistently been at 65 percent or higher. **The Commission Panel determines that the 55 percent to 45 percent labour to non-labour ratio for use in the capital formula for FBC and FEI is reasonable and appropriate.**

The Commission Panel has also considered Dr. Lowry's evidence in support of relying upon industry specific indexes for Capital expenditures as construction costs are not necessarily rising in the utility sector. While this may be the case, the Panel considers that there is insufficient evidence to suggest that capital costs for Fortis' sustainment and other projects are captured by Dr. Lowry's proposed indexes. Hence, a reliance on construction cost based indexes may not be a true reflection of actual costs and the Commission Panel is not persuaded a move to these indexes is warranted at this time.

2.1.5 Setting the X-Factor and Stretch Factor

2.1.5.1 Introduction

Fortis states there are two different approaches that can be used to set the X-Factor, a Pure Total Factor Productivity (TFP) approach and a Hybrid Judgement-based approach. Under the pure TFP approach, the X-Factor is derived from rigorous mathematical models that calculate the growth of total factor productivity. In this approach, the X-Factor is ordinarily defined as the measured

industry TFP growth plus an adjustment for any difference between the inflation index used in the PBR index formula and the rate of input price inflation for the regulated sector. (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 45–46)

Fortis describes the following elements as influencing the measured TFP growth:

1. *TFP growth estimator methodology.* Typically either an econometric modelling or an indexed based approach.
2. *The sample of companies.* As broad a sample as possible. Since it is impossible to ensure the firms in the study are “exactly compatible” it is important to consider the results of the analysis in the context of the specific utility in question and its proposed PBR plan.
3. *The measurement period.* In general, the most recent data should be used. The length of study periods from other North American jurisdictions is between five and 20 years.
4. *Choice of output measure.* Ideally a comprehensive set of cost drivers should be used.
5. *Choice of Input Measures.* Input measures should represent the operating and capital costs associated with the utility. Inclusion or exclusion of particular cost items may add to the bias of TFP estimates.

Fortis also states that “[i]n practice, the X-Factor values estimated through the pure TFP approaches are often adjusted to reflect circumstances of a specific company and by a judgement-based stretch factor.” Although Fortis previously asserted that in the pure TFP approach, the X-Factor is derived from ‘rigorous mathematical models,’ it concludes that the result of a TFP growth study is “thus dependent on expert judgement in a number of areas.” (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 45–46)

Under the hybrid judgement approach, “the mathematical derivations of the X-Factor, such as TFP studies, are still used as guidance for the determination of X; however, practical matters such as the actual effects of X on the company’s bottom line and expected business conditions during the PBR term are also considered to determine a final measure.” Fortis cites research that shows that the parameters that affect a regulated company’s costs, revenues and risks should be considered and asserts that these parameters include items such as the PBR term, cost items subject to flow-through in customers’ rates, the implementation of other sharing models such as earnings sharing

mechanisms and the use of historical or expected performance as a basis for X-Factor estimation.
(FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 50–51)

Both Fortis and B&V utilize the hybrid judgement approach. B&V's studies resulted in TFP trends of approximately -4.0 percent to -5.0 percent, yet it recommends an X-Factor of 0.0 percent. B&V states that "[c]are must be taken in using the results of any TFP study values because the underlying assumptions of the study may not match the implementation of a proposed plan. The TFP calculated in this study includes an ex-post measure of capital that may differ from the capital treatment that separates a portion of capital such as CPCNs for treatment outside of the plan."
(Fortis Exhibit B-1-1, Appendix D2, p. 1)

According to Dr. Overcast "even if you come up with a TFP number, there are some things that you would have to use your judgment on to reflect how that might impact the final X-Factor that you are going to recommend. This judgement, is required because there is no way of 'separating out' CPCN and 'all of the other pass-through costs', from the total cost of any utility in the study" (T3:466). However, B&V provides no specific analysis of its adjustments to the TFP factor. B&V's recommended X-Factor is based on "several features of the overall plan that we believe reduce the negative TFP closer to zero. The 0% X-Factor would include a stretch factor as well"
(FEI Exhibit B-11, BCUC 1.44.1).

Fortis does not accept the recommendations of B&V, and instead applies its own hybrid judgement approach to propose an X-Factor of 0.5% for each utility, stating that this "is well above the range specified in the B&V TFP report." According to Fortis, the reason it proposes to adopt a more challenging X-Factor is to account for Fortis' specific circumstances and the overall design of the PBR plan. In particular, Fortis' proposed PBR plan excludes large capital projects approved as CPCNs, and because the B&V studies cannot separate categories of spending "educated judgement is required to adjust the TFP value for the companies in the study." (FEI Exhibit B-1, pp. 52–53; FBC Exhibit B-1, pp. 48–49).

PEG provides the following formulaic description of its proposed X-Factor:

$$X = MFP^N + Stretch$$

stating that MFP^N is a multifactor productivity index that uses the number of customers to measure output. PEG explains that the term stretch reflects an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. PEG adds that “[t]his depends in part on the company's operating efficiency at the start of the PBR plan. It also depends on how the performance incentives generated by the PBR plan compare to those in force for sampled utilities during the index sample period.” (FEI Exhibit C1-9, pp. 9, 70)

PEG describes the measure of productivity as:

$$Productivity = \frac{Outputs}{Inputs}$$

and further defines the multifactor productivity index as the change, or trend, in productivity:

$$trend\ Productivity = trend\ Outputs - trend\ Inputs.$$

(FEI Exhibit C1-9, pp. 9, 70)

As can be seen above, while PEG uses the term multifactor productivity (MFP) growth when assessing industry productivity growth, B&V uses the term TFP growth. PEG suggests that MFP growth is the correct term, stating that indexes are sometimes called TFP indexes but are better described as MFP indexes since multiple input categories are considered but some inputs (*e.g.* purchased power) are usually excluded. (FBC Exhibit C6-9 p. 57; FEI Exhibit C1-9, p. 57)

Dr. Lowry agreed that the terms MFP and total factor productivity (TFP) are used interchangeably, but commented that “[t]he reason that I prefer the term Multi-Factor Productivity is when one [does] these studies there are — almost always some utility costs that are excluded from the calculations. For example, even in the Black & Veatch work they excluded the purchase power costs of the utility.” (T7:1347)

PEG does not address the issue of judgement based adjustments to the TFP trend results. However, with regard to the exclusion of pass-through costs, it states “Suppose, for example, that expenses for the procurement of energy are not addressed by the indexing mechanism of the PBR plan. These costs should then be excluded from the definition of cost used in the index research. Similarly, the exclusion of a sizable share of routine capex from the indexing mechanism may make it appropriate to exclude some plant additions from the MFP research.” (Exhibit C1-9, p. 16)

Commission Discussion

In these Proceedings, the terms TFP and MFP have been used interchangeably. However, we note that in the strictest sense neither study dealt with all inputs so they are both reporting MFP trends. Nevertheless, we will use the terms interchangeably, but if context requires, we will differentiate between the two.

Further, after reviewing the evidence and submissions of parties, the Panel notes differing usage of the terms TFP/MFP and TFP/MFP *change* or *trend*. The four studies (one for gas utilities and one for electric utilities from B&V and from PEG) are designed to measure the *change* or *trend* in TFP/MFP, although the study results have been frequently referred to, by many parties, as TFP/MFP. The Panel will use the term *trend* in TFP/MFP when referring to study results. However, quotations from parties may not always contain consistent terminology.

B&V states that it utilizes the hybrid judgement approach, while PEG appears to use the pure approach. In both cases, the X-Factor recommendations are based on TFP/MFP trend studies. Fortis applies further judgement to arrive at its proposed 0.5 percent. Fortis describes the pure TFP approach as being derived from “rigorous mathematical models that calculate the growth of total factor productivity.” However, a considerable amount of judgement was involved in both studies regarding assumptions such as study length, input and output criteria.

The essential difference between B&V and PEG’s approaches is that B&V applies a single adjustment to its resulting TFP trend to account for both a stretch factor and the fact that a

number of flow-through costs are proposed in Fortis' PBR plans. In contrast, PEG explicitly excludes those flow-through costs from its study inputs. Further, PEG makes explicit its assumptions concerning the stretch factor. This eliminates any need for a judgement based adjustment to the MFP trend result.

In this Decision, the Panel will examine further the underlying assumptions applied by each of the experts, in addition to the judgement-based factors applied by Fortis that underlie its X-Factor recommendations. The Panel will take the following approach:

1. Establish a measure of the MFP/TFP trend upon which to base the X Factor.

There was considerable disagreement between the two experts concerning TFP/MFP trend study methodology. The Panel notes the submission of CEC that "the Commission has a serious problem with the evidence. The differences of opinion are not straight forward and understandable but are tied into esoteric economic theory and debates about methodology and assumptions, for which only PhD's seem to have perfunctory conclusions" and that "one of the most serious questions for the Commission to resolve is whether or not it is really suitable to impose this morass of complicated debate into the rate making process." (CEC PBR Final Argument, p. 57) We find CEC's comments curious, given the fact that it is referring, at least in part, to its own witness.

To this, Fortis replies that "The Commission is capable of weighing the expert evidence and coming to a considered decision, and should do so". (Fortis PBR Reply, p. 64). The Panel agrees with Fortis. Accordingly, in establishing the measure of TFP growth, we will examine the report submitted by B&V as part of Fortis' Applications, in addition to the report submitted by PEG for CEC.

The Panel agrees with Fortis that the result of a TFP growth study is dependent on expert judgement. However, in this proceeding, because there is considerable disagreement between the two experts in many of the study areas, where this occurs, the Commission Panel will assess the differing opinions and we will rely on our own judgement.

2. Apply any adjustments to the TFP that may be required before applying a stretch factor. Fortis states that an adjustment to account for inflation may be required. In addition, the Panel will consider any changes that arise from criticisms made by the parties that we have accepted.
3. Consider, to the extent the Panel finds appropriate, the TFP findings made by the AUC and the OEB as described in the Jurisdictional Benchmarking Report submitted by B&V.
4. Apply a stretch factor. As part of its determination of a stretch factor, the Panel will consider available evidence from the previous PBR period and the X-Factor that was applied

during that period. We agree with Fortis that a stretch factor is judgement based and will use our judgement to determine one that is appropriate.

5. Consider any other parameters that may be appropriate in the determination of the X-Factor. This may include consideration of the elements of Fortis' proposed PBR Plan along with any other specific circumstances of Fortis. This also includes X-Factor evidence from other jurisdictions. Here, the Panel will apply its judgement as to what extent this evidence is relevant to the determination of the X-Factor in this Proceeding.

2.1.5.2 The B&V Studies

2.1.5.2.1 Overview

The B&V TFP trend studies (one for gas utilities and one for electric utilities) were prepared for Fortis. The gas utility database consists of 95 utilities operating in 30 states in the United States (US) for the period 2007 through 2011, which, according to B&V, is the latest available five-year period for the data. The utilities' customer bases range from 86 for Brainard Gas in Ohio to 5,549,399 for the Southern California Gas Company. The sample companies have varied operating histories and include some that have been in existence for over 150 years and others that have been in existence for less than 20 years. There is also a mix of utilities that require transmission mains and those that do not. Pacific Gas and Electric Company has 5,744 miles of transmission main while a number of utilities have none. (FEI Exhibit B-1-1, Appendix D2, p. 2)

The electric utility database consists of 72 electric utilities operating in the US for the period 2007 through 2011, which, according to B&V, is the latest available five-year period for the data. The utilities' customer bases range from 28,372 for Fitchburg Gas & Electric Light Company to 5,278,738 for Pacific Gas & Electric Company. The companies operate in different regulatory environments including bundled and unbundled environments.¹ (FBC Exhibit B-1-1, Appendix D2, p. 2)

¹ In a bundled environment, commodity costs and delivery costs are combined. In an unbundled environment, they are separated.

B&V states that its methodology is based on the use of a production function, which “underlies the estimate of TFP because each level of output corresponds to the different set of inputs required to produce that output.” It states that the “production function defines the relationship between the dependent variable output and the independent variables of capital and labour, which make up the factors of production.” (FEI&FBC, Exhibit B-1-1, Appendix D2, pp. 2, 10)

To calculate inputs, B&V measures the ex-post cost of capital, including return, depreciation and taxes, using Operating Revenue excluding gas costs and all other operating and maintenance expenses. It states that the calculation of this cost is based “on a method that the Federal Energy Regulatory Commission (FERC) refers to as the *Kahn Method*.” The measure of all other costs is “a direct composite measure as reported in the financial reports of each company.” (Fortis Exhibit B-1-1, Appendix D2, pp. 2, 10)

Dr. Overcast has not previously conducted a TFP trend study, although he testified that he had contracted Dr. Lowry to provide such a study (T2:289–290). Fortis states that “Dr. Overcast used his understanding of utility business economics and operations to design a reasonable TFP methodology that addressed shortcomings with applying the traditional TFP model to regulated gas and electric utility industries that do not fit the academic paradigm” (Fortis PBR Reply, p. 69).

B&V’s studies are criticised by PEG on a number of grounds. In particular, Dr. Lowry states that the Kahn method is designed to calibrate the X-Factor given a specific inflation measure and not to estimate the MFP trend. The principle areas of criticism are:

1. Improper approach to Output Measures;
2. Improper approach to Input Measures;
3. Use of arithmetic vs logarithmic growth rates; and
4. Study time period.

(FEI Exhibit C1-9, p. 73)

In many cases, PEG has calculated corrections to B&V’s reported TFP trends, to account for these purported errors. However, PEG states that it does not believe that the corrected results are of sufficient quality to serve as the basis for X-Factor calibration. “For example, we are still concerned that the sample period is too short and that costs are included in the study that should be excluded.” (FEI Exhibit C1-9, p. 62)

Fortis submits that “[t]he ‘corrections’, when examined closely, are revealed to be changes in Dr. Overcast’s assumptions to match Dr. Lowry’s own assumptions.” It further submits that “‘corrections’ are meaningless when Dr. Lowry’s assumptions do not approximate reality.” (Fortis PBR Reply, p. 74)

The B&V study results are shown in Table 2.1:

Table 2.1 B&V TFP Trend Results

	Gas Utilities	Electric Utilities
Average TFP Trend	-4.1%	-4.9%
Range	-3.2% to -4.9%	-3.9% to -5.5%

(Source: Fortis PBR Final Argument, p. 74)

B&V states that the TFP trend results derived from the studies “are theoretically sound and produce results consistent with the logical foundations of TFP analysis and the operating realities of electric [and gas] utilities.” In its view, the results are reasonable as the foundation of an electric TFP value determination taking into account the utility specific elements of the plan. (Fortis Exhibit B-1-1, Appendix D2, p. 11)

As previously discussed, Fortis proposes an X-Factor substantially higher than B&V’s recommended X-Factor. Fortis acknowledges that the proposed X-Factor is “the one area where B&V and [Fortis] part company.” B&V states that based on its review of the factors outside the PBR such as CPCN capital and other provisions, it “felt that even zero is a stretch”. B&V regards this additional stretch

factor as being more aggressive than is warranted. (FEI Exhibit B-11, BCUC 1.44.13; FBC Exhibit B-1, pp. 43, 48, 49, 53)

Commission Discussion

Of particular concern to the Commission Panel is Fortis' adoption of an X-Factor that B&V feels is "more aggressive than warranted." This suggests to the Panel that the studies' TFP trend results are too low to accurately reflect actual utility industry productivity trends. Accordingly, the Panel will examine the assumptions underlying the B&V TFP trend studies. The Panel will consider further Fortis' hybrid judgement approach to setting the X-Factor in Section 2.2.3.5 of this Decision.

PEG makes a number of comments and criticisms concerning specific assumptions underlying B&V's studies and proposes corrections to the results. These corrections, comments and criticisms also suggest that the B&V Study results are too low. To the extent that these criticisms are valid, this is further indication that B&V's results may be understated.

With regard to PEG's suggested corrections, the Panel acknowledges Fortis' argument that corrections that do not reflect reality are meaningless. However, if a correction is required to ensure that the study results do mirror reality, then those corrections are indeed meaningful. Accordingly, in the following sections of this decision, the Panel will further examine the assumptions underlying B&V's study, including PEG's critique of those assumptions and its proposed corrections.

2.1.5.2.2 Output Measures

For each of its studies, B&V proposes output measures that are a composite of the number of customers and capacity. These output measures are shown in Table 2.2.

Table 2.2 B&V Study Output Measures

Electric	Gas
Composite Output — Weighted by Electric Customers and Substation Capacity 60%/40%	Composite Output — Density-Weighted Number of Customers and Capacity

For the electric study, B&V states that it calculated its output measure (AH²) using the following formula:

$$AH = (AG*0.6)+(AA*0.4)$$

where AG = Customers Adjusted for Density and AA = Substation Capacity in MVA. (FBC Exhibit B-1-1, Appendix D2, Schedule 2 LDC Electric Utility Database)

For the gas study, the formula for the output measure (AB³) is:

$$AB = (AA*T)+[W*(1-T)]$$

where AA = Customers/Density Index; W = Total Capacity; and T = Distribution Customer Factor (Distribution Main 2" or less/Distribution Miles). (FEI Exhibit B-1-1, Appendix D2, Schedule 2 LDC Gas Database).

In both cases, B&V calculates the output measure for each year using the above formulas and then calculates the trend in output, or “% Output Change by Year”⁴ (FEI&FBC, Exhibit B-1-1, Appendix D2, Schedule 2 LDC Gas Database & Electric Utility Database)

² AH is the column heading for the output measure in FBC Exhibit B-1-1, Appendix D2, Schedule 2: Electric Utility Data Base.

³ AB is the column heading for the output measure in FEI Exhibit B-1-1, Appendix D2, Schedule 2: Gas Utility Data Base.

PEG is critical of this approach, stating that:

“[i]nstead of a proper output trend index, B&V calculated an output *level* index and then calculated its growth rate. In this case, the trend in the capacity index improperly dominated the trend in the number of customers served because of a different numeraire. One indication of the problem is that the estimated electric productivity trend would likely depend on whether substation capacity was measured in kVA or MV.” (FEI Exhibit C1-9, p. 60)

B&V did not comment on this issue of the calculation of the output trend.

Commission Determination

The Panel finds that the method for calculating the growth rate of an output level index is not an appropriate approach. Accordingly, the output trend calculated by B&V cannot be relied upon.

In making this determination, the Panel considered the following example of Allette Inc. taken from B&V’s Electric Utility Database. Table 2.3 shows B&V’s calculation of the output measure for the years 2008 and 2009 which relies on the capacity measure in MVA.

Table 2.3 B&V Output Measure for Allette Inc. for 2008 and 2009

Year	Density Weighted Number of Customers (AG)	Substation Capacity (MVA) (AA)	B&V Output Measure (AH)
2008	138,818	9,853	61,439
2009	146,486	9,593	64,350

(Source: FBC Exhibit B-1-1, Appendix D2, Schedule 2 Electric Utility Database)

The trend in B&V’s output measure is 1.047 (64,350/61,439). In Table 2.4, the Panel recalculated B&V’s output measure using capacity measured in KVA.

⁴ For the electricity study, % Change in Output 40/60 (column AI) = %Δ in AH. For the gas study, % Output Change by Year (column AC) = %Δ in AB

Table 2.4 Allette Inc. Output Measure based on Capacity Measured in KVA

Year	Density Weighted Number of Customers (AG)	Substation Capacity (KVA)	Output Measure Using KVA
2008	138,818	9,853,000	5,967,327
2009	146,486	9,593,000	5,869,922

(Output measure calculated by the Panel)

The trend in B&V's output measure is now 0.984 (5,869,922/5,967,327). This illustrates that the trend in B&V's output measure is dependent on the units used for capacity.

Table 2.5 Weighted Output Trend based on Trend in each Output

Year	Customers		Substation Capacity		% Change in Customers	% Change in Capacity	Output Trend
	2008	2009	2008	2009			
Using MVA	138,818	146,486	9,853	9,593	1.055	0.974	1.006
Using KVA	138,818	146,486	9,853,000	9,593,000	1.055	0.974	1.006

(% change in customers, % change in Capacity and Output Trend as calculated by the Panel)

Table 2.5 shows the output trend obtained by calculating the trend in each output measure and then combining those trends with a 60/40 weighting as suggested by PEG. The output trend is the same for both cases and thereby is independent of the units used.

The Panel finds B&V's approach of calculating the growth in the output measures is not an appropriate approach to the calculation of the output trend. Although capacity and number of customers are both outputs, they have different units and shouldn't be combined. **Accordingly, the Panel finds that B&V's method of calculating the output trend cannot be relied upon.**

2.1.5.2.3 Input Measures

The inputs to the B&V study consist of a capital cost component and a composite cost component that reflects labour, materials, services and rents. B&V states that both inputs are measured on an ex-post basis using actual financial data for each electric utility and because its input measure is cost based, it does not require an index to convert it to a quantitative base. (FEI Exhibit B-1-1, Appendix D1, p. 10)

However, B&V's methodology does require a cost weighting between the capital and composite cost components. For this purpose, B&V uses the following formula to determine the input cost (Y)⁵, on which the year-to-year change in input costs is based:

$$Y = D * (1-J) + (G*J)$$

where D is net plant for gas utilities and net plant less production expenses for electric utilities; G is O&M minus gas costs for gas utilities and O&M minus O&M production expenses for electric utilities; and J is the "Operating Ratio", defined as the ratio of G to operating revenue less gas cost for gas utilities and operating revenue less production expense for electric utilities. (Fortis, Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base)

B&V calculates the input trend in the same way it calculates the output trend. It uses the above formula to calculate an input cost level for each utility for each year. It then calculates the trend in the input cost level (which it labels "%Δ in Y" in its study). (Fortis, Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base)

CEC explored B&V's methodology, using the example of Alabama Gas from the gas study. The data is reproduced in Table 2.6 for 2007 and 2008.

⁵ B&V refer to this as Cost Change. To avoid confusion with the input cost trend, the Panel will refer to this as input cost level.

Table 2.6 Alabama Gas Example

	2007	2008	% Cost Change (2008/2007)
Net Plant (D in the formula above) (\$,000)	\$660,339	\$686,636	3.94%
Operating revenue less gas cost for gas (G in the formula above) (\$,000)	\$140,186	\$139,512	-0.48%
Operating Ratio (J in the formula above)	0.46	0.45	
Input Cost (\$,000) $Y = D*(1-J)+(G*J)$	\$498,392	\$517,627	
% Cost Change by Year %Δ in Y			3.86%

(Source: Fortis Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base;
FEI Exhibit B-8, CEC 1.81.22)

For this example, the TFP input cost growth, as calculated by B&V is 3.86 percent. However, CEC point out that net plant grows by 3.94 percent ($686,366 / 660,339 - 1$) and O&M by -0.48 percent ($139,512 / 140,186 - 1$). Further, the operating ratio suggests that the 2008 cost weights are 45 percent O&M (55 percent capital).

Accordingly, CEC asked Fortis why it is reasonable that the growth in the combined measure is nearly identical to the growth in net plant and not closer to 1.95 percent, which would be obtained by taking a weighted average of the growth rates. (FEI Exhibit B-8, CEC 1.81.22)

Fortis responds that:

“[t]he calculation of the input change is not an index. The change is based on the quantity of capital as measured by net plant times the price of capital as reflected in the proxy for capital cost applied to net plant. Similarly for O&M the quantity is measured by the dollars multiplied by the composite proxy price as measured by the percent that O&M represents of revenue. It is easy to see that capital has a larger impact on productivity than does O&M (\$26 million compared to \$700,000). Simply put, the small savings in O&M translates into a cost impact of less than one million dollars while capital costs increase over six times as much. By using the weighted

average of the two percentage changes, the estimate of TFP would not reflect the relative importance of each component of productivity.” (FEI Exhibit B-8, CEC 1.81.22)

PEG is critical of this approach, stating that “the growth of a proper cost trend index is a cost-share weighted average of the *growth* in the component costs. This finesses the problem of cost sub-indexes with different numeraires that make them impossible to meaningfully add up. B&V instead compute cost *level* indexes and then calculate the growth rates in these indexes.” PEG points out that in B&V’s approach, the trend in net plant value improperly dominates these calculations because net plant value is not a measure of annual cost like the O&M expenses that B&V uses. (FEI Exhibit C1-9, p. 60)

B&V states that there is no problem “with using cost level indexes with numeraries that differ from utility to utility.” It further states that:

“[e]ssentially, this is a concern only because the index method produces dimensionless measures of inputs and outputs so firms can be collected in the index. Since the B&V method treats each utility as its own entity because each utility has its own production technology set and its own input mix for all inputs this criticism is incorrect. This criticism would be correct for an index type measure because indexes use a dimensionless number that is calculated as the cost divided by a price index and is not really an actual measure of the input which has physical dimension such as miles of pipe or electric circuits.” (Fortis Exhibit B-45, p.69)

PEG calculates that using proper output and cost trend indexes and using B&V’s sub-indexes raises the MFP estimate by the amount of 0.65 percent for gas utilities and 0.27 percent for electric utilities (FEI Exhibit C1-9, pp. 62, 65).

Commission Determination

The Panel has previously found that it is not appropriate to calculate the output trend using an output level index. Instead, a correct approach is to calculate the trend in each output and then combining those trends using an appropriate weighting. The same principle applies to the calculation of the input trend.

B&V's input measure combines operating costs, which are an annual measure, with net plant which is a point in time measure. Thus, B&V combines \$ (net plant) with \$ per year (operating costs). This is similar to combining different output measures as previously discussed. CEC calculates an input trend of 1.95 percent, as opposed to the growth rate of 3.86 percent of the input level index, when combining the two inputs with the weighting suggested by B&V. The Panel has no reason to dispute this assertion and notes that an overstated input trend will, all else equal, tend to understate the TFP trend. **Accordingly, the Panel finds that B&V's method of calculating the input trend cannot be relied upon.**

2.1.5.2.4 Inflation in Input Costs

PEG is critical of the tendency of B&V's cost index to overstate costs, stating that using a cost trend unadjusted for inflation materially biases the productivity trend (Exhibit C1-9, p. 58).

In its view, when the Kahn estimate of X is used to estimate the MFP trend and GDPPI is used as the inflation differential, the Kahn estimate is biased by the MFP trend of the economy less the input price differential. PEG states that "[a] Kahn method using US data might nonetheless be used to calibrate the X-Factor of a Canadian PBR plan were the input price differentials and the MFP trends similar in the United States and Canada. However, there is no reason to believe that they are." (Exhibit C1-9, p. 73)

PEG asserts that the input price inflation of energy distributors averaged more than 300 basis points annually in the United States during the years of the study, which materially biases B&V's productivity trend estimate. It considers this a very large error, which "by itself goes a long ways towards explaining the unusually negative trends produced by B&V." PEG calculates an upward adjustment of 3.22 percent to the TFP of gas utilities and 3.35 percent to the TFP of electric utilities to account for this (FEI Exhibit C1-9, pp. 58–59).

B&V argues that, with respect to capital, there is no material bias in its estimate of TFP because it uses net plant to measure capital inputs which is a conservative factor compared to gross plant adjusted for inflation. Regarding the quantum of PEG's proposed adjustment, B&V believes that

“given the length of the period any impact or bias would be relatively minor and certainly not the three percent mentioned in the PEG report simply because the net plant measure is far below the gross plant reduced by three percent per year.” (Exhibit B-45, p. 68)

Commission Determination

The Commission Panel agrees with PEG concerning the tendency for B&V’s cost based input to understate TFP in the event that inflation in the study dataset is greater than the inflation faced by Fortis. B&V doesn’t disagree. B&V also doesn’t disagree when PEG states that “input price inflation of energy distributors averaged more than 300 basis points annually in the United States.” B&V does argue that, with respect to capital, the effect is not material, because of the way it measures capital inputs. The Panel disagrees. With regard to B&V’s argument that the input is less because net plant is below gross plant, the Panel notes that a measurement of net plant value is a cost based measurement that reflects the cost of plant additions.

Accordingly, the Panel finds that B&V’s cost based input methodology understates the TFP trend.

2.1.5.2.5 Study Period

CEC states that:

“[i]n choosing a sample period for an indexing study used in X-Factor calibration, it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2011. It is also desirable for the sample period to reflect the long-run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest technology trend. Moreover, the accuracy of the measured capital quantity trend is enhanced by having a start date for the indexing period that is several years after the first year that good capital cost data are available. It should also be noted that 2011 was a year of recovery in the United States from the severe recession of 2008- 09.” (FEI Exhibit C1-9, pp. 24, 35)

PEG also states that:

“productivity research for X-Factor calibration commonly focuses on discerning the current *long-run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in outputs and/or inputs. The long run

productivity trend is faster than the trend during a short-lived surge in input growth or lull in output growth but slower than the trend during a short-lived lull in input growth or surge in output growth.” (FEI Exhibit C1-9, p. 15)

In B&V’s view, a shorter period is representative of the types of efficiency gains that might be reasonably expected during a five year plan. B&V submits that PEG’s

“concern about the recession’s impact is totally misplaced simply because utility management has the responsibility to manage earnings to market expectations regardless of the macroeconomic circumstances. It would be reasonable to assume that if there was any impact of the recession and inflation during this period, utilities would have attempted to seize every efficiency opportunity that would be accretive to earnings.” (Exhibit B-45, Rebuttal Evidence to CEC, p. 68)

B&V states that “the shorter period also avoids a number of practical issues such as the impact of restructuring costs that are not properly included in a TFP study since the costs are not included in rates” (Exhibit B-45, Rebuttal Evidence to CEC, p. 69).

B&V also states that there are a number of long-term trends in new technologies that are fully reflected in the TFP trends in the analysis. These include such trends as “directional drilling, live main insertions, joint trenching and so forth all of which represent mature technologies that are incorporated in the TFP results.” However, in its view, using a longer period for an indexing study cannot produce a reasonable expected TFP for a short period simply because the longer period is biased by technology and scale impacts that cannot be replicated in the near term. (Fortis Exhibit B2-11, CEC 3.61.1; Fortis Exhibit B2-10, BCUC 3.23.19.2)

B&V also states that

“[i]t is also important to note that because the customer and capacity measures of output do not suffer from volatility caused by weather or by the business cycle directly, there is much less need for using long historical periods to estimate TFP for use with a much shorter regulatory control period. Using a long period for estimating TFP may include changes in technology that cannot be replicated during the regulatory control period.” (FEI Exhibit B-1-1, Appendix D2, p. 10)

In PEG’s view, whether or not the output index is cost based and excludes volatile usage variables, the sample period matters when using Kahn’s method because an inflation differential is implicit in

the calculation and this can be volatile. PEG states that “[it] is notable that in 1993 Dr. Kahn used the longest sample period that available data permitted at the time.” (FEI Exhibit C1-9, CEC Evidence, p. 56)

Commission Determination

The Panel agrees with B&V that if there is evidence of an anomalous productivity trend during the study period that is not likely to continue beyond the study period, it may be appropriate to make an allowance. However, B&V has provided no such evidence of any such trend in the period of 1999 to 2011.

With regard to matching the study period to the PBR Plan length, the Panel agrees that a short-term study may be representative of the efficiencies in a five year PBR plan. However, in order for this to be the case, the five-year study period should be in a similar place in the economic cycle that the PBR period will be in in order for the study period to be representative of the PBR period. Since, by definition it is impossible to accurately predict the future, there is no way to ensure that one can pick the appropriate five-year study window to match the economic conditions that a utility will face in the next five years. **The Panel finds that a short study period is not appropriate.**

A long-term study period is superior to a short-term study period because a long term doesn’t accentuate any short-term trends. **Accordingly, the Panel finds that a study period should at least be long enough to smooth out any significant short-term economic trends.** In this regard, because the four-year period of the B&V study covered the most severe recession in almost 70 years, the results may be prone to a significant bias.

However, there is no direct evidence of what this bias is. Turning to the PEG studies, the Panel notes that in addition to the 1999-2011 study for gas utilities and the 2002–2011 study for electricity utilities, PEG also conducted studies using a subset of its data, from 2008–2011, which provide results for the same period as the B&V study. MFP trend results from PEG’s 2008–2011 studies are compared to PEG’s longer-term study results in Table 2.7.

Table 2.7 Comparative MFP Results for Different Study Periods

	1999–2011 gas; 2001–2011 electric	2008–2011
Gas Utilities	0.96%	-0.07%
Electric Utilities	0.93%	0.90%

(Source: Exhibit C1-9, pp. 24, 35)

Looking only at the difference between the results of the two study periods, the Panel considers this a directional indicator that the result of the shorter study period used by B&V tends to produce a TFP trend that is lower than the longer-term trend. **Accordingly, the Commission Panel finds that B&V’s TFP trend results may require significant adjustment to allow for the short study period B&V used, particularly in the case of the gas utility study.**

The Panel notes that this finding that a longer study period is more appropriate is consistent with the finding of the AUC that “using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation.” We note also that the two studies conducted by the OEB were eight and seven years. (Fortis Exhibit B-1-1, Appendix D8, p. 67; Fortis Exhibit B-1-1, Appendix D2, p. 14)

2.1.5.2.6 Use of Logarithmic Growth Rates vs Arithmetic Growth Rates

PEG submits that B&V calculates the average annual growth rates in its cost and output indexes by averaging their *arithmetic* growth rates. In its view, this is well known to be an inaccurate method and PEG considers it more accurate to take the average of logarithmic growth rates. Using B&V’s composite output measure, PEG calculates that this raises the average annual growth in the MFP estimate by 0.88 percent for the gas study and 0.27 percent for the electric study. (FEI Exhibit C1-9, p. 62)

B&V states that using logarithms in an academic setting would not create an issue whereas many of the participants in a rate case are not trained economists and may be uncomfortable in the

rigorous academic environment. It submits that it is important to communicate with all of the parties in a case and since there is no inherent need to use more complicated formulas, its approach seemed to be reasonable and has a basis in historic calculations of index values. It also states that there was no claim that the results were expected to be accurate to three or four decimal places. (Exhibit B-45, p. 69)

Commission Determination

The Commission Panel accepts PEG's evidence that using arithmetic growth rates is an inaccurate methodology noting that B&V does not dispute this. Further, there is no reason to dispute the quantum of the correction proposed by PEG.

We generally agree with the position of B&V regarding the need to communicate with all parties. However, this is not an issue of the third or fourth decimal place. **Given the materiality of this issue, the Panel finds that B&V's use of arithmetic growth rates results in a substantial understatement of the TFP trend.**

2.1.5.2.7 Summary of B&V Studies

Fortis submits that Dr. Overcast's methodology "is rooted in a practical understanding of how utilities operate. Dr. Overcast's methodology yielded results that make more intuitive sense given that the North American utility industry is characterized by mature utilities with significant capital requirements for system replacement." However, it "is not suggesting that Dr. Overcast's approach yields perfect results." (Fortis PBR Reply, p. 76)

Fortis also states that "[t]he Commission does not need to condemn the expertise or the work product of either Dr. Lowry or Dr. Overcast to determine this case". (Fortis PBR Reply, pp. 75–76)

CEC submits that the B&V productivity results are in fact theoretically unsound and produce results that are inconsistent with the logical foundations of TFP analysis, stating that "the failings of the B&V study be acknowledged and that the study be explicitly assigned no weight in the Commission's deliberations." (FEI Exhibit C1-9, CEC Evidence, p. 23)

CEC further submits that “[t]he B&V study has numerous flaws that reduce its relevance in this proceeding to the vanishing point” (Exhibit C1-9, CEC Evidence, p. 58). However, it also states that “the corrected results are consistent with its own estimate of *long* run productivity trends” (Exhibit C1-9, pp. 85–86).

Commission Determination

The Panel has a number of concerns about the B&V studies and is not persuaded that the TFP trend results reported by B&V can be used as a basis to establish an X-Factor.

Dr. Overcast employs a study methodology that is, by his own admission, non-standard. There is no evidence that this methodology has been accepted in any other proceeding. Further, Dr. Overcast has not previously conducted a TFP trend study.

The Panel previously found B&V’s use of output and input level indexes inappropriate and cannot be relied upon to generate meaningful input and output trends. We have also made determinations in the areas of input cost inflation, the use of arithmetic vs logarithmic measures and the study length. In all cases, we found flaws in the study methodology that tend to understate TFP trends.

Given the number of shortcomings in B&V’s methodology and the errors that arise from these shortcomings, the Panel does not accept B&V’s study results.

The Panel notes that there was also considerable argument concerning the following aspects of B&V’s input assumptions concerning the input measure:

1. The use of net plant vs. return on net plant; and
2. The omission of depreciation expense from the input measure.

Having not accepted the B&V’s study results, the Commission Panel will not consider these issues further.

2.1.5.3 The PEG Studies

2.1.5.3.1 Introduction

PEG’s gas distribution MFP trend study, prepared for CEC, is based on data for 64 utilities, including “most of the larger distributors in the United States.” PEG states that “[s]ome of the sampled distributors also provide gas transmission and/or storage services but all were involved more extensively in gas distribution.” (FEI Exhibit C1-9, p. 21)

For the electric utility study, PEG states that “[t]o be included in the study the data were required, additionally, to be of good quality and plausible. Data from 75 companies met these additional standards and were used in our indexing work” (FEI Exhibit C1-9, CEC Intervener Evidence, p. 31).

PEG describes the I-X formula as an Attrition Relief Mechanism (ARM), differentiating between a single ARM, where all spending, capital and O&M is driven by a single formula, and a double ARM, where capital spending is driven by a separate formula than the O&M spending formula. (Exhibit C1-9, pp. 3–5) PEG’s study results are shown in Table 2.8.

Table 2.8 MFP Trend Results for PEG Studies

Gas			Electric		
O&M	Capital	Single ARM	O&M	Capital	Single ARM
0.98%	2.15%	0.96%	1.51%	0.86%	0.93%

(Source: FEI Exhibit C1-22, BCUC 2.4.1; FBC Exhibit C6-21, BCUC 2.4.1. Based on X-Factor recommendations in the Exhibits indicated less the 0.2 included Stretch Factor)

B&V submits that the PEG studies rely on an academic paradigm or academic model and that “[i]n the academic model it is possible to assume away many of the intricacies of actual process. When

those assumptions stray as far away from actual facts as in the case of the PEG method the only alternative is to reject the results and give no weight to the estimates of TFP.” (Exhibit B-45, pp. 3, 33)

In B&V’s view, the academic paradigm cannot be used in a regulatory proceeding. However, B&V is unable to explain why the academic paradigm is prevalent in regulatory proceedings, stating that “[i]t is difficult to explain why the process of estimating TFP in a regulatory setting has not raised these issues in detail (at least in the United States and Canada) previously. In part, it may be that almost all of the work related to estimating TFP has been performed in the academic paradigm without a critical and detailed examination of the issues related to the economics of actual utility operations.” (Exhibit B-45, Rebuttal Evidence to CEC, p. 32)

In addition to criticizing PEG for its use of the academic model, B&V also criticizes PEG because it has not provided the “most up-to-date analysis of the academic paradigm,” citing the following elements that are not included in the PEG model:

1. The impact of sunk costs on the development of the appropriate TFP values for gas and electric utilities; and
2. Both billed and unbilled outputs in the measure of the output component of the TFP analysis. The principal unbilled output discussed in the literature is a measure of the capacity component of output.

(Exhibit B-45, pp. 20–21)

Commission Discussion

The Panel is not persuaded by Dr. Overcast’s argument to reject the academic paradigm and notes that he rejects only some elements while actually arguing for the inclusion of certain elements of the academic paradigm that Dr. Lowry had not included.

We do not consider it necessary to make a determination concerning which elements of the academic paradigm may or may not be theoretically valid. However, the Panel will consider cases where B&V provides evidence that a specific assumption underlying PEG’s study, either flowing

from the academic paradigm or any other source, is incorrect and it can show that it has a material impact on the results.

2.1.5.3.2 Output Measures

Table 2.9 shows the output measures used by PEG in its study.

Table 2.9 PEG Output Measures

Electric	Gas
number of customers served	number of customers served

Dr. Lowry states that:

“[t]he number of customers served is a good measure of the number of services, which is a legitimate measure of system capacity. The number of customers typically has the highest explanatory power of the scale variables considered in econometric models of distribution cost.... The number of customers served is correlated with peak delivery capacity because it is dominated by the trend in the number of residential and commercial customers. These customers typically have low load factors.” (Exhibit C12-4, p. 5)

Fortis submits that “[b]y choosing to use only one measure of output — net customer growth, Dr. Lowry has an incomplete specification of the output measure and ignores the substantial differences in customer mix that create different output mixes and input mixes to serve customers in different utilities.” (FEI Exhibit B-45, p. 4)

Fortis further submits that outputs will be understated (and TFP overstated), by definition, when Dr. Lowry has only accounted for one type of output produced by utilities (customers) and has ignored another (capacity) (Fortis PBR Reply, pp. 68–69).

However, Fortis proposes linking its O&M formula spending to only the number of customers. In that context, B&V believes it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula because “[t]he capacity component is not easily measured and would lack transparency if that measure were used. As a result, B&V believes it is appropriate to use

customers as a reasonable proxy for the capacity variable in the formula.” B&V also states that “there is no straightforward measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since extensions of the system to serve customers adds new capacity to the system.” (FEI Exhibit B-1, p. 57; FBC, Exhibit B-1, pp. 53, 56)

Commission Discussion

The Commission Panel is not persuaded that PEG’s output measure is incomplete or understates the output trend. There is no evidence that this is the case. Further, the Panel notes that, with the exception of FEI’s growth capital formula, which uses service line additions, the growth term proposed by Fortis for its PBR formulas uses only customer count. B&V fully endorses that approach, in spite of its position that capacity is a key determinant of utility costs and that it used capacity as an output measure in both of its studies.

2.1.5.3.3 Input Measures

Table 2.10 shows the inputs for the PEG studies.

Table 2.10 PEG Study Inputs

Electric		Gas	
Input Quantity	Input Price	Input Quantity	Input Price
A weighted average of the growth in quantity sub-indexes for labor, materials and services, power distribution plant, and general plant.	A weighted average of the growth in price sub-indexes for these same input groups.	The difference between the growth rates of applicable O&M expenses and a two-category O&M price trend index.	A weighted average of the growth rates in price sub-indexes for capital and O&M inputs. The weights were based on the shares of these input classes in each company's applicable gas distributor cost.

(Source: FEI Exhibit C1-9, pp. 23, 34)

B&V disputes the assumptions used to calculate the sub-indexes in the PEG Report. In its view, this is one of the shortcomings of the academic model. It states that the assumptions required to calculate the inputs are not valid because they rely on the ability to use a single factor (adjusted for regional differences) to convert historic book costs from nominal dollars to real dollars (the deflator) and then rely on a single price index (adjusted only for regional differences in the case of labour) to calculate a measure of inputs (the input quantity). It submits that if either the deflator or the input price is incorrect the results of the PEG method are meaningless and both are incorrect in the PEG analysis. (FBC Exhibit 45, p. 4)

PEG countered that its indexes are chain weighted, cost weighted indexes and it was only in the sub-indexes that apply to the individual categories that fixed weights are used. (T7:1397)

PEG states that it used input price indexes only to calculate the trends in the quantity sub indexes for major input categories such as capital and labour.

“Considerable care was taken in choosing the price subindexes. All of the price subindexes were specific to the utility industry and all but those for Material and Services (M&S) expenses reflect regional trends. Although the labor price index pertains to multiple utility industries (including, for example, water utilities), the capital and M&S price indexes for gas utilities are specific to that industry and the capital and M&S price indexes for electric utilities are specific to that industry. The labor price index is specific to salaries and wages because pensions and other benefits are excluded from the analysis.” (Exhibit C12-4, p. 4)

PEG further states that it:

“calculated the productivity growth trends of individual utilities and then took their average. The growth in the summary input quantity index for each utility was a cost-weighted average of the estimated growth in the quantity subindexes for that utility. Time-varying and utility-specific cost share weights were used in these calculations where practicable. For example, the summary input quantity index for power distribution has separate subindexes and company-specific cost shares for distribution capital, general capital, labor, and materials and services.” (Exhibit C12-4, p. 4)

B&V submits that, in contrast, its approach is much simpler.

“It does not require the creation of an index for all companies because it is not possible to create a meaningful index since companies are not comparable in terms of the technology used, the mix of inputs and the mix of outputs. The B&V approach assumes that each company is unique and that it is possible to estimate TFP for that unique mix of inputs and outputs by using only each utility as a separate entity and then find a measure of central tendency to estimate the industry TFP.” (Fortis Rebuttal Evidence, p. 4)

However, the B&V study methodology considered only price inputs and did not need to convert prices to units of input, so did not actually employ the direct method. PEG does not disagree with B&V, but states that its

“approach to input quantity measurement is more the rule than the exception in productivity research. Even though the input price indexes employed in such research are not a perfect match for the costs they deflate, productivity indexes are widely used in PBR and in macroeconomic research by government agencies such as Statistics Canada. One reason is that the average inflation in the prices of the true basket of goods and services will usually not differ markedly from the inflation in a basket that is more practical to calculate.” (Exhibit C12-4, p. 3)

PEG acknowledges that “[i]n the measurement of utility input trends the accuracy of the indirect approach is greater to the extent that the inflation indexes employed track trends in utility prices and use cost shares that evolve over time (so that the index is chain-weighted) and match those of the utility.” (Exhibit C12-4, p. 4)

Commission Determination

The Commission Panel is not persuaded that the use of an input cost index in the estimation of TFP trends “cannot produce a meaningful and logical measure of expected TFP for regulated monopolies” as claimed by B&V. We accept PEG’s explanation that no such assumptions are relied on. Further, utilities compete for inputs in an unregulated marketplace. They are faced with labour and material price inflation. In order to compute an input quantity index, either the actual inflation measure that applies to the company must be used, or assumptions about inflation must be made.

What is at issue is the relative accuracy of those two different approaches — the ‘direct’ method that utilizes costs faced by individual utilities as opposed to the index method that utilizes costs averaged over the study sample.

Our view is that both methods can provide meaningful results. However, we do acknowledge that the direct method, which is advocated by B&V, is conceptually more straight-forward than the index method employed by PEG. It does not rely on the study author’s ability to create indexes that are reflective of the actual prices and price inflation faced by the companies in the study and is accordingly, to the extent that the actual data is available, likely to be more accurate. However, B&V provides no evidence that such information is available and that employing the direct method using that data would be more accurate.

The Commission Panel questions whether it is practical to obtain input indexes that are specific to individual utilities. In this regard, Fortis proposes to use a fixed weight index that is not specific to the utility industry in its PBR formula as opposed to a measure of inflation that reflects its own specific circumstances.

The Panel does not agree with B&V that “it is not possible to create a meaningful index since companies are not comparable in terms of the technology used, the mix of inputs and the mix of outputs.” PEG acknowledges that its methodology will typically not match the cost shares of an individual utility. Instead, it purports to use them to calculate the average productivity trends of a large sample of utilities. In his view, inaccuracies in applications to individual utilities due to improper cost shares tend to average out. We have no reason to dispute this assertion and are not persuaded by B&V’s argument that “small errors in measurement across utilities add up to large errors in the measurement of TFP.” B&V has not provided any evidence that the differences will be material or that any systemic bias results from small errors of measurement.

The Panel finds PEG’s approach to using input cost indexes to calculate input quantities is acceptable. However, although PEG states that “considerable care was taken in choosing the price

sub-index,” further consideration of those sub-indexes is required. Accordingly, in the next section the Panel will consider the labour price index and in the following section, the construction index.

2.1.5.3.3.1 Input Labour Price Index

PEG states that for the electric study, the growth rate of the labour price index was calculated for most years as the growth rate of the national employment cost index (ECI) for the salaries and wages of the utility sector of the US economy plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole. The quantity sub-index for other O&M inputs was the ratio of the expenses for these inputs to a materials and services [M&S] price index using price sub-indexes for power distributor M&S inputs obtained from the Global Insight Power Planner service. (Exhibit C1-9, p. 74)

For the gas study, PEG states that “[t]he O&M input price indexes summarized trends in the prices of labor and M&S inputs. Price sub-indexes for the M&S inputs of US gas utilities were obtained from the Global Insight Power Planner service.” (Exhibit C1-9, CEC Evidence, p. 75)

Fortis submits that the index Dr. Lowry used to deflate labour costs reflects a mix of costs that are too high for the utilities in the sample or FortisBC, which results in an input quantity that is too low and a TFP trend that is too high. This causes the industry to appear more productive in its use of labour than it really is. (Fortis PBR Final Argument, pp. 109–110)

In the view of B&V, the reason PEG adopts this approach to measuring labour cost inputs

“lies directly in the use of the competitive model to develop the theory that underlies the academic paradigm and the absence of any consideration for the fundamental nature of regulated utilities. Since the labor input measure is not valid absent the assumptions that the technology and mix of labor employed are the same there can be no viable TFP estimate. This is not a problem for competitive industries because all firms use the same technologies and mix of labor types. The PEG reliance on the competitive model assumptions to estimate TFP cannot produce a meaningful and logical measure of expected TFP for regulated monopolies even if regulation over time may equate revenue to cost in the accounting sense.” (Exhibit B-45, Fortis Rebuttal Evidence to CEC, p. 12)

PEG replies that “no simplistic or idealized assumptions that might sometimes be invoked in simplified competitive market models used by academicians are required for the analysis.” (Exhibit C14-4, pp. 1, 3)

PEG also comments that “[t]he imperfections of off-the-shelf labor price indexes haven't prevented Fortis from proposing to use the AWE as an inflation measure in their RCIs. The AWE that Fortis proposes to use is a fixed-weight index and is not specific to the utility industry at all, much less to the energy distribution sector of the utility industry.” (Exhibit C14-4, pp. 3–4)

Commission Determination

The Commission Panel has previously found PEG’s use of cost indexes to be an appropriate way to calculate an input quantity. Therefore, the Panel considers that using a labour price index to convert a labour cost into a labour quantity is an appropriate way to establish labour input quantities, provided the price index used is appropriate.

We do not accept B&V’s criticism that a labour input is not valid because the assumption that all firms use the same labour mix is only valid in a competitive industry. There is sufficient similarity among distribution gas or electricity utilities to make such an assumption. **In the absence of specific information of the labour mix at each utility, the Panel finds an assumption of a labour mix to be reasonable.** We note that B&V had no need to make such an assumption as it only used cost inputs.

With regard to Fortis’ contention that the labour price index that PEG used reflects a mix of costs that are too high for the utilities in the sample, Fortis provides no evidence to persuade the Panel that this is the case. **The Panel finds that no adjustment to PEG’s study results is necessary to account for any potential bias introduced by its labour input index assumptions.**

2.1.5.3.3.2 Input Construction Index

The PEG study utilized the Handy Whitman fixed weight construction index to determine the input capital quantity trend. Fortis relied on confidential Exhibit B2-31 Gas Cost Utility Cost Trend Tables (Handy Whitman Indexes) to compare the Handy Whitman Indices for Steel and Plastic Main for the period 1998 to 2001. The index for steel main has a significant increase, while plastic pipe increased to a lesser degree. Thus, the increase in the cost index for steel main is roughly twice that for plastic main. (Exhibit B-45, p. 26)

However, Fortis states that in 1973, 92 percent of the mains installed were steel and 8 percent plastic, but that by 2011, the ratio had changed to 85 percent plastic and 15 percent steel (T7:1521). Given that the relative weighting of the sub-indices are based on 1973 values, Dr. Lowry agrees that using the total plant index assumes that a “fairly large” proportion of the total plant consists of steel mains (T7:1432–1521).

Fortis argues that “Dr. Lowry’s selection of a fixed-weight index with a distant base year is at odds with the views of Coelli et al who emphasize that indexes used in the context of productivity studies should be chain-weighted (not fixed) so that the weights in the ‘basket’ change to keep pace with developments over time” (Fortis PBR Final Argument, p. 29).

Fortis submits that a construction price index that treats utilities as if they still mostly install expensive steel pipe or copper conductor as had been the case 41 years ago will overstate the real price of inputs and overstate Dr. Lowry’s TFP. In its view, this issue alone resulted in Dr. Lowry’s calculated TFP being overstated by orders of magnitude. (Fortis PBR Reply, p. 68)

Elsewhere in its reply submission, Fortis states that “adjusting Dr. Lowry’s X-Factor for this bias alone would result in a significantly lower X-Factor.” (Fortis PBR Reply, p. 61)

Commission Determination

The Commission Panel agrees that a fixed weight index may not reflect the actual cost of utility plant as well as indexes that are weighted to reflect actual utility plant costs. However, with regard to the specific issue of plastic vs steel pipe that Fortis describes, the Panel is not persuaded that the use of a single plant index results in an overstatement of TFP trend by orders of magnitude.

The Panel accepts that in 2011, 85 percent of installed main was plastic and 15 percent steel represents an industry average. However, there is no direct evidence as to exactly what the percentage of installed mains is steel and what percentage is plastic for the specific utilities in the study period. There is also no evidence of how the steel and plastic mix applies to different diameter pipe. Therefore, it is not possible to determine what adjustment, if any is required. However, the Panel agrees that given the rise in the proportion of plastic main generally, and the difference in the price increase for plastic main as opposed to steel main, the fixed weight Handy Whitman Index is likely to overstate the trend in input cost.

For these reasons, the Panel is prepared to consider a modest reduction to the PEG TFP trend result for gas utilities to account for the weighting of construction costs as described by Fortis. **The Panel, using its best judgement, finds a reduction of 0.06 percent to the MFP trend results from PEG's gas utility productivity study to be appropriate.**

There is no evidence on the record concerning copper conductors. Therefore the Panel will not consider this issue any further with respect to PEG's electric utility study.

2.1.5.3.4 Measurement of Capital Cost

PEG states that its approach to the measurement of capital cost "permits its decomposition into price and quantity indexes". It states that it used for this purpose a COS approach to simulate the approach to capital cost measurement in North American utility regulation. This approach assumes straight line depreciation and a book valuation of capital. The trend in the rate of return is a

weighted average of the trends in the regulated returns on equity and the embedded cost of debt.
(FEI Exhibit C1-9, pp. 18–19)

Fortis submits that the service value of utility plant does not decline steadily, as Dr. Lowry's approach assumes. "TFP will be too high, by definition, if plant that still has full service value is being treated as if it is not required to generate outputs." In its view, this is a key instance where Dr. Overcast has identified upward bias in Dr. Lowry's calculations and it is a matter of "objective fact, not a difference of expert opinion." (Fortis PBR Reply, pp. 68–69)

To illustrate this point, Dr. Overcast testified that "a third of all the main in the ground is over 41 years old, is still in full service and provides full service value, even though it's fully depreciated."
(T6:292)

B&V also cites testimony before the Commerce Commission (New Zealand) in 2009 which concluded: "although it is critical – given the characteristics of energy network assets – to use a service potential profile that reflects one-hoss shay⁶ deterioration in measuring the *capital input quantity* [the capital cost charges can be based on a range of forms of depreciation provided they satisfy the condition of ex ante FCM. To ensure consistency with regulatory reporting we use return of capital based on straight-line depreciation]." (Exhibit B-45, Fortis Rebuttal Evidence to CEC, p. 27, remainder of quote added from original)

Dr. Lowry states that it is controversial to use an approach to capital that doesn't involve gradual depreciation and notes that the gradual depreciation approach is used in "innumerable studies by federal statistical agencies like Statistics Canada in studies of the MFP trends of the economy."
(T6:1333)

He also testified that "studies have shown that when you have a mix of assets of different ages, that as each of them goes *kaput*, they don't all go *kaput* at once. They go *kaput* all the time. And

⁶ 1HS refers to a "One-Hoss Shay", which in this context describes a capital asset that exhibits neither input decay or output decay during its lifetime.

actually that is [a] surprisingly similar quantity trajectory to what you would get with a gradual depreciation scenario” (T6:1332).

Dr. Lowry also stated that in his view, the IHS methodology does not necessarily reflect the cost of replacement capital. He testified:

“...because you are replacing the old input, and so that’s falling off as you add the new one. It’s only under cost of service regulation that that would necessarily result in a bump in your quantity. That’s the approach that Black and Veatch has disputed. But I think, as I’ve mentioned, ... they kind of go back and forth between the cost of service paradigm in which, thanks to gradual depreciation you do get a bump in capital quantity with replacement, but with the more one-hoss shay approach, you wouldn’t necessarily because you are replacing an asset that supposedly until that time was perfectly serviceable.” (T7:1359–1360)

In PEG’s view “it is not clear that a correctly implemented IHS approach to capital costing would produce MFP trends markedly different from those that I report in [Dr. Lowry’s] testimony. Dr. Makholm has used this approach in research and testimony once in Maine and twice in Alberta. The estimated MFP trends he reported in these three studies were 0.44%, 0.78%, and 0.96% respectively.” (Exhibit C12-4, p. 3)

Dr. Overcast disagrees, stating that “the basis for that conclusion can’t possibly be correct” because the PEG method excludes the 33 percent of all gas main in the US, from their measure of inputs. He bases this estimate on the Pipeline and Hazardous Safety Material Administration’s database, which reports the age of these assets. (T1:1509)

However, Dr. Overcast does not suggest a specific adjustment to PEG’s TFP trend results to account for the difference between the two methodologies. Further, B&V states that in its study, it used the change in net plant (gross plant additions less annual depreciation expense) and did not adjust this value for inflation. (Exhibit B-45, p. 27)

Commission Determination

The Panel is not persuaded that the results of the PEG study should be adjusted to account for any potential upward bias that may be attributable to the assumption of gradual depreciation in the capital costing approach. Although assuming gradual depreciation may bias the results upward, there may also be an offsetting effect because of the increased maintenance costs associated with aging capital. Further, B&V provides no quantitative analysis of any potential bias and Dr. Lowry states that “it is not clear that including costing would produce MFP trends markedly different” from those reported in the PEG study. The Panel finds no reason to disagree.

The One-Hoss Shay methodology is an element of the academic paradigm that Dr. Overcast is critical of Dr. Lowry for not including. However, the Panel accepts Dr. Lowry’s evidence that this element is controversial, and notes that B&V also appears not to take this approach in its study assumptions.

Accordingly, the Panel finds that no adjustments are necessary to account for PEG’s capital costing approach.

2.1.5.3.5 Negative Salvage

Fortis submits that capital inputs will be understated (and Dr. Lowry’s TFP trend results overstated), “by definition, if there is no recognition given to the material net cost of decommissioning plant (net negative salvage).” (Fortis PBR Reply, pp. 68–69)

Dr. Lowry states this is a reasonable simplification given its small importance (FBC Exhibit C6-15, IR1.3.11).

Commission Determination

B&V provides no quantification of the impact of not including negative salvage, and there is no evidence that indicates that the inclusion of negative salvage will have a material impact on the results of Dr. Lowry’s studies. In the absence of any evidence to the contrary, the Panel accepts Dr.

Lowry’s assertion that “this is a reasonable simplification given its small importance.” **Accordingly the Panel declines to make any adjustments to the study results to account for negative salvage.**

2.1.5.3.6 Input Inflation vs. Output Inflation

Fortis submits that the PEG results are overstated because PEG has not “calibrated” its calculations. Fortis further submits that Dr. Lowry clearly indicates in his evidence that “...when a macroeconomic inflation measure is used, the ARM must be calibrated in a special way if it is to reflect industry cost trends.” It also states that:

“[u]sing an output-based inflation index is problematic because the measure of output inflation already incorporates the effects of economy-wide productivity gains. In other words, BC-GDPIIFDD already incorporates the effects of the BC economy-wide productivity gains and therefore would not necessarily be indicative of the input price inflation likely to be experienced by the Companies during the plan term. For this reason, the theory requires the TFP estimates to be calibrated to produce an appropriate X-factor in order to correct for the difference between output inflation included in the inflation factor and the industry input.”

In Fortis’ view, PEG ignores this integral component of its own theory and does not calibrate its X-Factor range recommendations “despite recommending that the Companies use the macroeconomic indicator BC-GDPIIFDD for its I-Factor” (Fortis PBR Reply, pp. 70–71).

The adjustment suggested by B&V is based on a calculation of growth in revenue per customer provided by PEG (as equation 16 in its filed evidence):

$$\text{growth Revenue/Customer} = \text{growth GDPPI} - \left[\left(\text{trend MFP}^{\text{Industry}} - \text{trend MFP}^{\text{Economy}} \right) + \left(\text{trend Input Prices}^{\text{Economy}} - \text{trend Input Prices}^{\text{Industry}} \right) + \text{Stretch} \right]$$

B&V states that “The term in brackets must be calculated to produce the appropriate X-Factor under the PEG methodology.” (Exhibit B-45, p. 60)

Using as an example the X-Factor for capital for gas distribution utilities, B&V calculates the term in brackets as follows:

$$\begin{aligned} \text{GrRevPerCust} &= \text{BC} - \text{GDPIIFDD}_{\text{Growth}} - [(1.34_{\text{trend MFP Ind.}} - (-0.45_{\text{trend MFP Econ}})) \\ &\quad + (1.31_{\text{trend IP Econ}} - 3.16_{\text{trend IP Ind.}}) + (0.20_{\text{Stretch Factor}})] \\ &= \text{BC} - \text{GDPIIFDD}_{\text{Growth}} - [0.14_{\text{Calibrated X-Factor}}] \end{aligned}$$

B&V used the following factors in the equation above:

Table 2.11 Adjustment Inputs

Adjustment Inputs			
	Economy	Industry	Stretch Factor
Trend MFP	- 0.45% ³¹	1.34% ³²	0.20% ³³
Growth BC-GDPII ^{FDD}	1.76% ³⁴		
Trend Input Price	1.31% ³⁵	3.16% ³⁶	

³¹ PEG Evidence Exhibit FEI C1-9 and FBC C6-9, p.14,

³² Recommended X derived from Response to BCUC IR1.22.1, Attachment BCUC-CEC (1) 10.3

³³ Ibid. p.70

³⁴ BC-GDPII^{FDD} (2003 to 2012) from Table 7, Section 5 PEG Evidence

³⁵ Calculated as MFP Trend Economy + Growth BC-GDPII^{FDD}; Deduced from Dr. Lowry's formula [15]

³⁶ Input Price Trend of U.S. Gas Distributors (1999-2011) from Table 3, Section 3 PEG Evidence

B&V compares the resulting X-Factor to the X-Factor calculated by PEG and describes the difference as the calibration. The resultant calibrations are 1.03 percent for FEI and 0.92 percent for FBC. (Exhibit B-45, pp. 63–64)

PEG comments that “X will be larger, slowing revenue growth, to the extent that the industry MFP trend exceeds the economy-wide MFP trend embodied in the GDPPI.” It asserts that the MFP trend of the US economy is believed to be fairly brisk, with 1.1 percent average growth in the last 10 years. In its view, this warrants a sizable adjustment to the X-Factor in the US when the GDPPI is used as the inflation measure. In contrast, it states that in Canada, however, the analogous MFP

index has declined by 0.45 percent annually on average over the last ten years. (FEI Exhibit C1-9, pp. 13–14)

The AUC considered calibration to the TFP trend, in the event that an output-based inflation measure is chosen for the PBR plan. The AUC Panel found that both components of the approved I-Factors (AWE and CPI) can be considered input based price indexes so no further adjustment was required. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, pp. 86–87, 92–94)

Commission Determination

The Commission Panel is not persuaded that the adjustment proposed by B&V is required. The Panel accepts that “the theory requires the TFP estimates to be calibrated to produce an appropriate X-factor in order to correct for the difference between output inflation included in the inflation factor and the industry input.” The calculation provided above by B&V relies on the assumption that the I-Factor is GDPPI, which is a measure of output inflation. However, the Panel has previously approved the use of the CPI and AWE, which Fortis argues are reflective of the input inflation it faces.

Accordingly, the Panel finds that B&V’s proposed calibration is not required.

2.1.5.3.7 Summary of PEG Studies and Comparison to other Studies

2.1.5.3.7.1 The AUC Studies

For its Performance Based Rate Regulation proceeding, the AUC engaged the National Economic Research Associates (NERA) to conduct a TFP trend study applicable to Alberta gas and electric companies. NERA filed its report dated December 30, 2010. The study was based on a population of 72 US electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP trend of the distribution component only of the electric companies. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, p. 59)

In addition to NERA’s study, PEG on behalf of an intervener, also performed an MFP trend study for the gas distribution industry. PEG’s analysis examined the productivity growth of 34 U.S. gas distribution companies for the period from 1996 to 2009. In its study, PEG calculated the TFP trends of the sampled companies as providers of gas transmission, storage, distribution, metering and general administration services. (FBC Exhibit B-1-1, Appendix D8, p. 59)

Table 2.12 AUC Hearing TFP Study Results

Jurisdiction	TFP/MFP	Period Covered	Dataset
Alberta—NERA	0.96%	1972–2009	72 U.S. electric and combination electric/gas companies
Alberta—PEG	1.32% – 1.69%	1996–2009	34 U.S. gas distribution companies over the period of 1996 to 2009

(Source: Exhibit B-11, BCUC 1.1.2)

While acknowledging the value of a separate productivity study focusing on gas distributors, the AUC ultimately did not rely on the PEG report on the basis that: 1) the choice of a sample period in PEG’s study was primarily based on Dr. Lowry’s personal judgment, not on objective criteria; and 2) PEG’s lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. Instead, the gas distribution companies that were parties to the proceeding, agreed that NERA’s study provided a reasonable starting point for determining the TFP trend for gas distributors.” (FBC Exhibit B-1-1, Appendix D8, pp. 86–87)

The issue of the choice of NERA’s output index — throughput — was explored in the AUC proceeding. The AUC found that when selecting an output measure, it must be matched to the type of PBR plan. In this case, the AUC accepted the single throughput output index as appropriate as the proposed PBR plans were price-cap plans. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, pp. 82–83)

B&V is of the view that “a separate measure of TFP should be used for gas and electric utilities just based on fundamental differences in both the cost and output drivers.” (Exhibit B-1-1, Appendix D1, p. 34)

B&V is critical of NERA’s TFP academic study methodology, because “the real world of utility operation is not the world of the current academic paradigm. In order to become useful for application in utility regulation, academic studies must be modified to adequately model the key drivers of cost and be more comprehensive in scope by including all of the costs associated with delivery service.” (Fortis Exhibit B-1-1, Appendix D2, pp. 31–32)

B&V submits that “the AUC Plan and the NERA study on which it was based should not be used as a basis for the development of a PBR Plan for FortisBC” (FBC Exhibit B-1-1, Appendix D2, p. 39).

CEC asserts that the NERA study “was designed to provide a long term analysis with a long term MFP trend and as such remains consistent with other analysis” (CEC PBR Final Argument, p. 47).

Commission Determination

The Commission Panel agrees with B&V that the NERA study results should not be applied to FEI, as the study only considered electric distribution utilities. However, the Panel considers that the NERA study results have relevance in this proceeding and is inclined to assign them some weight with regard to the electric utility productivity trend. In making this determination, the Panel considered the study length, the dataset used for the study and the output measure relative to the PBR plan the study was prepared for. These issues have all been thoroughly canvassed in this proceeding.

The TFP of 0.96 percent approved by the AUC is comparable to the results of PEG’s gas utility study presented in this Proceeding.

Given that the PEG AUC study was rejected by the AUC, and has not been tested in this proceeding, the Panel will place no weight on it

2.1.5.3.7.2 The OEB Studies

Table 2.13 OEB Approved TFP Trend Results

Jurisdiction	TFP/MFP	Study Date	Period Covered	Dataset
Ontario 3 rd Generation	0.72%	2007	1988-2006	US Utilities
Ontario 4 th Generation	-0.33%	2013	2002-2012	Ontario Electric Utilities

(Source: FEI Exhibit B-11, BCUC 1.1.2)

Under the third generation PBR, the OEB decided that due to the lack of a comprehensive Canadian (or Ontario) utilities’ financial and operational database, the data from US peer group companies may be used to measure TFP. The study utilized U.S. data for the period of 1988–2006 and calculated a productivity factor of 0.72 percent, which was approved by the OEB in September 2008. However, for the fourth Generation PBR the TFP study was based on Ontario data instead of US data. (FBC Exhibit B-1-1, Appendix D2, p. 14)

A report prepared for the OEB by PEG explained that:

“the 2012 TFP and econometric results were impacted by three issues with the 2012 data: 1) data were not available on embedded distributors’ LV payments made to host distributors; 2) at least 13 distributors adopted international financial reporting standards (IFRS) for the first time in 2012; and 3) a number of distributors cleared balance sheet deferral accounts in 2012 and moved the associated costs to their Trial Balance OM&A expense accounts. Of these three data issues, PEG’s TFP results were most affected by the clearing of the deferral accounts to expense.”⁷

⁷ Empirical Research in Support of Incentive Rate-Setting: 2012 Update, September 2013, by PEG, available in Fortis Exhibit B-27, Witness Aid, Empirical Research in Support of Incentive Rate-Setting: 2012 Update Report to the Ontario Energy Board September 2013, p. 25

Commission Discussion

There are issues that, in the Commission Panel's view, limit the applicability to this proceeding of both the third and the fourth generation OEB studies.

The fourth generation study is a study of Ontario electrical distribution utilities. There is no evidentiary basis on which to conclude it is applicable to a gas distribution utility, or how the results can be modified to so apply. Accordingly, the Panel will give no weight to this study with regard to the determination of a TFP trend for the gas utilities. For the same reason, the Panel assigns no weight to the third generation study.

With regard to the applicability of the fourth generation study to electric utility MFP trends, the Panel is concerned that the results may be skewed by the three issues outlined in the PEG report, in particular the issue of clearing the deferral accounts. Accordingly, in the absence of further evidence, the Panel is not prepared to give any weight to this study.

Regarding the applicability of the third generation study to the electric utility MFP trends, the Panel is mindful of the objections of Fortis that the study period is over seven years ago, and will assign no weight to that study.

2.1.5.3.7.3 Summary of PEG's Studies

Fortis submits that "[u]nderstanding what causes a negative TFP value, and its significance, is fundamental to understanding why Dr. Overcast's measured negative TFP values make more sense than Dr. Lowry's large positive values in the present circumstances" (Fortis PBR Final Argument, p. 74).

CEC submits that the Commission has little choice in this debate but to conclude that the PEG research is the superior evidence and methodology by far, not only because of the technical explanations and analysis but because it yields usable results which the B&V evidence clearly does not. (CEC PBR Final Argument, p. 49)

IRG submits that “In this proceeding, the two witnesses clearly disagreed on a surprising number of issues. On balance, the IRG supports the more persuasive evidence of Dr. Lowry.” (IRG Final Argument, p. 3)

Commission Determination

The Commission Panel agrees with CEC and IRG and finds the PEG study results to be the best available evidence in this proceeding. In the Panel’s view, with the exception of a small adjustment required to account for the use of the fixed price construction index basket, the underlying assumptions are reasonable and the study length is appropriate. **Accordingly, the Panel considers these results to be an appropriate basis to set an X-Factor for the six-year PBR term.**

With regard to Fortis’ assertion that negative TFP trends make more sense, the Panel is not persuaded that this is the case. B&V asserts that “there’s a lot of infrastructure replacement going on,” but does not provide any specific evidence of this replacement for the utilities in either its own or PEG’s utility datasets over either study period. The Panel has previously found there are a number of methodology issues, including study period, the use of logarithmic vs. arithmetic growth rates and the way input levels are calculated, that can account for the negative TFP found by the B&V studies.

Considering the PEG study results and the adjustment to the gas study previously determined by the Panel to be required, the Commission Panel finds a TFP trend of 0.93 percent for electric utilities and 0.90 percent for gas utilities is appropriate.

2.1.5.4 Stretch Factor

2.1.5.4.1 The Proposed Stretch Factors

B&V states that its recommended X-Factor of 0 percent for each utility “is based on several features of the overall plan that we believe reduce the negative TFP closer to zero.” B&V does not

quantify the various adjustments it made to the TFP trend results, but states that “[t]he 0% X-Factor would include a stretch factor as well.” (FEI Exhibit B-11, BCUC 1.44.13)

Fortis proposes an X-Factor of 0.5 percent submitting that this “exceeds Dr. Overcast’s measured industry and economy wide productivity levels by a significant margin, and presents a challenge to the Companies to seek additional efficiencies” (Fortis PBR Final Argument, p. 61). B&V regards this additional stretch factor as being more aggressive than is warranted (FEI Exhibit B-1, pp. 43, 48).

FEI states that “[s]tretch factors are ordinarily a substitute for an Earnings Sharing Mechanism (ESM) and the amount of stretch factor is mainly subjective” (FEI Exhibit B-1, p. 42).

FEI also states that:

“[i]f the Commission determined a more aggressive ‘stretch’ productivity factor, FEI would reassess its plans on how to proceed but it is difficult to identify any particular response in the abstract. FEI would not consider the stretch productivity factor in isolation but rather would base its reassessment on the combined effect of the Commission determinations on all PBR Plan elements to determine whether or not the overall impact allowed the utility an opportunity to earn its fair return consistent with regulatory and legal principles.” (FEI Exhibit B-8, CEC 1.4.2)

This issue is pursued at some length by ICG. For example, it submits that:

“FBC has failed to provide any evidence that is relevant to whether it operates efficiently. In the absence of any relevant evidence, the Panel must assume that factors other than efficiency measures and efficient operations all but ensure higher than approved returns for FBC. Mr. Overcast confirmed that conclusions regarding the efficiency of FBC could not be drawn from either 1) the historic PBR Plans, or 2) TFP analysis. The evidence does not even permit the Panel to conclude that FBC is a high or low cost provider as compared to other utilities in BC. FBC consistently objects to such evidence being filed, and now must accept the consequences of such objections.” (ICG Final Argument, p. 4)

Commission Determination

The Commission Panel agrees with ICG that there is a lack of evidence as to the efficiency of Fortis’ operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. 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.**

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. As a result of this consultation, the Panel expects that agreement be reached 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.**

2.1.5.4.2 PEG's Recommendation

PEG states that:

“both Fortis units have operated under PBR in the past. However, the PBR plans for both companies exempted a large portion of capital cost from the force of PBR, and both companies have now operated for a few years under cost of service regulation. Neither company has presented convincing evidence of superior operating performance in this proceeding. On the basis of the available evidence, it is reasonable to assume that each company is an average cost performer.”

Based on this observation and the proposed 50-50 earnings sharing mechanism, PEG recommends a stretch factor of 0.2 percent. (FEI Exhibit C1-9, p. 70)

2.1.5.4.3 Previous Fortis PBR Plans

The parties involved in the NSP for FEI's previous PBR agreed that “linking the productivity factor to BC-CPI would be beneficial for both ratepayers and FEI since the productivity opportunities would increase as inflation increased, and conversely FEI would have more limited opportunities for productivity improvements if the rate of inflation decreased. The productivity factor agreed to was 50 percent of CPI for 2004 and 2005, and 66 percent of CPI from 2006 to 2009.” (FEI Exhibit B-1, p. 35)

For FBC, the 2006 Negotiated Settlement Agreement established an X-Factor of 2 percent for 2007, 2 percent for 2008, and 3 percent for 2009 (if the term of the PBR was extended). For the period 2009–2011, the Parties to the 2009 NSA agreed that some linking of the productivity factor to BC CPI would be beneficial. As such, the 2009 NSA established X-Factors of 1.5 percent for 2010 and 2011 when BC CPI is less than 3 percent, with the X-Factor increased to offset any increase in BC CPI above 3 percent. (Fortis Exhibit B-1-1, Appendix D1, p. 25)

FEI submits that:

“[a] utility’s past history with PBR plans may also be considered for X-factor determination. Ordinarily, utilities with no previous experience with PBR plans (as is the case for Alberta’s utilities) may have a better chance to improve performance at a faster rate than the industry average (the inefficient utilities have more —low-hanging fruit— or cost savings that can be implemented easily). This may justify a higher than usual X-factor used in Alberta in comparison to a utility like FEI that has years of recent experience with PBR and fewer available productivity improvement opportunities.” (FEI Exhibit B-11, BCUC 1.6.1)]

However, Fortis also argues:

- First, neither of the PBR experts in this case, including CEC’s own expert, used the previous negotiated X-Factor as the starting point for their recommendations. Rather, Drs. Lowry and Overcast both based their recommendations on industry productivity levels, which is consistent with what is done in other jurisdictions where PBR has not been negotiated. The TFP study undertaken by Dr. Overcast yielded a negative TFP. FBC’s prior history under PBR only came into play in determining the stretch factor. Drs. Lowry and Overcast agreed that the stretch factor should decline over time to recognize diminishing returns.
- Second, the fact that the X-Factor averaged 2percent during the last FBC PBR is not a rationale for adopting the same X-Factor today. TFPs have been declining, and accelerated infrastructure replacement continues. PEG recently calculated a negative TFP in Ontario, and even Dr. Lowry’s recommendation and NERA’s values in Alberta fall well short of the number advocated by ICG. (Fortis PBR Reply, p. 75)

2.1.5.4.4 Stretch Factors from Other Jurisdictions

The AUC approved a stretch factor of 0.2 percent be used by the respective Alberta distribution utilities in their PBR Plans. It was assumed that the transition to PBR from COS regulation would produce immediate expected increases in productivity growth. As such, the purpose for the

addition of the 0.2 percent stretch factor was to share between the companies and customers these immediate expected increases in productivity growth. (Exhibit B-1-1, Appendix D2, p. 5)

The OEB:

“concluded that there are considerable variances between existing efficiency cultures of the utilities and that a single stretch factor for all distributors is not appropriate. Therefore, two benchmarking evaluations were considered to divide the Ontario’s power distributors to three efficiency ‘cohorts’ where each cohort was given a specific stretch factor. While grouping of distributors into three cohorts was based on solid benchmarking techniques, the determination of stretch factors values was mainly subjective and based on the OEB’s judgment.” (FEI Exhibit B-1-1, Appendix D2, p. 14)

Table 2.14 OEB Stretch Factors

Characteristic	Cohort One	Cohort Two	Cohort Three
Criteria for cohort groups	Statistically superior econometric benchmark and (2) top quartile result in the unit cost index benchmark	Superior in one methodology and inferior in the other one	Inferior in both benchmarking techniques
Stretch factor value	0.2	0.4	0.6

(Source: Exhibit B-1-1, Appendix D-2, p. 14)

Commission Determination

In the absence of a benchmarking study, the Panel considers the following:

1. Fortis’ proposed stretch factor of 0.5 percent, which is in addition to the stretch factor embedded in B&V’s recommended X-Factor;
2. Dr. Lowry’s suggested stretch factor of 0.2 percent; and
3. The range set by the OEB of 0.2 percent to 0.6 percent.

A stretch factor in excess of 0.5 percent is substantial. It is, for example, considerably larger than PEG’s proposed stretch factor of 0.2 percent. When compared to stretch factors approved by the

OEB, this would put Fortis in the range of the least efficient utilities. This is contrary to FEI's assertion that "FEI has already realized significant efficiencies under its previous PBR that can only be achieved once" and that "efficiencies that can be expected to be achieved under PBR decline over successive PBR terms" (FEI Exhibit B-53, Panel 2.1). Accordingly, the Panel gives no weight to Fortis' proposed stretch factor.

The Panel agrees with Fortis that past history may be considered. However, the Panel also agrees that a utility that has years of recent experience with PBR may have fewer available productivity improvement opportunities. Accordingly, stretch factors from recent previous PBR periods could suggest upper limits to stretch factors going forward.

Upon reviewing Fortis' previous PBR Plans, we note that in all cases except for 2007 to 2009, inclusive, the X-Factor varies, based on forecast CPI. This is a different approach than proposed in this Application, where the X-Factor is fixed, regardless of inflation. The Panel does not find it appropriate to impute a stretch factor under these circumstances. To impute a stretch factor from FBC's negotiated X-Factors of 2 percent for 2007 and 2008, and 3 percent for 2009, the Panel assumes a TFP of 0.93 percent. This results in a stretch factor of a little over one percent for 2007 and 2008, and a little over two percent for 2009. However, given that FBC has been in a PBR regime for a substantial amount of time, it would not be appropriate to continue with the same stretch factor and a reduction is appropriate. Further, considering that FBC has been in a PBR regime longer than FEI, a lower stretch factor for FBC is appropriate.

Considering the stretch factor evidence before the Commission Panel, we determine a stretch factor of 0.2 percent for FEI and 0.1 percent for FBC to be appropriate.

2.1.5.5 Setting the X-Factor

As previously set out, in determining the X-Factor, in addition to considering the TFP trend and the stretch factor, the Panel will consider the adjustments that Fortis proposes to account for its specific circumstances and also apply our own judgement to determine if any additional adjustments are required.

2.1.5.5.1 Fortis' Proposed X-Factor

Fortis proposes an X-Factor of 0.5 percent, suggesting that, although it is substantially higher than B&V's recommended X-Factor, it is reasonable. In support of its proposed X-Factor, Fortis cites the following:

- a. Accelerated trend in asset replacement in the gas and electric utility industries. This has resulted in a more negative TFP trend than is attributable to Fortis, because Fortis proposes to exclude significant portions of capital from its formula spending.
- b. PEG's recommended X-Factors for Ontario utilities is close to zero; and
- c. A high-level comparison with illustrative revenue requirements forecasts show that the proposed 0.5 percent X-Factor, along with the proposed composite inflator, will result in rates that are lower than the rates under a cost of service model.

(FEI Exhibit B-1, p. 53; FBC Exhibit B-1, p. 49; Fortis Reply, p. 72)

Fortis also submits that "it can be argued that the X-Factor for a PBR plan with an earnings sharing mechanism is less significant than under a plan with no earning sharing mechanism." (FEI Exhibit B-1, p. 51, FBC Exhibit B-1, p. 47)

ICG submits that "[a]ssuming the Panel approves a PBR Plan, the ICG recommends an X-Factor of 2% to match the average X-Factor during the last PBR Plan" (ICG Final Argument, p. 23).

2.1.5.5.2 Single ARM vs Double ARM

In PEG's view, the single ARM approach has a more solid empirical foundation provided that the capital cost tracker is redesigned along more conventional lines. PEG believes that a single ARM, applicable to most of the companies' revenues, and separate ARMs for capital and operation and maintenance expenses are both potentially workable for the Fortis companies. However, in its view, an issue with the single ARM approach is the unusually large amount of capex that would be separately addressed by a cost tracker. PEG recommends tightening the eligibility standards for the capital cost trackers to mitigate this issue. (FEI Exhibit C1-22, BCUC 2.3; FEI Exhibit C1-22,

BCUC 2.4.1)

FEI states that although the costs are looked at separately to allow more appropriate cost drivers to be assessed from each side, its building block model proposes the same X-Factor for each block. It further submits that a single X-Factor is what Dr. Lowry refers to as a single-arm approach, which is the same approach that is taken in “all of the other plans that the Commission has evidence before it on.” (T8:1397)

2.1.5.5.3 Adjustments for Excluded Capital

Fortis proposes to exclude all CPCN capital from its formula driven spending envelope. For FEI, this includes all capital over \$5 million and for FBC all capital over \$20 million and in some cases, capital projects of any size below \$20 million. PEG estimates that this amounts to 30 percent of all capital expenditures for FEI and 40 percent for FBC. (FEI Exhibit C1-22, CEC Response to BCUC 2.4.3)

PEG states that there is no established methodology for making such exclusions. However, when asked to provide study results assuming exclusion of similar amounts of capital, it reported an increase in the single arm MFP trend to 1.98 percent. In its view, “[t]his result would be pertinent for the calibration of an X-Factor for a comprehensive revenue cap index, assuming that CPCN costs flow through a tracker.” (FEI Exhibit C 1-13-1, CEC Response to BCUC 1.13.3)

2.1.5.5.4 X-Factor Evidence from Other Proceedings

X-Factor evidence was also presented from Alberta and Ontario. In Ontario, X-Factors are either the result of negotiated settlements or are calculated as the sum of the TFP trend and a stretch factor.

Fortis submits that when reviewing the X-Factors in other jurisdictions, the timing of these decisions is important when there is evidence of accelerating asset replacement occurring in the last five years that is expected to continue during the PBR term. Apart from Alberta’s X-Factor of

1.16 percent, all of the other cited X-Factors over 1.0 percent were set at least five years ago, presumably based on even older information. (Fortis PBR Reply, p. 72)

With regard to the AUC's X-Factor, Fortis submits that it is based, "by and large, on expert evidence that used the same academic assumptions used by Dr. Lowry that do not properly reflect actual productivity." It further states that "[b]oth experts in this proceeding also considered the NERA analysis relied upon by the AUC to be incorrect." (Fortis PBR Reply, p. 72) However, Dr. Lowry stated that although there were "lots of little technical errors" in the NERA study, he does not suggest that the result is upward-biased (T7:1386–1387).

Commission Determination

The Commission Panel has the following comments concerning the three factors Fortis cites in support of its proposed X-Factor:

- a. **Accelerated asset replacement trend.** This issue arises because B&V and Fortis attribute the negative TFP trends from the B&V studies to accelerated asset replacement. The Panel has previously determined that shortcomings in the study methodology may account for the negative TFP trends. Further, the Panel has determined that it will not accept the results of the B&V studies. Accordingly the TFP trend results from these studies cannot be used as a basis for even the hybrid judgement approach. We will not consider the issue of asset replacement any further in making our X-Factor determination.
- b. **PEG's Ontario X-Factor Recommendation.** In our review of the OEB proceedings, the Panel found that the principle reason the MFP trend was close to zero was due to the OEB requirement to clear deferral accounts. As such, the OEB result has little relevance in this proceeding. The Panel will not consider this issue any further.
- c. **Comparison to COS Rates.** We do not consider an "illustrative revenue requirements forecast" to be a reasonable basis on which to make an X-Factor determination. The "illustrative forecast" has not been adequately tested and, as such, may be prone to error and bias. It cannot be viewed as a cost of service requirement for the next five years.

With regard to Fortis' statement concerning the reduced importance of the X-Factor if the PBR plan includes an earnings sharing mechanism, it is unclear to the Panel how, if at all, this may have influenced either B&V's or Fortis' judgement based adjustments. It is not clear to the Panel what is

meant by “reduced importance”. It is not appropriate to use the presence of an ESM to justify an X-Factor that may, for example, be too low. In that circumstance, the X-Factor would enable the utility to over recover its costs. While sharing that over-recovery with its customers does mitigate the effect of the over recovery somewhat, it is not sufficient justification to use an X-Factor that is understated.

For all of the above reasons, the Panel is unable to approve the X-Factor as applied for.

The Panel accepts PEG’s assertion that the single ARM has a more solid empirical foundation. In addition, the Panel agrees with Fortis that its proposed plan has the characteristics of a single ARM approach. However, the Panel is concerned that because of this proposed treatment of capital expenditures, an adjustment to the single ARM X-Factor may be required.

The Panel is mindful of the comments of both experts regarding excluded capital. We agree that if significant capital spending is excluded from the PBR formula driven spending envelope, adjustments to the formula may be necessary. B&V included this consideration in its upward adjustment of approximately 4 percent but, as discussed previously, does not provide any details concerning that adjustment. Accordingly, it is not possible to discern the directionality of the adjustment to allow for excluded capital, although the magnitude of the gross adjustment suggests that the effect of excluded capital may be to drive the TFP trend upwards. The results reported by PEG are also suggestive that its reported single ARM MFP trend is too low when applied to a PBR plan with a significant amount of excluded capital. **Accordingly, if significant capital is to be excluded from the formula, the Commission Panel finds that the X-Factor requires an upward calibration.**

The Panel considers the matter of excluded capital further in Section 2.3.5 of this Decision. There, the Panel finds that the CPCN based exclusion criteria proposed by Fortis is not appropriate and invites further submissions from parties on the issue of the threshold for excluded capital. Accordingly, **the Panel will not apply any adjustments at this time, but directs that this issue be revisited when a further determination on the dollar threshold is made.**

Having considered FEI’s special circumstances and the overall design of the PBR plan, no further adjustments are required at this time.

Accordingly, the Commission Panel has determined the following X-Factors should be applied to Fortis’ proposed PBR formulas for the PBR term:

Table 2.15 Approved X-Factors

Utility	TFP	Stretch Factor	X-Factor
FBC	0.93	0.1	1.03
FEI	0.90	0.2	1.10

2.1.6 Exogenous or Z-Factors

Fortis proposes that exogenous factors, which it characterizes as “non-controllable and unforeseen costs/revenues,” be flowed through to rates during the PBR term (FEI Exhibit B-1, p. 70). The Companies state in their Final Argument that “it is not necessary, and is impractical, to be overly prescriptive in advance as to mechanisms for addressing exogenous factors”; therefore, Fortis submits that it will notify the Commission and stakeholders of exogenous events in a variety of ways, including through the Annual Review process or through a letter to the Commission, depending on the type of exogenous factor event (Fortis PBR Final Argument, p. 48). Fortis states that the recovery of exogenous factor events in rates may be achieved through a variety of mechanisms such as flow-throughs, deferral accounts and true-ups. (Exhibit B2-11, CEC 3.29.7)

The Companies provide a list of exogenous factors in their Applications. This list serves as an example of types of events that fall under the classification of “exogenous”; however, the Companies submit that this list is not exhaustive but merely serves as an example of the types of events that would lead them to apply to the Commission for exogenous factor treatment. The exogenous factors listed in the Applications are as follows:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;

- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to Commission decisions (examples include rate design issues, depreciation rate changes and changes to cost of capital).

Certain of the above exogenous factors, including catastrophic events, bypass or similar events, and major seismic incidents are further explored in the BCUC IR 3.22 series of questions in Exhibit B2-8 of the Fortis PBR proceedings. For instance, Fortis described a bypass event as a situation where a customer may be physically taking service from another supplier while remaining within the service territory and thus making no use of the Company's facilities, or where it has become economic to leave the Company's service area for another location because of rate or other utility policies that have caused the costs to the customer to exceed its standalone costs. Fortis submitted that a bypass event qualifies as exogenous because, unlike in an unregulated environment, the Company is not free to adjust its prices between its marginal cost and the standalone cost of its customers.

Fortis does not propose to apply any criteria or a materiality threshold to exogenous factor events. Instead, the Companies submit that "[w]hile, in principle, all unforeseen events that are beyond the Companies' control should be treated as exogenous, the Companies' evidence is that they may choose not to apply to recover amounts related to small events that do not have an impact on the Companies' ability to serve its customers and that do not have a material cost impact." (Fortis PBR Final Argument, pp. 47–48)

Fortis' proposed treatment for exogenous factors is consistent with the Companies' approach in previous PBRs; however, it differs from the approach taken by other Canadian jurisdictions under PBR. The other jurisdictions take a more prescriptive approach to the definition of exogenous factors through the establishment of a set of applicability criteria and a materiality threshold. This provides for greater clarity when determining if an event is eligible for exogenous factor treatment. (Fortis Exhibit B2-11, CEC 3.27.2)

Materiality

Fortis submits that the Commission should not impose a materiality requirement because “the cost increases or decreases arising from exogenous factors are non-controllable costs, and are therefore prudent by definition.” The Companies further submit that any costs/revenues arising from non-controllable events would be recoverable in rates under cost of service-based ratemaking without any materiality threshold; therefore, the same logic should apply to PBR-based ratemaking. (Fortis PBR Final Argument, p. 47)

In response to CEC IR 3.32.6, Fortis states: “Exogenous factors should, in principle, flow through. However, when the changes are *de minimis* management may not seek recovery.” Fortis further states that the “decision not to apply for recovery of a small cost must be treated as a practical determination, appropriately made by the Companies at the time and not by the Commission in advance” (Fortis PBR Final Argument, p. 48).

Fortis indicates that if the Commission determines that a materiality threshold is required, it should be based on a dollar value as this would be simpler than looking at ROE impact. Fortis referenced Ontario’s thresholds which are in the range of \$1 million to \$1.5 million (T4:801) and further states that the Commission should take into account the relevant size of each of the Companies if the Commission decides to establish a materiality threshold (T4: 803).

Other Jurisdictions

Table 2.16 shows the criteria and materiality threshold established by the AUC:

Table 2.16 AUC Treatment of Exogenous (“Z”) Factors

Jurisdiction	Treatment	
	Applicability	Materiality
ALBERTA		
Z-Factor <i>(Unforeseeable events outside the control of the company, for which the company has no other reasonable opportunity to recover the cost within the PBR formula)</i>	1. The costs/impact of event must be attributable to events outside management's control. 2. The costs/impact of event must have a significant influence on the operation of the company 3. The costs/impact of event should not have a significant influence on the inflation factor in the PBR formulas. 4. The costs/impact of event must be prudently incurred. 5. The impact of the event was unforeseen (Z-Factor)	40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established

(Source: Exhibit B2-11, CEC 3.27.2, p. 67)

In response to CEC 3.31.1, Fortis provided the following assessment of the AUC criteria established for Exogenous or “Z-” Factors:

- Fortis considers criteria 1 and 5 to be implicitly established within the Companies’ own proposals, as evidenced by the Companies’ description of exogenous factors as “non-controllable” and “unforeseen” within their Applications.
- Fortis does not agree with criterion 2 and submits that “placing a materiality limit is most likely to deny prudent cost recovery and increasing the underlying risk.”
- Fortis does not support criterion 3 because it considers it improbable that even a substantial rise in the inflation rate for the I-Factor in the PBR Formula could recover the costs of exogenous factors such as catastrophic events, major seismic incidents, and Acts of war, terrorism or violence. Fortis further asserts that the aforementioned exogenous factors are likely to have substantial impacts on economy-wide input prices.
- Fortis considers criterion 4 to be “unnecessary” because prudence in all expenditures, not just exogenous costs, is required by regulated utilities. (Exhibit B2-11, 3.31.1)

Table 2.17 shows the criteria and materiality thresholds established by the OEB:

Table 2.17 OEB Treatment of Exogenous (“Z”) Factors

Jurisdiction	Treatment	
	Applicability	Materiality
ONTARIO		
4th GENERATION IR		
Z-Factor <i>(treatment for unforeseen events)</i>	1. Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived. 2. The amount must have been prudently incurred. 3. The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor	1. Utility with Revenue Requirement less than or equal to \$10 Million: \$50 thousand Threshold 2. Utility with Revenue Requirement greater than \$10 Million but less than or equal to \$200 million: 0.5% of distribution revenue requirement Threshold 3. Utility with Revenue Requirement of more than \$200 million: \$1 million Threshold
EGD and Union (2008-2012 plans)		
Z-Factor <i>(non-routine events that were not otherwise recovered in the annual adjustment mechanism)</i>	1. The event must be causally related to an increase or decrease in the distributor's cost 2. The cost increase/decrease must be beyond the control of the Company management and not a risk a prudent utility could mitigate 3. The cost increase/decrease must not be otherwise reflected in the annual rate adjustment mechanism 4. The cost increase/decrease must be prudently incurred	The amount of the cost increase/decrease, for the sum of all individual events reflected in an annual Z factor filing, must be greater than the materiality threshold of \$1.5 million.

(Source: Exhibit B2-11, CEC 3.27.2, pp. 67–68)

Fortis provided an assessment of the OEB criteria during the Oral Hearing. The Companies consider criterion 1, which requires that amounts be causally related to the Z-Factor event, to be a given and therefore not necessary to be explicitly established as a criterion. Fortis also considers criterion 2 regarding prudence to be an unnecessary criterion since all costs incurred by the utility must be prudently incurred. Fortis does not agree with the OEB’s third criterion establishing a materiality threshold for the reasons discussed previously in the analysis of the AUC criteria. (T4:805)

Intervener Submissions

CEC submits that Fortis' proposal for treatment of exogenous factors provides the Companies with considerable discretion and that the proposal is misaligned with customer interests (CEC PBR Final Argument, p. 151). CEC identifies four key issues with Fortis' exogenous factor proposal:

1. Inadequate definition and lack of applicability criteria;
2. Lack of materiality clause;
3. Prudence not explicitly required; and
4. No obligation for "exogenous" savings to be brought forward on an equal footing.

CEC proposes the following criteria for exogenous factors:

1. Attributable entirely to events outside the control of a prudently operated Utility;
2. Directly related to the Exogenous event and clearly outside the base upon which the rates were originally derived;
3. Mitigated to the greatest extent by the Utility;
4. Prudently incurred; and
5. Greater than 30 basis points of ROE for the Utilities per year for exogenous events.

(CEC PBR Final Argument, pp. 157–158)

CEC submits that it is appropriate to establish criteria for determining whether or not an event is eligible for exogenous factor treatment so as to distinguish between costs that are justifiably extraordinary and costs that would otherwise be expected to be incurred under the PBR formula-driven spending. (CEC PBR Final Argument, p. 154)

CEC recognizes that there is an expectation of prudence in all expenditures but it still considers it necessary to include prudence as an explicit criterion. CEC submits that "as Z factors are explicitly intended to address extraordinary circumstances it is not unreasonable for the costs to be challenged." (CEC PBR Final Argument, p. 156)

CEC further recommends that Fortis be required to disclose all exogenous events that result in benefits to the ratepayers at the annual review. (CEC PBR Final Argument, p. 158)

No other interveners made submissions on Fortis' proposed treatment for exogenous factors.

Fortis Reply

The Companies take issue with CEC's proposed criterion 3 which states that exogenous factors must be mitigated to the greatest extent by Fortis. The Companies submit that they are governed by the prudence test and any exogenous factor will be tested under their proposal. The Companies further submit that a guideline that is "focused on outcomes rather than prudent conduct, which CEC appears to be advocating, is contrary to the UCA" (Fortis PBR Reply, p. 45).

Fortis submits that CEC's proposed materiality threshold of 30 basis points of ROE is large and could impair the Companies' opportunity to earn a fair return. Fortis submits that to put CEC's proposal in context, the proposed materiality threshold is equivalent to greater than \$4 million of FEI's Operations and Maintenance (O&M) expense and is likely greater than \$45 million of FEI's capital. (Fortis PBR Reply, p. 44)

Commission Determination

The Panel finds it necessary to include exogenous factors as part of the Companies' PBR plan in order to protect both the ratepayers and the shareholders. However, the Panel agrees with CEC that the Companies' proposal for exogenous factors is inadequately defined. **The Commission Panel therefore establishes the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:**

- 1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;**
- 2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;**
- 3. The impact of the event was unforeseen;**
- 4. The costs must be prudently incurred; and**
- 5. The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.** This is further defined in the section below.

The Panel considers the establishment of the above criteria necessary for transparency and greater clarity for all stakeholders as to why an amount is being brought forward for exogenous factor treatment. The criteria create an objective measure for assessing whether a potential event should appropriately be treated as an exogenous factor as opposed to solely relying on the Companies' judgment as to whether or not an amount should be brought forward for review by the Commission. The certainty provided by these criteria will improve the alignment between shareholder and customer interests.

Materiality

The Commission Panel finds that a materiality threshold is a necessary component of the exogenous factor criteria as it meets the Companies' guiding PBR principle of reducing the regulatory burden over time. Establishing a materiality threshold also reduces the reliance on Fortis' judgment and instead creates a more transparent and objective process for determination of exogenous factor applicability.

In determining the appropriate materiality threshold, the Panel considered the balance between regulatory efficiency, providing the Companies with a reasonable opportunity to recover prudently incurred costs and allowing ratepayers the opportunity to realize the benefits of cost savings. The Panel also considered the materiality thresholds set by other jurisdictions, including Alberta and Ontario as well as CEC's proposed materiality threshold of 30 basis points of the Companies' ROEs.

The Panel agrees with Fortis' submission that CEC's proposed materiality threshold is too high and could impair the Companies' opportunity to earn a fair return. The Panel also agrees with Fortis that basing a materiality threshold on a dollar value would be simpler and more straightforward.

The Commission Panel finds that materiality thresholds for FEI and FBC, amounting to 0.5 percent of each Company's 2013 Base O&M, are appropriate. The Panel has used its best judgement to arrive at this quantum. It is an amount that is proportional to the relative size of the companies and is also a dollar value.

Using FEI's February 21, 2014 Evidentiary Update filed as Exhibit B-1-5 as a proxy, the materiality threshold for exogenous factors for FEI is approximately \$1.15 million [2013 Base O&M of \$229,489,000*0.5%]. Using FBC's Application filed as Exhibit B-1 as a proxy, the materiality threshold for FBC is approximately \$300,000 [2013 Base O&M of \$59,848,000*0.5%]. While the Panel acknowledges that exogenous factors could relate to either O&M or Capital, it considers using Base O&M as the foundation for calculating the dollar value threshold for each Company to be reasonable as the prescribed amounts are within the range identified by Fortis in the Oral Hearing and are reflective of the relative sizes of FEI and FBC.

The Commission Panel directs the Companies to provide materiality threshold calculations as part of their Compliance Filings. These calculations must also reflect all changes to each Company's 2013 Base O&M directed in this Decision.

The Commission Panel further directs that exogenous events not be aggregated. The materiality threshold must be applied to the costs/savings of each exogenous factor event and the costs/savings for a specific event must exceed the materiality threshold in order to be eligible for exogenous factor treatment.

The Panel notes that exogenous factors must be treated symmetrically to create a fair balance of risk between the utility and ratepayers. **Thus, the materiality threshold applies both to exogenous savings as well as to exogenous costs. That is, any event resulting in savings must meet the criteria before it is accepted as an exogenous saving.**

Process for Exogenous Factor Applications

The Panel agrees with Fortis that it is not necessary to be overly prescriptive in terms of the timing of an exogenous factor application. The Panel recommends that to provide regulatory efficiency where possible, exogenous factor applications should be included as part of the Annual Review Process. However, Fortis may notify the Commission at other times during the year of exogenous events by letter to the Commission. The Commission Panel notes that consideration of exogenous

events is not restricted to those raised by the Companies. Any party may make an application at any time in support of what it considers to be an exogenous event.

The Panel also agrees with Fortis that it is not practical to be overly prescriptive at this time as to the appropriate recovery mechanism for exogenous factor events. The Panel therefore accepts Fortis' proposal to address the appropriate recovery mechanism of exogenous amounts on a case-by-case basis. These recovery mechanisms could include, among other things, flow-throughs, deferral accounts, or true-ups. **The Panel directs Fortis to include a proposal for the appropriate recovery mechanism as part of any exogenous factor applications.**

2.1.7 Flow-Through Items

Fortis proposes to flow-through various items which the Companies characterize as “known” or “foreseen” but not controllable. These flow-through items will be forecast each year during the Annual Review Process and thus not included within the PBR formula. For flow-through items which also have an accompanying deferral account, any variances between actual and forecast amounts will be added to the deferral account and amortized into rates outside of the formula. FEI already has a number of deferral accounts for these purposes; FBC is requesting establishment of certain deferral accounts for the same purpose. The issue of deferral accounts related to flow-through items is addressed in the next section. For flow-through items which do not have accompanying deferral accounts, Fortis proposes that the variances between forecast and actual amounts each year will be subject to the 50/50 Earnings Sharing Mechanism (ESM). (FEI Exhibit B-11, BCUC 1.21.4, 1.21.5; FBC Exhibit B-7, BCUC 1.37.4, 1.37.5) Please refer to Section 2.3.1 for further discussion of the ESM.

FEI proposes to classify the following items as flow-through:

- Interest Expense;
- Return on Equity;
- Taxes;
- Pension and Other Post-Employment Benefits (OPEB);

- Insurance Expense;
- Revenues;
- Depreciation and Amortization; and
- Rate Base other than Plant in Service (i.e. working capital, deferred charges).

(FEI Exhibit B-1, pp. 68–69)

FBC also proposes to classify the above items as flow-through, with the exception of non-Sales Revenue. FBC clarifies that it intends only to flow-through revenue from sales of electricity. (FBC Exhibit B-7, BCUC 1.37.4) However, in the Oral Hearing FBC further clarified that while the flow-through revenue is primarily electricity sales, there are other forms of tariff revenue included within the flow-through revenue category (T4:827, lines 9-14). Additionally, FBC proposes to flow through Power Purchase Expenses through the use of its Power Purchase Expense deferral account. (FBC Exhibit B-1, pp. 61–63; FBC Exhibit B-1-5, p. 1)

FEI described the ways in which it attempts to control each of the flow-through items to minimize the impact on customer rates, stating that for each of the proposed flow-through items there are “often components that are controllable and others that aren’t.” FEI further submitted that “[i]n most cases, it is the rate component of the expense that results in the item being deemed uncontrollable...” (Exhibit B-8, CEC 1.46.1)

In its response to CEC IRs 1.34 through 1.40, FBC described the variables which go into its determination of each flow-through item and also provided a discussion of the variables which are a function of company policy and practice and therefore may be somewhat controllable by the Company. (Exhibit B-10, CEC IRs 1.34 through 1.40)

Fortis submits that including uncontrollable costs within the PBR formula could result in windfall gains or losses to either the Companies or the ratepayers (Fortis PBR Final Argument, p. 42). Fortis also stated in the Oral Hearing: “...PBR is not about passing on uncontrollable costs between customers and companies, it’s about incenting efficiencies and controllable costs.” (T4:811)

Insurance Expense

FBC's Projected 2013 Insurance Expense is \$1,588,000 and its 2014 Forecast Insurance Expense is \$1,734,000 (FBC Exhibit B-1, Table B6-5, p. 53). While FBC proposes to treat the entire insurance expense as flow-through, it is proposing to capture only the variance between forecast and actual insurance premiums in the Insurance Variance Deferral Account. (FBC Exhibit B-1, p. 263)

FBC stated:

“[i]nsurance premiums are driven by insurance market conditions which change continually and are affected by large global losses, due to catastrophic events such as earthquakes, hurricanes and forest fires, as well as through general market conditions related to the unpredictability of investment returns and loss history... This lack of controllability around insurance premiums is what has driven the request for an Insurance Variance Deferral Account as part of the 2014-2018 PBR Application.” (FBC Exhibit B-7, BCUC 1.187.3)

FBC further stated:

“[t]he primary reason FBC proposes to only capture the variance between Forecast and Actual Insurance Premiums in the Insurance Expense deferral account is to provide for consistent treatment between Electric and Gas divisions.” (FBC Exhibit B-24, BCUC 2.58.5)

Of the total 2014 Forecast for Insurance Expense for FBC, Insurance Premiums make up approximately 84 percent with a forecast amount of \$1,460,000. The remaining 16 percent is attributable to First and Third Party Liability Expense, which is forecasted to be \$274,000 for 2014. An additional component of Insurance Expense is Asset Valuations, for the 2014 Forecast this amount is zero. FBC states that Asset Valuations are incurred every four years and therefore, this expense is only included in the 2017 Forecast. (FBC Exhibit B-24, BCUC 2.59.1)

FBC stated that it “would not object to changing the method of determining O&M Expense in order to exclude only insurance premiums from the I-X formula, providing the 2013 Base O&M Expense is revised to include the forecast \$274 thousand of First and Third Party Liability Expense” (FBC Exhibit B-24, BCUC 2.59.1).

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FBC provided the following breakdown of insurance expense for 2013 Projected and 2014 Forecast:

Table 2.18 FBC Insurance Expense

	2013	2014 Forecast	Variance
	(\$000s)		
Premiums	\$1,422	\$1,460	\$38
Appraisal Fees	\$60	-	\$(60)
1 st & 3 rd Party Claims	\$106	\$274	\$168
Total	\$1,588	\$1,734	\$146

(Source: FBC Exhibit B-24, BCUC 2.59.2.1)

FEI's entire Insurance Expense is attributable to Insurance Premiums (Exhibit B2-24, Undertaking No. 8).

Intervener Submissions

CEC raises the following concerns in its Final Argument about Fortis' proposed flow-through items:

1. The substantial dollar amount of the flow through items and the resultant loss of oversight of significant expenditures;
2. The loss of incentive to control partially controllable expenditures;
3. The combination of the incentive to reduce costs related to achieving revenues while flowing through the revenues, resulting in the lost opportunity for ratepayers;
4. The ability for a utility to flow through costs that might otherwise be included in its formulaic spending resulting in undeserved earnings at ratepayer expense.

(CEC PBR Final Argument, p. 172)

CEC further highlights its concern that by virtue of entering into the PBR regime and thus moving from a cost of service revenue requirement application to an annual review process, the Commission will lose the following:

1. Most of the oversight on flow through items; and
2. Openness and transparency.

(CEC PBR Final Argument, p. 172)

CEC points out that the flow-through items represent approximately 80 percent of FEI's revenue requirement or 60 percent of the delivery margin revenues (CEC PBR Final Argument, p. 173; Exhibit B2-8, BCUC 3.51.3). For FBC, approximately 82 percent of the revenue requirement is determined outside of the PBR mechanism (FBC Exhibit B-7, BCUC 1.21.1). CEC submits that given the fact that the majority of the costs and revenues are outside of the PBR formula, the result is a "significant loss of openness and transparency that would otherwise be afforded under a Cost of Service review." (CEC PBR Final Argument, p. 173)

CEC states that it "does not accept that the Utility is essentially unable to influence the vast majority of its costs." It submits that "[a]ctivities such as managing interest expense and taxes are key customer concerns that are tracked outside but are not entirely outside management control and under PBR there is limited to no incentive to manage these costs, nor appropriate oversight in the Annual Review." (CEC PBR Final Argument, p. 175) CEC further submits that "partially controllable areas may be a good place to apply more innovation especially since the earlier PBRs have apparently resulted in all the 'low hanging fruit' being already picked" (CEC PBR Final Argument, p. 176).

CEC also states that "incremental revenues in FEI are derived through RNG [Renewable Natural Gas], NGT [Natural Gas Transportation], new markets and increases in throughput and customer additions among others." CEC submits that it is "unreasonable to expect that the Utility will expend significant additional resources seeking projects that will increase customer load for customer benefit because such efforts are likely to increase costs included in the formulaic spending envelope and as such would not be in the Utilities' best interest." (CEC PBR Final Argument, p. 178)

CEC notes in its Final Argument that the Companies would not object to excluding only the insurance premiums portion of insurance expense from the I-X formula; however, CEC does not indicate whether it recommends this treatment (CEC PBR Final Argument, p. 189).

With regard to Rate Base other than Plant in Service, CEC submits “there is no particular need to have these variances subject to ESM... these items should be handled in a similar manner with other flow through items where the actual costs and revenues are the basis for customer rates.” (CEC PBR Final Argument, pp. 190–191)

BCPSO submits that it is reasonable that only the insurance premiums portion of insurance expense be excluded from the PBR formula; however, BCPSO disagrees with FBC’s proposed calculation of the insurance expense to be added to the 2013 Base O&M (BCPSO FBC Non PBR Final Argument, p. 4).

Fortis Reply

Fortis submits that its proposed flow-through treatment actually maintains the existing risk profile for customers and the Companies, and it is consistent with how these items would be treated under a cost of service model. Fortis further submits that eliminating flow-through treatment of uncontrollable costs would actually shift risk to the Companies. (Fortis PBR Reply, p. 39)

Fortis states that the flow-through items will be reviewed each year under PBR at the Annual Review, which is twice as often as under a two-year cost of service revenue requirements application.

Fortis further submits: “It is perplexing that CEC seems unwilling to rely on FortisBC’s willingness to propose revenue generating initiatives under PBR when it seems to trust FortisBC under COS [cost of service] and the incentives in each case are identical” (Fortis PBR Reply, p. 40).

Commission Determination

Fortis’ proposed lists of flow-through items are substantial when compared to the Companies’ overall revenue requirements. FEI’s proposal for flow-through items is comparable to its previous PBR plan, though certain items such as Late Payment Charges have been re-classified from controllable to non-controllable which has resulted in additional items being removed from the

PBR formula in the current Application. Under FBC's previous PBR plan, fewer items were treated as flow-through in comparison to FBC's current PBR plan.

The Panel is concerned by the Companies' broad-sweeping approach to its treatment of flow-through items and believes that it is likely that certain components within the broader expense/revenue categories could be classified as partially controllable and therefore added back into the PBR formula. However, the Panel acknowledges that whether or not certain of the proposed costs/revenues are controllable, partially controllable, or non-controllable, it may not be appropriate to inflate these costs using the proposed I-X formula, and there is no evidence on the record which provides alternative formulaic methods to apply to these costs/revenues.

Additionally, while a substantial percentage of the Companies' revenue requirements are proposed to be classified as flow-through, the largest percentage relates to cost of gas for FEI and Power Purchase Expense for FBC, neither of which are appropriate for inclusion in the PBR formula. The Panel recognizes the importance of aligning the PBR plan with the X-Factor research. Since many of these flow-through items were not excluded from the X-Factor research, excluding them from the formula reduces the Companies' risk and therefore should be considered a benefit to them.

Based on the aforementioned considerations, the Commission Panel approves FBC and FEI's proposed flow-through items with the exception of the items discussed below. The Panel notes that this determination relates only to whether or not Fortis' proposed costs and revenues are approved to be treated as flow-through items. The subsequent section in this Decision (Section 2.2.5.1) addresses whether variances between forecast and actual flow-through costs/revenues are approved to be recorded in deferral accounts.

Insurance Expense

The Commission Panel directs the Companies to flow-through only the Insurance Premiums portion of Insurance Expense. The remaining components of Insurance Expense must be added to the Companies' 2013 PBR O&M Bases. **The Panel directs the Companies to update the flow-**

through expenses in the Final Compliance Filings so that only Insurance Premiums are included in the Insurance Expense flow-through.

Flow-Through Items Subject to 50:50 Earning Sharing

The Panel agrees with CEC that it is not appropriate to apply the 50/50 ESM to flow-through items. Through responses to IRs, Fortis has identified the following flow-through items to which it proposes to apply the 50/50 ESM: FEI's Industrial delivery revenues, and FEI and FBC's rate base other than Plant in Service. However, this treatment was not specifically described in either Company's Application so the Panel is unclear as to whether there are other flow-through revenues and/or expenses currently proposed to receive this treatment. **The Commission Panel rejects Fortis' proposal to apply the 50/50 ESM to any of the flow-through revenues/costs and directs that the ESM mechanism is not to be applied to flow-through items.**

Issues Raised by CEC

With respect to the issues raised by CEC regarding the Companies' lack of incentive to develop revenue-generating projects during the PBR term, the Panel accepts Fortis' proposal to bring forward revenue-generating items at the Annual Reviews. The Panel does not consider the incentives regarding revenue generation to be any more or less impactful under a PBR regime than they are under a cost of service regime.

The Panel acknowledges CEC's concerns regarding lack of oversight and openness/transparency over the flow-through costs/revenues and agrees that a robust and thorough Annual Review process is a critical element of the PBR plan. This issue is addressed in Section 2.3.6 of the Decision as part of Annual and Mid-Term Reviews.

2.1.7.1 Deferral Accounts for Flow-Through Items

FBC proposes to establish a number of deferral accounts that are designed to specifically address some of its proposed flow-through items. The requested deferral accounts are:

- Tax Variance deferral account, with amortization in the following year;
- Property Tax Variance deferral account, with an amortization period of 3 years;
- Insurance Expense deferral account, with amortization in the following year; and
- Interest Expense deferral account, with an amortization period of 3 years.

FEI has previously received Commission approval to utilize the four deferral accounts listed above. The amortization periods for FEI's deferral accounts are the same as the amortization periods requested by FBC. (FEI Exhibit B-1-1, Appendix F4)

FBC submits that the deferral accounts are required in order to avoid windfall gains and losses given the uncontrollable nature of the proposed flow-through items. Additionally, FBC submits that this reduces the "controversy" around forecasting during the Annual Review process as any variances will be captured in the deferral account. (T4: 830)

FBC states that by utilizing these deferral accounts, customers only pay for expenditures that are actually incurred. FBC also submits that establishment of these deferral accounts will be consistent with FBC's sister companies, such as FEI (FBC Non PBR Final Argument, pp. 78–80).

For the deferral accounts which are proposed to have a three year amortization period – the Interest Expense Variance deferral account and the Property Tax Variance deferral account – FBC submitted that three years is appropriate because it provides a reasonable balance between rate smoothing and ensuring that customers are paying for the true cost of service in a timely manner. Additionally, FBC noted that the requested amortization period is consistent with FEI's approved amortization period for the same deferral accounts. (FBC Exhibit B-7, BCUC 1.190.6)

Further submissions on the nature of the proposed deferral accounts were also canvassed by the Commission Panel during the Oral Hearing Phase conducted on July 14, 2014 (Exhibit A-44).

Intervener Submissions

BCPSO has no concerns with FBC's proposed approach to calculating forecast income and property taxes for 2014 (BCPSO Non PBR Argument, p. 14).

BCPSO points out that FBC's main rationale for the difference in recovery periods for the two tax-related deferral accounts appears to be that the proposed recovery aligns with the recovery periods for comparable FEI deferral accounts. BCPSO submits that the amortization periods for refund/recovery should be more principled than just "that's how FEI does it." These principles should include considerations of: matching cost/benefits to the appropriate period as well as rate stability. BCPSO submits that a one-year refund/recovery period would appear appropriate unless there is a significant balance that is likely to create material rate instability. BCPSO does not elaborate on why one year is more appropriate. (BCPSO Non PBR Final Argument, p. 18)

In its Final Argument, CEC appears to support the deferral treatment for these proposed flow-through costs because they "can provide customers with reassurance that they will be paying the actual costs rather than forecast costs." CEC is of the opinion that the utilities have some control over income taxes, property taxes and interest expense but indicated that so long as they are being treated outside of the PBR formula, there will need to be a robust review of these expenses during the annual reviews. (CEC PBR Final Argument, pp. 187–189)

During the Oral Hearing Phase on July 14, 2014, the Panel posed the question: "are these deferral accounts necessary," and further "what other options are available?" (FBC Exhibit A-44, FEI Exhibit A-38) CEC and COPE submitted that they support FBC's proposal to establish these deferral accounts with the additional suggestion by CEC that tighter oversight is required. Most of the interveners observed that these deferral accounts were not in place during the last PBR and questioned the need for them at this time. The ICG suggested that another method would be to take the 2013 inflation adjusted actuals into the PBR formula and eliminate the need for deferral

accounts. IRG supported the proposal by ICG. Several interveners suggested that these deferral accounts are a transfer of risk from the utility to the ratepayer. (T8:1421, 1433, 1439, 1446–1451, 1462)

Commission Determination

In the previous section of the Decision, the Panel has determined that Fortis' proposed flow-through items, with the exception of a portion of Insurance Expense, are approved to be treated as flow-throughs to the customer. Now, the secondary issue is how to deal with the variances between forecast and actual amounts which will arise each year.

The issue before the Panel is whether establishment of these deferral accounts are necessary in order to enable the flow-through of expenditures. This issue applies to both FEI and FBC although FEI did not explicitly apply for any new deferral accounts for flow-through items.

The Panel notes that these deferral accounts were non-existent during FBC's last PBR and therefore does not agree that they should now be considered *necessary* in order to flow through these costs to ratepayers. During the last PBR, any differences between actual and forecast expenditures of prior years were identified in the Annual Reviews and then flowed through to the calculated revenue requirement for the current year. For example, incremental interest costs above the previous year's forecast were flowed through to the customer before the ROE sharing mechanism was applied. This method still allows for the flow through of these types of expenditures *without* the use of deferral accounts, particularly in the case where a deferral account has an amortization period of only one year.

FBC has requested the establishment of a Tax Variance deferral account and an Insurance Expense Variance deferral account with proposed amortization periods of one year. Because these deferral accounts are not required to flow through expenses under the PBR plan and the amortization periods proposed are limited to one year, **the Commission Panel denies FBC's request to establish the Tax Variance deferral account and the Insurance Expense Variance deferral account.**

With regard to the requested Property Tax Variance deferral account and the Interest Expense Variance deferral account, the Panel acknowledges that the situation is somewhat different due to the fact that FBC has proposed three-year amortization periods for these deferral accounts. While the Panel recognizes that rate smoothing is an important consideration when setting amortization periods for deferral accounts, it does not consider this to be a determinative factor in the case of these requested deferral accounts. The variances between forecast and actual/projected property tax and interest expense do not appear large enough to warrant a need to spread the amounts over multiple years. Therefore, the Panel applies the same reasoning for these requested deferral accounts as we did to the Tax Variance deferral account and the Insurance Expense Variance deferral account. The use of deferral accounts is not necessary to flow-through variances between forecast and actual expenses under PBR. **Accordingly, the Commission Panel denies FBC's request to establish the Property Tax Variance deferral account and the Interest Expense Variance deferral account.**

The Panel notes that the denial of these deferral accounts does not impact the determination that the actual expenditures of these items should be flowed-through to customers (see previous section in this Decision). In order to reflect in rates the actual costs related to these flow-through items as close as possible to the period in which they were incurred, **the Commission Panel directs FBC to true-up these costs each year.** Finally, the Panel also clarifies that these flow-through items should be applied first, and then a calculation of the earnings sharing mechanism will follow. This is the same treatment as conducted by FBC in its last PBR.

The Panel notes the distinction between FBC and FEI's current treatment of many of the flow-through items in that FEI has previously received approval for the deferral accounts requested by FBC in the Application.

However, the Panel refers to its determinations made above for FBC and re-iterates that these deferral accounts are not necessary to flow through costs to ratepayers. **Accordingly, the Commission Panel directs FEI to discontinue the usage of the following deferral accounts: the Tax**

Variance deferral account, the Property Tax Variance deferral account, the Insurance Expense Variance deferral account and the Interest Expense Variance deferral account.

For the deferral accounts which have a one-year amortization period – the Insurance Expense Variance deferral account and the Tax Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into 2014 rates and then discontinue the use of these accounts. For the deferral accounts which have a three-year amortization period – the Property Tax Variance deferral account and the Interest Expense Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into rates over three years and then discontinue these accounts. FEI must not add any additional variances to these four deferral accounts commencing January 1, 2014.

In order to reflect in rates the actual costs related to these flow-through items as close as possible to the period in which they were incurred, **the Commission Panel directs FEI to true-up these costs each year.** Finally, the Panel also clarifies that these flow-through expenses should be applied first, and then a calculation of the earning sharing mechanism will follow. In other words, the same treatment as conducted by FBC in its last PBR should be followed.

2.1.8 Growth Term

2.1.8.1 O&M Growth Term

Both utilities include a term in their O&M formula to account for an increase in spending that they submit is required to account for net additional customers added to the system. The term is a ratio between the current year's expected average number of customers and the previous year's actual number of customers:

$$(AC_t/AC_{t-1})$$

where AC is the average number of customers that the utility serves in the year t or t-1. The effect of this term, all else equal, is to increase (or decrease, as the case may be) the previous year's O&M spending by that ratio. (FEI Exhibit B-1, p. 57; FBC Exhibit B-1, pp. 52–53)

Intervener Comments

BCPSO submits that “[w]hile growth in customers is a driver of costs, the history of costs does not support both an increase related to inflation and an increase related to growth” (BCPSO PBR Final Argument, p. 8).

Table 2.19 shows FBC’s actual O&M per customer.

Table 2.19 FBC Actual Controllable O&M per Customer

	2008	2009	2010	2011	2012
Controllable O&M (\$000)	39,860	40,113	39,649	41,411	40,087
Number of Customers	108,722	110,286	111,551	112,754	113,587
Actual O&M per Customer	\$367	\$364	\$355	\$367	\$353

(Source: FBC Exhibit B-11, BCPSO 1.37.3)

For FBC, over the five years of actual results, the total O&M increases from \$39,860,000 in 2008 to \$40,087,000 in 2012, an increase of 0.14 percent in controllable O&M, compared to a 4.4 percent increase in customers over the same period. BCPSO’s expert, Mr. Bell submits that history does not support the need for a growth factor for O&M for FBC because the actual O&M per customer remains fairly constant. (FEI Exhibit C5-6, BCPSO Evidence, p. 13)

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Table 2.20 FEI Actual Controllable O&M

	2010	2011	2012	2013
Number of Customers ⁸	824,125	830,390	834,888	840,721
Actual O&M ⁹ (\$ 000)	206,518	213,606	212,269	233,891
Actual O&M per customer ¹⁰	\$251	\$257	\$254	\$278
Less Pension/OPEB/Insurance ¹¹ (\$ 000)	13,443	14,538	21,529	21,255
Total Controllable O&M (\$ 000)	193,075	199,068	190,740	212,636
Controllable O&M per Customer	\$234	\$240	\$228	\$253

BCPSO states that for FEI, the 2012 cost per customer is \$254, which is only 0.40 percent higher than the 2011 amount of \$253 (In FEI Exhibit B-6, BCPSO 1.16.2, FEI provided \$253 as the PBR tracked O&M per customer as opposed to the \$257 as shown in Table 2.20 which is calculated from the information in the Panel IR). This increase is lower than the inflation increase for that period, and in its view, does not demonstrate a need for a growth factor. It states that “[p]roviding a growth component, in excess of the I-X would not provide an incentive to continue this pattern of constant cost per customer.” (FEI Exhibit C5-6, BCPSO Evidence, p. 13)

Fortis disagrees, stating “[t]he simple fact that the results are provided on a per customer basis means that customer growth is reflected implicitly in the calculations already” (FEI Exhibit B-44, pp. 3–4).

However, Mr. Bell explains that if there was a need to allow for both inflation and a growth component, “one would expect to see that the O&M per customer would be going up on a constant basis, and I didn’t find that, and so that was how I reached the conclusion that to have an inflation factor as well as a growth factor would produce forecasts that are likely in excess of what is.” (T6:1307)

⁸ Exhibit B-54 Fortis Panel IR Response, Attachment 2.1, which includes 2012 customer count adjustment of 14,892 extended back to 2009

⁹ Exhibit B-1-5, Evidentiary Update February 2014, Table C3-1

¹⁰ Calculated as Total PBR¹⁰ Tracked O&M/Number of Customers

¹¹ Exhibit B-54 Fortis Panel IR Response, Attachment 2.1

Table 2.21 FBC FTE Count for the Period 2010 to 2012

2010	2011	2012
537.66	527.63	542.13

(Source: FBC Exhibit B-11, BCPSO 1.71.2)

BCPSO also argues that even if O&M costs do increase with growth, costs aren't as highly correlated to growth as the proposed formula suggests. It cites FBC's FTE levels, shown in Table 2.21 and FBC's comment that "[t]he FTE levels for 2013 and for the remainder of the PBR Period are expected to be at a level similar to 2012 on a total company basis." From this, BCPSO concludes that: "[g]iven the fact that the history of O&M does not support a growth factor, and the fact that FBC itself does not foresee growth in staff, a growth factor is not needed." (FBC Exhibit B-11, BCPSO 1.71.2; FEI Exhibit C5-6, p. 13)

Fortis submits that "[a] valid analysis cannot be based on a simple review of historical results, as they are highly dependent on the time period chosen and the assumptions made." (FEI Exhibit B-44, p. 3)

During the Oral Hearing, Mr. Bell testified that he agreed that as a utility adds customers, it must add various facilities and resources to serve those customers. However, in his view, "[u]sually a utility does not add incremental resources for each new service," because the utility would not "require additional resources immediately to maintain those facilities." Mr. Bell also stated that "[a]s you add more and more, eventually you need to add more resources" and that "when you reach a threshold" there will be a cost associated with adding the requisite resources. Mr. Bell agreed that these incremental costs apply when either FEI or FBC add customers. (T1:1311–1312)

In Fortis' submission, there are two reasons why it is reasonable to use customers to account for growth in the context of O&M. "First, adding customers directly impacts O&M. Costs for billing and meter reading are directly correlated to customer count and will increase as customer count grows. Costs for transmission and distribution operations and maintenance are indirectly related to

customer count and will incrementally increase as customer and customer capacity requirements grow.” (FEI Final Argument, p. 33)

B&V submits it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula because “it effectively adds an estimate of additional O&M expense associated with system growth to the plan’s revenue adjustment.” (FEI Exhibit B-1, p. 57; FBC, Exhibit B-1, p. 53)

In Fortis’ view, changing the O&M formula by removing growth, as advocated by Mr. Bell, is tantamount to increasing the productivity improvement requirements imposed on the Companies. Further to this, Fortis believes the structure of the O&M formula should remain the same as it has been in the past so that the productivity improvement requirements are clearly set out in the X-Factor, and not disguised in some combination of the X-Factor and growth or other elements of the formulas. (FEI Exhibit B-44, pp. 3–4)

CEC states that “there is a solid rationale for having an explicit term for operating scale in an escalation formula” (FEI Exhibit C1-22 BCUC 2.5.1).

2.1.8.2 Capital Growth

Table 2.22 shows the growth terms Fortis proposes for its Capital Formulas.

Table 2.22 Capital Formula Growth Terms

	FEI	FBC
Growth capital	$(SLA_t/SLA_{t-1})^{12}$	(AC_t/AC_{t-1})
Sustainment Capital	(AC_t/AC_{t-1})	(AC_t/AC_{t-1})
Other Capital	(AC_t/AC_{t-1})	(AC_t/AC_{t-1})

(Source: FEI Exhibit B-1, pp. 62-64; FBC Exhibit B-1, pp. 56-67)

¹² SLA = Service Line Additions

B&V states that:

“[o]f the three categories of regular capital expenditures that FEI has included in its PBR formula, Growth Capital differs from Sustainment and Other capital in that it is primarily driven by customer additions. In particular, Growth Capital is driven by service line additions (which are calculated as a percentage of gross customer additions) that arise from providing service for new customers. For that reason, the PBR formula FEI proposes to apply to Growth Capital is tied to the forecasted service line additions for the upcoming year. FEI will re-forecast the level of service line additions for upcoming years (driven off of the gross customer additions) in the PBR Annual Reviews.” (FEI, Exhibit B-1, p. 62)

With regard to FEI’s sustainment and other capital, B&V notes that in actual fact, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no convenient measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since the addition of mains to serve customers adds new capacity to the system. (FEI, Exhibit B-1, p. 63)

Concerning FBC, B&V states that:

“in actual fact, growth, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no straightforward measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since extensions of the system to serve customers adds new capacity to the system.” (FBC Exhibit B-1, p. 56)

Table 2.23 shows FBC’s historic capital spending for the years 2007 through 2012.

Table 2.23 FBC Total Non-CPCN Capital (\$ thousands)

	2007	2008	2009	2010	2011	2012
Generation Capital	19,781	15,355	18,411	17,555	15,956	6,985
Transmission-Dst Capital	95,575	76,321	72,416	104,488	48,109	35,734
Other Capital	13,834	7,912	8,342	8,448	12,145	9,674
Total Capital	129,190	99,588	99,169	130,491	76,210	52,393

(Source: FBC Exhibit B-15, ICG 1.36.1)

Table 2.24 shows capital expenses per customer FBC.

Table 2.24 FBC Capital Spending per Customer (\$)

	2007	2008	2009	2010	2011	2012
Customer Count	108,722	110,286	111,551	112,754	113,587	108,722
Generation Capital per cust.	\$182	\$139	\$165	\$156	\$140	\$64
Trns/Dst Capital per cust.	\$879	\$692	\$649	\$927	\$424	\$329
Other Capital per cust.	\$127	\$72	\$75	\$75	\$107	\$89
Total Capital per cust.	\$1188	\$903	\$889	\$1,157	\$671	\$482

(Source: FBC, Exhibit B-11, BCPSO 1.37.3)

Intervener Submissions

BCPSO states that there is no pattern of correlation between capital and customers and therefore submits that, “there is no demonstrated need for a growth factor for FBC capital” (FBC Exhibit C5-6, BCPSO Evidence, p. 14)

CEC submits that “there may be factors related to growth that increase costs but submits that they do not do so in a liner manner and that providing for both inflation and growth in a linear manner results in an unreasonable spending allowance.” (CEC PBR Final Argument, p. 68)

Commission Determination

Should the PBR Formulas include a Growth Term?

Mr. Bell suggests that because O&M expenses per customer haven't risen as quickly as inflation, there is no need for the O&M revenue formula to account for growth. The Panel does not agree with this interpretation. It is not possible to draw this conclusion because the evidence is inconclusive. The Panel agrees with Fortis that a historical examination of per-customer spending doesn't provide any information concerning the link between customer growth and costs incurred to meet the growth.

It is possible for expenses to be decreasing, for example due to efficiencies, at the same time that they are increasing due to an increase in the number of customers. Similarly, efficiencies could potentially drive a reduction in FTEs at the same time that an increase in customers drive an increase in the number of FTEs required.

With regard to efficiency driven cost reductions, the Panel notes that previously, FBC was under a PBR regime and during this period the X-Factor was approximately 2 percent for 2007, 2 percent for 2008, 3 percent for 2009 and 1.5 percent for 2010 and 2011. Inflation ran at approximately 2 percent during that period. (FBC, Exhibit B-1-1, Appendix D 1, p. 25) Given that FBC underspent its formula spending envelope during the last PBR, it is not unreasonable to expect that actual O&M per customer increased at a rate near or less than that of inflation.

Considering the issue of the effect of growth on spending generally, the Panel notes that a utility that services one million customers incurs more spending – both O&M and capital – than does a utility that serves 100,000 people. Therefore, it is reasonable to conclude there are cost increases associated with growth. Further, BCPSO acknowledges that customer growth is a driver of costs. The Panel is persuaded that it is appropriate that a revenue cap formula, such as the one Fortis proposes, should account for growth. However, what is at issue is the correlation between the actual number of customers and spending and therefore, what the growth factor should be.

Is the Growth Factor Fortis proposes the Correct One?

With the exception of FEI's growth capital formula, all growth terms are based on the number of customers. FEI's Growth Term is based on the number of service line additions. The Growth Term Fortis proposes for all formulas, except growth capital for FEI, is linear with a scale factor of 1. That is, if the number of customers is doubled, the spending envelope is, all else equal, doubled; if the number of customers triple, the spending envelope is tripled; etc. This relationship is the same over any range of customer numbers. For FEI's growth capital formula the same relationship applies to the number of service line additions.

However, growth related expenses may not be correlated in the manner suggested by the formula. Both capital and O&M growth related expenditures may be somewhat lumpy, causing spending requirements to increase in a step-wise manner. In this regard the Panel agrees with Mr. Bell's observation that costs only increase when a threshold in growth is reached.

For example, over a sufficiently large range of customer additions, there is correlation between the number of customers and the number of service trucks needed – increase the number of customers and there will be an increase in the number of trucks required. However, increasing by one customer, or ten, or even one hundred may not trigger the need for an additional truck. It is only when a threshold of new customers is reached that the need for a new truck is triggered and both the capital and O&M expenses associated with that new truck are required.

CEC argues that while costs do increase with growth, they may not do so in a linear manner. The Panel agrees this may be the case, and considers two examples of where costs do not increase linearly. A non-linearity may arise because of economies of scale. A utility that serves a million people may not incur 10 times the O&M spending as does a utility that serves 100,000. As the number of customers increases, the scale factor decreases. Potentially, many different scale factors could apply as the number of customers increases or decreases. Similar scaling issues may also apply to FEI's proposed growth capital Growth Term.

The issue of correlation between costs and the number of customers is further underlined by FBC's comments in its Non-PBR Reply (pp. 11–18). In response to a suggestion by CEC that customer service related costs be reduced to reflect a reduced number of customers, FBC submitted that it is inappropriate because "the costs for that department do not decline commensurately." Although this statement was made by and about FBC, it applies equally to FEI.

If the growth term in the formula doesn't accurately reflect Fortis' actual growth related spending requirements, in the Panel's view, the Growth Term should be adjusted. The adjustment may be in the form of a calibration to the proposed growth term – i.e. $0.5 * (AC_t / AC_{t-1})$ instead of $*(AC_t / AC_{t-1})$. Further, the calibration factor may be different for different levels of AC. However, there is no evidence of what, if any, calibration is required.

Of further concern to the Panel is that the Growth Term relies on Fortis' estimate of the average number of customers in the upcoming year. In the event of over estimation, the spending envelope will be larger than otherwise required, thereby resulting in an opportunity to over-collect. Although ratepayers and shareholders share, on a 50:50 basis, any over-collected amounts, this represents a transfer of wealth from the ratepayer to the shareholder. If estimates do not display any significant bias either upward or downward over time, this is not an issue. However, consistent overestimates of customer growth will result in an unjust transfer from the ratepayer to the shareholder.

In Fortis' proposed PBR mechanism, if there is an over estimate, there is never an opportunity for true-up. This is similar to the potential for bias that we observed in the use of a forecast inflation term.

Given these issues, the Panel is not persuaded that the proposed Growth Term is appropriate. We consider that the Growth Term as proposed has the potential to provide a more generous spending envelope than is warranted. **Given the lack of evidence concerning the quantum of the required adjustment, the Panel applies its best judgement and directs that the Growth Term be reduced by 50 percent. Further, to eliminate the possibility of potential bias, the Panel directs that the**

ratio be calculated as the ratio of the number customers or service line additions one year previous, to the number of customers or service line additions two years previous. The Panel recognizes that this introduces some lag into the formula calculation, but we consider it necessary in order to eliminate the potential of upward bias. This is the same approach we took in the case of the Inflation Factor. **Accordingly, the Commission Panel approved Growth Terms of $0.5 * (SLA_{t-1}/SLA_{t-2})$ for FEI's growth capital and $0.5 * (AC_{t-1}/AC_{t-2})$ for all other cases.**

If Fortis has evidence that a different growth term is more appropriate, it can bring forward that evidence at any time.

2.2 Key PBR Plan Components

2.2.1 Earnings Sharing Mechanism

An Earnings Sharing Mechanism (ESM) is a mechanism added to some PBRs to allow for the sharing of efficiency cost savings between the customer and the utility. ESMs are described as “regulatory tools in a PBR that are designed to enhance the alignment between customer and company interests and share the risks and the benefits of the PBR plan.” In addition, if symmetrical, they serve to soften the impact of unintended consequences such as excessive utility gains or losses within a PBR. FBC states that in regulatory literature there are two schools of thought regarding ESM usage. One school asserts that ESMs decrease the incentive power of the PBR plan and impose additional regulatory burden and cost. The other indicates that ESMs allow for improved cost tracking and mitigates concerns with excessive profits or losses and represents a fair approach to sharing the benefits of a PBR plan. (FBC Exhibit B-1, p. 64)

Fortis, citing support from B&V, has proposed that a symmetric ESM be made a component of the PBR Plan. The proposal is for an ESM based on the 2007 PBR which called for sharing on a 50:50 basis among customers and the utilities of earnings either above or below the allowed ROE in a given year. The plan is for the shared earnings to be projected during each Annual Review process but finalized after year-end when actual results are known. (FBC Exhibit B-1, pp. 64–65)

Intervener Submissions

CEC submits that the proposed plan has eliminated an opportunity for the customer to address concerns and adjust earnings accordingly and has also eliminated the no surprise clause and the line-by-line review process to determine levels of sharing. CEC considers that these changes represent a departure from customer interests. CEC also submits that the ESM does not limit customer risk as it does not limit the extent of utility financial earnings and serves to support a longer period between rebasing because the utility must share its earnings. This extended period has its downside for customers, one of which is the lack of transparency as there is no oversight over the five-year period. This extended period provides an additional three years with which to take advantage of additional earnings as compared to a standard two-year cost of service process. (CEC Final Argument, pp. 109–120)

None of the other Interveners had specific comments with regard to the ESM.

Fortis Reply

Fortis, in Reply, notes much of what CEC has to say relates to the PBR generally and are out of context. With respect to the ESM failing to limit the risk to the customer because it does not limit the earnings available to the utility, Fortis points out that the ESM serves to mitigate risk as there is equal sharing of both upside and downside results thereby creating balance. (Fortis PBR Reply, p. 45)

Commission Determination

The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers. In our view, the inclusion of an earnings sharing mechanism balances the interests of the customer and the utility. That is, to the extent that there are gains or losses relative to the approved ROE, the fact that they are shared on a 50:50 basis between the ratepayer and the utility is reasonable. The Panel notes that the purpose of implementing a PBR mechanism is to provide an environment where efficiencies are created through actions initiated by the utility. Accordingly, there is an expectation that all things being equal, the Fortis utilities will, over the

course of this PBR, generate efficiency savings resulting in earnings which allow them to exceed the approved ROE return. Fortis has proposed that these savings be shared. To deny the customer the opportunity of sharing these savings would not be in their interest. However, the Panel does acknowledge that in approving a symmetrical ESM we are, in effect, reducing the risk faced by Fortis on the downside and there is a potential negative rate impact in the event of unforeseen circumstances. However, given the historical performance of the Fortis utilities in achieving their approved ROE, we consider this downside risk to be limited.

The Commission Panel has considered the submissions of CEC with respect to the inclusion of an ESM. The points raised by CEC seem to be more concerned with the approval of a PBR and how it is designed than with the ESM itself. These include matters such as the elimination of the no surprise clause, the potential for earnings by simply not spending and the proposed term of the PBR relative to a more traditional cost of service agreement with a shorter time frame. While the Panel acknowledges that these matters are important, we agree with Fortis that with respect to having an ESM or not, CEC's arguments are out of context. To the extent possible, matters such as these will be dealt with in other parts of this Decision.

Given the apparent lack of trust between the parties in this proceeding and concerns with the potential to game the results, the Commission Panel considers the inclusion of an ESM to be a positive measure in that there is a sharing of gains or losses and does not favour either side. Additionally, the Panel notes that none of the parties have proposed its elimination. Given these factors, the Commission Panel considers an ESM mechanism to be appropriate at this time.

2.2.2 Efficiency Carry-Over Mechanism

An Efficiency Carry-Over Mechanism (ECM) is a plan component that allows the utility to receive benefits in periods following a PBR period for savings resulting from measures taken and costs incurred during the PBR period. Fortis describes the ECM as a means to incent the utility to pursue efficiency initiatives throughout the entire PBR period. It is justified on the basis that without it, the utility will have decreasing levels of motivation to initiate efficiency improvements as the PBR period moves forward. Fortis states this is because under a fixed-term PBR, the payback to a

utility's investment in efficiency improvements is earned only on those savings up to the end of the PBR. Therefore, the utility is motivated to initiate changes resulting in savings early in the PBR period to maximize its payback or in some cases to put off such projects because there is insufficient time remaining in the PBR to earn a return even recover costs. Inclusion of an ECM allows the utility to initiate efficiency improvements later in the PBR period but continue to earn a share of the return into the period following the PBR. (FEI Exhibit B-1, pp. 72–73; FBC Exhibit B-1, pp. 65–68)

The Commission approved the use of an ECM in the 2004 PBR Plan for FEI. The ECM allowed accumulated capital carrying cost and depreciation benefits to continue at a rate of 2/3 in the first year and 1/3 in the second year following the end of the PBR. In the current Applications, Fortis is proposing an enhanced ECM for both FEI and FBC which includes two additional components; the inclusion of O&M savings in addition to capital and the use of a five-year rolling carry-over period for the sharing of savings following the year in which the improvement occurred, regardless of when the PBR period ends. Fortis states that including O&M savings in the ECM maintains a balance between capital and O&M savings initiatives, and that the inclusion of a five-year rolling carry-over period eliminates concerns with timing from decision-making and promotes ongoing efficiency improvement initiatives. (FEI Exhibit B-1, p. 74; FBC, Exhibit B-1, pp. 66–67)

Based on this, Fortis proposes implementing the five-year carry-over plan where the incremental O&M and capital savings are calculated as the sum of:

1. Variance of current year formula based O&M less cumulative O&M savings from prior years of the PBR Plan; and
2. Current year plant additions savings relative to current year allowed plant additions derived from PBR capital formula multiplied by a base rate factor of 12 percent (15 percent for FEI).

Fortis states that the 12 percent rate base factor represents the avoided revenue requirements from reduced capital expenditures. Avoided revenue requirements components include return on rate base, depreciation expense and associated taxes. The 50:50 sharing between ratepayer and shareholder will apply to the ECM in the same manner as it does within the PBR period.

Fortis states that the inclusion of an ECM has the support of B&V “because it permits the utility to maintain a continuous improvement culture rather than be concerned about the inability to earn the required return on investments made in efficiency and productivity in the later years of the PBR Plan.” This is possible because disincentives to install new productivity initiatives as the PBR Plan ends do not exist. (FEI Exhibit B-1, pp.74–75; FBC Exhibit B-1, pp. 67–68)

Intervener Submissions

CEC considers the proposed ECM to be detrimental to ratepayer interests and does not agree with the mechanism proposed by Fortis. CEC recommends the ECM as proposed by the utility be rejected outright. It submits that its issues with the proposed ECM mechanism are significant and that the theory and rationale behind the mechanism is incorrect and the benefit claims are “presumed rather than actual.”

CEC considers the inclusion of O&M in the ECM represents additional ratepayer costs with no additional benefits. This “amplifies the underspending of an overly generous formula.” CEC further states that in addition to the inclusion of O&M and a rolling carry-over mechanism, the current ECM proposal includes a full payment rather than a declining one, has a longer term and includes an increase of the rate base benefit factor (from 14 percent to 15 percent for FEI). It submits that these changes are detrimental from a customer perspective and are not well supported in evidence.

CEC has numerous other issues with the proposed ECM mechanism. These include perverse incentives, basing rewards or benefits on a presumption that they last for at least 5 years and its inclusion eliminates benefits which would have been derived from rebasing. In CEC’s view the key issue is the determination of the appropriate time for rebasing embedded savings and further submits that this could vary considerably based on the nature of the efficiency project and life of potential savings.

CEC accepts that there will be instances where there will be value in the utility having longer payback periods available. These may be warranted where the utility has made a significant investment in efficiency measures. However, in such instances deferral accounts could be used as a mechanism to manage such longer-term payback periods. These would not limit the payback to any term and would reduce risk for the utility and ratepayers in addition to ensuring that there will be greater Commission oversight. (CEC Final Argument, pp. 23, 125–130)

BCPSO notes that ECMs are not common in PBR plans, pointing out that Fortis was only able to identify two jurisdictions in Canada where they exist. BCPSO's concern with the use of ECMs in this instance is that Fortis is using the building block model where:

“the utility can under spend on O&M and capital in each year and earn superior returns, and then claim an ECM. But there is no need, in circumstances where the utility can benefit from underspending the formula, to also provide an additional incentive to underspend in the form of an ECM.” (BCPSO PBR Final Argument, p. 11)

BCPSO's overarching concern is best summarized in the following statement: “the issue is that the company can spend less O&M and Capital, and in effect double dip, gain during the PBR period by spending less, and then achieve superior returns after the end of the PBR for the same reductions.” It submits that there is not a need for an ECM in this PBR. (BCPSO Final Argument, pp. 11–13)

BCPSO points out that Fortis' ESM is also a Loss Sharing Mechanism, in that it provides for a 50:50 sharing of earnings above and below the allowed ROE. In the event Fortis fails to earn its allowed return during the PBR period, the ESM requires ratepayer contribution above the formula derived costs during the PBR term, then additionally, the ECM requires ratepayer's shared contributions after the PBR term. (BCPSO PBR Final Argument, p. 14)

ICG does not support an ECM as it “does not believe that regulatory parameters affect efficiency initiatives in the manner suggested by FBC, at least sufficiently to justify the excess returns.” ICG submits that an ECM must not be a windfall for the utility and the Panel needs to be certain that its inclusion will benefit customers. However, if approved, the efficiency gains have to be measured and must be allocated symmetrically. That is “if efficiency gains are achieved then the utility

receives a higher return, but if efficiency losses are realized then the utility receives a lower return.” (ICG Final Argument, pp. 23–25)

ICG considers the utility to be responsible for achieving and then measuring efficiency savings. It provides a hypothetical example where the utility spends \$1 million on an efficiency initiative to achieve a \$500,000 efficiency saving. If the savings are than expected results then the utility, not the customer, pays the difference between the cost of the efficiency measure and actual savings. It appears that ICG is recommending that the 50:50 sharing mechanism which has been proposed by Fortis and approved by the Panel be suspended for the ECM applied beyond the end of the PBR period. In this way, the utility would receive the credit for any gains and also bear any losses related to an approved ECM in the period following the PBR. (ICG Final Argument, pp. 23–25)

Fortis Reply

Fortis, in Reply, views the position taken by CEC as to the “the customer continu[ing] to reward the utility when there are no earnings which it is ‘sharing with the customer’” as “starting from the wrong premise.” It reiterates that the inclusion of an ECM is designed to make the company whole for the costs not yet recovered in rates prior to the end of the PBR. In addition, it takes issue with CEC’s suggestion that the lack of research and documentation is the reason the ECM should be rejected pointing out that the concept is familiar in that ECMs have been used in previous PBRs and are currently in place in Alberta and Quebec. Fortis also notes that Dr. Lowry’s comments on ECMs were largely supportive of including this component.

Fortis had no additional comments regarding CEC’s concerns with respect to term length of the current ECM proposed and the move away from a declining payment schedule which had characterized earlier iterations.

Fortis also withheld comment on CEC’s contention that the time for rebasing savings is not always five years and varies by the nature of the efficiency project and the length of potential savings. The Commission Panel notes that Fortis had previously addressed CEC’s suggestion that as an alternative deferral accounts could be used as a mechanism to manage longer payback periods. In

response to CEC FEI 3a.38.5 Fortis states: “FEI believes that a deferral account approach would involve more regulatory process and would run counter to the objectives under PBR of streamlining the regulatory process and aligning the interests of customers with the interests of the utility.” Fortis further states that such an approach may be possible and could be applied to larger scale initiatives but it would be less practical to employ this with smaller scale programs. (Fortis Reply, pp. 49–52; FEI Exhibit B2-2, CEC 3a.38.5)

Fortis states in response to BCPSO’s comments that the underlying premise of its argument “is that the Commission is incapable of doing its job” and the inclusion of an ECM represents a significant downside for the customer. In Fortis’ view, the Commission should be reviewing this Application on the basis that it will be able to determine just and reasonable rates when next there is a COS Application. (Fortis PBR Reply, pp. 47–49)

Fortis makes no reply to the ICG submissions.

Commission Determination

The Commission Panel cannot help but acknowledge the level of cynicism and distrust implicit in the submissions of the interveners with respect to the inclusion of an ECM in the Fortis PBR. It is clear from these submissions that the interveners view the proposed ECM as being one-sided and very much in favour of the utility. BCPSO is perhaps most emphatic when it states that in spite of under spending on both O&M and capital in each year and earning what might be described as superior returns, Fortis then gets to claim their part of the ECM in the period subsequent to the PBR period. Concerning BCPSO’s comments, Fortis’ interpretation is that it is based on the underlying premise that “the Commission is incapable of doing its job” and in its view the Commission should consider this Application from the perspective that it will be able to determine just and reasonable rates in the next COS Application. The Commission Panel agrees. Our review of this Application should lead to determinations that, to the best degree possible, we can anticipate and control the ability of the utility to “game” any element of the PBR and minimize opportunities for Fortis to benefit at the expense of the ratepayer.

In the view of the Commission Panel, the ECM proposal put forward by Fortis favours the utility and puts the ratepayer at risk for future payments following the PBR period with no assurance that the savings will carry forward. Specific concerns of the Panel include:

Five-Year Rolling Carry-Over Period

As structured, the ECM is based on the assumption that any savings which occur warrant a payback period (which is shared between the ratepayer and the utility) of five years. There has been no compelling evidence to suggest that five years is an appropriate time period for all or any efficiency initiatives. The Panel notes that ECMs do not appear to be commonplace and, where they exist, no evidence has been presented to suggest they have a five-year payback period. There are variations of ECMs in both Alberta and Gaz Metro but neither of these extend for a five year period. (T2:305)

The Use of a Formula Driven O&M ECM Calculation

The ECM, as proposed, rewards additional O&M savings in later years of the PBR by carrying the reward for them over to the post PBR period. This, in the view of Fortis, provides an incentive to continue to develop efficiency measures in later years of the PBR. The Panel acknowledges there is some logic to this but also notes that there has been no attempt in the proposal to separate those savings that are related to an actual initiative from those that result from simply not spending the funds or being unable to do so due to circumstances unforeseen by Fortis. In either case, the savings would apply and carry over (albeit shared with ratepayers) into the post PBR period. Even if identified during the rebasing process, there would be instances where the Commission would have no option but to approve the inclusion of these savings as justified new expenses in future revenue requirements while, at the same time, allowing the savings for them to carry forward into the post PBR period. The Commission Panel considers the risk associated with this to be considerable. Moreover, while incenting the development of efficiency initiatives later in the PBR period, the Fortis proposal equally incents under-spending or gaming the formula.

The Use of a Formula Driven Capital ECM Calculation

Many of the concerns raised with respect to the O&M ECM formula also apply to capital. Delay of projects, whether through circumstances beyond the utility's control or by design are a commonplace occurrence. To apply a formula without consideration of the individual circumstances would leave it open for unintended consequences and potentially a windfall for the utility.

Given these reasons, the Commission Panel denies the Fortis request for the proposed ECM methodology. However, the Panel acknowledges that there will be instances where there are efficiency related programs with associated costs which may remain unimplemented if an ECM did not exist. Therefore, in spite of the concerns raised, we are persuaded that there is value in the inclusion of some form of ECM mechanism as a means of incenting the development of efficiency initiatives throughout the PBR period. However, the ECM mechanism must be transparent, flexible and allow a decision to be made on each initiative based on its individual circumstances taking into account the benefits, the period of the benefits, costs and likelihood for success. In addition, there is a need to track these investments and determine whether they deliver on the promised benefits. Creating a formal process to deal with ECM initiatives will provide greater transparency and hopefully reduce the distrust and cynicism referred to earlier.

Accordingly, the Commission Panel determines that the following steps are required in order for Fortis to receive approval for an ECM initiative;

- 1. ECMs will in most cases be handled within the context of the Annual Review although where warranted, the Commission could consider an ECM measure within the year.**
- 2. For each proposed initiative for which the benefits are expected to extend beyond the term of the PBR, Fortis will file an ECM proposal providing a description of the proposal, its timing, costs and benefits, and reasoning as to why it is appropriate and how long benefits should be paid.**
- 3. Parties will have the opportunity to comment on the proposal.**

If agreed to by the parties, the proposal will go to the Commission with a recommendation for approval. If not agreed to, the proposal will go to the Commission for a Decision or development of

further process. Based on these submissions, the Commission will make a determination as to the justification of each ECM proposal on a case-by-case basis.

2.2.3 Managing Service Quality

2.2.3.1 Purpose of SQIs

One of the more contentious issues with the Fortis PBR proposal is determining the role that SQIs play within a PBR Mechanism. SQIs have been recognized as an effective way to measure the performance of a utility from a variety of perspectives. These may include but are not limited to safety, customer service and service availability. As noted by FEI in its Application, SQIs “are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality” (FEI Exhibit B-1, p. 77). This raises the question that if service quality has been compromised in the interests of cost savings or efficiencies or simply suffers with no linkage to a particular act, what should be the consequences?

The Fortis proposal envisions that each year during the Annual Review, it will present the FEI and FBC projected results for SQIs to the parties and the related discussion will serve to provide an understanding of issues affecting the Companies’ ability to meet established benchmarks. Fortis has further clarified this issue by stating that unsatisfactory performance as measured by non-financial SQIs are more appropriately assessed at the mid-term review allowing for measurement over a longer time horizon. (Exhibit B-1-1, Appendix D7, p. 17; Exhibit B2-8, BCUC 3.25.1) Thus, it seems that while SQIs will be a matter for discussion at the Annual Review, Fortis views the Mid-Term Review as the appropriate time to determine whether a serious problem or degradation of service exists.

Fortis has outlined no specific process for dealing with a degradation of SQI results. It takes the position that if there has been a serious unaddressed degradation in results that remains unaddressed, the Commission can explore potential off-ramps. Fortis describes the “off-ramp provision” as contemplating a complete regulatory review of the PBR Plan. This would be triggered only if there was “sustained serious degradation of the SQIs.” (Exhibit B2-8, BCUC 3.25.2) This is in

contrast to previous PBRs where the SQIs were reviewed annually and interveners had some level of input as to the level of earnings share if SQI benchmarks were not met.

Fortis' position on penalties or rewards is that given Fortis' lack of control, they should not be linked to SQI performance relative to their benchmarks. As an example, Fortis notes that "colder than normal weather coupled with higher gas costs can increase call centre volume dramatically and result in a one-time reduction in SQI beyond the reasonable control of the Company." In such instances, it should not necessarily be rewarded or penalized. Fortis acknowledges that one of the themes throughout the proceeding is that the Commission should be concerned that Fortis' SQI proposal lacks enforceable consequences. It points to its ongoing history with the management of SQIs as support for its current proposal. It also states that its witnesses have consistently voiced their commitment to managing the business in a manner that maintains existing service levels. (Fortis PBR Final Argument, pp. 151–152; Exhibit B2-11 CEC 3.40.1; Exhibit B2-8, BCUC 3.25.3)

Intervener Submissions

CEC submits that in the event of performance failures without adequate explanations, it is appropriate to enforce consequences. It also notes the lack of a definition for a serious service degradation and cites the AUC Decision¹³ which developed a consultation process as a means of setting performance measures within PBR. CEC sees this as "an appropriate method of ensuring that the most important performance metrics are established and included as criteria for incentive payments." CEC believes the Fortis proposal leaves too much ground between the degradation of service and the move toward off-ramps. If service is degraded, the Commission is placed in the position of either accepting the results of degraded service or having to reconsider the entire regulatory process. CEC recommends that where targets are missed, the utility be subject to Commission examination during the Annual Review with a determination of appropriate consequences. (CEC PBR Final Argument, pp. 210–212)

¹³ Included as Exhibit B-1-1, Appendix D8, pp. 91, 881–883

ICG considers the purpose of SQIs is to ensure the utility does not sacrifice service quality during a PBR. However, its position is that SQIs are “not sufficiently sensitive, with too many confounding factors, for service quality indicators to detect any changes to either O&M activities or capital investments during a PBR Plan.” ICG argues that while reliability indicators like System Average Interruption Duration Index (SAIDI) or System Average Interruption Frequency Index (SAIFI) can change over time if maintenance activities or investments in infrastructure change, year-to-year changes are more affected by weather than any other factor. Consequently, ICG does not consider the professed purpose of SQIs to be achievable. (ICG Final Argument, pp. 35–36)

BCPSO notes that in the previous PBR, SQI results were reviewed annually and participants were able to make submissions with regard to whether a deviation from a benchmark was sufficient to warrant a limiting of incentive payments to the utility. Its view is that this approach should be taken in the current PBR plan as it falls short of cancelling the PBR in its entirety yet recognizes that customers suffer from a drop in service quality and should be compensated. (BCPSO PBR Final Argument, para. 64)

COPE states that at the “heart of the problem with the Companies’ Service Quality Indicators proposal is that the way it approaches the *service* side of the [regulatory] compact is not consistent with its approach to the financial *performance and reward* side. It adopts a mechanism of financial risks and rewards to boost the financial performance of the utilities, but rejects that approach to service performance.” (COPE Final Argument, p. 6)

COPE’s expert witness, Ms. Alexander provides substantial commentary on the application of penalties for sub-standard performance on SQI’s and recommends a program be put in place. These are also referred to as “compensation credits” designed to compensate the customer who has suffered the poor service quality (T5:875). Ms. Alexander was able to provide numerous examples in other jurisdictions where such penalty schemes are in place. (FEI Exhibit C2-13, BCUC 1.14.2)

In Final Argument, COPE muses that the use of the word “penalty” was unfortunate in that it was not an accurate reflection of Ms. Alexander’s concept, which was compensatory in nature and not really punitive. In spite of extolling the virtues of the approach recommended by its witness, COPE stops short of specifically advocating that the Commission consider implementation of a penalty based regimen. In its conclusions COPE states that it agrees emphatically with the Fortis statement made in Final Argument:

“In the event that the Commission considers the proposed PBR Plan and the existing statutory mechanisms to be insufficient, and considers it necessary to incorporate a term into the PBR Plan that makes earnings sharing conditional upon maintaining service quality, the Commission should proceed with caution to ensure that the PBR Plan remains compliant with the UCA and fair to the Company as well as rate payers” (FEI PBR Final Argument, p. 161)

COPE’s concern is that the PBR is slanted toward the utilities and a reinforcement of the customer service side of the regulatory compact is needed. It views the SQI component of the PBR proposal as seriously deficient and asserts there is a need for mechanisms to ensure sufficiently robust service standards that will inhibit any incentive the utility may have to cut corners. To this end COPE states that “SQI’s must be meaningful, they must be measurable, and they must have teeth” recommending the Commission develop an effective mechanism to rebalance PBR incentives to achieve this. (COPE Final Argument, pp. 46–50)

IRG does not support Ms. Alexander’s penalty recommendations and recommends the Commission reject them. In IRG’s view, the avoidance of penalties would become a distraction for FBC management and staff and not result in any material increases in service quality, reliability or safety. (IRG Final Argument, p. 12)

Fortis Reply

Fortis acknowledges that using Off-Ramps as an enforcement tool for SQIs is a blunt instrument. The Companies see it as a tool of last resort, stating that they have proposed the same service quality trigger that existed in previous PBRs. Related to this, Fortis does not define sustained serious service degradation considering it best to allow the Commission to consider all of the

circumstances before a decision is made to terminate the PBR. (Fortis PBR Final Argument, pp. 88–89)

In considering the proposal to limit PBR incentives as a means of enforcing service quality, Fortis makes the following submission:

“Under section 59 of the UCA, a rate is ‘unjust’ or ‘unreasonable’ if the rate is either ‘(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility’ or (b) insufficient to yield a fair return. The rates under PBR are set based on the utility taking appropriate steps to deliver a particular level of service quality. The rate yielded by the PBR Plan is, in effect, too high if service quality declines materially as a result of some imprudent conduct by the utility. A finding of imprudence is a precondition to disallowing a portion of the incentive because the overall PBR must still confer an opportunity to earn a fair return. The presumption of prudence would apply.” (Fortis PBR Reply, p. 90)

Commission Determination

There does not appear to be consensus among the interveners with respect to the Fortis SQI proposal. CEC, BCPSO and COPE are all in agreement that the Fortis proposal for the handling of SQIs falls well short of optimum and, to be effective, has to include consequences for serious degradation of service. For ICG and IRG the primary concern appears to be access to reliable service and neither supports the introduction of a penalty regimen as a means of achieving this. ICG has also raised concerns as to the effect of confounding factors such as weather on key reliability measures or whether established measures are effective at measuring the impact of changes in maintenance and infrastructure over shorter PBR time periods.

The Commission Panel is in general agreement with CEC, BCPSO and COPE with respect to the need for consequences related to service degradation. The Fortis proposal for the management of SQIs within PBR is much too vague and lacks consequences other than the potential for an off-ramp. The PBR is being approved with incentives for the utility to create efficiencies and reduce unnecessary cost. However, if O&M and maintenance capital are too tightly constrained this may result in a degradation of key service level areas. Therefore, the Panel considers that incentives related to reducing costs and creating efficiencies need to be counter balanced to ensure this occurs without a degradation of service levels as measured by SQIs. Confounding this somewhat is

the point raised by ICG that the short-term actions taken by the utility affect long-term SQI results but may have limited effect on short-term measurements for some SQIs. On the other hand, external factors such as weather may have a significant impact on short-term SQI measurements which dissipate when considered over the longer term. Fortis has acknowledged this latter point by recommending that an assessment of unsatisfactory performance on SQIs should not occur until the mid-term review following year three of PBR. The Panel notes there is no evidence on the record concerning the length of time it takes for an action undertaken by a utility to be reflected in SQI performance. In the Panel's view a drop in performance on a SQI would likely depend on the particular performance measure and the severity of the action or inaction of the utility. Therefore, the Commission Panel is not persuaded there is justification for SQI review to be delayed beyond the next Annual Review.

Considering these issues the Commission Panel determines that there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs. The Panel considers that a failure to underline the importance of SQIs sends the wrong message to the utility and invites behaviours which may not support the achievement of safe and reliable service.

The next question is "what consequences are most appropriate?" The ultimate consequence as proposed by Fortis is to invoke the off-ramp option and cancel the PBR. In the view of the Panel this should remain but in addition there is a need for less drastic alternatives to terminating the PBR. Ms. Alexander has proposed that the Commission institute a penalty regimen with predefined penalties (also referred to as compensation credits) assessed to the utility for failure to meet one or more SQI targets. This option received little support from the intervener group. Another option is to tie the achievement of the full earnings-sharing ratio conditional upon maintaining service quality levels. This approach, which was recommended by BCPSO, addresses a number of the concerns of interveners and creates consequences for failure to achieve satisfactory levels of service quality without going to a penalty based regimen as proposed by Ms. Alexander. This modified approach offers the advantage of linking consequences only to incentive earnings which exceed the Commission approved I-X formula driven ROE returns. Reducing excess earnings to no lower than the approved ROE is not unjust or unreasonable. In addition, because the maintenance

of service quality is tied to the earnings sharing mechanism, it will only apply when there are incentive earnings to share. This clearly establishes the achievement of service quality standards as a precondition to the earning of incentives. As a consequence, concern that a utility may be motivated to put the achievement of service standards at risk in order to earn an incentive is, to a degree, mitigated. **Therefore, the Commission Panel determines that the incentives earned must be linked to the achievement of service quality standards.**

2.2.3.2 What SQIs are Appropriate?

The issues related to which SQIs are appropriate for this PBR received extensive review within the proceeding. Fortis has proposed a set of SQIs it considers appropriate for the purposes of the PBR. It has also provided a proposal for discontinuing some of the SQIs currently in place. The Fortis proposal and related issues raised by interveners will now be discussed.

Fortis' Proposed SQIs

Table 2.25 outlines the SQIs FEI and FBC have proposed. Fortis has proposed a benchmark as a measure of service quality for many of these.

Table 2.25 Service Quality Indicators (SQIs) Proposed by FEI and FBC

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
Emergency response time	Percent of calls responded to within one hour	95%	Percent of calls responded to within two hours	85%
First contact resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter reading accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone service factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All injury frequency rate	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	--	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries	--
Customer satisfaction index	Informational indicator	--	Informational indicator	--
Public contact with pipelines	Informational Indicator – 3 year rolling average of number of line damages per 1,000 BC One calls received	--	N/A	N/A
System Average Interruption Duration Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIDI (average cumulative customer outage time)	--
System Average Interruption Frequency Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIFI (average customer outages)	--

(Source: FBC Exhibit B-1, p. 69; FEI Exhibit B-1, p. 76)

Discontinued SQIs Proposed by Fortis

As previously noted, Fortis has also proposed to discontinue a number of existing SQIs which they believe are of little value going forward. These include the following:

FEI Discontinued SQIs Proposal

- Transmission Reportable Incidents
- Leaks per Km of Distribution System Mains
- Number of Third Party Distribution System Incidents
- Accuracy of Transportation Meter Measurement First Report
- Number of Customer Complaints to the BCUC
- Percent of Industrial Customer Bills Accurate
- Number of Prior Period Adjustments

(FEI Exhibit B-1-1, Appendix D7, pp. 16–17)

FBC Discontinued SQI Proposal

- Generator Forced Outage Rate
- Residential Connections Completion Time
- Residential Extension Quoting Time
- Residential Extensions Completion Time
- Injury Severity Rate
- Vehicle Incident Rate

(FBC Exhibit B-1-1, Appendix D6, pp. 12, 13)

Intervener Submissions

More generally, CEC takes the position that the SQIs put forward by Fortis do not adequately protect the ratepayer. An example of this is the lack of asset health SQIs which may incent the delay of maintenance activities resulting in undesired consequences. It considers many of the proposed SQIs to be of greater interest to residential customers than to commercial customers noting that FEI has no insight into commercial sector satisfaction given the cancellation of the Large Commercial Customer Satisfaction Survey. (CEC PBR Final Argument, pp. 194–196; pp. 203–204)

In assessing SQIs, CEC recommends the Commission consider measures that:

- Provide long-term protection to all ratepayer groups from service degradation or increased expenses;
- Deter cost-cutting in areas that can or could affect service quality and reliability;
- Adequately address all areas of service, especially those that may be likely targets for cost-cutting; and
- Are measurable/quantifiable.

(CEC PBR Final Argument, p. 193)

COPE considers Ms. Alexander's approach to calibration of benchmarks to be reasonable and balanced and urges the Commission to adopt best practices and not rely "on the lowest common denominator in establishing its policies for SQI in the context of a PBR." COPE supports the notion of relying on 3 year averages as a means of controlling service volatility. (COPE PBR Final Argument, pp. 27–30)

Intervenors have made the following recommendations with respect to specific SQIs proposed by the Companies in their applications:

(i) Emergency Response Time

FEI proposes to change to the Canadian Gas Association (CGA) definition of an emergency event and the CGA response time calculation. Based on the CGA definition, FEI has, over the 2010 to 2012 period, responded to emergency calls within one hour 97.7 percent of the time. FEI proposes to set its emergency response benchmark at 95 percent stating that it is approximately equal to the industry average and in the top quartile of CGA members. (FBC Application, Exhibit B-1-1, Appendix D7, pp. 5–6)

CEC and BCPSO recommend that FEI should be required to maintain its emergency response time metric at current levels (97.4 percent) which it has been able to achieve on a consistent basis, rather than setting it at a lower level (95 percent). (CEC PBR Final Argument, p. 215; BCPSO PBR Final Argument, p. 19)

Over the same period FBC has responded to an initial identification of a loss of power, to arrival of FBC staff at the trouble site within two hours or less, 93 percent of the time. FBC states that its current benchmark is 85 percent and represents a level of response expected by its customers. It proposes to maintain the benchmark at this level.

BCPSO submits that the FBC emergency services benchmark should be set at least 90 percent as since 2007 FBC has achieved a level of 91 percent or higher and this is the level that customers have been receiving and has been sustained at current expenditure levels. (BCPSO PBR Final Argument, p. 16)

(ii) Meter Exchange Appointment

CEC and BCPSO agree with FEI's proposed 95 percent benchmark. CEC does not support the COPE proposal to replace this metric with a missed appointment customer credit of \$25. (CEC PBR Final Argument, pp. 215, 216; BCPSO PBR Final Argument, p. 19)

(iii) First Contact Resolution

CEC considers first contact resolution as important to customers, but its usefulness complements other measures (CEC PBR Final Argument, p. 217).

(iv) Telephone Service Factor (emergency)

CEC and BCPSO agree with the proposed benchmark that 95 percent of calls be answered within 30 seconds or less (CEC PBR Final Argument PBR, p. 216; BCPSO PBR Final Argument, p. 19).

(v) Telephone Service Factor (Non-emergency)

CEC submits that the average wait time is not necessarily indicative of the wait time experienced by some customers. CEC recommends the Companies develop an abandonment rate measure and SQI. (CEC PBR Final Argument, pp. 216–217)

Ms. Alexander recommends 80 percent for both FEI and FBC referring to this as the best practice standard. (FEI Exhibit C2-10, p.27) BCPSO had no objection to the proposed Telephone Service metric (BCPSO PBR Final Argument, p. 19).

(vi) Billing Index and Meter Reading Accuracy

Ms. Alexander recommends that both of these indexes be eliminated for FBC as modern computerized billing systems make billing and meter reading highly accurate and timely. However, the metric should be retained for the gas utility. (FEI Exhibit C2-10, pp.28–31)

CEC disagrees with COPE pointing out the measure allows for the identification of problems. (CEC PBR Final Argument, p. 217)

Fortis Discontinued or Informational Only SQIs

Both CEC and COPE have concerns that the Companies have removed any SQIs with benchmarks or targets that are related to reliability. CEC notes that establishing SQIs intended to reflect the experience between the customer and the company are inadequate protection of customer interests pointing out that the interests of ratepayers go far beyond the typical ‘customer experience’. CEC list customer interests such as asset health, corporate responsibility, special irrigation concerns or energy efficiency activities as examples of customer interests which are not covered by SQIs. (CEC PBR Final Argument, p. 202) Specific issues related to dropped or Informational Only SQIs are as follows:

(i) SAIDI and SAIFI

FBC proposes to report on the SAIDI and SAIFI service quality indicators on an informational basis only. Fortis suggests that these indicators are not considered to have a significant linkage between costs and results and it may take years for the results to be evident.

CEC believes that whether an indicator responds immediately or not to cost cutting should not exclude its use. In CEC’s view, the ratepayer needs protection from long-term degradation in reliability which in its view stems from asset health which can be affected by the level of expenditures on maintenance. (CEC PBR Final Argument PBR, p. 203–205)

COPE submits that FBC's generally acceptable performance for reliability as exhibited by SAIFI and SAIDI would be placed at risk during the PBR period by relegating it to an informational SQI with no performance target. (COPE Final Argument, p. 18)

(ii) All Injury Frequency Rate (AIFR)

Both FEI and FBC propose the use of the AIFR as an informational SQI. COPE argues that the Companies should be held accountable for AIFR results. While recognizing that the Companies cannot control the conduct of all their employees at all times, its expert witness, Ms. Alexander notes "management is in charge of the workplace culture, the safety systems, and the educational activities designed to prevent as many workplace accidents as possible." (COPE Final Argument, p. 40)

(iii) Public Contact with Pipelines

FEI has introduced the public contact with pipelines SQI to reflect the importance of educating the public on the risk associated with pipeline contact. The SQI is a "measure of the overall effectiveness of the public's awareness to minimize damage to the gas system, which will reduce risk to public safety and service interruptions for customers." FEI proposes that this SQI be an informational measure with no benchmark. (FEI Application, Exhibit B-1-1, Appendix D7, pp. 12, 13)

COPE argues that this is an important measure related directly to public safety and FEI should conduct itself in a way which mitigates risks and be held accountable for the results (COPE Final Argument, p. 38).

Fortis Reply

Fortis considers it appropriate that it has relied on a suite of SQI's that focus on the direct customer experience noting that the interveners seek to include additional performance indicators concerning a variety of matters including asset health and corporate responsibility. Fortis acknowledges that these matters may be of interest to customers but argues that it does not necessarily follow that SQIs related to these matters should be covered under the PBR plan. In

support of its approach, Fortis notes that the Companies do not have the discretion to allow assets to deteriorate and they already report to the Commission in considerable detail in a more useful format (citing comments from T6:1196 with reference to metrics on the state of the assets and the reporting regimen through the Oil and Gas Commission).

Fortis argues that its current level of service is high and

“[i]ncreasing service level requirements above the benchmarks proposed by FortisBC will give rise to asymmetric risk in circumstances where there is no direct correlation between utility spending and service levels.” In other words, the odds are higher of missing a high benchmark metric as compared to a lower one unless it can be determined that additional expenditures can produce the desired results. It explains that it has set a reduced benchmark of 95 percent in the case of Emergency Response times because “the odds of falling below the benchmark of 97.6% for reasons beyond utility control are significantly higher than would be the case with a benchmark set at 95%.” (Fortis PBR Reply, p. 84)

Commission Determination

There are two key issues that the Commission Panel must address. The first of these is concerned with whether the SQI’s proposed by Fortis are appropriate. If not, what SQIs should be added? Related to this is whether the informational indicators as proposed, should be so categorized or whether some of these should be upgraded to full SQIs with performance benchmarks. The second issue deals with the level of the performance benchmarks.

Are Fortis’ Proposed SQIs Appropriate?

Under the *Utilities Commission Act* the Commission has an obligation to ensure the utility is supplying “reasonable, safe, adequate and fair service” (s. 25). Reasonable, safe and adequate service entails providing services that are reliable, responsive to consumer needs and protective of the safety of the public which includes both ratepayers and employees of the Utilities. The Commission Panel considers Fortis’ contention that SQIs should be focused on the customer experience as being too narrow in scope. In our view, the SQIs are a mechanism to assist the Commission to ascertain whether the Companies are living up to the obligations envisaged in the regulatory compact and legislated under the UCA.

The proposed benchmarked SQIs are focused primarily on the areas of direct interaction between the Companies and customers and don't fully reflect all of its service obligations. **Therefore, the Commission Panel finds that they are not a balanced set of indicators covering reliability, responsiveness to consumer needs and providing for the safety of the public.** All of these are required to enable the Commission to evaluate whether the Companies are meeting obligations under the UCA.

The Commission Panel notes that only two of the benchmarked SQIs proposed by FEI relate to safety (Emergency Response Time and Telephone Response – Emergency) and only one FBC SQI is safety related (Emergency Response Time). The remaining benchmarked SQIs, five in the case of FEI and four for FBC relate to customer/company interactions. Further, FEI has no service quality indicators dealing with reliability of service while FBC has only two, SAIFI and SAIDI, both of which are proposed as informational indicators. In our view, this does not reflect a balanced approach.

A concern has been raised by many interveners with respect to the elimination or a move to informational status of reliability related SQIs. Given the length of term of the PBR, the Panel agrees and is equally concerned that there are no SQIs with established performance targets to address reliability. Moreover, in our view, the lack of SQIs fails to meet the Commission's need to assure itself that service quality, as required by legislation, is being met.

The Commission Panel has separated SQIs into three categories: Safety, Customer Needs and Reliability. **Within these categories the Commission Panel approves the following SQIs proposed by Fortis:**

- **Safety**
 - **Emergency Response Time**
 - **Telephone Service Factor (emergency)**
- **Customer needs**
 - **First Contact Resolution**
 - **Billing Index**

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- **Meter Reading Accuracy**
- **Telephone Service Factor (non-emergency)**
- **Meter Exchange Appointment**

In addition, the Commission Panel directs that a number of Fortis' proposed informational SQIs be re-classified as benchmarked SQIs. These include:

- **Safety**
 - **All Injury Frequency Rate**
 - **Public Contact with Pipelines**
- **Reliability**
 - **SAIDI (weather normalized) FBC only**
 - **SAIFI (weather normalized) FBC only**

Further, the Panel approves the following informational indicators:

- **Customer Satisfaction Index**
- **Telephone Abandon Rate**

and we direct Fortis to reinitiate the following informational indicators:

- **Generator Forced Outage Rate**
- **Transmission Reportable Incidents**
- **Leaks per KM of Distribution System Mains**

Telephone Abandon Rate, while reported by Fortis to be very low (T6:1275), has not been reported previously. The Panel considers this a useful measure in determining the level of service failure which is important given the Fortis proposal to lower its Telephone Service Factor SQI benchmark metric. The Panel has also directed Fortis to reinstate Generator Forced Outage Rate, Transmission Reportable Incidents and Leaks per KM of Distribution System Mains as informational indicators. While the Panel accepts the FBC argument that it has a portfolio of resources to draw upon if a generator fails, we note that a generation failure might impact power purchases thereby having an impact on rates. Because of this, it remains a valuable indicator. Likewise the Panel considers

Transmission Reportable Incidents a valuable informational indicator as it tracks the number of reportable incidents to outside agencies such as the BC Oil and Gas Commission and WorkSafe BC.

With respect to the proposed SQIs which have been approved, the Panel notes the position of Fortis that the Billing Index and Meter Reading accuracy may not be needed due to their consistently positive results, and agrees with Fortis' assessment of the value to customers. However, we recommend that this be revisited at some future Annual Review during the PBR.

The Panel has changed a number of informational indicators to benchmarked SQIs. Under Safety, AIFR and Public Contact with Pipelines have been added. In the view of the Panel both of these measures reflect important safety concerns. The Panel agrees with COPE that while the Companies cannot control the actions of their employees, they are accountable for them, and as such, are responsible to take steps to mitigate any harmful behaviour. Therefore, this is an appropriate SQI metric which should be benchmarked and managed. The Panel has a similar view with Public Contact with Pipelines. As pointed out, performance on this SQI is a reflection of public awareness and while the public cannot be controlled, FEI can heavily influence performance on this SQI through the activities it undertakes to create awareness.

Under Reliability, the Panel has added SAIDI and SAIFI as benchmarked SQIs for FBC. We agree with COPE's and CEC's arguments that the ratepayer should not be placed at risk over the PBR period by relegating this to an informational indicator. This SQI goes to the heart of concerns raised by interveners with respect to underspending of capital. While the Panel acknowledges that both of these measures have to be viewed over the longer term and may be more affected by weather in the short term, we consider them valuable as indicators of utility performance.

Level of Performance Benchmarks

With regard to existing SQIs, Fortis proposes changes to two performance benchmarks. FEI proposes that Emergency Response Time be reduced from its average performance level over the 2010 to 2012 period of 97.7 percent to a slightly reduced performance benchmark of 95 percent.

The Commission Panel considers the performance benchmark of 97.7 percent (FEI Exhibit B-1-1,

Appendix D7, p.6) to be appropriate as it reflects current performance and directs Fortis to set the SQI benchmark at this level for the purposes of the PBR. The Panel further directs that the FBC Emergency Response benchmark be set at 93 percent, which reflects the average Emergency Response achieved over the 2010 to 2012 period. The Panel acknowledges the concerns raised by Fortis with respect to the odds of falling below this level. This concern is dealt with in Section 2.3.3.3 where the introduction of “satisfactory performance ranges” is addressed.

A second change recommended by Fortis is related to FEI’s non-emergency Telephone Service Factor. Fortis proposes to reduce the percentage of calls answered in 30 seconds to 70 percent from 75 percent. **The Commission Panel approves the reduction to 70 percent.** Although there is evidence that the industry standard is 80 percent, the Panel grants this approval for two reasons:

- Fortis reports a very low abandon rate in the 2 percent range for both FEI and FBC.
- FEI has implemented the call-back capability of its new system with substantial uptake. This mitigates to an extent the impact of unreasonable wait times.

In consideration of these factors, the Panel is persuaded that customer needs are being met. In addition, the Panel has ordered that in the future Fortis track phone call abandon rate as an informational indicator. If there is an increase in abandon rates the Commission may revisit telephone service SQIs in the future. **The Commission Panel approves the Fortis proposed benchmarks for all other proposed benchmarked SQIs.** The Panel notes that all of these are sufficiently high to be reasonable or reflect an average of recent performance levels.

For all new benchmarked SQIs the Panel directs Fortis to rely upon a 3 year average for 2010, 2011 and 2012 in calculating its performance benchmark. This methodology will be addressed further in Section 2.3.3.3.

A summary of these determinations and performance benchmarks are included in Table 2.26. **The Commission Panel directs Fortis to utilize the SQIs set out below for the PBR period. The Panel considers these to be balanced and collectively address service reliability, safety and customer needs.**

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Table 2.26 Approved Service Quality Indicators (SQIs)

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
Safety SQIs				
Emergency Response Time ^{3,5}	Percent of calls responded to within one hour	97.7%	Percent of calls responded to within two hours	93%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All Injury frequency rate ^{1,5}	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64
Public contact with pipelines ^{1,5}	3 year average of number of line damages per 1,000 BC One calls received	16	N/A	N/A
Responsiveness to Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter Reading Accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Customer Satisfaction Index	Informational indicator	--	Informational indicator	--
Reliability SQIs				
System Average Interruption Duration Index – Normalized ^{1,5}	N/A	N/A	3 year average of SAIDI (average cumulative customer outage time)	2.22
System Average Interruption Frequency Index – Normalized ^{1,5}	N/A	N/A	3 year average of SAIFI (average customer outages)	1.64
Generator Forced Outage Rate ²	N/A	N/A	Informational indicator.	--
Transmission Reportable Incidents ²	Informational indicator – Number of reportable incidents to outside agencies	--	N/A	
Leaks per KM of Distribution System Mains ²	Informational indicator	--	N/A	

¹Changed from an informational indicator to a benchmarked indicator

²Added as informational Indicator

³Benchmark changed

⁴Added benchmarked SQI

⁵Benchmark calculated as the average over the 2010, 2011 and 2012 period

2.2.3.3 Process to Review and Manage SQIs

The first issue the Panel must consider is whether holding the Companies to firm performance benchmarks is a reasonable approach to manage SQIs in a PBR context. Once this has been determined, the next issue is how best to implement a process to tie consequences to the failure to achieve reasonable performance on SQIs.

FEI explains that in establishing the SQI benchmarks it has relied on the Company's performance over recent years or on general industry standards. (FEI Exhibit B-1-1, Appendix D7, p. 2). It believes it is appropriate to base the proposed benchmarks on performance in recent years because the benchmarks are then reflective of the costs required to provide the service levels. (FEI Exhibit B-6, BCPSO 1.26.1) The use of a rolling average acts to smooth out annual results providing for a longer term indicator of any trends that may be developing. (FEI Exhibit B-6, BCPSO 1.26.1; FBC Exhibit B-7, BCUC 1.60.1.1)

As noted earlier, COPE has taken the position that the best way to determine SQIs and reduce volatility in results is to rely on a three year average for determining performance benchmarks for SQIs. Fortis has responded by pointing out that a drawback to relying upon an average is that actual amounts will fall above and below the average. Thus, what might be interpreted as a decline in service may not be reflective of what is occurring. (Fortis PBR Reply pp. 82–83)

Fortis has noted that in using a three-year average to set the SQI benchmark, by definition there will be years within the average that are below the average. For these reasons the Companies do not see the merit of tying specific consequences to the SQI benchmark targets. (Fortis PBR Reply, pp. 82-83)

Commission Determination

The Commission Panel agrees with Fortis and determines that it is not appropriate to require Fortis to be held to a specific performance benchmark for the following reasons. First, it does not take into account why SQIs are part of the PBR in the first place; that is to help mitigate the potential of serious degradation of service levels. Does being a percentage point below a prescribed performance benchmark result in a serious degradation of service? In most cases a drop of this amount would have minimal impact yet could result in a penalty being imposed. Second, there is the issue of averages. If averages are relied upon to determine the performance benchmarks it follows that results will fall below the benchmark approximately one half of the time. **Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.** The achievement of performance metrics that fall within this range is acceptable. Performance outside of this range would be unacceptable representing a serious degradation of service which would be subject to consequences. Performance benchmarks would continue to be determined which would serve as a target only and failure to reach them would not have consequences.

Determining the Performance Benchmarks and an Acceptable Performance Range

While the Panel agrees with Fortis that a three-year average helps to smooth out annual results, we do not agree with the use of a rolling average. Use of a rolling average is inconsistent with the concept of a satisfactory performance range as it could perpetuate a downward trend. The Panel agrees with BPCSO that setting the benchmark based on the last three-year period for which annual data was available (2010, 2011 and 2012) establishes the benchmark at a level that is reflective of the costs required to provide this level of service. The Panel has previously approved a performance range which provides for normal annual variability. **The Panel determines it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for the SQIs that the Panel has directed to be modified or added.** Once set, these will serve as performance benchmarks for the balance of the PBR.

The Commission Panel has considered options for setting an acceptable performance range for SQI metrics. In our view this is not simply a matter of setting a plus or minus percentage range that would be applied to all SQIs. Rather, a variety of factors like the economy, weather and the potential for variation must be considered in determining the range. **For this reason, the Panel directs the Companies, in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory.** An appropriate time to deal with this is in the period leading to the first Annual Review. Consultation among the parties should form a part of the process with recommendations flowing from it. **In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.**

In establishing the performance range for SQIs, the Panel expects the Companies and the stakeholders to take into consideration the following factors:

- The variance that has been experienced in the benchmark historically;
- The historic trend in the benchmark;
- The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;
- The sensitivity of the benchmark to external factors such as weather or economic conditions; and
- The impact of lower SQI levels on the provision of reliable, safe or adequate service.

Failure to Meet SQI Benchmarks

Where one or more of FEI or FBC's SQI performance metrics are outside the established range, the matter will be handled as part of the Annual Review. **Where the parties are unable to agree on a resolution to mitigate the problem or the parties consider further process to be warranted, the Panel directs them to refer the matter to the Commission.**

Where, after due process, the Commission finds that Fortis has failed to provide adequate service and the failure was, in whole or in part, due to the actions (or inactions) of Fortis, the Commission may reduce the share of earnings above the allowed rate of return that would otherwise flow to

the Company. The reduced share of earnings would be credited to customers in the form of a compensation credit. **The Panel directs that the maximum reduction to the incentive earnings will be an adjustment to the earnings sharing mechanism to reflect a 60 percent ESM share to the customer rather than the standard 50 percent.**

When assessing the magnitude of any reduction in each Company's share of the incentive earnings, the Commission will take into account the following factors:

- Any economic gain made by each Company in allowing service levels to deteriorate;
- The impact on the delivery of safe, reliable and adequate service;
- Whether the impact is seen to be transitory or of a sustained nature; and
- Whether each Company has taken measures to ameliorate the deterioration in service.

Where there are no incentive earnings to share (i.e. the rate of return achieved by the Companies are at or below the approved rate of return), the Commission may still assess whether the level of service provided by the Company is adequate. In this case, the actions taken will be driven by the provisions in the UCA. This might include ordering Fortis, under section 25 of the UCA, to take certain actions to remedy a service deficiency or the imposition of an administrative penalty under section 109.2 of the UCA.

2.2.4 Off-Ramps

Off-ramps are described in the Companies' Applications as "a term of a PBR Plan that contemplates a complete regulatory review of the PBR Plan in particular limited circumstances" (FBC Exhibit B-1 pp. 69–70; FEI Exhibit B-1 p. 77). This section addresses off-ramps that could lead to a broader review of the entire PBR Plan and potentially to a termination of the PBR Plan altogether.

There are two off-ramp triggers proposed, a financial trigger and a non-financial trigger. The financial trigger is engaged when the post-sharing earnings of the Company exceeds or drops below the allowed ROE by 200 basis points. Given the 50:50 earnings sharing mechanism, this means that actual earnings would have to be above or below the approved ROE by 400 basis points

to trigger a review of the PBR Plan. Fortis states that the allowed variance between the actual and approved ROE before the off ramp is triggered must be large enough to incent the Companies to pursue efficiencies while at the same time be limited enough to safeguard against potential excessive profits or losses. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

Fortis proposes that the non-financial trigger would be engaged if the Companies' service levels fell to an unacceptable level. In the Companies' view, only a "sustained serious degradation of the SQIs" would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet an SQI(s) must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

2.2.4.1 Financial Trigger

Previous Fortis PBR Plans in British Columbia

Neither of the earlier PBR plans of FEI or FBC included a firm quantitative reopener or off-ramp. However FEI and FBC, as part of the Annual Review process had the right to request a change or termination of the PBR Plan if there were unacceptable outcomes associated with it.

B&V states: "[t]his provision does not represent the best approach to addressing serious issues with a PBR plan." However, B&V sees the provision as "understandable" within a negotiated settlement that includes a number of other provisions. (FEI and FBC Exhibit B-1-1, Appendix D1, pp. 46–47)

The 2004 FEI PBR Plan had a trigger of +/- 150 basis points around the approved ROE (after earnings sharing) but this was not considered an automatic off-ramp. It was open for parties to request a Commission review of the 2004 Plan if the threshold was exceeded. The 2007 FBC PBR Plan had a trigger mechanism of +/- 200 basis points around the approved ROE but this was not an off-ramp. If the earnings threshold was exceeded, the earnings variance (positive or negative)

would be placed in a deferral account for review and disposition at the next Annual Review. (Fortis PBR Final Argument, p. 56)

In the previous PBR period, the Companies exceeded their allowed rate of return by a maximum of 145 basis point (FEI) and by 115 basis points (FBC) (Exhibit B2-11, CEC 45.4). Considering its previous PBR plan, FBC states: “FBC’s going-in rates for this PBR Plan already incorporate substantial productivity savings achieved through the 2007-2011 PBR period, and those that have been realized in the 2012-2013 period through a renewed productivity focus. As a result, it will be challenging for this PBR Plan to produce the same level of savings that were realized under the 2007 Plan.” (FBC Exhibit B-1, p. 5)

Intervener Submissions

CEC submits that the +/- 200 basis point differential post-sharing is too high. CEC notes this is equivalent to a +/- 400 basis point variance if there were no earnings sharing mechanism and is 50 basis points higher than the previous FEI PBR plan. CEC states that there is “little justification for either the number itself or for an increase.” The proposed financial trigger is viewed by CEC as relatively high in comparison to other jurisdictions where the trigger is +/- 300 basis points with no earnings sharing mechanism. (CEC PBR Final Argument, pp. 165–166)

CEC recommends that the financial off-ramp should be set at the level of +/- 150 basis points (CEC PBR Final Argument, p. 171). CEC further advocates the use of a multi-pronged trigger to better protect customer interests if a PBR plan is approved (CEC PBR Final Argument, pp.167–168).

CEC also contends that the financial trigger is asymmetric in that Fortis, regardless of the PBR trigger, has the ability to file a cost of service application at any time if its actual rate of return falls too far below the allowed return. CEC does not see the consumer having the same redress if actual ROE is consistently significantly above the allowed ROE but below the trigger. CEC further asserts that Fortis could moderate or apply a cap to its earnings to avoid triggering an off-ramp.

Fortis refutes the suggestion that the off-ramp is asymmetric. Fortis submits that customers have the same opportunities afforded by an off-ramp as the Companies. Fortis may address financial

distress through an application to the Commission while customers may use an equivalent mechanism of filing a complaint to the Commission. In addition, Fortis states there is nothing in the PBR Plan “that would (i) purport to unlawfully fetter the Commission’s discretion in the future, or (ii) skirt the rule against retroactive ratemaking.” (Fortis PBR Reply, pp. 52–53)

Fortis also refutes the concept of a multi-prong trigger. In response to a CEC information request, stating it would not support a two-year trigger concept because:

- Dual trigger points are more prone to controversy for potential gaming concerns. (i.e. by increasing expenditures in one year to lower the actual ROE to compensate for a high ROE achieved in a previous year); and
- Fortis intends to pursue efficiencies and savings on a consistent basis throughout the PBR term. In Fortis’ view this means that if the two-year trigger was set significantly below the single year trigger, there is a high likelihood that if one year’s results were above the two-year trigger level, the subsequent year likely would be as well. This would trigger the off-ramp to the detriment of achieving longer-term benefits under the plan. (Exhibit B2-11, Fortis CEC 3.45.3, pp. 114–115)

Fortis submits that CEC has provided no rationale to explain why a multi-prong trigger point is more appropriate than a single trigger point. (Fortis PBR Reply, p. 53)

ICG supported the off-ramp elements of the Fortis application (ICG PBR Final Argument, p. 25). No other interveners addressed the financial trigger in the off-ramp.

Commission Determination

The Commission Panel views the triggering of an off-ramp as setting in motion a two-stage process. The first stage consists of a process before the Commission to assess potential remedies to the situation, including the potential for amending or re-calibrating the PBR plan to allow it to continue. A second stage to the process would be triggered if satisfactory solutions could not be found through modification of the PBR plan. This stage would deal with how to exit from the plan. This could include a variety of options from going back to a cost of service methodology to a redesign of the PBR.

With respect to the financial trigger, the Commission Panel agrees with Fortis that it should strike a balance between being high enough to incent the utility to vigorously pursue efficiencies and savings while being low enough to provide a safeguard for customers and the utility if either profits or losses become excessive. The applied for +/- 200 basis points post-sharing means that the achieved ROE before the earnings sharing is calculated would be +/- 400 basis points. This compares to the one year trigger point set in Alberta at +/- 500 basis points (with no revenue sharing) and the OEB trigger point of +/- 300 basis points, both of which are criticized by Fortis' consultant as being too broad. The AUC tempered its one-year trigger by also imposing a two-year trigger of +/- 300 basis points. The Panel notes that Fortis' expert witness testified that "I'm not aware that any utility would get to the point of being 200 basis points below their allowed return without filing a cost of service application" (T4:791).

In the Commission Panel's best judgement, a multi-pronged trigger strikes an appropriate balance between incenting the Companies to find efficiencies and savings and protecting the interest of the ratepayers. The Panel directs that an off-ramp be triggered if earnings in any one year vary from the approved ROE by more than +/- 200 basis points (post sharing). The Commission Panel further directs that should earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years, the off-ramp will be triggered.

The Panel is of the view that a 50 basis point differential is in all likelihood not significant enough to give rise to Fortis' concern regarding multi-year triggers being "significantly below" single year triggers.

Regarding intervenor concerns that the single-year trigger is too high, the Panel notes that even with substantial productivity savings, Fortis did not exceed their allowed rate of return in their previous PBR periods. The Panel is of the view that the trigger points approved in this Decision will not stifle efficiency efforts and will provide an appropriate balance of protection for the Companies and the ratepayers.

2.2.4.2 Non-Financial Trigger

Fortis proposes that the non-financial trigger would be engaged if service levels fell to an unacceptable level. In the Companies' view only a "sustained serious degradation" of service quality, as measured by the SQIs, would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet one or more SQIs must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 2)

Fortis also submits that there are less drastic options to deal with declining service levels, noting that SQIs will be reviewed at each Annual Review. If appropriate, the Companies will work cooperatively with the interveners and the Commission to address any performance deficiencies. (Fortis PBR Final Argument, p. 58)

Fortis further submits that in the event there is a finding that some action of Fortis directly caused or contributed to a decline in service quality, the Commission has options under the UCA that include:

- Ordering Fortis to take certain steps to address service quality; and
- The power to levy administrative penalties after a hearing if the Companies breach the Commission order.

(Fortis PBR Final Argument, p. 155)

Intervener Submissions

CEC raises a number of concerns with respect to the non-financial trigger and submits that:

- the non-financial triggers act as a 'framework for determining whether there is need for a complete regulatory review of the PBR plan' rather than as an off-ramp under which a complete regulatory review of the PBR would be undertaken;
- there is no obligation to maintain specific benchmarks;
- the term "sustained serious degradation" is extremely vague and open to interpretation and debate and should be defined by the Commission.

CEC agrees that the off-ramp should not be triggered if the issue is not caused by the Companies' actions. CEC recommends that the definition of when the off-ramp is triggered should encompass the concept of "prudent Utility management." (CEC PBR Final Argument, pp. 168–169)

BCPSO notes that in the 2004 PBR there was an option for participants in the Annual Review to make submissions to limit incentive payments to the Company if a deviation from an SQI Benchmark was significant. BCPSO recommends that this option be included in the current PBR plan. (BCPSO PBR Final Argument, p. 20)

COPE submits that:

- The Applications and evidence are "bereft of any guidance" as to the definition of a "sustained serious degradation of service quality" (COPE Final Argument, p. 7);
- A review as to whether there was a serious degradation in service quality would not occur until the Mid-term Review. This, in COPE's view would make it "difficult, if not impossible" for the off-ramp to be executed before the final days of the PBR (COPE Final Argument, p. 9);
- Fortis intends the off-ramp to be triggered only if there is a consensus it should be. This, in COPE's view, makes the off-ramp meaningless (COPE Final Argument, p. 10); and
- Even if it is determined that there is a serious sustained degradation of the SQIs, and the off-ramp provision is executed this would still not result in an adjustment to the financial results achieved. (COPE Final Argument, p. 13)

ICG supports the off ramp provisions of the FBC Application (ICG Final Argument, p. 25). Other interveners did not comment specifically on the merits of the non-financial trigger.

Commission Determination

Definition of "Sustained Serious Degradation"

Several interveners have raised concerns with respect to the lack of definition as to what encompasses a sustained serious degradation of service that would warrant the triggering of a review of the complete PBR plan and potentially the termination of the plan. Fortis, by stating that the Mid-Term Review would be the earliest time one could assess whether serious degradation has

occurred, implies that “sustained” means degradation is ongoing over two or more years. The concept of what constitutes “serious” degradation is even more vague, with Fortis stating that failure to meet one or more benchmarks does not necessarily constitute unacceptable performance, particularly where under normal conditions there are circumstances that impact the SQI that are outside the Companies’ control. (Fortis PBR Final Argument, p. 58)

The Commission Panel finds that providing a specific definition of what constitutes a “sustained serious degradation” in service is not practical. The determination of a sustained serious degradation entails judgments that can only be made based on the specifics of the circumstances that have given rise to the purported degradation. The Panel recommends the following criteria as the basis of the assessment of whether “sustained serious degradation” has occurred:

- Has the degradation persisted for two or more years and can it be reasonably anticipated to occur in the future?
- Has Fortis undertaken actions that are expected to mitigate the deficiency?
- Is the degradation due to random events that are not expected to recur?
- If the events impacting the SQI also are affecting other utilities, are the other utilities experiencing the same degradation of service quality?

In Section 2.3.3.3 the Panel sets out the consequences if Fortis fails to provide adequate safe and reliable service. We have also added additional SQIs to those proposed and amended some of the filed SQIs. We are of the view that this provides adequate incentive to the Companies to maintain appropriate service levels. This should render less likely the occurrence of “sustained serious degradation” of service quality.

Parties are directed to review the concept of “sustained serious degradation” of service levels at each Annual Review and provide recommendations to the Commission as to whether additional considerations to those set out above are appropriate. In particular, parties are requested to bring recommendations forward to the Commission where there have been a “sustained serious degradation” of service.

2.2.5 Capital Expenditures – What's In What's Out

2.2.5.1 Introduction

Fortis proposes to include only a portion of its capital spending in its formulaic capital spending envelope. This gives rise to a number of issues, including:

1. What is the appropriate base capital upon which to base the formula?
2. What proportion of capital spending should be included? What, if any, capital projects should be excluded from the formula?
3. How can capital expenditures, which are often lumpy, be appropriately matched to a much less lumpy formula driven spending envelope?
4. How can the ratepayer be protected from chronic underspending relative to the formula driven spending envelope?
5. How can Fortis be protected in the event that necessary capital expenditures drive the actual capital expenditures above the formula driven spending envelope?

The Panel will review these issues in the following sections. First we will review the approach that Fortis is proposing and how capital has been treated in previous Fortis PBR plans. We will also review the AUC's approach to PBR capital as it has been widely discussed in this proceeding.

The Panel considers the issue of the base capital in Section 3.1.3 of this Decision.

2.2.5.2 Treatment of Capital during Previous PBR Periods

Prior to 2004, PBR plans for FBC covered only O&M. All capital spending was approved separately. For FEI, in the PBR plan in effect from 2005 to 2009, "capital expenditures were escalated by a formula that incorporated forecast inflation and productivity factors. It included a 50/50 earnings sharing mechanism between customers and shareholders". FEI further states that "[e]ach year, the capital expenditure forecasts were developed using the customer additions forecast for growth capital and the forecast average number of customers for all other base capital. The base capital expenditures were not rebased during the term of the PBR. However, similar to the treatment for O&M, there was a prospective true-up in the formula capital expenditures for actual customer

growth.” FEI adds that CPCN additions were excluded from the capital formula, and instead addressed in separate regulatory processes. (FEI Exhibit B-1, pp. 34–35)

FEI states that there were “significant capital savings” achieved over the term of its PBR period and that benefits to ratepayers included:

1. Reduced rates during the term of the PBR via the earnings sharing mechanism; and
2. Rebasing of the savings in the opening rate base and future rates after the PBR ended.

FEI further describes the capital expenditures:

“During the 2004 PBR, FEI’s actual base capital expenditures for the six-year period were \$490.million. This was \$80.1 million, or about 14 percent on average, below the formula- allowed capital expenditures of \$570.3 million for the period. The year-to-year amounts of the formula-based and actual capital expenditures are provided in Attachment 2 to Appendix D4 which is a copy of Exhibit B1-48 from the 2012 Generic Cost of Capital proceeding. FEI’s actual capital spending was under the formula-based number in each year except 2009 where the actual spending was approximately \$1 million above the formula-based amount.” (FEI Exhibit B-1, p. 38)

CEC submits that FEI capital underspending during the previous PBR period shows a total of about \$80 million with the annual amounts showing about \$9 million in the 2008 to 2009 period. The aggregate benefit from underspending the capital formula was approximately \$50 million of which the Company received half or \$25 million. This benefit grows and accumulates annually until rebased at the end of the PBR period. Rebasing earlier when the PBR period expired and not extending the PBR process would have saved customers approximately half of the capital payment to the Utility.

It further submits that “[t]his is an example of the failure to understand PBR processes properly. CEC had such a misunderstanding when it participated in extending the previous PBR term and failing to rebase the formula as quickly as possible. CEC has had the advantage of this regulatory process to learn just how poorly PBR incentives are aligned with customer interests. CEC submits that the Commission should ensure that such an error does not happen again.” (CEC PBR Final Argument, pp. 90–91)

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2.2.5.3 Fortis' Proposal

The formula proposed by FBC for all capital and by FEI for sustainment and other capital is:

$$C_t = C_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}} \right)$$

Where: *C*=Capital Expenditures subject to formula
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

and for FEI's growth capital:

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: *GC* = Growth Capital
SLA = Service Line Additions
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

The Panel has reviewed the growth terms for the above formulas in Section 2.2.6 of this decision. In addition, the I- and X-Factors were reviewed in Sections 2.2.2 and 2.2.3, respectively. The Panel will not comment further on the formulas themselves, but will now review the size and nature of capital projects to which the formulas apply along with the consequences of underspending and overspending relative to the formula.

2.2.5.4 CPCN Capital

Fortis proposes separate ratemaking treatments for CPCN projects. CPCN expenditures will be excluded from the formula and will continue to be subject to the existing criteria for determining the need for a CPCN application. It states that “[m]ajor capital project expenditures will only be included in rate base after receiving CPCN approval from the Commission and being placed into service.” (FBC Exhibit B-1, p. 55)

For FEI, all projects in excess of \$5 million require a CPCN. For FBC, a CPCN is required for projects in excess of \$20 million and any other projects: 1) likely to generate significant public concerns; or

2) that FBC or the Commission wishes to handle through a CPCN; or 3) that a credible majority of stakeholders believes should involve a CPCN. (FEI Exhibit B-1, p. 250; FBC Exhibit B-1, p. 226)

Fortis states that “[t]here is no practical way to capture CPCN capital projects under the PBR Plan.” In its view, “[t]he nature of capital expenditures is such that the controllable and generally planned investments are included in the plan while other capital should be outside the plan.” Fortis also states that Enbridge has proposed a similar customized PBR Plan with separate capital updates for the later years of the plan. (FEI Exhibit B-11, BCUC 1.10.2.; FBC Exhibit B-7, BCUC 1.19.2)

B&V considers that the exclusion of CPCN capital is an appropriate means of addressing capital under a PBR Plan. It states that it is akin to the adoption of a capital tracker, which is incorporated in PBR plans elsewhere. (FBC Exhibit B-1, p. 55) Fortis submits that “The AUC has been approving significant capital trackers, which are similar in nature to FortisBC CPCNs.” (Fortis PBR Final Argument, p. 48)

PEG agrees that the Fortis proposal is tantamount to a tracker treatment for CPCN costs. However, in its view, the eligibility requirements are unusual and incentives to contain the cost of capex for these projects are a concern. Dr. Lowry states that “[i]f you would have a more conventional CAPEX tracker or at least raise the materiality threshold, the problem would — most of the problem would go away.” (FBC, Exhibit C1-22, BCUC-IR2, 2.7.2; T7:1487)

With regard to FBC’s proposed base capital formula driven spending envelope, ICG submits that “[t]he replacement of detailed project by project analysis of the past with a formula based approach should not be expected to provide better capital expenditure targets. It is more likely that such a change will result in excess returns not related to efficiency gains.” (ICG Final Argument, p. 19)

2.2.5.5 Fortis’ Proposed Dead-Band

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, BCSPPO 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, BCSPPO submits there should be a cumulative threshold that reflects the cumulative nature of capital.” (BCSPPO PBR Final Argument, p. 10)

2.2.5.6 Fortis’ Expected Capital Expenditures during PBR

2.2.5.6.1 FEI’s Capital Spending

FEI estimates approximately \$672 million to \$689 million of proposed formula driven capital expenditures over the PBR period. FEI believes this allowed capital under PBR provides suitable incentive to find efficiencies for capital expenditures without raising concerns of compromising safe, reliable natural gas service or service quality. (Exhibit B-11, BCUC 1.10.3)

FEI lists the following CPCN projects that will be excluded from the capital formula:

1. The Huntingdon Station Bypass. Loss of functionality of certain sections of the Huntingdon Station can lead to the complete outage on both the CTS and FEVI systems, thereby triggering a potential gas supply service outage to 660,000 customers. A new station bypass at Huntingdon Station, is necessary to reduce the risk of a service outage estimated at approximately \$7 million.
2. Preload and Stabilize Remaining Right of Way between Delta Station and Tilbury Station to stabilize most of the Right of Way in the Burns Bog to mitigate the risk of ground movement and associated pipe damage. No estimate provided.
3. The Coastal Transmission System and Intermediate Pressure System sustainment projects, required in order to ensure the ongoing safety, integrity, and reliability of the system, estimated at approximately \$220 million.
4. The Kingsvale-Oliver Reinforcement Project (KORP). The reinforcement would further integrate and expand service using available capacity on T-South and SCP. The KORP provides an opportunity to deliver a growing supply of British 26 Columbia gas to the Pacific Northwest and California markets. *Estimated at \$440 million.*

(FEI Exhibit B-1, pp. 250–253; FEI Exhibit B-11, BCUC 1.10.3; T4:665)

Coastal Transmission System upgrades and KORP alone amount to approximately the same amount as the projected formula driven spending in the entire PBR period (Exhibit B-11, BCUC 1.10.3).

2.2.5.6.2 FBC's Capital Spending

FBC estimates a little over \$300 million of formula capital in the PBR period. The estimated CPCN projects amount to somewhat less than half of the estimated formula capital. FBC lists the following proposed CPCN projects:

Table 2.27 Proposed FBC CPCN Projects

Project	Application Filed	Est Start Date	Est In Service Date	Est Cost (\$ million)
Kelowna Bulk Transformer Capacity Addition	2016	2017	2019	14.5
Grand Forks Transformer Addition	2016	2017	2019	5.9
Ruckles Substation Upgrade	2015	2016	2019	5.9
Central Okanagan Substation	2017	2018	2019	24
Grand Forks to Warfield Fibre Installations	2014	2014	2015	4.8
Corra Linn Spillway Concrete and Spill Gate Rehabilitation	2016/2017	2015	2033	21.6
Kootenay Long Term Facilities Strategy	TBD	2014	2016	16.4
Upper Bonnington Unit 1, 2, 4 Refurbishment	2015	2016	2019	21.0
Total				114.1

(Source: FBC Exhibit B-25, BCUC 2.45.1)

2.2.5.7 The AUC Approach

B&V summarized the criteria for the capital tracker mechanism adopted by AUC as:

1. The project must be outside of the normal course of the company's ongoing operations
2. Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party; and
3. The project must have a material effect on the Company's finances

(FEI Exhibit B-1-1, Appendix D1, p. 8)

PEG considers the AUC's capital tracker requirements to be overly broad. It states that capex projects potentially eligible for tracker treatment should have some combination of the following attributes:

- Large (i.e. having a material effect on the company's finances)
- Non-revenue producing
- Not associated with unusually rapid O&M productivity growth that permit project self financing;
- Not reflected in the productivity research on which the X-Factor is based; and
- Required by a government agency or other powerful external party.

(FBC Exhibit C6-21, BCUC 2.9.1)

2.2.5.8 Issues Arising

2.2.5.8.1 The Lumpiness of Large Capital Expenditures

Fortis states that:

“[g]iven the lumpy nature of capital additions and the growing need for infrastructure replacement, a separate capital tracker is both a reasonable term of a PBR plan and a critical element to maintain a safe and reliable system while providing the utility an opportunity to earn the allowed return. As noted elsewhere in the TFP reports, the addition of infrastructure replacement costs significantly impacts productivity because costs increase without any change in capacity or number of customers. Thus cost increases with no change in output assuring a negative TFP. By including a capital adjustment provision, regulators assure that a consistent program of infrastructure improvement occurs, meeting the goal of a safe and reliable utility system.” (FBC Exhibit B-1, p. 55)

CEC submits that “it is clear that CPCN's for major capital projects replacing portions of the system could and would impact the future sustainment capital requirements, as would such projects aimed a [sic] implementing life extension options. CEC submits that this is an area of very loose discipline with regard to the operation of a PBR formula for capital. CEC submits that the Commission can only resolve this by confining the types of capital allowed in the PBR formula.” (CEC PBR Final Argument, p. 98)

Fortis states that “These projects, and the lumpiness of the expenditures associated with them, are well outside normal steady-state operations. Indeed, there is no provision for expenditures of these types in the determination of the 2013 Base Capital; hence classification of these projects as Major Capital is appropriate.” (Exhibit B2-8, BCUC 3.8.8)

BCPSO expresses concerns about “the potential for the utilities to ‘game the CPCN process’ by grouping together projects that have historically been included (or ought to be included in) in base capital.” In the view of BCPSO, “[i]f Fortis is able to lump costs together to meet the threshold for a CPCN, they may be able to either have costs added to O&M, or have capital that was below the CPCN threshold in the past, now be treated as CPCN, and thus reduce what was historically outside CPCN.” (BCPSO PBR Final Argument, p. 21)

With regard to FBC, CEC states that “[a]n inspection of the CPCN projects suggest they are generally routine but lumpy investments, such as the construction of a new substation” (FEI Exhibit C1-13-1, CEC Response to BCUC 1.13.2).

2.2.5.8.2 A Materiality Capital Exclusion Threshold

As previously noted, FEI’s \$5 million CPCN threshold is a quantitative criteria. Capital projects less than \$5 million do not generally require a CPCN although the Commission could so require it.

Accordingly, FEI’s threshold is very much akin to a materiality threshold that is a capital exclusion based solely on a dollar figure. However, FBC’s CPCN criteria, although incorporating a materiality threshold of \$20 million, are much broader and allow for the Company to determine whether a CPCN is required for capital projects less than \$20 million. The notion of a materiality threshold for both companies was explored in the proceeding.

Regarding FEI’s \$5 million CPCN threshold, Ms. Roy stated that it was originally set in 2004 and “it may be low.... Five million dollars is a fairly small number” (T4:665). However, she also stated that FEI usually don’t have a lot of capital projects with a cost of 5 million, and that “[w]e sometimes

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have some that are 8 to 9 [million], and then after that they tend to jump to more than \$20 million". (T4:665–666)

Mr. Swanson stated that when the \$20 million CPCN threshold criteria was set for FBC, it represented roughly 1 percent of revenues (T4:665). Ms. Roy commented that "one percent of our [FEI's] delivery revenue requirement is about \$65 million. That's a pretty high CPCN threshold. It would definitely require some kind of recalibration of either the base or the X-Factor". (T4:666–667)

2.2.5.8.3 Timing of Capital Spending

Fortis states that "[t]he Companies have some control over capital spending otherwise it would be inappropriate to include capital in the PBR formula." (Fortis Exhibit B2-11, CEC 3.5.2)

CEC submits that "[i]n fact they have quite a lot of judgment control on when to undertake sustainment capital but very little control over the need for the sustainment capital." In its view, "[i]t is the control over the timing of the sustainment and other capital that enables the Utilities to underspend a capital formula without consequences, particularly when the capital formula has been set sufficiently high." It submits that the Commission should focus close attention to the areas where the Utilities have judgment latitude because these are the highest potential areas where unwarranted rewards for no real savings can occur." (CEC Final Argument, p. 96)

2.2.5.8.4 Impact of CPCN Capital on O&M

Capital projects funded outside the PBR formula may give rise to subsequent reductions in spending relative to the formula driven O&M spending envelope. For example, a CPCN project that is tracked outside the formula to replace an older leak-prone pipe will, in all likelihood, reduce the ongoing maintenance requirements.

FEI states:

"CPCN projects may reduce some O&M costs. Those O&M reductions may or may not be covered under the PBR Plan. For example, a CPCN project that reduced

electric lines losses results in lower purchased power expenses and would pass through automatically because purchased power costs are not part of the PBR Plan mechanism. A similar result would occur for the gas system where new pipe replaces older leakier pipe and the quantity of lost and unaccounted for gas would be reduced. Some O&M expenses such as leak surveys are still required even for new installations so there is no saving at all. Finally, there may be fewer repairs on the new segments of main but it is also true that other segments have aged and the expected repairs increase.” (FEI Exhibit B2-8, BCUC 3.11.3)

FEI also submits that “all CPCN applications, whether submitted during the PBR term or during a cost-of-service RRA test period, should include a full assessment of the costs and benefits of the project. This is a standard requirement in the Commission’s CPCN Application Guidelines.” (FEI Exhibit B2-1 BCUC 3a.305.1)

Fortis agrees that CPCN projects may reduce some O&M costs and that these reductions “may or may not be covered under the PBR Plan.” However, when asked about the upcoming CPCN projects, FBC stated that “[n]one of the projects identified above are forecast to result in incremental capital and/or O&M cost savings during the proposed PBR term and trailing ECM window.” (FBC Exhibit B-24, BCUC 2.43.2; Exhibit B2-8 BCUC 3.11.3) FEI argues that “not all CPCN projects generate future savings. Indeed some CPCN projects involve both capital and/or O&M cost increases.” (FEI Exhibit B2-8, BCUC 3.11.3)

Fortis further states that:

“[t]he impact of CPCN projects and the ‘potential’ savings or costs that may result from them are already accounted for in the PBR formula through FEI’s proposed X-factor. As discussed in B&V’s TFP studies, the electric and natural gas utility industry-wide productivity factors are well into the negative zone while FEI’s and FBC’s proposed X-factor is a positive 0.5%. A contributing factor to FEI and FBC being able to accept large implicit stretch factors is that the capital costs of CPCN projects are not part of their PBR plans.” (FEI Exhibit B2-1 BCUC 3a.305.2)

Fortis submits that PEG’s discussion “is premised on a plan such as that that exists in Alberta. And even then, on the type of capital tracker that the AUC has moved away from, recognizing that it is unworkable in practice.” (T8:1399)

CEC submits that “all O&M savings or other cost reduction that are a result of CPCN activity should be flowed through as a matter of course and that the Utilities proposition to not do so is misaligned with customer interests” (CEC PBR Final Argument, p. 85).

In the case of FBC, Mr. Swanson testified that “what we found is over that five-year period, the net result of all those CPCNs was actually an increase in O&M. So had we flowed all that through the formula you would have in fact increased O&M not decreased O&M because there’s not a lot of CPCNs where ... the theoretical CPCN where you invest in some piece of infrastructure that makes a bunch of labour go away. Those types of CPCNs simply don’t often exist in our world.” (T2:332)

However, CEC cites a specific example of O&M benefits resulting from a capital project. FBC proposes to track AMI outside its PBR plan which CEC interprets to mean that it does not impact the PBR formula. It states that the AMI impact for 2018 includes savings of \$4.4 million in meter reading savings which are partially off-set in new operating costs for a net reduction of approximately \$2.8 million in O&M. When the savings are excluded, the PBR O&M forecast increases from \$63.3 million to \$66.1 million. (CEC Final Argument, p. 83)

CEC submits that “there is no process to ensure that all AMI O&M benefits are captured and excluded. The AMI hearing identified many benefits that were not defined and or estimated. To the extent any of these are O&M related and outside of the company process for deducting them to flow them through to customers, they may result in sharing with the Utility shareholder inappropriately. CEC submits this would be a misalignment with customer interests.” (CEC Final Argument, p. 83)

2.2.5.8.5 Impact of Price Spikes

CEC submits that

“the potential for capital costs to be driven by market supply demand conditions resulting in significant price spikes, which subsequently have subsided. The nature of such perturbations in the market makes the application of a formula highly problematic because they can lead to potential under allowance for capital expenditures and risks to the system or if embedded into the base potential over

allowance in the formula putting the customers at risk of paying for phantom savings of underspending an overly generous formula. CEC submits that the current PBR proposals for capital are more likely to contain the later [sic] problem.” (CEC PBR Final Argument, pp. 106–107)

Commission Determination

The Panel will address the issue of capital excluded from formula driven spending by addressing the following questions:

1. Should there be any capital exclusion criteria at all?
2. Is the CPCN Criteria an appropriate Exclusion Criteria?
3. Is a Dollar Threshold Appropriate?
4. What should the Quantum of a Dollar Threshold be?

Should there be any Capital Exclusion Criteria at all?

In the Panel’s view, the more capital excluded from formula spending, the fewer benefits of PBR accrue to ratepayers and shareholders alike. Excluding significant amounts of capital reduces the ability of the utility to achieve operational efficiencies. However, it also provides opportunities for a utility to game the system, such as by combining smaller projects into larger projects that will be excluded from the formula. Also, by including more capital in the formula, larger, and potentially lumpier, projects are included. This gives rise to challenges to the utility to manage and also possibly increases risk to ratepayers and shareholders alike.

The Commission Panel finds that it is appropriate to exclude some capital projects from the capital formula spending envelope. There are certain capital projects that are outside the normal course of business, that the utility is required to undertake and that the utility has little or no control over should not be included in the formula. In our view, these projects should be accorded exogenous treatment, in much the same way that certain O&M expenses are.

It also may be appropriate to consider an exclusion criteria based on the size of the project and we will examine this issue in the following sections.

Is the CPCN Criteria an Appropriate Exclusion Criteria?

The Panel is not persuaded there is any basis to link exclusion from CPCN requirement to exclusion from the PBR formula. Section 45 of the UCA requires that “a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity requires or will require the construction or operation.” Exclusion from this requirement is based on a balance of regulatory efficiency and the broader public interest. Otherwise, all capital projects would be subject to CPCN requirements.

In the case of FEI, the CPCN threshold limit amounts to a materiality threshold of \$5 million. However, in the case of FBC, with the number of projects below \$20 million subject to CPCN requirements, the CPCN threshold doesn’t provide a clear, transparent materiality limit. In proposing the CPCN exclusion criteria as the PBR capital exclusion criteria, Fortis is effectively arguing that in the case of FEI a \$10 million dollar project is too lumpy, yet for FBC a \$10 million dollar project could, unless otherwise subject to CPCN requirements, be managed as part of the formula spending envelope. In the Panel’s view, this supports the conclusion that the use of CPCN criteria as an exclusion criterion for the PBR formula is arbitrary. Further, the CPCN requirements do not differentiate between routine capital projects and projects that are not routine. Therefore, they are not a good indicator of the exogenous nature of the capital project.

Is a Materiality Threshold Appropriate?

Many parties argue that the lumpy nature of large capital projects is more likely to result in a variance between formulaic and actual spending. The Panel does not agree that larger capital projects necessarily have a propensity for lumpiness. It is not necessarily the magnitude of the project that contributes to the lumpiness, but the annual spend—which depends upon both the total spending and the duration of the project—and the number and nature of other projects undertaken concurrently. For FBC, for example, under the formula, approximately \$20 million to \$30 million dollars will be spent each year on a variety of sustainment projects with different costs and durations. There does not seem to be a significant difference between a one-year project with a

cost of \$2 million that is included in the capital formula spending envelope and \$2 million spent in one-year of a three year \$6 million CPCN project that is excluded from the formula.

As CEC asserts and Fortis acknowledges, the utilities do have some control over capital spending. The Panel expects the utilities to take a proactive role in the management of their capital projects, regardless of the materiality of the threshold, so there is as little variance as possible while ensuring that there is no underspend of the type that CEC alleges have occurred during the previous PBR period.

Parties also raised concerns that there is an opportunity for the utility to combine smaller projects into a larger project that will trigger a CPCN requirement, and thereby exclude all of those smaller projects from the PBR formula driven spending envelope. Unless those smaller projects are replaced by other small projects, the result will be, all else equal, an under-spend relative to the formula driven spending envelope.

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.**

In addition, the earnings sharing mechanism, which the Panel approved elsewhere in this decision, ensures that ratepayers share half of the benefits of that underspend, although that may amount to returning half of the money that has, in some sense, been over-collected from them because of the underspend.

In the Panel's view, a further potential mitigation is to increase the limit of the size of capital project that is subject to formula spending. The larger the limit, the less likely that smaller projects can be combined.

If a Materiality Threshold is Set, at What Level Should it be Set?

The Panel is of the view that, if a materiality threshold is appropriate, it should be set at such a level that considers both the lumpy nature of projects and the ability of the companies' professional management teams to manage that lumpiness. The threshold should reflect a balance of risk with the benefits of the operational efficiencies that arise from the more holistic approach to management provided by the inclusion of capital within the formulaic spending envelope. In the following section the Panel will consider the quantum of the threshold.

However, a number of arguments have been raised against a higher materiality threshold. FEI and FBC argue that a contributing factor to being able to accept large implicit stretch factors is that the capital costs of CPCN projects are not part of their PBR plans. The Panel does not agree with this argument. The Panel has applied relatively small stretch factors to each utility. Further, neither the B&V nor the PEG study excluded capital spending for CPCN Projects or even applied a threshold of materiality for capital spending in their studies - the X-Factor accepted by the Panel is based on a TFP trend study that included all of the capital spending of the utilities. Accordingly, as Dr. Lowry testified, if the X-Factor is to be applied to a capital spending envelope that is substantially less, it requires adjustment. The Panel has not made any such adjustment and considers the X-Factor approved in this proceeding to be appropriate for use with an increased materiality limit. If any adjustment is required, in the Panel's view an upward adjustment may be appropriate to account for the proposed CPCN-based exclusion criteria. However, at this time, the Panel declines to make such an adjustment.

Interveners raise concerns about the formulaic approach to capital spending generally, arguing that even the proposed approach, with its CPCN exclusion, leaves the utilities significant opportunity to underspend. To the extent that this is the case, increasing the threshold will provide even greater opportunities to underspend.

The Commission Panel does not disagree with these intervenor concerns. However this is not sufficient reason to warrant either disallowing the capital spending formula entirely or even

keeping the CPCN limit as proposed. It is only by increasing the amount of capital covered by formula that the full benefits of PBR can be achieved.

However, the Panel does not consider it appropriate to set a different exclusion threshold at this time and will seek further comment on this issue as set out in the Summary section below.

Summary

In summary, the Panel finds that the current CPCN exclusion criteria as proposed are not appropriate. There are circumstances where the nature of the project justifies exclusion from the formula (i.e. an exogenous factor). However, the lumpiness of the expenditures is not, in itself, sufficient criteria. As previously stated, the Panel expects the utilities to manage their capital projects in a manner that is consistent with the spending envelope provided by the PBR plan. Further, there may be circumstances where capital that is not exogenous should be excluded from the formula. The threshold for such exclusion should be based on a dollar-amount.

The Panel invites further submissions on this matter, specifically on the issues set out below:

1. What exogenous criteria should be established for excluded capital?
2. In addition to a capital exogenous factor, is a materiality threshold required?
3. If a materiality threshold is appropriate, at what level should it be set in order to realize the full benefits of PBR? Given your responses to 1, 2 and 3, what should the base capital be set for FEI and FBC for 2016?
4. Is a cumulative dead-band of 15% over two years sufficient to protect both ratepayers and shareholders?
5. What reporting procedures should be in place to allow parties sufficient time to review proposed capital spending?
6. Should the CPCN threshold be raised to match or exceed the PBR formula materiality threshold?

Submissions should be received in accordance with the following timetable:

Submission from Fortis	December 31, 2014
Submissions from Interveners	April 30, 2015
Reply Submission from Fortis	June 30, 2015

The Commission will provide further direction concerning process following Fortis' reply.

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

Other Issues

a. The Impact of Capital on O&M

To the extent that a project results in a reduction of maintenance expenditures, the utility will have the opportunity to underspend its maintenance spending envelope. The Panel recommends that, if capital associated with a particular CPCN is excluded from the formula, the CPCN review of that project should include an assessment by the Commission of any potential impact of the project on O&M. If appropriate, an adjustment to the formula based O&M spending envelope should then be made.

b. AMI Capital

With regard to CEC's concern about the benefits of the AMI project not being captured, the Panel does not agree. Table B6-5 in the Application and the spreadsheet at Attachment 1.1 of Panel IR 1.1 show O&M formula spending reduced by over \$7.5 million to account for AMI benefits over the PBR period.

2.2.6 Mid-Term Review and Annual Review Process

The purpose and content of the Annual Review was a significant point of contention in the hearing. Fortis envisaged the Annual Review process as primarily an information sharing forum similar in scope and process to Annual Reviews held in previous PBRs (FEI Exhibit B-1, pp. 78–79; FBC Exhibit B-1, pp. 71–72). A number of interveners saw the Annual Review as having a broader scope and dealing with a variety of issues. Fortis submits that a clear definition of the purpose and scope of the Annual Review is required if the PBR is to operate successfully. (Fortis PBR Reply, p. 54)

The Mid-Term Review is proposed by the Companies as an opportunity for stakeholders to review the outcomes of the PBR and suggest adjustments to certain planned parameters if required. The Mid-Term Review will form part of the third Annual Review, acting as a “checkpoint” that allows parties to address discrete flaws in what is otherwise a workable PBR plan. CEC was the only intervener to raise issues specific to the Mid-Term Review. (FBC Exhibit B-1, pp. 69, 70; FEI Exhibit B-1, pp. 76–77)

Unlike past PBRs, which were put in place following a negotiated settlement process, under this PBR the Annual and Mid-Term Review processes are taking place after a hearing process where stakeholders expressed serious reservations with the applied for PBR, with some parties opposing the use of a PBR altogether. In this environment, the Panel considers there is a need for the review processes to be more extensive, at least in the first few years, in order to build trust between the Companies and stakeholders and to ensure that the PBR process is working fairly and effectively.

Fortis' Annual Review Proposal

Fortis envisages the Annual Review to be identical to the process that was undertaken in previous PBRs. This process would consist of a workshop, one round of information requests from the Commission and interveners, letters of comment, and a Commission determination of rates. Fortis states that as part of the Annual Review process, the following actions will occur:

- The Companies will present the current year's projections and the upcoming year's forecasts for a number of measures;
- Flow-through items will be trued-up to actuals for the prior year; and
- Inputs in the PBR formula, such as inflation and customer growth will be re-forecast.

(FEI Exhibit B-1 p. 79; FBC Exhibit B-1, pp. 71–72; Fortis PBR Final Argument, p. 59)

Intervener Submissions

The issues or concerns raised by interveners with respect to the Annual Review include:

- The inadequacy of treatment of SQI's (COPE Final Argument p. 51). If the SQI's targets are not achieved there should be the opportunity for interveners to make submissions that the incentive earnings of the Company are reduced (BCPSO PBR Final Argument, p. 20);
- The reviews are too limited. There should be an opportunity to review PBR performance and to make improvements to the PBR Plan, under Commission oversight. There should be a greater opportunity for stakeholders to get information and pursue any areas that are deemed necessary to ensure the ongoing applicability of the PBR formula. (CEC PBR Final Argument, pp. 162–163);
- There should be a review of efficiency proposals at the Annual Review (CEC PBR Final Argument p. 26);
- The Annual Review process will be much more expensive than estimated by Fortis. The regulatory efficiencies expected by Fortis will not be achieved. (CEC PBR Final Argument, pp. 11–12; BCPSO PBR Final Argument, para. 13); and
- Fortis should be required to disclose all exogenous events that result in benefits to the ratepayer at the Annual Review (CEC PBR Final Argument, p. 158).

Fortis Reply

The Companies responded to these criticisms by stating that:

- If there was concern about a deterioration of service that was seen to be due to the fault of the Company, there would be significant discussion at the Annual Review, potentially leading to a decision by the Commission (T5:1051).
- While the review of the cost of service will not be as detailed as in a revenue requirements application, since controllable costs are largely formula driven, the Annual Review will provide more frequent reporting than would normally exist under Cost of Service regulation (Fortis PBR Final Argument, p. 59).
- One of the key benefits of the PBR will be eliminated if Fortis is required at each Annual Review to provide a detailed justification of individual efficiencies achieved in the prior year (Fortis PBR Reply, p. 54).
- The regulatory cost savings under past PBR plans provide an evidentiary basis to conclude there will be direct cost savings under the proposed PBR plan. Given that the most contentious aspects of the Companies' revenue requirements will be determined by the formula, it is logical to expect both direct and indirect savings. Intervener arguments on regulatory cost are founded on errors or flawed logic (Fortis PBR Reply, pp. 15–16).

Commission Determination

The Panel finds that a more extensive Annual Review process is necessary to build trust among all stakeholders and to ensure the PBR Plan functions as intended. This will address some of the concerns expressed by CEC with respect to the consensus requirement to bring forward issues and with respect to the timing of airing concerns related to PBR elements. The Panel finds that the enhanced ability to assess the PBR Plan at Annual Reviews also addresses the concern expressed about the symmetry of the financial distress criterion. If the PBR plan is seen by any stakeholder as inducing financial distress, the issue may be raised at the Annual Reviews and if not resolved, brought to the Commission for resolution.

In what follows, the Commission Panel sets out the activities to be undertaken in all Annual Reviews before describing topics to be covered in the first Annual Review.

All Annual Reviews

The Commission directs that the Annual Review process include the following:

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.
2. Review of the current year projections and the upcoming year's forecast (FEI Exhibit B-1, p. 78, 79; FBC Exhibit B-1, p. 71, 72). For further clarity, these items are listed below:
 - a. Customer growth, volumes and revenues;
 - b. Year-end and average customers, and other cost driver information including inflation;
 - c. Expenses (determined by the PBR formula plus flow-through items);
 - d. Capital expenditures (as determined by the PBR formula plus flow-through items);
 - e. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;
 - f. Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and
 - g. Any proposals for funding of incremental resources in support of customer service and load growth initiatives.
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 (see Section 2.3.2 for a more detailed discussion of the ECM).
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 (see Section 2.2.4 for details).
5. Review of the Companies' performance with respect to SQI's. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service (see Section 2.3.3.2 for details).
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.

7. Assess and make recommendations to the Commission on the scope for future Annual Reviews.

Given this more comprehensive Annual Review, the Panel is of the view that a Mid Term Review will not be required. **Accordingly, Fortis' request for a Mid-Term Review is denied.**

2.2.6.1 Unique First Annual Review Requirements

The Commission Panel directs, in the first Annual Review, in addition to the items previously set out, a consultation process to determine the performance range for SQIs be undertaken.

3.0 MAKING PBR WORK

3.1 Key Issues

3.1.1 Load Forecasts

As part of FBC's previous revenue requirements applications (RRA) review process, the Load Forecast Technical Committee (LFTC), consisting of representatives from FBC, interested interveners and Commission staff, was established to review and make recommendations on FBC's load forecasting methods and results. A report was filed by the LFTC which outlined the methodology to be undertaken by FBC in developing its 2014 Load Forecast.

In its current Application, FBC explains that its sales revenues are a function of both the load and the applicable rate at the time the energy is consumed. FBC's revenues are expected to increase slightly over the PBR period based on its total load forecast provided on page 80 of its Application and detailed in Appendix E2 of Exhibit B-1-1, and shown below

Table 3.1 FBC's Load Forecast

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	3,351	3,416	3,369	3,447	3,422	3,520	3,570	3,607	3,642	3,675	3,715
After-Savings						3,496	3,519	3,537	3,554	3,572	3,596
After-Savings Growth	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%

(Total load forecast shown in GWh)

FBC proposes that load will be forecast each year at the Annual Review and then considered along with the revenue requirement to establish rates for the forecast year (Exhibit B-1, p. 62). BCPSO observes that since load growth will be updated during each Annual Review, the emphasis should be on the 2014 load forecast for 2014 rates (Exhibit B-1, p. 71; BCPSO FBC Non PBR Final Argument, p. 8).

FBC also states that its acquisition of the distribution assets owned by the City of Kelowna on March 31, 2013, added approximately 14,500 customers to the FBC system; approximately 1,500 commercial, 9 industrial, and the remainder residential. The current customers load mix for City of Kelowna is approximately 45.4 percent, 32.6 percent and 22.0 percent for residential, commercial and industrial loads, respectively.

Due to the unavailability of sufficient historical load information prior to the transaction, FBC indicates that it is not possible to ensure that the same forecast methods applied to the existing FBC load classes would also be reasonable to apply to the City of Kelowna load classes. Therefore, the City of Kelowna load is forecast as a whole, and then allocated to the three load classes according to the proportions identified above (Exhibit B-1, pp. 81–82).

BCPSO, the only intervener that commented on FBC's 2014 load forecast, claims that FBC's calculation of rate-driven savings in 2014 has several flaws and submits that "FBC has just started to recognize rate-driven savings in its load forecasts. Clearly more consideration needs to be given as to how to appropriately estimate such savings given its current load forecast methodology." (BCPSO, FBC Non PBR Final Argument, pp. 9–10) However, BCPSO makes no specific recommendations or adjustments to FBC's Load Forecast for 2014.

Commission Determination

The Commission Panel accepts FBC's load forecasts and agrees that the methodology used by FBC conforms to the recommendations set by the LFTC and outlined in its report dated November 25, 2011.

The Panel notes that that City of Kelowna integration did not have any significant impact as this load was previously captured under the Wholesale customers load forecast, whereas now the load is split across the residential, commercial and industrial customer classes. The Panel accepts this reclassification; however, we are unclear as to why FBC is unable to obtain sufficient historic load information from the City of Kelowna. **FBC is directed to provide an explanation at the next Annual Review as to why this information for past years is unavailable.**

Concerning the issue raised by BCPSO on FBC's rate-driven savings in 2014, the Panel agrees with FBC. This results in a relatively small impact (a point acknowledged by BCPSO) as rate-driven savings are only 0.27 percent of the total gross forecast load (FBC Non PBR Final Argument, p. 26; BCPSO Non PBR Final Argument, p. 9). The Panel recommends that the parties bring forward any material load forecasting issues as part of future Annual Reviews during the PBR period.

3.1.2 Determining the Base O&M

As a general approach, FBC proposes that the Commission rely upon the 2013 Approved O&M expenditures as a starting point for determining the PBR opening O&M. These would be adjusted by specific changes which have occurred since these amounts were approved in the FBC 2012–2013 RRA Decision.¹⁴ In FBC's Application, the 2013 Approved O&M combined with specific adjustments proposed by FBC serve as a basis for a revised starting point for the PBR. FBC refers to this as the 2013 Base O&M. As a starting point, the methodology for determining the 2013 Base O&M will be considered.

¹⁴ In the Matter of an Application by FBC regarding its 2012–2013 RRA & Integrated System Plan, Decision dated August 15, 2012 [herein referred to as the FBC 2012–2013 RRA Decision]

3.1.2.1 Methodology for Base O&M Determination

As noted, FBC has used the 2013 Approved O&M amount as the starting point. This has been chosen as an appropriate starting point because it results from a full review in an oral public hearing. To this, Fortis makes three types of adjustments. These are as follows:

- Adjustments that recognize the sustainable savings of \$452,000 realized in 2012 and that will carry over to future years.
- Adjustments reflecting the rebasing of 2013 Approved to the expected 2013 Actual for items currently captured in deferral accounts that are considered non-controllable. These total \$3.238 million and include \$900,000 for Mandatory Reliability Standards (MRS), \$180,000 related to the annualized impact of the reinstatement of PST and \$2.158 million for Pension and Other Post-Employment Benefits (OPEB).
- Other O&M expenses and reductions allowing for delivery of cost-effective service to customers. These include a reduction of \$909,000 in the Trail Office Lease Payments due to the purchase by FBC and an increase of \$350,000 for recurring maintenance to FBC's generating units.

FBC states that the purpose of these adjustments is to provide an appropriate starting point for the PBR period and the approach it takes is reasonable and common practice where revenue requirements have been recently assessed. As noted in Table 3.2 below, the net effect of these adjustments is to increase the Base O&M from \$57.621 million in the 2013 Decision to a new base of \$59.848 million. (FBC Exhibit B-1, pp. 50–51)

Table 3.2 2013 Base O&M Calculation

		(\$ thousands)	
1	2013 Decision		57,621
2			
3	Net Sustainable Savings		(452)
4			
5	<u>2013 Adjustments</u>		
6	Mandatory Reliability Standards	900	
7	Provincial Sales Tax	180	
8	Pension/OPEB (O&M Portion)	2,158	3,238
9			
10	<u>Incremental O&M</u>		
11	Trail Office Lease	(909)	
12	Generation Maintenance	350	(559)
13			
14	2013 Base O&M		59,848

(Source: FBC Exhibit B-1, p. 51)

Intervener Submissions

CEC is not in agreement with the methodology proposed by FBC. It does not consider the 2013 Approved O&M, with adjustments, to be an appropriate starting place because the 2013 O&M projection is not supported by any significant amount of actual 2013 history. It describes the 2013 O&M approved amount as “a forecast developed in 2011, or before, as part of the FBC 2012–2013 Revenue Requirements Application process.” Further, when approved, the Commission had no intention of using it as a basis for a PBR process.

CEC’s position is that considerable attention should be paid to 2012 Actual O&M costs in the development of the 2013 O&M Base amount pointing out that it is the latest, most accurate representation of business in the specific timeframe. It submits that in creating the 2013 O&M Base, care must be taken to remove all non-recurring cost items. Relying on the FBC response to BCUC IR 1.95.1, CEC observes that actual 2012 expenditures are not materially different from 2011 and the cost per customer is similar. It also points out that the 2012 Approved cost per customer

(\$483) is substantially higher than the 2013 Approved (\$463) and higher than that of 2011 (\$470). (CEC FBC Non PBR Final Argument, Base O&M, pp. 3–6)

BCPSO submits that relying upon the 2013 Approved O&M as a base for PBR is a reasonable approach noting that the 2013 Approved O&M per customer is lower than the 2012 Approved. An alternative to this would be to use the actual results from 2013 as they would constitute the best available evidence on which to base O&M on a forward-looking basis. (BCPSO Non PBR Final Argument, p. 6)

ICG is not opposed to using FBC's 2013 Approved O&M expenses as a base but asserts this number should be reduced to ensure reasonable targets under the PBR Plan (ICG Final Argument, p. 21).

FBC Reply

FBC disagrees with using either 2012 actual as proposed by CEC or 2013 Actual O&M expenditures as proposed by BCPSO. In FBC's view, it is important to use the 2013 Approved O&M as a starting point because this amount received Commission approval in a recent regulatory proceeding. In addition, FBC's approach is endorsed by B&V and is in alignment with the method used in the 2007 PBR Plan. Further, it disagrees with CEC's critique concerning the Commission's intentions when it last examined and approved O&M expenditures. FBC states that it "does not alter the fact that 2013 Approved O&M represents the most recent Commission approved O&M figure for the Company, or the fact that the figure was determined following a thorough regulatory process." (FBC Non PBR Reply, p. 3)

Concerning CEC's analysis and submissions on the comparison of 2011, 2012 Actual, and 2013 projected O&M costs and resultant per customer costs, FBC argues that it ignores the reason why 2012 Actual expenditures were lower than both 2012 and 2013 Approved expenditures and not sustainable into the future. FBC states that the lower 2012 actual costs were a result of the August timing of the 2012–2013 RRA Decision, which was released three quarters (actually two-thirds) of the way through 2012. This resulted in savings which are not sustainable. (FBC Non PBR Reply, p. 4)

FBC also has issues with the use of 2013 Actual for the base as proposed by BCPSO pointing out that the 2013 Actual O&M has not been considered as a figure in the hearing and is not on the record. The Panel notes that this is no longer true as it is now on the record as part of the response to the Commission Panel IR. In any case, FBC states that relying on 2013 Actual O&M would not be a simple change to make as it “could not simply be substituted for 2013 Approved O&M. Instead, each of the proposed adjustments would need to be re-analysed and modified for 2013 Actual O&M to be used as a starting point.” (FBC Non PBR Reply, pp. 1–5)

Commission Determination

The Commission Panel determines that an appropriate starting point for the development of the PBR O&M Base is the 2013 Approved O&M. We agree with FBC that this figure has been scrutinized in a recent regulatory proceeding and accept that this is common regulatory practice. Reliance on actual O&M amounts for 2012 would be inappropriate given the timing of the FBC 2012–2013 RRA Decision and the Company’s explanation that it postponed expenditures scheduled for this period while it awaited the results of the Commission’s review. Equally, a reliance on 2013 Actual O&M expenditures presents its own set of challenges due to the labour disruption which would require its own set of adjustments and a limited evidentiary record on which to base them.

In the following sections, we consider the evidence, address arguments raised by the parties and determine the appropriate PBR Opening O&M Base for FBC.

3.1.2.2 Determining the FBC PBR Opening O&M Base

As outlined previously, FBC uses the 2013 Approved O&M of \$57.621 million as a starting point for the O&M formula. It then makes a number of adjustments, as listed in the previous section, which result in a 2013 Base O&M of \$59.848 million. This is the figure to which FBC proposes to apply the approved I-X formula during the PBR term.

Over the course of the proceeding, a number of issues related to O&M have been raised by interveners. These include labour costs and benefits, regulatory efficiencies, the impact of AMI and exclusions from the O&M formula. The Company addressed these as follows:

a. Labour Costs and Benefits

The Company applies the same approach to compensation and benefits for all of its employees. This includes a total compensation package aimed at the median level of a peer group of companies. The only change in employee compensation packages planned over the PBR period is to transition its executive employees to a new health and welfare benefits plan.

FBC was involved in a labour disruption of the International Brotherhood of Electrical Workers (IBEW) but, in its assessment, there was no impact on a net basis to O&M expenses that resulted from this. The Company explained that labour costs savings were offset by cost increases in other areas as a result of the disruption. Many of these related to lower labour capital loadings due to delayed capital expenditures. The additional costs included:

- An increase to the O&M portion of benefit costs. While total benefit costs remained the same, less was loaded into capital due to delayed capital expenditures.
- Higher overtime costs for management and exempt employees.
- An increase to O&M as a result of salaries not being paid to IBEW staff, which meant that only 40 percent of salaries could be considered avoided capital rather than the traditional 60 percent allocation.
- A greater portion of labour and vehicle costs were charged to 2013 O&M expense not capital. This results from capital expenses being carried over from 2013 to future years.

(FBC Non PBR Final Argument, pp. 18–19)

FBC submits that the impact of the labour disruption on O&M expense is not reflective of its ongoing operations and does not impact 2013 Base O&M Expense. Accordingly, it does not necessitate adjustment of the O&M formula during PBR. (FBC Non PBR Final Argument, pp. 18–23)

b. Regulatory Efficiencies

FBC argues that expected savings due to the change to PBR do not warrant a reduction from the 2013 Base O&M. FBC argues that it has been regulated under various PBR plans for much of the period since 1996. PBR has become a more normal state and the staff contingent has remained constant during PBR and non PBR periods. Additionally, looking forward, the regulatory department will continue with annual reviews, on-going regulatory work for Certificate of Public Convenience and Necessity (CPCN) applications, cost of capital matters, rate design and other regulatory work. (FBC Non PBR Final Argument, pp. 20–21)

c. Impact of Advanced Metering Infrastructure Approval

FBC notes that the Application was prepared on the basis that the Advanced Metering Infrastructure (AMI) Project Application would be approved and in the event it was not, the PBR Application would be amended. The Application is consistent with approval of the project and therefore needs no adjustment. (FBC Non PBR Final Argument, p. 21)

d. Exclusions from the O&M Formula

O&M expenses related to pension and OPEB, insurance expense and the AMI project are to be tracked outside of the PBR formula. FBC points out that the AMI project will be subject to expenditures and savings which will be highly variable during the implementation phase. By tracking these costs outside of PBR any savings will flow directly to the ratepayer. FBC also addresses insurance expenses and indicates that, as reflected in answers to IRs, it would not object to excluding only insurance premiums from the Base O&M. This would be consistent with the handling for FEI and would involve increasing the 2013 Base O&M by \$274,000 to account for the First and Third Party Liability Expense. (FBC Non PBR Final Argument, pp. 21–23)

Table 3.3, as provided by FBC provides a historical context for O&M actual expenditures and outlines the 2012 and 2013 Approved O&M and a projection for 2013 for each of its departmental work areas. In addition, along the bottom of this table, information related to customer growth and resultant O&M per customer is included. (Exhibit B-7, BCUC 1.95.1)

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Table 3.3 Historical O&M Per Customer

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
	(\$000's)							
Generation	\$ 1,894	\$ 2,152	\$ 2,217	\$ 2,399	\$ 2,331	\$ 2,282	\$ 2,556	\$ 2,492
Operations	\$ 14,924	15,057	14,892	18,604	19,730	19,920	20,938	20,816
Customer Service	\$ 6,272	5,835	5,975	6,398	6,766	6,624	7,510	7,541
Communications & External Relations	\$ 1,079	1,150	1,639	1,469	1,244	1,431	1,440	1,469
Energy Supply	\$ 546	739	827	893	986	1,069	1,124	1,124
Information Technology	\$ 2,834	2,938	2,929	2,903	2,925	2,841	2,988	2,974
Engineering	\$ 1,184	1,143	1,242	2,363	2,615	2,701	2,822	2,791
Operations Support	\$ 1,651	1,028	993	1,315	1,240	1,223	1,205	1,252
Facilities	\$ 2,834	3,537	3,700	3,720	3,596	3,685	3,389	3,466
Environment, Health & Safety	\$ 616	645	727	867	894	925	953	953
Finance & Regulatory	\$ 3,631	3,624	3,576	3,882	3,823	4,392	4,080	4,271
Human Resources	\$ 1,540	1,558	1,638	1,747	1,816	1,840	1,874	1,874
Governance	\$ 2,006	2,066	2,284	2,031	2,134	1,792	2,490	2,373
Corporate	\$ 3,716	4,545	3,510	4,484	3,444	4,118	3,800	4,225
Advanced Metering Infrastructure	\$ -	-	-	-	-	-	-	-
Total O&M	\$ 44,725	\$ 46,017	\$ 46,149	\$ 53,075	\$ 53,544	\$ 54,843	\$ 57,169	\$ 57,621
Customers	108,722	110,286	111,552	112,756	113,587	113,588	121,566	124,581
O&M per Customer	\$ 411	\$ 417	\$ 414	\$ 471	\$ 471	\$ 483	\$ 470	\$ 463

(Source: FBC Exhibit B-7, BCUC 1.95.1)

In response to Commission Panel IR 1.3.1, FBC has further updated this information by providing the 2013 Actual O&M expenditures in Table 3.4 that follows. Tables 3.2 and 3.3 provide further context to the discussion and the submissions of the parties that follow.

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Table 3.4 2013 O&M

	2013 Approved	2013 Projection	2013 Actual
	(\$000s)		
Generation	\$ 2,492	\$ 2,556	\$ 2,513
Operations	20,816	20,938	20,886
Customer Service	7,541	7,510	7,631
External Relations	1,469	1,440	1,426
Energy Supply	1,124	1,124	1,083
Information Technology	2,974	2,988	2,948
Engineering	2,791	2,822	2,737
Operations Support	1,252	1,205	1,252
Facilities	3,466	3,389	3,493
Environment, Health & Safety	953	953	877
Finance & Regulatory	4,271	4,080	3,908
Human Resources	1,874	1,874	1,835
Governance	2,373	2,490	2,400
Corporate	4,225	3,800	3,706
Total O&M Expense	\$ 57,621	\$ 57,169	\$ 56,696
2013 O&M Adjustment	-	-	576
Total O&M	\$ 57,621	\$ 57,169	\$ 57,272

(Source: FBC Exhibit B-53, Panel 1.3.1)

Intervener Submissions

CEC has proposed that FBC's PBR O&M Base be reduced by \$755,000 to \$59.093 million based on an analysis of FBC O&M Departments. On a departmental basis CEC is recommending the following:

- a. Generation...reduce by \$113,000;
- b. Operations...reduce by \$312,000;
- c. Customer Service...reduce by \$152,000;
- d. Information Technology...reduce by \$14,000;
- e. Engineering and Project Management...reduce by \$31,000;
- f. Finance and Regulatory...reduce by \$100,000; and
- g. Environmental Health and Safety...reduce by \$31,000.

The reasons for these reductions vary by department but fall into the following broad categories: unexplained expenses added to 2013 Approved O&M, under or over expenditures to either 2012 or 2013 amounts, expected savings flowing from reduced customer counts, and expected savings due to CEC's interpretation of employee counts and the dollar amounts related to them.

CEC also takes issue with the FBC proposal to add \$350,000 for incremental generation maintenance which FBC states are for major unit inspections. CEC submits that the cost of inspections will vary significantly because of the various sizes, ages and conditions of plant units. It considers these major unit inspections to be "non-controllable" and should be tracked outside of the PBR.

CEC also submits that the flow-through process should be expanded to include "the expenditures required to complete the 'major' O&M inspections required to comply with regulations and/or which must be completed to insure assets are maintained at industry standards." CEC classifies a single inspection costing more than \$50,000 as "major." It argues that these major inspections are uncontrollable because they cannot be avoided and the timing of them is out of the Company's control as either regulations or industry standards drive the timing of activities. Its position is that the cost of a major inspection is driven by the nature of the inspection and the asset being inspected. Because of this, it is reasonable to expect significant variance among inspections and the actual cost could vary significantly from the amount embedded in the PBR Base amount. CEC also submits that a further reason to track these costs outside of the PBR Base is because it is inappropriate to tie them to the "Average Customer element within the PBR formula, since the cost of major inspections are not in any way influenced by the total number of customers." (CEC FBC Non PBR Final Argument, Base O&M, pp. 5–6)

BCPSO asserts that FBC's "sustained savings" are not based on savings resulting from efficiency initiatives but represent the cumulative total of corporate departmental variances between approved and projected O&M expense, some of which were positive and some negative. BCPSO commented on FBC's answer to BCUC IR 1.1.1 stating that a reduction of \$587 thousand in explainable variances was made while increased costs totalling \$135 thousand across a number of

departments had no explanation. BCPSO argues that the full amount of \$587 thousand should be considered sustained savings due to the lack of explanation for the increases. In addition, BCPSO makes the following comments:

- FBC's proposed adjustments for MRS, re-instatement of PST and Pension/OPEB is reasonable as is the adjustment for the Trail lease and generation maintenance.
- The potential to include first and third party liability insurance in the formula, as suggested by Fortis in its response to BCUC IR 2.59.1, is reasonable. However, the proposed \$274,000 increase to the PBR O&M base is not reasonable. It should be based on 2013 not a 2014 projection. BCPSO suggests that \$106,000 is a more appropriate amount for the first and third party liability expenses. It did not address FBC's reasons for the higher forecast.
- BCPSO agrees with FBC's proposal to set up the 2013 deferred O&M account to acknowledge FBC's scheduled and necessary maintenance work from 2013, which will be required and performed in 2014, in addition to the scheduled 2014 programs (BCPSO FBC Non-PBR Final Submission, para. 1.1).

(BCPSO FBC Non PBR Final Argument, pp. 5–7)

ICG cites the 15 percent increase in expenses from 2010 to 2011 and the 12 percent increase from 2012 to 2013 that will be embedded into rates in the event the base is established using 2013 approved O&M expenses. ICG proposes to reduce the applied for Base O&M expenditures by 20 percent given the absence of evidence regarding operating efficiencies and its concern as to fairness to customers. (ICG Final Argument, p. 21)

FBC Reply

Fortis is unclear as to how BCPSO arrived at the \$587 thousand and \$135 thousand it has incorporated into its submission. The reference relied upon by BCPSO lists different numbers than those stated by BCPSO and FBC assumes a calculation error was made. It believes what should have been proposed is modifying the sustainable savings from the proposed \$452,000 to \$559,000. FBC makes no further comment other than to state it disagrees with BCPSO's recommended savings adjustment regardless of the number relied upon. (FBC Non PBR Reply, p. 7)

FBC takes issue with the detailed approach taken by CEC to establish a base. Incremental costs and savings are considered by FBC “to be sustainable going forward, regardless of whether or not it may be attributed to one single item. As all of the savings and costs are expected to continue to be realized during the PBR Term, they are appropriately embedded into the 2013 Base O&M.” Fortis also points out that a fundamental PBR Plan premise is that O&M expenses are to be determined on an aggregate level across all departments. It further states that to incorporate those portions of the sustainable savings adjustment that reduces Base O&M while excluding those that increase Base O&M is inconsistent and illogical. Fortis relies upon this explanation to deal with those costs which it has added without further explanation. These include \$122 thousand for Operations, \$14 thousand for Information Technology and \$31 thousand for Engineering Services and Project Management. (FBC Non PBR Reply, pp. 9–10)

FBC makes a number of submissions concerning CEC’s department-specific submissions. With regard to departmental under spending, FBC considers the aggregate level of expenses as being more important than individual department expenses. Using the Generation Department as an example, FBC points out that one year’s lower projected savings for non-routine activities would skew the net effect of overall expenditures. It takes a similar position with the \$190,000 in savings from Operations it considers to be non-sustainable. FBC further states that CEC’s proposed reduction of \$152,000 in Customer Service related to the reduced number of customers is likewise inappropriate, as the costs for the department did not decline commensurately with a decline in customers. Moreover, call volumes were higher than expected which resulted in higher labour costs. Concerning savings related to employee counts in the Finance and Regulatory department, FBC provides a detailed explanation of its labour issues and the dollar amount attributable to them, stating that the position taken by CEC is misinformed. (FBC Non PBR Reply, pp. 11–18)

The information provided by FBC in response to the Panel IR confirmed the 2013 Actual O&M expense of \$56.272 million, which is \$473,000 below the 2013 projection. In response to Commission Panel IR 1.3.1, FBC states that an adjustment of \$576,000 had been made to capture O&M expenses that were planned for 2013 but were delayed due to the labour disruption and will be spent in 2014. This amount is lower than the \$800,000 that was originally estimated. FBC’s

position is that these amounts would have been spent had it not been for the labour disruption and should be incorporated into any comparison. If this is taken into consideration, the 2013 Actual O&M is \$103,000 higher than the 2013 Projected O&M and \$349,000 lower than the 2013 Approved O&M. FBC further explains in response to Panel IR 1.3.2 that the 2013 Actual O&M, even in consideration of the adjustment for 2013's delayed O&M, is not reflective of typical operating conditions as activities of supporting departments were impacted by the labour disruption during nearly half of the year. (Exhibit B-53, Panel 1.3.1–1.3.2)

With respect to CEC's recommendation to exclude dam inspections over \$50,000 to be processed as a flow-through, FBC disagrees. It submits that CEC has provided no evidence suggesting that the \$350,000 amount budgeted is inaccurate or that the cost per year will fluctuate. The costs have been determined based on FBC's experience and knowledge and "are, to a certain extent, controllable in that they are not unforeseen, incremental expenses." FBC states that a 15-year inspection schedule which will be guided by condition, risk and operational priority will allow the company to prioritize maintenance. FBC also points out that 11 of its 15 generating units have received recent upgrades and the condition of the various units is relatively consistent. (FBC Non PBR Reply, pp. 21–22)

Commission Determination

The range of differences among most of the parties with respect to the proposed PBR Opening O&M Base is not large. CEC has proposed that FBC reduce its PBR Opening O&M Base by \$755,000 or approximately 1.2 percent and BCPSO has proposed a reduction of \$135,000 or 0.2 percent.

The one exception to this is ICG, who takes the position that the PBR Opening O&M Base should be reduced by 20 percent because of FBC's lack of evidence regarding operating efficiencies and concern as to fairness to customers. ICG provided no evidence in support of this, other than pointing out that O&M has increased substantially in the 2010–2011 and 2012–2013 time periods. Given the lack of ICG's analysis and evidence supporting how the 20 percent figure was arrived at, the Commission Panel places no weight on the ICG submissions in this regard.

Prior to considering any of the recommended adjustments to the FBC 2013 Base O&M proposal in the following sections, the Panel addresses a number of issues which have a bearing on O&M in this proceeding.

Labour Disruption and Impact of PBR on the Regulatory Department

The Commission Panel acknowledges that the lengthy labour disruption has been a factor that has had a significant impact on 2013 O&M expenses and, as a result, it is difficult to draw too many conclusions from 2013 O&M actual expenditures. However, the Panel agrees with FBC's proposed 2013 deferred O&M expense account of approximately \$576 thousand, as at December 31, 2013 (Exhibit B-53, Panel 3.1). **In accordance with FBC's proposed methodology as outlined in BCUC IR 2.90.13, the Panel approves the deferral account and directs that these deferred expenses be treated outside of Base O&M.**

The Panel also acknowledges that in spite of a PBR there will remain a need for its regulatory department to handle ongoing regulatory activities. FBC has spent much of its recent history under PBR and when not under PBR there were no additional staff positions added. Therefore, the Commission Panel accepts the move back to PBR does not warrant a reduction to the 2013 Base O&M to account for the labour disruption or the impact of PBR on the regulatory department.

Tracking Pension and OPEB, the AMI Project and Insurance Expenses Outside PBR

FBC makes submissions with respect to pension and OPEB, insurance expense and the AMI project being tracked outside of the O&M formula due to potential variability. None of the Interveners object to this proposal in principle. However, BCPSO raises concerns as to FBC's calculations of the amount to be excluded if it were only insurance premiums that were excluded from base costs and first and third party liability expenses were not flowed-through.

The Panel has previously determined that only the premium portion of insurance expenses is flowed-through (see Section 2.2.5). In this event, FBC proposes an increase to the 2013 Base O&M of \$274,000 which is the 2014 Forecast for First & Third Party Liability Expense.

Table 2.17 on page 89 of Exhibit B-24 shows the FBC Insurance Expense and the projected cost for 2013 and the 2014 forecast for First and Third Party claims is as follows:

- (i) Fluctuation in the number and significance of claims;
- (ii) Increase in the Company's customer base by 13 percent due to the acquisition of the City of Kelowna's assets;
- (iii) Increase in third party adjusting fees by 20 percent in 2013;
- (iv) The potential for liability deductibles to increase.

(Exhibit B-24, BCUC 2.59.2.1)

The Panel agrees with BCPSO that FBC's proposed increase to the Base O&M to include the 2014 forecast for first and third party liability expenses is not consistent with the method with which FBC has determined its other Base O&M expenses. Further, the Panel is not persuaded that the substantial increase in first and third party liability insurance from the projected \$106,000 in 2013 to the forecast \$274,000 in 2014 is justified. A 13 percent increase in customer base due to the City of Kelowna acquisition and a 20 percent increase in third party adjusting fees do not support a change of this magnitude. In addition, FBC provided no historical information to support this increase based on fluctuation in the number and significance of claims (Exhibit B-24, BCUC 2.59.2.1).

The Panel therefore finds it more appropriate to base the Insurance costs on FBC's 2013 Projection of \$106,000 with further adjustments to reflect the impact of the increase to FBC's customer base resulting from the City of Kelowna acquisition and the increase in third party adjusting fees. The Panel has utilized the percentage increases stated by FBC in its response to BCUC IR 2.59.2.1 and has applied an approximately 33 percent increase to the 2013 Projection for First & Third Party Liability Insurance and has thus arrived at a 2013 Base O&M adjustment of \$140,000.

Accordingly, the Commission Panel determines that a more appropriate addition to the PBR Opening O&M Base to account for first and third party liability expenses is \$140,000.

The Commission Panel accepts the FBC proposal, which allows for pension and OPEB, insurance expense premiums (with the exception of first and third party liability insurance expense), and AMI project costs to be tracked outside of the formula. **The Panel directs that these be excluded from the calculation of the earnings for the purpose of the ESM.**

Major Generation Unit Inspections

Concerning the handling of Major Generation Unit Inspections, the Commission Panel is not persuaded that a case has been made to remove them from the Base O&M at this time. FBC provides assurances that the \$350,000 it proposes is reflective of its experience and knowledge in this area. The Company also provides assurances that there is relative consistency in the condition of most of the generating facilities with 11 units having been recently upgraded and state that their schedule will be guided by condition risk and operational priority. **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. With respect to tying a growth factor to Major Unit Inspections, we are in agreement with CEC. However, this is one of many costs and removing this item from the approved formula calculation will only serve to create confusion. The Panel in Section 2.2.6 outlined its concerns with the Growth Factor proposal made by Fortis and has directed that this be reviewed at the first Annual Review meeting.

Adjustments to PBR Opening O&M Base

The Panel considers the PBR Opening O&M Base proposal to favour FBC. The Company has control over the determination of savings it deems to be sustainable and chooses to offset these against departmental over-expenditures in arriving at its sustainable savings adjustment. This would be reasonable if there was a justification of the additional departmental over-expenditures but this is not the case. This issue was raised by both CEC and BCPSO. CEC has proposed that the sustained savings be increased by \$167,000 (from Operations, Engineering and Information Technology)

while BCPSO has argued that sustained saving should be increased by \$135,000. FBC takes the position that it is inconsistent and illogical to incorporate savings which reduce the base but exclude those that increase it. The Panel does not agree. If costs have exceeded approved amounts they require the same level of scrutiny and explanation as any new costs. This is even more important when determining a base for a PBR with a five-year outlook.

More generally, FBC has taken the position that in a given year it may experience unanticipated higher or lower expenses. In response to Commission Panel IR 1.3.2, the Company refers to vacancies created by staff turnover as an item resulting in temporary savings. It further explains that the offset to this is the potential for unanticipated one-time higher expenses such as those for legal that serve to offset those savings. The Panel is not persuaded that the scenario described by Fortis accurately depicts the situation as it exists with respect to balance. Savings related to unanticipated staff vacancies are a fact of life for every organization as events happen that cannot be anticipated which result in savings while a suitable replacement is found. Where these types of savings will occur departmentally is impossible to predict but the fact that they will occur is predictable and savings will be made within the Company. On the other hand, unanticipated higher expenses do occur but there is no evidence to suggest that these occur with the frequency or magnitude as do savings arising from, for example, staff vacancies. The Fortis response to BCUC IR 3.45.4 may provide some insight. In all but one year between 2003 and 2012 FBC has achieved higher than its approved ROE. The lack of balance between unanticipated savings and unanticipated additional expenditures cannot be quantified in exact terms but may be a factor in FBC's historical ROE performance.

In consideration of these factors, the Commission Panel considers that in addition to other directives elsewhere in this Decision, a downward adjustment in the PBR Opening O&M Base is warranted. The Panel, in its best judgement, directs that in addition to the adjustments proposed by FBC a further reduction of \$200,000 be made. This is in addition to any further adjustments to 2013 Base O&M directed in this Decision.

3.1.2.3 Executive Compensation Study and Short-Term Incentive Plan

In the FBC 2012–2013 RRA Decision, the Commission was of the view that FBC’s compensation package should be reviewed in its entirety before a determination could be made as to whether it was appropriate. The Commission directed FBC to provide benchmarking information on all elements of its executive compensation in its next RRA.

In this Application, FBC submitted a May 2013 Executive Compensation Review conducted by Hay Group Limited (Hay) on a confidential basis. Subsequently, a redacted version of this review was submitted in response to BCUC IR 1.221.1.1. FBC engaged Hay, its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of more than 250 Canadian Commercial Industrial Companies. The Hay study looked specifically at “*Total Direct Compensation*” which is comprised of base salary, short-term incentives, and long-term incentives. (FBC Exhibit B-7, Attachment 226.1.1, Executive Compensation Benchmarking Study)

The following summarizes the observations from Hay’s Executive Compensation Review:

- FBC’s target *Total Direct Compensation* is below market median for all roles; however, actual *Total Direct Compensation* is somewhat moderated by the strong actual short-term incentive payouts, which ultimately position most FBC executives close to the market median;
- FBC’s executive base salaries are generally positioned around the market median, and the target total is close to median for most roles;
- Actual total cash compensation (excluding long term incentives) is very competitive, with all roles above market median.

(FBC Exhibit B-7, Attachment 226.1.1, Executive Compensation Benchmarking Study, pp. 8–11)

In its study, the Hay Group used its comparable Canadian Commercial Industrial reference group which consisted of 275 different companies. When questioned about the appropriateness of the broad-based comparator group included in the study, FBC stated that this group is appropriate for the following reasons:

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- There exists a broad spectrum of commercial and industrial organizations with which FBC competes for executive talent;
- A larger comparator group leads to more stable data year over year;
- These organizations represent a stable, national comparator upon which to base compensation policy.

(Exhibit B-7, BCUC 1.219.1.1)

FBC also filed its 2013 Short-Term Incentive Plan (STIP) targets and explains that there are both corporate and personal objectives to be obtained before STI's are granted. Table 3.5 shows FBC's 2013 corporate targets and weightings:

Table 3.5 FBC's 2013 Corporate Targets and Weightings by Category

The targets and weightings for 2013 are:

Category	Measurement	2012 Results	2013 Targets			Weight
			Minimum 50%	Target 100%	Maximum 150%	
Financial	Regulated Earnings	\$48.5	Plan -2% \$43.2M	Plan \$44.1M	Plan +2% \$45.0M	30%
Safety	All Injury Frequency Rate (AIFR)	1.72	Target +10% 1.80	Average of last 3 years 1.64	Target -10% 1.48	10%
	Recordable Vehicle Incidents	22	Target +10% 30	Average of last 3 years 27	Target -10% 24	10%
Customer	Customer Service Index (CSI)	8.4	8.3	8.5	8.7	12.5%
	System Average Interruption Duration Index (SAIDI)	1.95	Target +5% 2.33	Average of last 3 years 2.22	Target -5% 2.11	12.5%
Regulatory	Regulatory Performance	-	Subjective	Subjective	Subjective	25%
TOTAL						100%

(Source: Exhibit B-7, Attachment 221.1)

FBC explains that the STIP is based on corporate and individual performance objectives and that the corporate objectives have four components: Financial, Safety, Customer and Regulatory. Each component has three measures: threshold (50 percent), target (100 percent) and maximum (150 percent) and the benefits are allocated as follows:

- If performance is below target, the variance from target is prorated between threshold (50 percent) and target (100 percent);

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- If performance is above target; the variance is pro-rated between (100 percent) and maximum (150 percent).

The target payout levels and the design of the weightings for the purpose of determining payouts are:

Position	Weightings		Target Bonus Level (% of Salary)
	Individual	Corporate	
President and CEO	20%	80%	50%
Vice Presidents	50%	50%	30 - 40%

(Source: Exhibit B-7, Attachment 221.1)

With respect to the competitiveness of the STIP, the Hay Group makes the following comments:

- Actual total cash [Base Salary + Actual STI] is very competitive, with all FortisBC executives above market median. This is driven by strong actual STI grants as compared to the market, with all actual STIs above the 70th percentile.
- The strong STI rewards driving competitive total cash are largely offset by weak long-term incentive (LTI) compensation, resulting in actual total direct compensation [Actual Total Cash + LTI] generally around market median.

(Exhibit B-7, Attachment 226.1.1)

Table 3.6 provides a review of STI payments as a percentage of salary from a historical perspective.

Table 3.6 Short-Term Incentive Payments to FBC Executives for the Last Five Years

	Actual STI as % of Salary				
	2008	2009	2010	2011	2012
President & CEO	56.94%	60.00%	79.08%	85.00%	76.92%
EVP HR, Customer and Corporate Services	41.86%	45.65%	56.96%	67.62%	60.34%
EVP Network Services, Engineering and Generation	41.86%	45.65%	43.48%	65.74%	60.49%
VP Finance & CEO	44.19%	45.65%	52.17%	63.83%	68.02%
VP Operations Support, Gen Counsel & Corporate Services	49.50%	46.67%	48.00%	54.16%	50.74%
VP Resource Planning	38.64%	45.65%	50.00%	-	-
VP Energy Solutions & External Relations	-	-	46.95%	63.50%	58.94%
VP Energy Supply & Resource Development	-	-	46.36%	59.76%	68.97%
VP Strat Plan, Corporate Development and Regulatory Affairs	-	-	62.79%	63.83%	68.02%
VP Customer Service	-	-	-	-	46.48%

(Source: Exhibit B-7, BCUC 1.221.1.2)

A review of this table shows that there has likely been an increase in STIP in the 2011/2012 years as compared to 2008 or 2009.

Commission Determination

FBC's long-term incentive amounts (i.e. stock options and PSUs) are not recovered from the ratepayer and the Company has provided limited information on this component. Because of this, the Commission Panel focuses on the short-term incentives as a percentage of base salary and total cash compensation.

The three main areas of concern to the Panel are:

- Whether the Hay study comparator group is reasonable;
- Whether the STIP targets will provide benefits to the ratepayers; and
- Whether short-term incentive amounts paid to executives are reasonable.

Hay Study Comparator Group

The Commission Panel accepts that FBC competes for executive talent in the broad spectrum of commercial and industrial organizations. Therefore, FBC's rationale for the choice of the larger, broad-based comparator group is reasonable.

Provision of Benefits to Ratepayers

The Panel has concerns as to whether all of the components of FBC's corporate and individual performance objectives or scorecard provide value to the ratepayer. The Panel notes that the corporate financial objective with the highest weighting, at 30 percent, is regulated earnings. While there is no disagreement as to the importance of a utility being healthy and financially sound financially, the Panel is not persuaded that exceeding its approved ROE is in the interest of ratepayers.

For these reasons, the Panel is not persuaded there is sufficient evidence to support the need for the STIP to be fully funded by the ratepayer. **The Commission Panel finds that 30 percent of the STIP costs are on the account of the shareholder. Therefore, the Panel directs FBC to recover only 70 percent of the STIP from the ratepayer and reduce its O&M Base accordingly.**

Reasonableness of STI Paid to Executives

The evidence regarding executive total direct compensation indicates that the actual STIP is very competitive when compared to the market median. This is confirmed by the Hay Study which states that weakness or shortfall in the competitiveness of long-term compensation is somewhat moderated by the strong actual short-term incentive payouts (Exhibit B-7, Attachment 226.1.1, p. 8). Of concern to the Commission Panel is the extent to which actual Total Cash paid to executives for base salary and STI exceeds the target or median Total Cash paid as indicated in the confidential report (Exhibit B-1-1, Appendix C 2). As noted previously in Section 3.1.2.2, FBC has stated that its approach to total compensation is to be in the median level in its peer group. The Panel accepts this. However, if there is a shortfall in the amount of executive compensation as pointed out by the Hay Group, it is with the long-term elements of the plan, not the STI. In the Panel's judgment it is not reasonable to offset any shortfall in long-term incentives of the executive compensation plan by increasing the STI to a level that is well above target. **Therefore, the Commission Panel finds that the STI costs as they relate to the ratepayer are to be restricted to the target (as outlined in the Hay Report) STI compensation only. The Panel understands that this equates to the target median within its comparative peer group and directs any amounts in excess of the target median to be borne by the shareholder.**

In summary, FBC is to calculate the STIP payment based on the target median and then deduct 30 percent of this calculation to arrive at the amount to be borne by the ratepayer. Any STIP amounts paid in addition to this are to be borne by the shareholder.

As part of its Compliance Filing, FBC is directed to provide the following information for 2013: (i) the amounts spent on the Executive STI, and (ii) the amount that would have been spent if only the target STI had been met (as per page 9 of the Executive Compensation Benchmarking, Exhibit

B-1-1, Appendix C-2). The difference between these two amounts must be deducted from the Base O&M. If required, the filing may be made on a confidential basis with reasons.

3.1.3 Base Capital

There is considerable disagreement among the parties with respect to the inclusion of capital expenditures for FBC within the PBR. Much of this disagreement stems from concern that the methodology chosen by FBC leaves too much open to the Company's judgement and because of this, the customer is disadvantaged. The Commission Panel holds similar concerns. This was discussed in Section 2.3.5 where the Panel considered these matters and has determined that a further review of the capital exemption is required. This is to be addressed further in accordance with the timetable set out by the Panel in Section 2.3.5 with the expectation that the parties will recommend an appropriate threshold for capital to be included in the PBR formula. Until that time, the Panel has approved FBC's proposed approach to formula capital. Accordingly, this section will only deal with setting a base capital for the period up to and including 2015.

Similar to the approach taken with O&M, FBC has used the 2013 approved capital expenditures of \$101.970 million from the 2012–2013 Decision as its starting point for the capital formula. Then, the following adjustments are made:

- Major projects such as Polychlorinated Biphenyls (PCB) environmental compliance, the Kelowna Bulk Transformer Capacity Addition, the Trail Office Lease/Purchase, the Kootenay Long Term Facility and Advanced Metering Infrastructure totalling \$54.882 million are deducted.
- Adjustments for 2013 non-controllable items to account for the return of PST and pension and OPEB amounts related to higher actuarial estimates are then made. FBC expects the pension amounts to decrease over the 2014 to 2018 period.

(Exhibit B-1, pp. 56–59, pp. 180–182; FBC Final Argument pp. 24–28)

These adjustments are outlined in detail, by capital category, in Table 3.7 below and result in a 2013 Base of \$49.180 million. This is comprised of \$19.194 million for Sustainment Capital, \$19.760 million for Growth Capital (primarily for new connects), \$8.134 million for Other Capital and \$1.723 million for PST and pension adjustments.

Table 3.7 2013 Base Adjustments (\$ thousands)

	2013 Approved	Less Major Projects	Applicable to Formula	PST	Pension	2013 Base
Generation Sustainment Capital						
All Plants Concrete and Structural Rehabilitation	408	-	408			
Lower Bonnington Powerhouse Windows	4	-	4			
All Plants Minor Sustainment Projects	1,032	-	1,032			
Upper Bonnington, South Slocan & Corra Linn Powerhouse Windows	131	-	131			
Upper Bonnington Old Plant Various Unit Upgrades	378	-	378			
Lower & Upper Bonnington & Corra Linn Fire Panels	231	-	231			
All Plants Public Safety and Security	179	-	179			
	2,363	-	2,363	19	86	2,468
Transmission, Stations and Distribution Sustainment Capital						
Transmission Sustainment	5,378	-	5,378			
Station Sustainment	1,723	-	1,723			
PCB Environmental Compliance	9,021	(9,021)	-			
Distribution Sustainment	8,828	-	8,828			
Communications Upgrades	318	-	318			
SCADA System Upgrades	584	-	584			
	25,852	(9,021)	16,831	132	616	17,579
SUSTAINMENT CAPITAL	28,215	(9,021)	19,194	151	702	20,047
Transmission, Stations and Distribution Growth Capital						
Ellison to Sexsmith Transmission Tie	318	-	318			
Kelowna Bulk Transformer Capacity Addition	2,865	(2,865)	-			
New Connects	17,198	-	17,198			
Ellison Feeder 2 to Sexsmith Feeder 1 Tie	908	-	908			
Distribution Small Growth Projects	714	-	714			
Distribution Unplanned Growth Projects	622	-	622			
GROWTH CAPITAL	22,625	(2,865)	19,760	155	723	20,638
OTHER CAPITAL						
Buildings	769	-	769			
Furniture & Fixtures	106	-	106			
Fleet	2,260	-	2,260			
Telecommunications	159	-	159			
Meters	353	-	353			
Tools	398	-	398			
Information Systems	4,089	-	4,089			
Trail Office Lease Purchase	10,000	(10,000)	-			
Kootenay Long Term Facility	7,980	(7,980)	-			
Okanagan Long Term Solution	31	(31)	-			
Advanced Metering Infrastructure	24,985	(24,985)	-			
	51,130	(42,996)	8,134	64	298	8,495
TOTAL CAPITAL EXPENDITURES	101,970	(54,882)	47,088	369	1,723	49,180

(Source: Exhibit B-1, p. 181)

FBC describes its capital categories as follows:

- “Sustainment Capital – Consists of expenditures for system reinforcements, replacements and upgrades to generation, transmission and distribution assets to ensure safety, integrity and reliability.
- Growth Capital – Consists of expenditures for infrastructure upgrades required to meet customer and associated load growth.

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- Other Capital – Consists of expenditures for Information Systems, Vehicles, Metering, Telecommunications, Facilities, and Tools and Equipment.”

(Exhibit B-1, p. 178)

FBC provides an illustration of how the formula will work in Table 3.8 below.

Table 3.8 PBR Capital Formula Inputs and 5-Year Forecasts

Line No.	Particulars	2013 Base (1)	2014 Formula (2)	2015 Formula (3)	2016 Formula (4)	2017 Formula (5)	2018 Formula (6)
1	2013 Base Capital (\$000)	\$ 49,180					
2	Less Capital Tracked Outside of Formula						
3	Pension/OPEB (Capital portion)	(6,741)					
4		42,439					
5							
6	Average Number of Customers	128,796	129,770	130,922	132,142	133,385	134,687
7	% Change In Customers		0.76%	0.89%	0.93%	0.94%	0.98%
8							
9	Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
10							
11	Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
12							
13	I-X Mechanism (1+I-X)		101.81%	101.92%	101.84%	101.86%	101.80%
14							
15	Net Inflation Factor ((1 + Line 7) * Line 13)		102.58%	102.62%	102.79%	102.82%	102.75%
16							
15	Formulaic Capital (Line 15 * Prior Year)		43,534	44,764	46,012	47,309	48,630
16	Add: Capital Tracked Outside of Formula						
17	Pension/OPEB (Capital portion)	6,741	6,396	5,952	5,508	5,133	4,826
18	PCB Compliance - Substations		6,062				
19	Advanced Metering Infrastructure Project		16,765	18,233	583	741	604
20							
21	Total Capital Under PBR		72,758	68,950	52,103	53,183	54,060

(Source: Exhibit B-1, p. 58)

Table 3.7 shows how the base capital will be adjusted annually. This takes into account the percentage change in the average number of customers and the application of the I-X formula to arrive at its current estimate of the formulaic capital for each of the PBR years. Added to this is capital for PCB Compliance (substations), AMI and the capital portion of Pension/OPEB. These amounts vary each year and are proposed to be covered under PBR but are tracked outside of the formula. As a result, the amount of capital proposed to be covered under PBR varies from \$72.758 million in 2014 to amounts in the \$52 to \$54 million range in years 2016 to 2018.

In Table C5-3 of the Application (Exhibit B-1, p. 182), FBC provides its forecast of capital expenditures over the PBR period. These indicate that the Company's expectations are that given a non PBR environment, Forecast Sustainment Capital will exceed, Growth Capital will be lower and

Other Capital will be higher than those amounts generated by the formula and driven by 2013 Approved amounts. In total, the amounts generated by the formula are 3.1 percent lower than FBC's five-year capital forecast.

Intervener Submissions

CEC notes that FBC's forecast capital expenditures vary significantly by major functional area and by total capital classification. It points out that 2014 capital expenditures are forecast to be 50 percent higher when compared to the Approved 2013 Base Sustainment Capital. This drops by \$6.3 million in 2015. In addition, other functional areas have no capital forecast in some years.

CEC also raises concern as to FBC's history of under spending its capital against approved amounts and whether the Company is able to accurately predict future costs. To support its argument, it relies upon FBC's response to BCUC IR 1.148.3 showing that since 2008, capital expenditures have been below approved capital by amounts ranging from three to 37 percent. CEC acknowledges that extenuating circumstances contributed to under-expenditures in 2012 and 2013 and its comments refer to total capital spending but submits that this nonetheless provides an indication of the magnitude of the variance. The historical results suggest that actual capital expenditures can be lower than approved by amounts that are far greater than the 3.1 percent as forecast by FBC. CEC points out that there is a real possibility that FBC could significantly underspend against PBR approved amounts with little short-term impact on safety, performance or reliability. Stakeholders may perceive this potential for significant losses or gains as contrary to the "just and reasonable" rate principle. (CEC FBC Non PBR Final Argument, Base Capital, pp. 5–6)

ICG agrees with the classification of capital projects as base or major capital but argues that the evidence does not provide criteria that could consistently identify those projects that would fall outside of base capital. A reliance on a formula approach to determine capital expenditure targets is not likely to produce better results than the project-by-project analysis conducted in the earlier PBR. ICG urges the Commission to reject the FBC PBR Plan proposal "at least until FBC refines the method for ensuring only recurrent expenditures are in base capital, and until FBC can measure efficiency gains (savings) resulting from efficiency initiatives." However, if the Commission does

include capital expenditures in the PBR Plan, ICG recommends that the base capital be set on 2013 Actual capital expenditures rather than the 2013 Approved amounts. (ICG Final Argument, pp. 17–21)

FBC Reply

FBC disputes the CEC argument concerning consistently under spending its approved capital. It points out that even CEC agrees that there were extenuating circumstances in 2012 and 2013 that led to the lower spending levels. In addition, the Company asserts that the largest part of the variance between actual and approved amounts were those related to CPCNs. Because the Company is seeking to have CPCNs tracked outside of the formula, this problem should be alleviated.

FBC argues that CEC has ignored the fact that the PBR formula is designed to be applied at the aggregate level rather than the functional level which is in keeping with the PBR guiding principle of ‘keeping it simple.’ FBC states “the type of granular analysis conducted by CEC is contrary to this principle and unnecessarily increases the complexity of the mechanism.” Its position is that determining the capital at the aggregate level allows it to determine the appropriate allocation of overall funds. (FBC PBR Reply, pp. 35–36)

Concerning ICG’s submissions, FBC states that it is not appropriate to use a test of “non-recurring” to identify capital falling outside of the formula arguing that it is appropriate to include expenditures that are generally knowable and manageable based on past budgeting experience and customer growth. CPCN projects should not be placed under the formula as they represent large, discreet and “lumpy” investments. (FBC PBR Reply, p. 41)

Commission Determination

The positions of the Interveners with respect to the determination of base capital seem to be founded on past experience with actual capital expenditures as compared to approved capital expenditures. CEC has taken a historical view and has compared total actual versus approved

capital as evidence supporting its position that history is likely to repeat itself in the current PBR. ICG, while refraining from referring to specific numbers, has urged the Commission to consider the current capital expenditures in light of past capital expenditures.

The Commission Panel finds the CEC and ICG arguments to be unpersuasive and puts little weight on them. Both CEC and ICG have made their submissions based on variances in total capital expenditures with no recognition of the steps taken by Fortis to adjust the capital covered under the PBR formula down in recognition of those projects which are non-recurring or of a one-off nature. Nor have their arguments considered the implications of these adjustments. As a result, the Panel considers this to be an “apples and oranges” proposition with little basis for comparison. However, as noted in Section 2.3.5, the Panel has determined that a further review of the capital is required. This could result in a larger dollar threshold for capital included in the PBR formula. In considering changes to the scope of capital projects and setting a dollar threshold, the Panel acknowledges it must consider FBC’s past history and be satisfied that the new capital base will reflect what is realistically required.

FBC has proposed the following with respect to setting the base capital for the PBR:

1. Acceptance of the 2013 Approved Capital Expenditures of \$101.970 million as the starting point for determining the base.
2. A deduction of \$54.882 million from this amount in recognition of various non-recurring projects.
3. The addition of adjustments for non-controllable items (Pension/OPEB, PCB Compliance and the AMI project).

FBC has also included acceptance of the CPCN criteria as a means of excluding projects from the formula. This has been dealt with earlier and will not be further discussed.

The Commission Panel will review each of these in turn.

Acceptance of 2013 Approved Capital Expenditures as the Starting Point

The Commission Panel accepts the 2013 Approved Capital Expenditures as an appropriate starting point for determining the base capital. The Panel acknowledges that 2013 actual expenditures were less than approved but accepts that this was largely due to matters related to the labour disruption. As was discussed in Section 3.1.2, this amount has been scrutinized carefully in a recent regulatory proceeding and given the labour disruption in 2013, the Panel considers this to be the most reliable starting point.

Deductions of \$54.882 million for Major projects

The Commission Panel accepts a deduction of \$54.882 million from 2013 Approved Capital Expenditures as proposed by FBC. As argued by FBC, this amount is for non-recurring projects and CPCNs which are responsible for a significant part of the continuing variance between actual and approved capital spending levels. The Panel considers the tracking of these outside the formula as a reasonable approach at this time given the concerns raised by interveners with respect to total actual versus total approved capital expenditures. As outlined in Section 2.3.5, the matter of exclusions from the capital formula will be readdressed in 2015.

Addition of Adjustments for Non-Controllable Items

The Commission Panel accepts that there is a need to accommodate amounts for Pension/OPEB, PCB Compliance (substations) and the AMI project and these are to be tracked outside of the formula. However, for clarity purposes, the Panel affirms, as previously determined in Section 2.3.1 that the earning sharing mechanism will not apply to these amounts. The Earnings Sharing Mechanism (ESM) will apply to formulaic capital only.

In consideration of all of these factors, **the Commission Panel approves FBC's 2013 Base Capital as applied for, subject to further adjustment as directed elsewhere in this Decision.**

3.2 Accounting Policies

FBC seeks the following approvals for changes in its accounting policies, effective January 1, 2014:

- a. Approval to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports;
- b. Approval to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense;
- c. Approval to allocate Executive costs between FEI and FBC effective January 1, 2014, by way of applying the Massachusetts Formula;
- d. Continued approval of FBC's direct overhead charging methodology; and
- e. Continued approval of FBC's capitalized overhead rate of 20 percent.

Each of these topics will be addressed in the following sections.

3.2.1 Discontinue Reconciliation of US GAAP to Canadian GAAP

In Order G-117-11, the Commission approved FBC's request to adopt US Generally Accepted Accounting Principles (GAAP) for the period 2012–2014. As part of that Order, the Commission requested that FBC provide an annual reconciliation from US GAAP back to Canadian GAAP.

The 2012 reconciliation provided by FBC in the 2012 Annual Report (amounts reported under 2011 Canadian GAAP for financial reporting purposes to amounts reported under US GAAP for regulatory accounting) was filed as Exhibit A2-2 by staff in this proceeding.

FBC states that it no longer maintains specific accounting records in compliance with pre-2012 Canadian GAAP since it is not used for any other reporting purpose. Therefore, it is becoming increasingly complicated and costly to prepare this reconciliation on a prospective basis. (Exhibit B-1, p. 245)

FBC estimates that approximately one week was spent reviewing the reconciliation for 2012 and that continuing to prepare this reconciliation is expected to not only increase the future

preparation and review time of its BCUC Annual Reports but that it also increases FBC's external actuarial costs. FBC also agrees that it will continue to be willing to communicate to the Commission any future accounting policy changes that will have an impact on setting customer rates. (Exhibit B-7, BCUC 1.174.3–1.174.4)

Based on these reasons, FBC requests approval to discontinue providing this reconciliation in its future Annual Reports. (FBC Non PBR Final Argument, pp. 47–48)

BCPSO supports FBC's request to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports. BCPSO's view is that the reconciliation becomes less informative each year, and the cost of performing the reconciliation is likely to grow, thus shifting the cost/benefit of this reconciliation over time. (BCPSO Non PBR Final Argument, p. 15)

No other Interveners commented on this issue.

Commission Determination

The Panel agrees with FBC that the reconciliation of US GAAP to pre-existing Canadian GAAP is no longer relevant and is therefore of limited use. The Panel also recognizes that continuing with this reconciliation creates unnecessary additional regulatory burden for FBC. **Accordingly, the Commission Panel approves discontinuance of the US GAAP to Canadian GAAP reconciliation. The Commission 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.**

3.2.2 Net-of-Tax Treatment of Pension/OPEB Funding

FBC seeks Commission approval to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective in 2014. Instead it proposes to add back the pension/OPEB expenses and deduct the contributions when performing income tax calculations (Exhibit B-1, p. 242). FBC states that the prepaid pension and OPEB liability deferral accounts are not amortized into rates in a manner similar to other deferral accounts that are subject to the net-of-tax treatment. Rather than being amortized, the prepaid pension and OPEB liability deferral accounts balances change

based on the amount of employee benefit expenses recognized and contributions paid in each year. As such, these employee future benefit deferral accounts are not drawn down in the same manner as other deferral accounts and their related net-of-tax deferral balances. (Exhibit B-1, p. 242)

FBC states that this change is consistent with FEI's treatment, which was approved in Order G-141-09. Further, FBC submits that the net-of-tax treatment is not common practice in the rate-regulated utility industry and identified several utilities that do not use the net-of-tax treatment (Exhibit B-7, BCUC 1.215.3).

Intervener Submissions

BCPSO submits that the going-in rate must be adjusted to reflect the change from recording the deferral account on a net-of-tax basis to including the income tax impact in income tax expense. If this is done, ratepayers should be indifferent to the change. (BCPSO FBC Non PBR Final Argument, p. 15)

No other Interveners commented on this issue.

Commission Determination

The Commission Panel approves FBC's request to discontinue the net-of-tax treatment for the pension and OPEB funding differences as applied for. The prepaid pension and OPEB liability deferral account balances change each year based on the amount of employee benefit expenses recognized and contributions paid. Therefore, the Panel considers FBC's request for a different treatment to be reasonable. The reasoning is particularly appropriate since these deferral accounts are not drawn down in the same manner as other deferral accounts.

The Panel directs the existing net-of-tax balances of the pension and OPEB to be carried forward as a starting point for 2014, with future additions to both accounts to be on a pre-tax basis and the timing of tax deductions to be recognized in the calculation of income tax expense.

3.2.3 Allocate Executive costs by way of the Massachusetts Formula

As an alternative to relying upon management estimates of time for cost allocations, FBC proposes to allocate executive costs between FEI and FBC effective January 1, 2014, by applying the Massachusetts Formula. The Massachusetts Formula is extensively used in industry and is a composition allocator that determines the amount of time and effort for each executive. (FBC Non PBR Final Argument, p. 49) FBC states that the objective of seeking to use the Massachusetts Formula is not to increase or decrease executive labour O&M cost, but rather to adopt a simplified method of allocation (Exhibit B-24, BCUC 2.25.5).

Intervener Submissions

ICG supports the use of the Massachusetts Formula for the allocation of shared service costs between FEI and FBC (ICG Final Argument, p. 22).

No other Intervener made submissions.

Commission Determination

The Panel recognizes the simplified method of allocating executive time between FEI and FBC and recognizes the high level of integration between the two companies at the executive level. **FBC's proposed methodology utilizing the Massachusetts Formula is approved.**

The Commission Panel directs any changes to executive cross-charges resulting from the Code of Conduct/Transfer Pricing Policy proceeding be reflected as an adjustment to the Base O&M.

3.2.4 Direct Overhead Loading

FBC utilizes direct overhead loading to allocate supervisory and administrative costs attributable to transmission and distribution (T&D) capital projects (Exhibit B-1, pp. 255–257; FBC Non PBR Final Argument, pp. 58–60). FBC explains that these costs are directly attributable to T&D capital projects and should be directly charged to these projects. However, for administrative efficiency

these costs are charged directly into a holding account and then allocated to T&D capital using a Direct Overhead loading factor in a manner similar to how Capitalized Overhead is applied. (Exhibit B-7, BCUC 1.179.1)

FBC submits that it first introduced this methodology in its 2004 RRA for purposes of reducing the administrative burden associated with charging labour time and costs to individual projects. FBC has been charging these costs to capital consistently for the past 13 years. (Exhibit B-7, BCUC 1.179.3)

In compliance with the last RRA Decision, FBC obtained an external audit opinion on the appropriateness of the direct overhead loading methodology. In its report, KPMG “finds that FBC direct overhead loading methodology...to be a reasonable basis...and may continue to be appropriate” (Exhibit B-1-1, Appendix F3, KPMG Report, p. 5).

KPMG also confirmed “these costs are removed from the O&M pool” and do not result in duplicating the allocation of the capitalized overhead, “as the evaluation of direct overhead rate is conducted with these direct overhead loading costs excluded from the remaining corporate cost pool...” (Exhibit B-1-1, Appendix F3, KPMG Report, p. 29).

Intervener Submissions

ICG recommends the Commission Panel accept the methodology pro-tempore and direct FBC to review it again prior to the end of the PBR Period. ICG suggests that three departments — Environment, Finance and Procurement — appear to estimate the percentage of their activities related to T&D operations and then a percentage of their residual costs are capitalized based on the volume of work. Mr. Pullman recommends that a more rigorous analysis should be performed on FBC’s time records rather than reliance on management’s estimates. (ICG Final Argument, pp. 28–29)

FBC Reply

FBC submits that Mr. Pullman has not properly distinguished the issue of capitalized overhead and direct overhead and stresses the fact that the KPMG Review made specific reference to the Company's methodology not resulting in duplication. FBC's position is that further review of the methodology is not necessary. (FBC Non PBR Reply, pp. 34, 36–38)

Commission Determination

The proposed methodology of utilizing a T&D loading factor is a simplified method of allocating supervisory and administrative costs that are attributable to these types of capital projects. There is no evidence that this simplification results in duplication of allocations or any other issues of concern. Accordingly, **the Panel approves FBC to continue its Transmission and Distribution direct overhead loading allocation during the PBR period.**

The Panel agrees that FBC has complied with the previous directives by its filing of the KPMG Report and does not consider further evaluation to be required at this time.

3.2.5 Capitalized Overhead

FBC seeks approval to continue to use a capitalized overhead rate of 20 percent during the PBR period. FBC submits that it operates in a capital-intensive industry and while many activities can be charged directly to a specific project, others are not as directly attributable and therefore require the capitalized overhead allocation. (FBC Non PBR Final Argument, p. 51)

FBC obtained an audit review from KPMG and submits that its 20 percent rate is appropriate, there is no one universally accepted guideline for capitalizing overhead, and FBC's allocation method was found to be a reasonable (Exhibit B-1, pp. 251, 254; Exhibit B-1-1, Appendix F3, KPMG Report).

FBC submits that it is expecting regular capital expenditures over the PBR Period to remain at levels generally consistent with, or higher than, regular capital expenditures made during 2010 through

2013. Further, it notes that reducing the capitalized overhead rate will have rate impacts for FBC's customers.

The KPMG Report compares two different models to estimate FBC's capitalization rate: the Survey model, which proposes an overhead capitalization rate of approximately 15 percent; and the Mathematical model, which proposes a rate of 17 percent. KPMG found that the Survey model provides more transparent linkage of the unallocated overhead costs related to capital activities and therefore "believes that the more appropriate capitalization rate is approximately 15 percent." (FBC Exhibit B-1-1, Appendix F3, KPMG Report, p. 27)

FBC submits that the KPMG rate is "indicative in nature, but not definitive" and does not agree that its rate of 20 percent should be reduced (FBC Exhibit B-7, BCUC 1.178). However, FBC states that if the Panel were to direct it to reduce the rate then it would "recommend a phased in approach to the rate reduction in order to mitigate the impact on customer rates." (FBC Exhibit B-7, BCUC 1.178.4) As an alternative, FBC agrees that "[i]t could be possible to utilize a percentage of forecast capital expenditures as an overheads capitalized allocator, however that approach would introduce higher variability in customer rates." (FBC Exhibit B-7, BCUC 1.178.7)

Intervener Submissions

BCPSO submits that 20 percent is too high and refers to KPMG's study indicating an appropriate rate of 15 percent. BCPSO does not agree with FBC's characterization that a lower rate would have a negative rate impact because that would be a one-time hit, with positive rate impacts being experienced in each subsequent year. (BCPSO FBC Non PBR Final Argument, p. 16)

ICG also highlights the inconsistency between FBC's current overhead capitalization rate of 20 percent versus the KPMG report and requests the Panel direct FBC to implement immediate changes to its capitalization policies. Mr. Pullman recommends the Commission direct FBC to determine its capitalized overhead as a function of its capital expenditures rather than its O&M expenses. Mr. Pullman further recommends that FBC be directed to capitalize overhead at 8 percent of capital expenditures instead of 20 percent of O&M. (ICG Final Argument, pp. 29–31)

FBC Reply

In response to ICG's recommendation for employing a capitalized overhead rate as a percentage of capital expenditures, FBC estimates the resulting rate impact may fluctuate between -1.2 percent to 6.3 percent during the PBR period. This will occur due to capital expenditure levels. Further FBC points out that ICG has provided no evidence as to why this percentage is appropriate. (FBC Non PBR Reply, pp. 32–33)

Commission Determination

The Panel directs FBC to reduce its capitalized overhead rate to 15 percent in 2014. This is the rate recommended by KPMG based on the audit report ordered by the Commission in FBC's last RRA Decision. The Panel considers the utilization of a rate recommended by FBC's external auditors is reasonable and prudent and thus an appropriate rate for the PBR period. The Panel accepts that reducing the capitalized overhead rate to 15 percent will have a rate impact of approximately 1.25 percent for FBC (Exhibit B-7, BCUC 1.178.1). However, over time this will be mitigated by a lower amount being capitalized, resulting in lower rate impacts on an ongoing basis.

Pertaining to Mr. Pullman's recommendation for determining capitalized overhead as a function of its capital expenditures, the Panel finds that ICG provided no evidence to suggest this method has been employed in other jurisdictions. Furthermore, the Panel finds that the suggested methodology would lead to lumpy results with no significant evidence of offsetting benefits (Exhibit C-10-7, ICG 1.2.2). Thus, the Panel is not persuaded there at this time to consider moving away from current practice.

3.2.6 Capitalization of Annual Software Costs

The capitalization of annual software costs was not requested by FBC in this Application. However, this request was proposed by FEI in its 2014–2018 PBR RRA. FEI is requesting approval to adopt a capitalization methodology for the treatment of annual software costs paid to vendors in support of upgrade capability. FEI states that the costs allocated to capital using this methodology are to fund only the upgrade component of the annual costs which extend the life of the affected

software assets. (FEI Exhibit B-1, p. 265) The impact of this capitalization methodology is a re-allocation of approximately 43 percent of FEI's annual vendor software costs from O&M to Capital. FEI states in its evidence that this requested change is consistent with the treatment employed by FBC.

Commission Determination

Given the description of annual software costs proposed by FEI, the Panel considers these to be annual licencing fees associated with software. **The Commission Panel agrees and also considers it inappropriate for FBC to capitalize these recurring fees and directs FBC to expense its annual software costs in a manner consistent with the direction provided to FEI by the Commission in Section 3.2.3 of the FEI 2014–2018 PBR RRA Decision.**

As part of its Compliance Filing, FBC is directed provide the following information: (i) the total amount paid in 2013 for annual software costs; (ii) the amounts originally included in FBC's Application for 2013 Base O&M and 2013 Base Capital related to annual software costs; and (iii) the increase to FBC's 2013 Base O&M as a result of this change in treatment of annual software costs and the resulting decrease to FBC's 2013 Base Capital.

Consistency between FBC and FEI can be beneficial and in the Panel's best judgement, it is appropriate for both FBC and FEI to treat annual software upgrade costs in the same manner. The Panel notes that expensing annual software costs is acceptable practice under US GAAP.

3.3 Deferral Accounts

FBC is requesting a number of new rate base deferral accounts and changes to existing deferral accounts. Additionally, there are a number of issues that arose during the last RRA that FBC proposes that this Panel revisit. These issues are further discussed in the following sections.

3.3.1 Deferral Account Financing

FBC requests revisiting the Commission's Decision in the 2012–2013 RRA, which it submits was incorrect (FBC Reply, p. 38). FBC proposes that deferral accounts should earn the weighted average cost of capital (WACC), which includes both equity and debt return (Exhibit B-1, p. 246; FBC Reply, p. 38).

In the 2012–2013 RRA Decision, the Commission found that “current period charges are not ‘investments’ which attract a capital return, they are deferred operating costs/current period expenses which, ... in the Panel's view should not attract rate base rate of return.” The Commission also stated that: “For expenditures which are amortized beyond one year, the Panel finds that the appropriate return is FortisBC's WACD. The Panel further finds that for true-up deferral accounts which are, by their very nature, a short term deferral, the appropriate interest return is FortisBC's short term interest cost.” (p. 105)

FBC's concerns with the current method are:

- Inconsistency between FBC's deferral accounts, as some are financed at the WACC, some are at the weighted average cost of debt (WACD) or short term interest, even though they have similar characteristics.
- Inconsistency with past practice. The last RRA decision was the first time the Commission introduced this distinction between capital and operating expenses in deferral accounts.
- The distinction between capital and operating expenses is inappropriately applied because once an item is given deferral treatment it ceases to be an operating expense.
- WACC reflects the company's cost of financing because it attempts to mirror the approved capital structure.
- Inconsistency with other Fortis companies.
- Inconsistency with other jurisdictions, like Alberta.

(FBC Non PBR Final Argument, pp. 64–74; FBC Reply, p. 39)

FBC also believes that the Commission erred in making a distinction between “investments” and “deferred operating costs/current period expenses” in the last RRA decision (FBC Non PBR Final Argument, p. 65).

Intervener Submissions

BCPSO argues that FBC did not look at other jurisdictions outside of Alberta. For example, Ontario applies the prescribed interest rate for Board-approved deferral and variance accounts to be equal to the Bankers' Acceptances three-month rate, as published on the Bank of Canada's website, plus a spread of 25 basis points. BCPSO submits that the approval sought by FBC should not be granted, and that the approach determined in the 2012–2013 RRA Decision should be maintained. (BCPSO FBC Non PBR Final Argument, s. 3.2)

ICG submits that FBC's deferral accounts should be financed in a manner similar to BC Hydro.

FBC Reply

FBC's Reply points out that the Ontario method is not in evidence and BCPSO did not raise this evidence until now (FBC Non PBR Reply, p. 43).

In response to ICG's submission, FBC drew several distinctions between an investor-owned utility versus a crown corporation (FBC Non PBR Reply, pp. 41–42).

Commission Determination

The Commission Panel recognizes different treatment exists between FEI and FBC in the handling of carrying costs for deferral accounts; however, the Panel is not persuaded by the evidence within this proceeding that FBC's deferral account financing, as it is currently approved in the 2012-2013 FBC RRA Decision, should be revisited. The Commission Panel therefore rejects the FBC proposal to revisit the 2012–2013 FBC RRA Decision.

In light of the concerns raised by FBC, the Panel believes that there is merit in looking at this issue more broadly. As such, the Panel requests the Commission initiate a review of deferral accounts and related carrying costs in the near future.

3.3.2 New Deferral Account Requests

FBC is seeking the establishment of several new deferral accounts. These are summarized in the table below:

Table 3.9 New Deferral Accounts Requested

NEW ACCOUNTS – RATE BASE	
Account Name	FBC Request
Rate Stabilization Deferral Mechanism (RSDM)	5-year amortization starting January 1, 2014
Earnings Sharing Mechanism (ESM) Deferral	Balance at December 31 of each year to be amortized into rates in the subsequent year
BC Hydro Application for a Power Purchase Agreement with FBC (RS 3808)	1-year amortization period commencing in 2014
Generic Cost of Capital Revenue Requirement Impact	1-year amortization period commencing in 2014
2014–2018 Annual Reviews	Amortize the following year
Insurance Expense Variance	Amortize the following year
Interest Expense Variance	3-year amortization
Tax Variance	Amortize following year
Property Tax Variance	3-year amortization
NEW ACCOUNTS — NON-RATE BASE	
Account Name	FBC Request
CPCN Projects Preliminary Engineering	Preliminary and investigative costs for CPCNs, attracting AFUDC. Transfer to capital project upon CPCN approval

(Adapted from Exhibit B-1, pp. 261–264, 273; FBC Non PBR Final Argument, pp. 74–80)

The Panel will address each of these now.

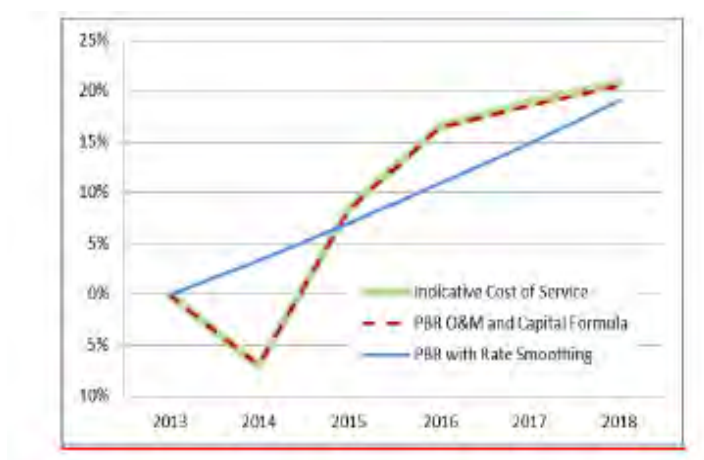
3.3.2.1 RSDM Deferral Account

FBC submits that the Rate Stabilization Deferral Mechanism (RSDM) deferral account is a mechanism for mitigating rate variability over the PBR Period with a five-year amortization starting January 1, 2014.

FBC proposes that the revenue requirement forecast during the PBR term be levelized and states that this RSDM has been proposed, in part, due to Order E-15-12 which accepted the Waneta Capacity Purchase Agreement (WAX CAPA) (Exhibit B-1, pp. 3, 261). In Recital I of Order E-15-12, the Commission recognized that WAX CAPA has the potential for disproportionate rate impacts in the early years of the agreement and the Commission directed FBC to “develop a rate smoothing proposal for the Commission’s approval either through a separate submission or with the next Revenue Requirements Application.”

FBC states that in the absence of this account, ratepayers will face a rate decrease in 2014 followed by a larger rate increase in 2015:

Figure 1 Comparison of Rate Increase Scenarios



(Source: Exhibit B-1-6, Figure B7-1)

The rate increases attributed to the WAX CAPA in year 2015 and in year 2016 before implementation of the rate smoothing mechanism are as follows:

- Rate increases attributed to the WAX CAPA in year 2015: 7 percent (approximately)

- Rate increases attributed to the WAX CAPA in year 2016: 4 percent (approximately)
(Exhibit B-15, ICG 1.1.2)

FBC submits that there are two basic assumptions to the proposed RSDM:

1. The rate stabilization amount in 2014 and its subsequent amortization during 2015–2018 should be such as to generate a 3.3 percent Rate Impact in 2014 followed by a uniform Rate Impact thereafter during 2015–2018; and
2. The rate stabilization amount in 2014 and its subsequent amortizations during 2015–2018 should be such that it balances to zero by the end of 2018. (Exhibit B-1-6, Table D4-2, p. 261)

BCPSO is the only intervener that commented on FBC’s proposed RSDM and indicates that it has no concerns. (BCPSO Non PBR Final Argument, p. 18)

Commission Determination

The Panel has considered Order E-15-12, accepting FBC’s WAX CAPA as an energy supply contract, directing FBC to “develop a rate smoothing proposal.” This directive is an instruction to FBC to develop a rate-smoothing proposal for the impact of WAX CAPA only. It did not contemplate a rate-smoothing proposal combining the accumulated impact of both WAX CAPA *plus* rate impacts as a result of the PBR plan. The Commission Panel does not agree that these should be combined.

FBC’s proposed treatment for the RSDM is essentially a deferral account through which all of the PBR’s Revenue Requirements will be collected and flowed through under the guise of providing smooth rates. This raises the concern that there will be a lack of transparency created by the resulting levelized rate impact which may in turn obscure stakeholders’ abilities to assess whether the PBR plan has been a success, particularly when stakeholders see a flat rate year over year.

The Commission Panel denies FBC’s proposal to establish the RSDM combining the impact of WAX CAPA and other PBR rate impacts.

In its Compliance Filing, FBC must recalculate and show the 2014 revenue requirement and rate impact without the rate smoothing effect of the RSDM. FBC must also propose to the

Commission a method to treat the revenue requirement impact between the interim rate increase approved under Order G-151-13 and the rate resulting from this Decision. As stated in Order E-15-12, the Commission is prepared to consider a rate-smoothing proposal to deal with the impact of WAX CAPA.

3.3.2.2 ESM Deferral Account

FBC proposes to record amounts above or below the approved ROE in the requested ESM deferral account for either refund to or recovery from customers in the subsequent year.

BCPSO was the only Intervener to comment on the proposed ESM deferral account, submitting that it has “no particular concerns with the BCUC approving the RSDM or ESM deferral accounts.” (BCPSO Non PBR Final Argument, p. 18)

Commission Determination

The Commission Panel approves FBC’s proposal to establish an ESM deferral account. The Commission Panel considers the use of this deferral account to be an appropriate mechanism for refunding or recovering from customers the 50 percent of amounts above or below the approved ROE.

The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be at FBC’s short-term interest rate.

3.3.2.3 New Power Purchase Agreement Application Deferral Account

On May 24, 2013, BC Hydro filed an application for approval of a new long term Power Purchase Agreement (PPA) with FBC. FBC states that as an active participant in this regulatory proceeding it would incur costs related to responding to IRs and may potentially incur other costs depending on the scope and type of process determined by the Commission. Accordingly, FBC has requested approval to record the costs related to this proceeding in a deferral account. (Exhibit B-1, p. 262)

FBC originally forecast a 2013 addition to this deferral account of \$175,000 based on the assumption that the application would undergo an Oral Hearing process (Exhibit B-7, BCUC 1.186.1).

Pursuant to Order G-117-13, the Commission established a Written Hearing process for review of the BC Hydro PPA. When asked if the 2013 addition to the deferral account should be reduced based on this determination, FBC stated that it did not reforecast the addition to the deferral account in its Evidentiary Update because any variances from forecast deferral account balances would be trued up. (Exhibit B-24, BCUC 2.57.1)

No Intervenors commented on this new deferral account request.

Commission Determination

The Commission Panel approves the establishment of the BC Hydro Application for New Power Purchase Agreement with FBC deferral account as applied for by FBC. The Panel considers this treatment to be consistent with past deferral accounts approved for application-related costs. **However, the Commission Panel directs FBC to update its forecast addition to the deferral account as it relates to the Written Hearing as part of its Compliance Filing.**

The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with FBC's 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC's short-term interest rate (p. 105).

3.3.2.4 Generic Cost of Capital Revenue Requirements Impact Deferral Account

FBC requests approval to establish the Generic Cost of Capital (GCOC) Revenue Requirements Impact deferral account to record the 2013 revenue requirements impact of the Stage 1 GCOC Decision. It proposes to amortize the deferred balance into rates in 2014. FBC also proposes to record and flow-through any further revenue requirements impacts resulting from the Stage 2

GCOC Decision as soon as reasonably possible following the decision, taking into account the effective date of the Stage 2 order. (Exhibit B-1, p. 262)

No Interveners commented on this new deferral account request.

Commission Determination

The Commission Panel approves the establishment of the GCOC Revenue Requirements Impact deferral account. The Panel considers this treatment to be appropriate and consistent with past deferral account treatment given the proposed amortization.

The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC’s short-term interest rate.

3.3.2.5 2014–2018 Annual Reviews Deferral Account

As part of the proposed PBR Plan, FBC plans to hold Annual Reviews for the purpose of setting rates for each upcoming year. The cost of the Annual Reviews is proposed to be recorded in the 2014–2018 Annual Reviews deferral account, the balance of which FBC proposes to amortize into rates in the subsequent year. (Exhibit B-1, p. 264)

No Interveners commented on this new deferral account request.

Commission Determination

The Commission Panel approves the establishment of the 2014–2018 Annual Reviews Deferral Account. The balance of this account is to be amortized in the year following each Annual Review at FBC’s short-term interest rate.

3.3.2.6 Deferral Accounts Related to Flow-Through Items Under PBR

As described in Section 2.2.5.1 of this Decision, the Panel has denied the establishment of the following deferral accounts to record the variances between forecast and actual flow-through expenditures:

- Insurance Expense Variance;
- Interest Expense Variance;
- Tax Variance; and
- Property Tax Variance.

FBC also proposes the continuation of its Power Purchase Expense Variance deferral account and its Revenue Variance deferral account which were approved pursuant to Order G-110-12 (Exhibit B-1, p. 62). FBC states that any variances between actual and forecast sales revenue will accrue to the Revenue Variance deferral account with the majority of variances attributable to weather related to load variances, customer usage rates and customer count (Exhibit B-1, p. 269). Both the Power Purchase Expense Variance deferral account and the Revenue Variance deferral account have one-year amortization periods (Exhibit B-1-1, Appendix F4).

No Interveners commented on this matter.

Commission Determination

In keeping with the Panel's discussions and determinations for FBC's Flow-Through Items (Section 2.2.5.1 of this Decision), the Panel is not persuaded that continuation of the Power Purchase Expense Variance and Revenue Variance deferral accounts are necessary in order to allow for the flow through of these expenditures and revenues during the PBR. This is particularly relevant given the fact that these deferral accounts only have one-year amortization periods and thus are not being utilized for rate smoothing purposes. **Accordingly, the Panel directs FBC to discontinue the Power Purchase Expense deferral account and its related Revenue Variance deferral account during the PBR term. These expenses and revenues shall be flowed through to ratepayers each year through the annual flow-through mechanism.**

In its Compliance Filing, FBC is directed to provide its 2013 ending balances in these deferral accounts and illustrate the rate impact of flowing through these variances to 2014 rates. Variances between FBC’s forecast and actual results in 2014 and beyond shall to be flowed through to ratepayers annually.

3.3.2.7 CPCN Projects Preliminary Engineering Non Rate Base Deferral Account

FBC submits that it incurs preliminary and investigative engineering costs in the development of capital projects subject to CPCN applications. It states that it does not intend to include in revenue requirements the impact of forecast CPCN projects until approved and added to its plant in service. FBC therefore, considers it is appropriate to retain the preliminary and investigative costs outside of rate base and attracting Allowance for Funds Used During Construction (AFUDC). (Exhibit B-1, p. 273) FBC requests approval to establish the non-rate base CPCN Projects Preliminary Engineering deferral account. It proposes to transfer the costs in the requested non-rate base deferral account to the applicable capital project once the capital project is approved and added to plant in service. (Exhibit B-1, Table A2-1, p. 8)

FBC stated that if a capital project does not proceed, the preliminary and investigative engineering costs are not eligible for capitalization. However, as long as the costs were prudently incurred, they are eligible for recovery through rates. Therefore, FBC would likely apply to the Commission for inclusion in the subsequent revenue requirements application. (Exhibit B-24, BCUC IR 2.68.1)

No Interveners commented on this issue.

Commission Determination

In the FBC 2012–2013 RRA Decision, the Commission determined that “Preliminary and Investigative Charges can be separated into two groups:

- Those costs which at a future time may become capital projects.

- Those that contribute to the development of Plans, which are a regulatory requirement but are not actual capital projects.” (p. 112)

The Commission further stated: “Those projects which may in the future become capital projects are more properly considered operating expenses as they are not yet part of an approved capital project. Therefore, the Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC’s WACD until such time as they become part of a specific capital project.” (pp. 112–113)

Consistent with the Commission’s determinations in the FBC 2012–2013 RRA Decision, **the Commission Panel approves the establishment of the non-rate base CPCN Projects Preliminary Engineering deferral account**, as the costs to be included in this deferral account fall under the category of “costs which at a future time may become capital projects”, as described in the FBC 2012–2013 RRA Decision. However, **the Commission Panel rejects FBC’s proposal to apply AFUDC to this new deferral account** as it is not consistent with the determinations made in the previous RRA decision (p. 105). Accordingly, **the Panel directs FBC to comply with the previous Commission decision and apply carrying costs based on FBC’s WACD to this deferral account starting in 2014.** The Panel also notes that the decision to proceed with a capital project should generally be made within three years. This is consistent with the Commission’s directive that deferral accounts “with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates” [bold in original] (p. 106).

3.3.3 Requested Changes to Existing Deferral Accounts

FBC has made a number of requests for new or modified amortization periods. These requests are summarized in the table below, then discussed in detail following:

Table 3.10 Amortization Period of Various Deferral Accounts

AMORTIZATION PERIOD – NEW OR MODIFIED – RATE BASE	
Account Name	Request
Demand-Side Management	Change from 10 year to 15 year amortization period
On-Bill Financing Pilot Program	Change from 10 year to 15 year amortization period
2014–2018 PBR Application	5 year amortization, commencing January 1, 2014
Pension and OPEB Expense Variance	Change from 3 year to 11 year amortization (EARSL), commencing January 1, 2014
City of Kelowna Acquisition Customer Benefit	1-year amortization commencing in 2014
City of Kelowna Acquisition Legal and Regulatory Costs	1-year amortization commencing in 2014
2014–2018 Capital Expenditure Plan (Preliminary Engineering cost)	2-year amortization beginning 2014
BCUC Generic Cost of Capital Proceeding	2-year amortization beginning in 2014
BCUC Inquiry into the MRS Program	1-year amortization commencing in 2014
Kettle Valley Expenditure Review	1-year amortization commencing in 2014
Transmission Customer Rate Design	1-year amortization commencing in 2014
2012 Mandatory Reliability Standards Audit	1-year amortization commencing in 2014
Mandatory Reliability Standards 2012–2013 Incremental O&M Expense	1-year amortization commencing in 2014

(Adapted from Exhibit B-1, pp. 246–269; FBC Non PBR Final Argument, pp. 81–83)

3.3.3.1 Demand-Side Management and On-Bill Financing Pilot Program Deferral Accounts

The Commission Panel addresses Demand-Side Management and On-Bill Financing Pilot Program deferral accounts in Section 4.2, Other DSM Requests.

3.3.3.2 2014–2018 PBR Application Deferral Account

The 2014–2018 PBR Application deferral account was approved pursuant to Order G-110-12 to record the costs related to the PBR Application. These costs include legal fees, costs for expert witnesses and consultants, costs related to independent validation of study results, intervenor and participant funding costs, Commission costs, required public notifications, and miscellaneous

facilities, stationery and supplies costs. FBC requests approval to amortize these deferred costs over five years commencing January 1, 2014. FBC states that this amortization period is appropriate because it represents the period covered by the PBR Application. (Exhibit B-1, p. 265)

Commission Determination

The Commission Panel approves the amortization of the 2014–2018 PBR Application deferral account over six years commencing January 1, 2014. The Panel considers aligning the amortization period for this deferral account with the PBR term to be appropriate because it is consistent with the treatment of past deferral accounts approved for revenue requirement application costs.

3.3.3.3 Pension and OPEB Expense Variance Deferral Account

FBC requests approval to extend the amortization period for the Pension and OPEB Expense Variance deferral account from the currently approved 3 years to 11 years, which is the Expected Average Remaining Service Life (EARSL) of benefit plans. (Exhibit B-1, p. 265)

FBC cites several reasons for the request:

1. It more appropriately allocates the costs over the future period to which they are applicable;
2. Large fluctuations in this account can occur from year to year and the longer amortization period will allow rate smoothing;
3. The use of EARSL to account for Pension/OPEB expense was previously accepted and approved by the Commission.

(Exhibit B-7, BCUC 1.214.2)

In response to BCUC IR 2.78.1, FBC submitted that the benefits of maintaining a shorter amortization period are lower debt and equity financing costs accumulating on the deferred balance and a resultant lower cost to ratepayers. FBC also submitted that maintaining the shorter amortization period would put upward pressure on revenue requirements through the increased

amortization expense during the early part of the PBR period due to the fact that there is an estimated \$9.4 million variance in 2012 and 2013 pension and OPEB expense to be recovered from customers over a shorter period of time. FBC noted that pension and OPEB costs over the 2014–2018 PBR period are unknown as is the impact on revenue requirements. (Exhibit B-24, BCUC 2.78.1)

Commission Determination

The Commission Panel denies FBC’s request to change the Pension & OPEB Expense Variance deferral account amortization period from three years to the EARSL. FBC must therefore continue amortizing this deferral account over three years. The Panel recognizes that larger variances have been experienced in recent years. However, the Panel is not persuaded that deferring these costs so far into the future is appropriate or beneficial to ratepayers, particularly when taking into account the increased cost to ratepayers caused by the larger accrual of financing costs which would result if the deferral account balance was amortized over the longer time period.

3.3.3.4 City of Kelowna Related Deferral Accounts

The City of Kelowna Acquisition Customer Benefit deferral account was approved pursuant to Order C-4-13 to capture the 2013 Customer Benefit resulting from FBC’s purchase of the utility assets of the City of Kelowna, including an adjustment to the Revenue Variance deferral account. FBC requests approval to amortize the \$2.6 million deferred Customer Benefit into rates in 2014. The deferral account will then be discontinued effective January 1, 2015. (Exhibit B-1, p. 266; Exhibit B-1-1, Appendix F4)

FBC also requests approval to amortize the balance in the City of Kelowna Acquisition Legal and Regulatory Costs deferral account over one year, commencing January 1, 2014. The deferral account will also be discontinued effective January 1, 2015. (Exhibit B-1-6, p. 266; Exhibit B-1-1, Appendix F4)

Commission Determination

The Commission Panel approves the amortization of both the City of Kelowna Acquisition Customer Benefit deferral account and the City of Kelowna Acquisition Legal and Regulatory Costs deferral account over one year, commencing January 1, 2014. The Panel considers the short amortization period to be most appropriate given the nature and timing of when the costs/benefits were incurred. **The Panel directs that these deferral accounts be discontinued effective January 1, 2015, as proposed by FBC in the Application.**

3.3.3.5 2014–2018 Capital Expenditure Plan Deferral Account

Pursuant to Order G-110-12, approval was granted to FBC to capture the preliminary engineering costs for the preparation of its capital expenditure filing in the 2014–2018 Capital Expenditure Plan deferral account. FBC now requests approval to amortize this deferral account over two years starting in 2014. (Exhibit B-1, p. 266)

Commission Determination

The Commission Panel approves FBC's request to amortize the 2014–2018 Capital Expenditure Plan deferral account over two years.

3.3.3.6 2012 and 2013 Deferred Expenditures

On December 12, 2012, FBC applied to the Commission for approval to establish the following six new deferral accounts:

- BCUC Generic Cost of Capital (GCOC) Proceeding;
- BCUC Inquiry into the MRS Program;
- Kettle Valley Expenditure Review;
- Transmission Customer Rate Design;
- 2012 MRS Audit; and
- MRS 2012–2013 Incremental O&M Expense.

Following a review process, Commission Order G-23-13 directed FBC to transfer these costs into a single non-rate base holding deferral account with separate tracking and recording of costs. At that time, the Commission stated that it makes no determination on the cost recovery or amortization of these deferred costs and that FBC was to apply for recovery of these costs as part of its 2014 revenue requirements application. The Commission also stated that the issue of carrying costs for these incremental expenses, if approved, would be handled in the 2014 RRA.¹⁵

In the current Application, FBC is requesting approval for financing of the non-rate base account at the Company's WACC rate for 2013. It had previously sought WACD for all these deferral accounts in their 2012 deferral application. (Exhibit A2-3, p. 1) Further, FBC also seeks approval to transfer the balance in the non-rate base deferral account into the corresponding six rate base deferral accounts requested in the original December 12, 2012 application. (Exhibit B-1, p. 267)

BCPSO, in its Final Argument, states that FBC's proposed amortization periods are reasonable (BCPSO Non PBR Final Argument, p. 19).

No other intervenor provided comments on these deferred costs.

Commission Determination

The Panel has reviewed the materials contained in Exhibit A2-3; FBC's application for these six deferral accounts, Commission staff IRs and FBC responses, and Commission Order G-23-13 with accompanying Reasons and makes the following determinations:

BCUC Generic Cost of Capital Proceeding

For the costs associated with the FBC GCOC proceeding, the Panel notes that FBC was notified of the GCOC after it had filed its 2012 RRA and its Evidentiary Update. Therefore, it would not be reasonable to expect FBC to have anticipated and forecast the costs associated with this

¹⁵ Appendix A to Order G-23-13, pp. 2–3

proceeding. Accordingly, **the Commission Panel grants approval to FBC to establish a new deferral account to transfer the costs associated with the GCOC proceeding from the holding account to a separate deferral account for recovery from ratepayers. The Panel also approves the requested two-year amortization period, commencing in 2014.**

The Panel denies FBC's request to charge a WACC carrying charge to this deferral account.

Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its WACD to this deferral account. FBC shall also apply its WACD to calculate the carrying charges on the 2013 balance.**

BCUC Inquiry into the MRS Program

With regards to the MRS Inquiry, this proceeding was initiated after FBC's 2012–2013 RRA Decision was issued and does not fall within the scope of FBC's anticipated MRS-related activities based on its 2012–2013 RRA. It is therefore reasonable to conclude that the related costs would be part of the utility's "ongoing effort to remain within auditable compliance with all standards" (FBC 2012–2013 RRA, Tab 4, p. 54). The Panel finds the request to defer costs associated with the BCUC MRS Inquiry to be reasonable. Accordingly, **FBC's requested deferral account for the BCUC Inquiry into the MRS Program and its requested amortization period of one year beginning in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.** Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to this deferral account to calculate the carrying charges on the 2013 balance.**

Kettle Valley Expenditure Review

At the time of the 2012 deferral account application, FBC expected to incur approximately \$75 thousand for the regulatory process (mostly legal fees). These costs are now \$120 thousand higher than in the original application (Exhibit B-1-6, p. 267). The Commission Panel accepts that the Kettle Valley review was initiated by the Commission and is not a normal business expense which could be expected to be more accurately forecasted. Further, the Panel notes that Order G-36-12

approved all Kettle Valley expenditures with the exception of \$65,734. **Given these circumstances, the Commission Panel finds that it is also reasonable to approve FBC's (legal) costs related to this inquiry. Accordingly, the Panel approves FBC's request to establish the Kettle Valley Expenditure Review deferral account with the amortization period of one year, starting in 2014. The Panel denies FBC's request to apply WACC to the deferral account.** Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC is directed to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.**

Transmission and Self-Generating Customer Rate Design

FBC was notified of the Transmission Customer Rate Design review subsequent to its filing of the 2012–2013 RRA & ISP Application and its subsequent Evidentiary Update. Therefore, it would not have been reasonable for FBC to provide a forecast for this proceeding in its 2012–2013 RRA. In addition, the Panel considers the amount of costs forecast to be reasonable given the scope of work required by FBC. **Given these circumstances, FBC's deferral of the cost for the Transmission Customer Rate Design review and its requested amortization period of one year commencing in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.** Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC shall also apply its short-term interest rate to calculate the carrying charges on the 2013 balance.**

MRS Audit

In its 2012 deferral application, FBC states that it incurred \$806,759 in costs for the MRS audit process in 2012 yet it had only budgeted \$231,452 for internal labour costs. FBC therefore requested to defer the incremental labour costs of \$575,306 for future recovery.

The Panel finds that the 2012 MRS audit was an inquiry that is unique and therefore accepts that it was difficult for FBC to accurately forecast the costs associated with this proceeding. **The Panel approves FBC's request for deferral of the incremental 2012 MRS costs with an amortization**

period of one year commencing in 2014. However, the Panel denies FBC’s request to apply WACC to the deferral account. Consistent with the directives in the FBC 2012–2013 RRA Decision, the Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.

As the MRS audit is a non-recurring expenditure, it therefore should not be included in FBC’s Base O&M. **In its Compliance Filing, FBC must confirm that these MRS audit expenses were not included in its proposed O&M base. To the extent that these MRS audit costs are included in the O&M base, they must be removed.**

MRS 2012–2013 Incremental O&M Expenses

In its 2012–2013 FBC RRA Decision, the Commission approved O&M expenses related to MRS totalling \$1.2 million in 2012 and \$1.2 million in 2013 (p. 78). In the December 2012 deferral account application, FBC requested an additional \$0.3 million for 2012 and an additional \$0.9 million for 2013 of MRS-related O&M expenses to be placed in a deferral account.

In explanation, Fortis states that “there was no provincial experience on which it could rely for calibration or verification of its estimates, nor was it able to obtain comparables from its counterparts in other jurisdictions.” (Exhibit A2-3, BCUC 1.7.1.2) In the view of the Commission Panel, the MRS program is unique and accepts that there was little to rely upon in the preparation of accurate cost estimates. Therefore, in this instance we consider there to be justification for the cost overruns and are prepared to accept these additional costs.

The Panel approves the incremental costs (\$0.3 million for 2012 and \$0.9 million for 2013) related to its MRS O&M expense. The Panel grants approval for FBC to amortize these deferred costs into rates in 2014. The Panel denies FBC’s request to apply WACC to the deferral account. Consistent with the directives in the FBC 2012–2013 RRA Decision, the Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.

3.3.4 Other Rate Base Deferral Account Requests

3.3.4.1 On-Bill Financing Participant Loans Deferral Account

The Commission Panel makes specific determinations on the On-Bill Financing Participant Loans in Section 4.2.

3.3.4.2 Debt Issue Costs Deferral Account

FBC states that it calculates its debt issue costs, which include fees for auditors, legal, dealers, filings, rating agencies and trustees, using the straight-line method. These issuance costs are amortized over the term of the debt issuance. FBC indicates in its Application that it will be required to issue debentures in 2014 and that similar to its previously incurred debt issue costs, it intends to amortize the costs over the term of the debentures. A term of 30 years is currently forecast. (Exhibit B-1, p. 271)

Commission Determination

The Commission Panel approves the treatment of the deferred debt issue costs as applied for by FBC. The Panel considers this treatment to be appropriate as it is consistent with the past treatment of debt issue costs.

3.3.5 Request for Discontinuance of Deferral Accounts

Table 3.11 outlines the requests made by FBC related to the discontinuance of various deferral accounts:

Table 3.11 Summary of FBC's Request for Deferral Account Discontinuation

DEFERRAL ACCOUNT DISCONTINUATION REQUESTS	
Account Name	Request and Reference
Kelowna Bulk Transformer Capacity Addition Project	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 270)
Section 71 Filing (Waneta Expansion Power Purchase Agreement)	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, pp. 270–271)
Negotiation of new PPA between BC Hydro and FBC	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 271)
Right of Way Encroachment Litigation	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 271)
Trail Office Lease Cost	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 271)
Trail Office Rental to School District 20	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 271)
2011 Flow-Through and ROE Sharing Mechanism Adjustments	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
2012 Deferred Revenue	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
Harmonized Sales Tax Removal/Provincial Sales Tax Implementation	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Cost of Service and Rate Design Application	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
2012–2013 Revenue Requirements Application and 2012 Integrated System Plan	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
2011 Revenue Requirement Application Costs	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
BC Hydro Waneta Transaction Proceeding	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
Residential Inclining Block Rate Application	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Implementation of New Rate Structures	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Irrigation Rate Payer Group Consultation and Load Research	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Princeton Light and Power Deferred Pension Credit	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Princeton Light and Power Computer Software	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
US GAAP Conversion Costs	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Joint Pole use Audit, 2008	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
Joint Pole use Audit, 2013	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Mandatory Reliability Standards Implementation	See Commission Determination regarding these incremental MRS costs in Section 3.3.3.6 of the Decision.
Revenue Protection	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)

(Adapted from Exhibit B-1, pp. 9–10)

No Interveners commented on FBC's request to discontinue these deferral accounts.

Commission Determination

The Commission Panel approves FBC's request to discontinue the deferral accounts listed in Table 3.11 above, and as outlined in the Application and in its Evidentiary Update.

4.0 DEMAND-SIDE MANAGEMENT

As part of this Revenue Requirement Application, under section 44.2 of the UCA, FBC is requesting approval to spend \$3.0 million on Demand-Side Management (DSM) in 2014 (Exhibit B-1-1, Appendix H, p. 9). FBC withdrew its request for approval for the 2015–2018 DSM expenditures as a result of June 4, 2014 amendments to the DSM Regulations (Ministerial Order No 233). The amendments require that, from 2015, the avoided electricity cost for DSM be calculated using the long-run marginal cost (LRMC) of acquiring electricity generated from clean or renewable resources in BC. (T8:1386–1388)

FBC is also requesting approval to increase the DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years, to cease filing semi-annual reports on its DSM activities, and for changes to funding transfer rules. These requests are addressed below. (Exhibit B-1-1, Appendix H, pp. 18–19)

4.1 FBC's Expenditure Request for 2014

FBC is requesting approval to spend \$3.0 million on DSM in 2014.

The 2014 proposed DSM expenditure schedule comprises DSM programs in the Residential, Commercial (or General Service) and Industrial sectors as well as funding for Supporting Initiatives and Planning and Evaluation (See Appendix C), and have a portfolio level BC cost effectiveness result of 1.4. (Exhibit B-1-1, Appendix H, p. 9)

FBC states that they have reduced DSM funding from \$7.9 million approved for 2013 to \$3.0 million for 2014 primarily as a result of a lower cost of energy forecast. FBC submits that its avoided cost

of energy has decreased from \$84.84/MWh in 2012 to \$56.51/MWh. FBC bases this estimate on the cost of burning gas in a gas fired generator. (Exhibit B-1-1, Appendix H, p. 9, Attachment 4; FBC Non PBR Final Argument, pp. 108–109)

BCSEA submits that FBC's avoided cost for DSM is inaccurately low and is inappropriately based on FBC's short-run marginal cost, instead of being based on FBC's LRMC. BCSEA submits that there are also deficiencies in FBC's estimate of its short-run marginal cost, and that FBC's methodology does not reflect generation capacity costs or contribute to BC emission reduction and self-sufficiency objectives. (BCSEA FBC Non PBR Final Argument, pp. 12–15)

BCSEA also submits that, even assuming FBC's incorrect avoided cost estimate, the FBC DSM plan is not designed to produce all cost-effective efficiency and conservation savings (BCSEA Final Argument, p. 10). FBC disagrees with BCSEA's position, and counters that there is only a requirement to determine that expenditures are in the public interest, not that all cost-effective expenditures be made (FBC Non PBR Final Argument, p. 114).

BCPSO submits that the Commission should approve the reduced DSM spend as FBC's response to the reduction in LRMC is reasonable and FBC are still meeting the target of 50 percent of annual load growth (BCPSO FBC Non PBR Final Argument, p. 22). ICG submit that that the DSM spend should not be approved as the industrial sector DSM was not based on program analysis filed in the Proceeding and there is a lack of consistency with BC Hydro industrial DSM offerings (ICG Final Argument, pp. 25–27).

Commission Determination

The Commission Panel accepts the 2014 DSM schedule filed by FBC, attached as Appendix B of this Decision, and approves FBC's request under section 44.2 of the UCA to spend \$3.0 million on DSM in 2014. As it is now near the end of 2014, the Panel does not consider that FBC would be able to meaningfully impact its 2014 DSM spend should a higher budget be approved. Therefore, maintaining the applied for \$3.0 million is appropriate.

The Commission Panel is encouraged by FBC's statement that it will be working with stakeholders in developing a revised DSM plan. This provides an opportunity to address the concerns raised in the withdrawn filing. The Panel recommends that FBC follow the general principles put forward in the Decision issued with respect to the FEU 2014–2018 EEC Expenditure Request. Specifically, the Panel encourages a focus on its efficiency and cost-effectiveness within the DSM plan while maintaining an appropriate balance in allowing DSM access among ratepayer groups, and in particular for 'hard to reach' customers such as low income groups and renters.

4.2 Other DSM Requests

FBC made the following additional requests:

1. Approval to increase its DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years. FBC submits that the 15-year amortization period is supported by the estimated DSM measure life of 15.9 years. (Exhibit B-1-1, Appendix H, pp. 18-19)

BCSEA and BCOAPO support FBC's position (BCSEA Final Argument, p. 9; BCPSO FBC Non PBR Final Argument, p. 20). ICG, however, is opposed to the increase in amortization period and submits that "it is less expensive for ratepayers to pay for these costs at the time the costs are incurred rather than defer the costs and pay the return at WACC and related income taxes." ICG also recommends that Planning and Evaluation Expenditures be no longer capitalized (ICG Final Argument, p. 32).

2. Approval to cease filing semi-annual reports on its DSM activities (Exhibit B-1-1, Appendix H, p. 19).

BCSEA and BCPSO support FBC's request to submit annual rather than semi-annual DSM Report reports (BCSEA Final Argument, p. 9; BCPSO Non PBR Final Argument, p. 23).

3. Approval of changes to the DSM funding transfer rules set by the Commission for the 2012–2013 test period. Specifically, FBC requests that it be permitted to launch new programs without pre-approval from the Commission provided funds are transferred within the same approved Program Area, the new program meets with the DSM Regulations and has not been previously rejected by the Commission (Exhibit B-1-1, Appendix H, p. 11).

BCSEA supports FBC's request (BCSEA Final Argument, p.9). BCPSO support FBC's request provided DSM funding used to meet DSM Regulations adequacy requirements is not reduced as a result (BCPSO, Non PBR Final Argument, p. 23).

Commission Determination

The Commission Panel denies FBC's request to increase the DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years. The Panel considers that a 10-year amortization period provides a fair and reasonable return to the utility based on the existing level of DSM spending, and agrees with ICG that an increase in the amortization period would place upward pressure on rates over the long term.

The Commission Panel accepts FBC's request to submit annual rather than semi-annual DSM Reports as the request is reasonable and has not been opposed by Interveners.

The Commission Panel declines to rule on FBC's proposed DSM funding transfer rules as they are not applicable to the 2014 DSM funding application.

5.0 SUMMARY OF DIRECTIVES DETERMINATIONS AND FINDINGS

This Summary is provided for the convenience of readers. In the event of any difference between the Directions, Determinations and Findings in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	Therefore, the Commission Panel determines that it is appropriate to render a decision based on the substantial evidence before it and not move to a further process on the design of the PBR.	14
2.	In order to realize the full benefits of a five-year term, the Panel directs the term be extended through the end of 2019.	27
3.	Considering the potential for a significant impact on the I-X formula resulting from this, the Commission Panel denies Fortis' proposal to rely on forecast data in the determination of the I-Factor.	32
4.	Given these advantages, the Commission Panel determines that the I-Factor used in the formula is the actual index results of the previous year.	33
5.	The Commission Panel has reviewed the evidence and determines that the CPI-BC as calculated by Statistics Canada and BC-AWE indexes are most appropriate for use in this PBR.	33
6.	The Commission Panel approves a 55 percent labour weighting for use in the O&M formula for FEI and FBC.	34
7.	The Commission Panel determines that the 55 percent to 45 percent labour to non-labour ratio for use in the capital formula for FBC and FEI is reasonable and appropriate.	34
8.	The Panel finds that the method for calculating the growth rate of an output level index is not an appropriate approach. Accordingly, the output trend calculated by B&V cannot be relied upon.	45
9.	The Panel finds B&V's approach of calculating the growth in the output measures is not an appropriate approach to the calculation of the output trend.	46
10.	Accordingly, the Panel finds that B&V's method of calculating the output trend cannot be relied upon.	46
11.	Accordingly, the Panel finds that B&V's method of calculating the input trend cannot be relied upon.	50

12.	Accordingly, the Panel finds that B&V's cost based input methodology understates the TFP trend.	51
13.	The Panel finds that a short study period is not appropriate.	53
14.	Accordingly, the Panel finds that a study period should at least be long enough to smooth out any significant short term economic trends	53
15.	Accordingly, the Commission Panel finds that B&V's TFP trend results may require significant adjustment to allow for the short study period B&V used, particularly in the case of the gas utility study.	54
16.	Given the materiality of this issue, the Panel finds that B&V's use of arithmetic growth rates results in a substantial understatement of the TFP trend.	55
17.	Given the number of shortcomings in B&V's methodology and the errors that arise from these shortcomings, the Panel does not accept B&V's study results.	56
18.	The Panel finds PEG's approach to using input cost indexes to calculate input quantities is acceptable.	63
19.	In the absence of specific information of the labour mix at each utility, the Panel finds an assumption of a labour mix to be reasonable.	65
20.	The Panel finds that no adjustment to PEG's study results is necessary to account for any potential bias introduced by its labour input index assumptions.	65
21.	The Panel, using its best judgement, finds a reduction of 0.06 percent to the MFP trend results from PEG's gas utility productivity study to be appropriate.	67
22.	Accordingly, the Panel finds that no adjustments are necessary to account for PEG's capital costing approach.	70
23.	Accordingly the Panel declines to make any adjustments to the study results to account for negative salvage.	71
24.	Accordingly, the Panel finds that B&V's proposed calibration is not required.	73
25.	The Commission Panel agrees with CEC and IRG and finds the PEG study results to be the best available evidence in this proceeding.	78
26.	Accordingly, the Panel considers these results to be an appropriate basis to set an X-Factor for the six-year PBR term.	78
27.	Considering the PEG study results and the adjustment to the gas study previously determined by the Panel to be required, the Commission Panel finds a TFP trend of 0.93 percent for electric utilities and 0.90 percent for gas utilities is appropriate.	78

28.	Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.	80												
29.	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.	80												
30.	Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	80												
31.	Considering the stretch factor evidence before the Commission Panel, we determine a stretch factor of 0.2 percent for FEI and 0.1 percent for FBC to be appropriate.	83												
32.	For all of the above reasons, the Panel is unable to approve the X-Factor as applied for.	87												
33.	Accordingly, if significant capital is to be excluded from the formula, the Commission Panel finds that the X-Factor requires an upward calibration.	87												
34.	The Panel will not apply any adjustments at this time, but directs that this issue be revisited when a further determination on the dollar threshold is made.	87												
35.	Accordingly, the Commission Panel has determined the following X-Factors should be applied to Fortis’ proposed PBR formulas for the PBR term: Table 5.1 Approved X-Factors <table><tr><th>Utility</th><th>TFP</th><th>Stretch Factor</th><th>X-Factor</th></tr><tr><td>FBC</td><td>0.93</td><td>0.1</td><td>1.03</td></tr><tr><td>FEI</td><td>0.90</td><td>0.2</td><td>1.10</td></tr></table>	Utility	TFP	Stretch Factor	X-Factor	FBC	0.93	0.1	1.03	FEI	0.90	0.2	1.10	88
Utility	TFP	Stretch Factor	X-Factor											
FBC	0.93	0.1	1.03											
FEI	0.90	0.2	1.10											
36.	The Panel finds it necessary to include exogenous factors as part of the Companies’ PBR plan in order to protect both the ratepayers and the shareholders.	94												

37.	The Commission Panel therefore establishes the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment: 1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility; 2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived; 3. The impact of the event was unforeseen; 4. The costs must be prudently incurred; and 5. The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.	94
38.	The Commission Panel finds that a materiality threshold is a necessary component of the exogenous factor criteria as it meets the Companies' guiding PBR principle of reducing the regulatory burden over time.	95
39.	The Commission Panel finds that materiality thresholds for FEI and FBC, amounting to 0.5 percent of each Company's 2013 Base O&M, are appropriate.	95
40.	The Commission Panel directs the Companies to provide materiality threshold calculations as part of their Compliance Filings. These calculations must also reflect all changes to each Company's 2013 Base O&M directed in this Decision.	96
41.	The Commission Panel further directs that exogenous events not be aggregated.	96
42.	Thus, the materiality threshold applies both to exogenous savings as well as to exogenous costs. That is, any event resulting in savings must meet the criteria before it is accepted as an exogenous savings.	96
43.	The Panel directs Fortis to include a proposal for the appropriate recovery mechanism as part of any exogenous factor applications.	97
44.	Based on the aforementioned considerations, the Commission Panel approves FBC and FEI's proposed flow-through items with the exception of the items discussed below.	103
45.	The Commission Panel directs the Companies to flow-through only the Insurance Premiums portion of Insurance Expense.	103
46.	The Panel directs the Companies to update the flow-through expenses in the Final Compliance Filings so that only the Insurance Premiums are included in the Insurance Expense flow-through.	103– 104

47.	The Commission Panel rejects Fortis' proposal to apply the 50/50 ESM to any of the flow-through revenues/costs and directs that the ESM mechanism is not to be applied to flow-through items.	104
48.	The Commission Panel denies FBC's request to establish the Tax Variance deferral account and the Insurance Expense Variance deferral account.	107
49.	Accordingly, the Commission Panel denies FBC's request to establish the Property Tax Variance deferral account and the Interest Expense Variance deferral account.	108
50.	The Commission Panel directs FBC to true-up these costs each year.	108
51.	Accordingly, the Commission Panel directs FEI to discontinue the usage of the following deferral accounts: the Tax Variance deferral account, the Property Tax Variance deferral account, the Insurance Expense Variance deferral account and the Interest Expense Variance deferral account.	108– 109
52.	For the deferral accounts which have a one-year amortization period – the Insurance Expense Variance deferral account and the Tax Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into 2014 rates and then discontinue the use of these accounts. For the deferral accounts which have a three-year amortization period – the Property Tax Variance deferral account and the Interest Expense Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into rates over three years and then discontinue these accounts. FEI must not add any additional variances to these four deferral accounts commencing January 1, 2014.	109
53.	The Commission Panel directs FEI to true-up these costs each year	109
54.	Given the lack of evidence concerning the quantum of the required adjustment, the Panel applies its best judgement and directs that the Growth Term be reduced by 50 percent. Further, to eliminate the possibility of potential bias, the Panel directs that the ratio be calculated as the ratio of the number customers or service line additions one year previous, to the number of customers or service line additions two years previous.	118– 119
55.	Accordingly, the Commission Panel approved Growth Terms of $0.5 * (SLA_{t-1}/SLA_{t-2})$ for FEI's growth capital and $0.5 * (AC_{t-1}/AC_{t-2})$ for all other cases.	119
56.	The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers.	120
57.	Given these reasons, the Commission Panel denies the Fortis request for the proposed ECM methodology.	128

58.	Accordingly, the Commission Panel determines that the following steps are required in order for Fortis to receive approval for an ECM initiative; 1. ECMs will in most cases be handled within the context of the Annual Review although where warranted, the Commission could consider an ECM measure within the year. 2. For each proposed initiative for which the benefits are expected to extend beyond the term of the PBR, Fortis will file an ECM proposal providing a description of the proposal, its timing, costs and benefits, and reasoning as to why it is appropriate and how long benefits should be paid. 3. Parties will have the opportunity to comment on the proposal.	128
59.	Considering these issues the Commission Panel determines that there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs.	134
60.	Therefore, the Commission Panel determines that the incentives earned must be linked to the achievement of service quality standards.	135
61.	Therefore, the Commission Panel finds that they are not a balanced set of indicators covering reliability, responsiveness to consumer needs and providing for the safety of the public.	143
62.	Within these categories the Commission Panel approves the following SQIs proposed by Fortis: • Safety - o Emergency Response Time - o Telephone Service Factor (emergency) • Customer needs - o First Contact Resolution - o Billing Index - o Meter Reading Accuracy - o Telephone Service Factor (non-emergency) - o Meter Exchange Appointment In addition, the Commission Panel directs that a number of Fortis' proposed informational SQIs be re-classified as benchmarked SQIs. These include: • Safety	143– 144

	- o All Injury Frequency Rate - o Public Contact with Pipelines • Reliability - o SAIDI (weather normalized) FBC only - o SAIFI (weather normalized) FBC only Further, the Panel approves the following informational indicators: • Customer Satisfaction Index • Telephone Abandon Rate and we direct Fortis to reinitiate the following informational indicators: • Generator Forced Outage Rate • Transmission Reportable Incidents • Leaks per KM of Distribution System Mains	
63.	The Commission Panel considers the performance benchmark of 97.7 percent (FEI Exhibit B-1-1, Appendix D7, p.6) to be appropriate as it reflects current performance and directs Fortis to set the SQI benchmark at this level for the purposes of the PBR. The Panel further directs that the FBC Emergency Response benchmark be set at 93 percent, which reflects the average Emergency Response achieved over the 2010 to 2012 period.	145– 146
64.	The Commission Panel approves the reduction to 70 percent	146
65.	The Commission Panel approves the Fortis proposed benchmarks for all other proposed benchmarked SQIs.	146
66.	For all new benchmarked SQIs the Panel directs Fortis to rely upon a 3 year average for 2010, 2011 and 2012 in calculating its performance benchmark.	146
67.	The Commission Panel directs Fortis to utilize the SQIs set out below for the PBR period. The Panel considers these to be balanced and collectively address service reliability, safety and customer needs.	146
68.	Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.	149
69.	The Panel determines it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for the SQIs that the Panel has directed to be modified or added.	149

70.	For this reason, the Panel directs the Companies, in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory.	150
71.	In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.	150
72.	Where the parties are unable to agree on a resolution to mitigate the problem or the parties consider further process to be warranted, the Panel directs them to refer the matter to the Commission.	150
73.	The Panel directs that the maximum reduction to the incentive earnings will be an adjustment to the earnings sharing mechanism to reflect a 60 percent ESM share to the customer rather than the standard 50 percent.	151
74.	In the Commission Panel's best judgement, a multi-pronged trigger strikes an appropriate balance between incenting the Companies to find efficiencies and savings and protecting the interest of the ratepayers. The Panel directs that an off-ramp be triggered if earnings in any one year vary from the approved ROE by more than +/- 200 basis points (post sharing). The Commission Panel further directs that should earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years, the off-ramp will be triggered.	155
75.	The Commission Panel finds that providing a specific definition of what constitutes a "sustained serious degradation" in service is not practical.	158
76.	Parties are directed to review the concept of "sustained serious degradation" of service levels at each Annual Review and provide recommendations to the Commission as to whether additional considerations to those set out above are appropriate.	158
77.	The Commission Panel finds that it is appropriate to exclude some capital projects from the capital formula spending envelope.	170
78.	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.	172
79.	In summary, the Panel finds that the current CPCN exclusion criteria as proposed are not appropriate.	174
80.	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.	175

81.	The Panel finds that a more extensive Annual Review process is necessary to build trust among all stakeholders and to ensure the PBR Plan functions as intended.	178
82.	The Commission directs that the Annual Review process include the following: 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. 2. Review of the current year projections and the upcoming year's forecast (FEI Exhibit B-1, p. 78, 79; FBC Exhibit B-1, p. 71, 72). For further clarity, these items are listed below: a. Customer growth, volumes and revenues; b. Year-end and average customers, and other cost driver information including inflation; c. Expenses (determined by the PBR formula plus flow-through items); d. Capital expenditures (as determined by the PBR formula plus flow-through items); e. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; f. Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and g. Any proposals for funding of incremental resources in support of customer service and load growth initiatives. 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 (see Section 2.3.2 for a more detailed discussion of the ECM). 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 (see Section 2.2.4 for details). 5. Review of the Companies' performance with respect to SQI's. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service. (see Section 2.3.3.2 for details). 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	179– 180

	Reading Accuracy SQIs. 7. Assess and make recommendations to the Commission on the scope for future Annual Reviews.	
83.	Accordingly, Fortis' request for a Mid-Term Review is denied.	180
84.	The Commission Panel directs, in the first Annual Review, in addition to the items previously set out, a consultation process to determine the performance range for SQIs be undertaken.	180
85.	FBC is directed to provide an explanation at the next Annual Review as to why this information for past years is unavailable.	182
86.	The Commission Panel determines that an appropriate starting point for the development of the PBR O&M Base is the 2013 Approved O&M.	186
87.	In accordance with FBC's proposed methodology as outlined in BCUC IR 2.90.13, the Panel approves the deferral account and directs that these deferred expenses be treated outside of Base O&M.	195
88.	Accordingly, the Commission Panel determines that a more appropriate addition to the PBR Opening O&M Base to account for first and third party liability expenses is \$140,000.	196
89.	The Panel directs that these be excluded from the calculation of the earnings for the purpose of the ESM.	197
90.	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.	197
91.	In consideration of these factors, the Commission Panel considers that in addition to other directives elsewhere in this Decision, a downward adjustment in the PBR Opening O&M Base is warranted. The Panel, in its best judgement, directs that in addition to the adjustments proposed by FBC a further reduction of \$200,000 be made.	198
92.	The Commission Panel accepts that FBC competes for executive talent in the broad spectrum of commercial and industrial organizations. Therefore, FBC's rationale for the choice of the larger, broad-based comparator group is reasonable.	202
93.	The Commission Panel finds that 30 percent of the STIP costs are on the account of the shareholder. Therefore, the Panel directs FBC to recover only 70 percent of the STIP from the ratepayer and reduce its O&M Base accordingly.	203

94.	Therefore, the Commission Panel finds that the STI costs as they relate to the ratepayer are to be restricted to the target (as outlined in the Hay Report) STI compensation only. The Panel understands that this equates to the target median within its comparative peer group and directs any amounts in excess of the target median to be borne by the shareholder.	203
95.	As part of its Compliance Filing, FBC is directed to provide the following information for 2013: (i) the amounts spent on the Executive STI, and (ii) the amount that would have been spent if only the target STI had been met (as per page 9 of the Executive Compensation Benchmarking, Exhibit B-1-1, Appendix C-2). The difference between these two amounts must be deducted from the Base O&M.	203– 204
96.	The Commission Panel finds the CEC and ICG arguments to be unpersuasive and puts little weight on them.	209
97.	The Commission Panel approves FBC's 2013 Base Capital as applied for, subject to further adjustment as directed elsewhere in this Decision.	210
98.	Accordingly, the Commission Panel approves discontinuance of the US GAAP to Canadian GAAP reconciliation. The Commission 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.	212
99.	The Commission Panel approves FBC's request to discontinue the net-of-tax treatment for the pension and OPEB funding differences as applied for.	213
100.	The Panel directs the existing net-of-tax balances of the pension and OPEB to be carried forward as a starting point for 2014, with future additions to both accounts to be on a pre-tax basis and the timing of tax deductions to be recognized in the calculation of income tax expense.	213
101.	FBC's proposed methodology utilizing the Massachusetts Formula is approved.	214
102.	The Commission Panel directs any changes to executive cross-charges resulting from the Code of Conduct/Transfer Pricing Policy proceeding be reflected as an adjustment to the Base O&M.	214
103.	the Panel approves FBC to continue its Transmission and Distribution direct overhead loading allocation during the PBR period.	216
104.	The Panel directs FBC to reduce its capitalized overhead rate to 15 percent in 2014.	218
105.	The Commission Panel agrees and also considers it inappropriate for FBC to capitalize these recurring fees and directs FBC to expense its annual software costs in a manner consistent with the direction provided to FEI by the Commission in Section 3.2.3 of the FEI 2014–2018 PBR RRA Decision.	219

106.	As part of its Compliance Filing, FBC is directed provide the following information: (i) the total amount paid in 2013 for annual software costs; (ii) the amounts originally included in FBC's Application for 2013 Base O&M and 2013 Base Capital related to annual software costs; and (iii) the increase to FBC's 2013 Base O&M as a result of this change in treatment of annual software costs and the resulting decrease to FBC's 2013 Base Capital.	219
107.	The Commission Panel denies FBC's proposal to establish the RSDM combining the impact of WAX CAPA and other PBR rate impacts.	224
108.	In its Compliance Filing, FBC must recalculate and show the 2014 revenue requirement and rate impact without the rate smoothing effect of the RSDM. FBC must also propose to the Commission a method to treat the revenue requirement impact between the interim rate increase approved under Order G-151-13 and the rate resulting from this Decision.	224– 225
109.	The Commission Panel approves FBC's proposal to establish an ESM deferral account.	225
110.	The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be at FBC's short-term interest rate.	225
111.	The Commission Panel approves the establishment of the BC Hydro Application for New PPA with FBC deferral account as applied for by FBC.	226
112.	However, the Commission Panel directs FBC to update its forecast addition to the deferral account as it relates to the Written Hearing as part of its Compliance Filing.	226
113.	The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with FBC's 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC's short-term interest rate (p. 105).	226
114.	The Commission Panel approves the establishment of the GCOC Revenue Requirements Impact deferral account.	227
115.	The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC's short-term interest rate.	227
116.	The Commission Panel approves the establishment of the 2014–2018 Annual Reviews Deferral Account.	227

117.	Accordingly, the Panel directs FBC to discontinue the Power Purchase Expense deferral account and its related Revenue Variance deferral account during the PBR term. These expenses and revenues shall be flowed through to ratepayers each year through the annual flow-through mechanism.	228
118.	In its Compliance Filing, FBC is directed to provide its 2013 ending balances in these deferral accounts and illustrate the rate impact of flowing through these variances to 2014 rates. Variances between FBC's forecast and actual results in 2014 and beyond shall to be flowed through to ratepayers annually.	229
119.	The Commission Panel approves the establishment of the non-rate base CPCN Projects Preliminary Engineering deferral account	230
120.	The Commission Panel rejects FBC's proposal to apply AFUDC to this new deferral account	230
121.	The Panel directs FBC to comply with the previous Commission decision and apply carrying costs based on FBC's WACD to this deferral account starting in 2014.	230
122.	The Commission Panel approves the amortization of the 2014–2018 PBR Application deferral account over six years commencing January 1, 2014.	232
123.	The Commission Panel denies FBC's request to change the Pension & OPEB Expense Variance deferral account amortization period from three years to the EARSL. FBC must therefore continue amortizing this deferral account over three years.	233
124.	The Commission Panel approves the amortization of both the City of Kelowna Acquisition Customer Benefit deferral account and the City of Kelowna Acquisition Legal and Regulatory Costs deferral account over one year, commencing January 1, 2014.	234
125.	The Panel directs that these deferral accounts be discontinued effective January 1, 2015, as proposed by FBC in the Application.	234
126.	The Commission Panel approves FBC's request to amortize the 2014–2018 Capital Expenditure Plan deferral account over two years.	234
127.	the Commission Panel grants approval to FBC to establish a new deferral account to transfer the costs associated with the GCOC proceeding from the holding account to a separate deferral account for recovery from ratepayers. The Panel also approves the requested two-year amortization period, commencing in 2014.	236
128.	The Panel denies FBC's request to charge a WACC carrying charge to this deferral account	236

129.	The Commission Panel directs FBC to apply its WACD to this deferral account. FBC shall also apply its WACD to calculate the carrying charges on the 2013 balance.	236
130.	FBC's requested deferral account for the BCUC Inquiry into the MRS Program and its requested amortization period of one year beginning in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.	236
131.	The Commission Panel directs FBC to apply its short-term interest rate to this deferral account to calculate the carrying charges on the 2013 balance.	236
132.	Given these circumstances, the Commission Panel finds that it is also reasonable to approve FBC's (legal) costs related to this inquiry. Accordingly, the Panel approves FBC's request to establish the Kettle Valley Expenditure Review deferral account with the amortization period of one year, starting in 2014. The Panel denies FBC's request to apply WACC to the deferral account.	236– 237
133.	The Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC is directed to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	237
134.	Given these circumstances, FBC's deferral of the cost for the Transmission Customer Rate Design review and its requested amortization period of one year commencing in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.	237
135.	The Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC shall also apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	237
136.	The Panel approves FBC's request for deferral of the incremental 2012 MRS costs with an amortization period of one year commencing in 2014. However, the Panel denies FBC's request to apply WACC to the deferral account.	237– 238
137.	The Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	238
138.	In its Compliance Filing, FBC must confirm that these MRS audit expenses were not included in its proposed O&M base. To the extent that these MRS audit costs are included in the O&M base, they must be removed.	238
139.	The Panel approves the incremental costs (\$0.3 million for 2012 and \$0.9 million for 2013) related to its MRS O&M expense. The Panel grants approval for FBC to amortize these deferred costs into rates in 2014. The Panel denies FBC's request to apply WACC to the deferral account.	238

140.	The Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	238
141.	The Commission Panel approves the treatment of the deferred debt issue costs as applied for by FBC.	239
142.	The Commission Panel approves FBC's request to discontinue the deferral accounts listed in Table 3.11 above, and as outlined in the Application and in its Evidentiary Update.	241
143.	The Commission Panel accepts the 2014 DSM schedule filed by FBC, attached as Appendix B of this Decision, and approves FBC's request under section 44.2 of the UCA to spend \$3.0 million on DSM in 2014.	242
144.	The Commission Panel denies FBC's request to increase the DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years.	244
145.	The Commission Panel accepts FBC's request to submit annual rather than semi-annual DSM Reports.	244
146.	The Commission Panel declines to rule on FBC's proposed DSM funding transfer rules as they are not applicable to the 2014 DSM funding application.	244

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DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of September 2014.

Original signed by:

D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

N.E. MACMURCHY
COMMISSIONER

Original signed by:

D.M. MORTON
COMMISSIONER

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**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER G-139-14**

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
Application for Approval of a
Multi-Year Performance Based Ratemaking Plan
for the years 2014 through 2018

BEFORE: D.A. Cote, Panel Chair/Commissioner
D.M. Morton, Commissioner
N.E. MacMurchy, Commissioner September 15, 2014

O R D E R

WHEREAS:

- A. On July 5, 2013, FortisBC Inc. (FBC) applied to the British Columbia Utilities Commission (Commission) for approval of a proposed multi-year Performance Based Ratemaking (PBR) plan for the years 2014 through 2018 (Application);
- B. Among other things, FBC's Application includes the following requests, under section 59-61 of the *Utilities Commission Act* (UCA):
 - a. to make its interim rates at that time be permanent, effective January 1, 2013, and to increase the permanent rates for all customers by 3.3 percent, effective January 1, 2014;
 - b. a rate stabilization mechanism for the years 2014 to 2018;
 - c. the flow through, during 2014, of any increase or decrease arising from the Generic Cost of Capital Stage 2 proceeding;
 - d. certain accounting treatment and financing of deferral accounts;
 - e. certain accounting policies changes to be used in the determination of rates effective January 1, 2014; and
 - f. approval of a proposed PBR mechanism for setting rates during the years 2014 to 2018;

**BRITISH COLUMBIA
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- C. FBC also seeks acceptance of certain Demand-Side Management expenditures and changes, pursuant to section 44.2 of the UCA;
- D. On July 25, 2013, FBC held a Workshop in Kelowna, BC to review the Application;
- E. On September 5, 2013, a Procedural Conference was held jointly with FBC's affiliate, FortisBC Energy Inc. (FEI), who has also applied for a PBR plan with the Commission. The Procedural Conference considered the regulatory process for both the FEI and FBC Applications and the possibility of combining some parts or all of the two proceedings;
- F. By Orders G-151-13, the Commission amended the Regulatory Timetables and established that an Oral Hearing to review PBR related issues be held jointly with FEI. The Commission also approved a 3.3 percent interim and refundable rate increase for FBC, effective January 1, 2014;
- G. The Regulatory Timetables for review of the Application was further amended by Orders G-206-13, G-219-13, G-8-814, and G-10-14;
- H. The Oral Hearing on PBR related issues commenced on March 10, 2014 and was completed on March 18, 2014;
- I. Between April 25 and May 22, 2014, FBC and Interveners filed their Final Arguments on both PBR related and non-PBR issues. On June 12, 2014, FBC filed its Reply Arguments.
- J. A Commission Panel Information Request was issued on June 19, 2014 with an accompanying timetable for completion;
- K. On July 14, 2014, the Commission Panel held the Oral Argument Phase to address the Panel Information Requests, its related responses and certain topics identified by the Panel;
- L. The Commission has considered the FBC Application, the evidence and submissions by all parties in this proceeding and provides its Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

- 1. Pursuant to sections 59 to 61 of the *Utilities Commission Act*, the Commission Panel makes the following determinations:
 - a. The rate stabilization mechanism is denied;
 - b. Rates effective January 1, 2013 are to be made permanent;

**BRITISH COLUMBIA
UTILITIES COMMISSION**

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- c. Approval to flow-through the revenue requirement impact as a result of the decrease in the return on equity that was used to calculate its rates effective January 1, 2013 is granted; and
 - d. A PBR mechanism in setting rates for the period of 2014 to 2019 is approved, subject to the various amendments outlined in the Decision.
2. Pursuant to section 44.2(3) of the *Utilities Commission Act*:
- a. The Demand-Side Management (DSM) expenditure, up to \$3.0 million for 2014, is accepted;
 - b. The proposal to change the amortization period of existing and future DSM expenditures from 10 years to 15 years is denied; and
 - c. The proposal to discontinue the semi-annual reporting on its DSM program and to submit annual reports at the end of each calendar year, effective January 1, 2014 is accepted.
3. FortisBC Inc. is directed to submit a Compliance Filing to the Commission, within 60 days of this Order, with amended financial schedules that incorporate all the adjustments and directives as outlined in the Decision. FortisBC Inc. must also propose a method to treat the difference between the 2014 interim rate and the rate approved in this Decision.
4. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules that conform to the Decision.
5. FortisBC Inc. is to notify all customers, by way of an information notice, of the change in rates.
6. FortisBC Inc. must comply with all other directives contained in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of September of 2014.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

APPENDIX A

Page 1 of 1

Regulatory Process Summary

On August 23, 2013, the Commission issued a letter to all parties in both Applications suggesting combining the two applications for the purpose of dealing with the PBR elements of the two applications jointly. At a joint Procedural Conference, held on September 5, 2013, all parties agreed.

On September 12, 2013, the Commission Panel issued Order G-151-13 ordering a joint Oral Hearing on the PBR methodology for both FEI and FBC. All other matters were to be reviewed by separate Written Hearings.

There were two rounds of Information Requests (IRs) with the second round broken out into those questions concerning PBR methodology and those dealing with non PBR issues.

Further amendments to the Regulatory Timetable were made through Orders G-206-13, G-219-13, G-8-14, and G-10-14.

The Oral Hearing on PBR Issues commenced on March 10, 2014, and was completed on March 18, 2014.

FEI and FBC filed a joint Final Argument on the PBR issues on April 25, 2014. FBC's Final Argument for non PBR issues was received on April 28, 2014. Final Arguments from all Interveners were received by May 22, 2014, and the FBC Reply Argument (Non PBR Issues) and Fortis Joint Reply Argument (PBR issues) were received on June 12, 2014.

A Panel Information Request and request for additional submissions was issued on June 19, 2014 with an accompanying timetable for completion.

On July 14, 2014, the Commission Panel held a hearing to receive oral argument on the Panel IRs, related responses and the Panel's additional topics issued June 27, 2014.

APPENDIX B
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Summary Table of FortisBC 2014–2018 DSM Plan

1 2	Program Area	Plan Savings (MWh/year)					Plan Cost \$(000s)					Benefit/Cost Ratios			
		2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	TRC	mTRC	Utility	Part
3	Programs by Sector														
4	Residential	5,800	5,783	5,615	5,511	5,407	1,037	1,081	1,008	1,015	1,024	1.2	1.3	3.5	
5	General Service	6,200	6,304	6,408	6,512	6,616	1,134	1,166	1,195	1,223	1,256	1.4	1.7	3.3	
6	Industrial	800	800	800	800	800	148	150	152	154	156	2.8	2.8	5.7	
7	Sub-total Programs:	12,800	12,887	12,823	12,823	12,823	2,319	2,397	2,355	2,392	2,436	1.4	1.5	3.9	
8	Supporting Initiatives						190	190	190	190	190				
9	Planning & Evaluation						492	500	509	518	527				
10	Total (incl. Portfolio):						3,001	3,087	3,054	3,100	3,153	1.2	1.4	3.7	
11	Residential Programs														
12	Building Envelope	1,881	1,881	1,881	1,881	1,881	295	299	301	305	308	1.1	1.3	4.8	
13	Heat Pumps	553	553	553	553	553	158	159	161	163	164	1.1	1.1	2.4	
14	Lighting	2,136	2,067	1,997	1,928	1,859	176	171	164	158	153	1.4	1.4	5.9	
15	New Home	98	98	98	98	98	67	68	68	69	70	0.6	1.2	1.2	
18	Water heating	425	440	455	470	485	99	103	108	112	119	1.6	1.9	2.1	
19	Low Income & Rental	707	744	631	581	531	242	281	206	208	210	0.8	0.8	1.0	
21	Total	5,800	5,783	5,615	5,511	5,407	\$ 1,037	\$ 1,081	\$ 1,008	\$ 1,015	\$ 1,024	1.2	1.3	3.5	
22	General Service Programs														
23	Lighting	3,359	3,463	3,567	3,671	3,775	510	535	557	579	603	1.7	2.0	3.4	
24	BIP	2,641	2,641	2,641	2,641	2,641	592	598	605	611	619	1.1	1.5	3.1	
27	Irrigation	200	200	200	200	200	32	33	33	33	34	2.1	2.1	7.3	
28	Total	6,200	6,304	6,408	6,512	6,616	\$ 1,134	\$ 1,166	\$ 1,195	\$ 1,223	\$ 1,256	1.4	1.7	3.3	
29	Industrial Programs														
31	Ind Efficiency	800	800	800	800	800	148	150	152	154	156	2.8	2.8	5.7	
32	Total	800	800	800	800	800	\$ 148	\$ 150	\$ 152	\$ 154	\$ 156	2.8	2.8	5.7	

(Source: Exhibit B-1-1, Appendix H, Attachment 1, p. 14)

APPENDIX C

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GLOSSARY

AFUDC	Allowance for Funds Used During Construction
AIFR	All Injury Frequency Rate
AMI	Advanced Metering Infrastructure
Application	Multi-Year Performance Based Ratemaking Plan for the Years 2014 through 2018 Including Approval of Rates for 2014 in Accordance with the PBR Plan
ARM	Attrition Relief Mechanism
AUC	Alberta Utilities Commission
B&V	Black and Veatch
BC Hydro	British Columbia Hydro and Power Authority
BC-CPI	British Columbia Consumer Price Index
BCMEU	British Columbia Municipal Electrical Utilities
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCSEA	BC Sustainable Energy Association and the Sierra Club of British Columbia
Capex	Capital Expenditures
CEA	<i>Clean Energy Act</i>
CEC	Commercial Energy Consumers of British Columbia
CGA	Canadian Gas Association
Commission	British Columbia Utilities Commission
COPE	Canadian Office and Professional Employees Union Local 378
COS	Cost of Service
CPCN	Certificate of Public Convenience and Necessity

APPENDIX C

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CPI	Consumer Price Index
DSM	Demand-Side Management
DSM Regulation	Demand-Side Measures Regulation (BC Reg. 326/2008)
EARS�	Expected Average Remaining Service Life
ECI	Employment Cost Index
ECM	Efficiency Carry-Over Mechanism
ESM	Earnings Sharing Mechanism
EUCPI	Electric Utility Construction Price Index
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
Fortis	FortisBC Energy Inc. and FortisBC Inc.
GAAP	Generally Accepted Accounting Principles
Gabana	Gabana, Norman
GCOC	Generic Cost of Capital
GWh	Gigawatt hour
Hay	Hay Group Limited
IBEW	International Brotherhood of Electrical Workers
ICG	Industrial Consumers Group
IFRS	International Financial Reporting Standards
IRG	Irrigation Ratepayers Group
IRs	Information Requests
ISP	Integrated System Plan
IT	Information Technology

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KORP	Kingsvale-Oliver Reinforcement Project
LFTC	Load Forecast Technical Committee
LRMC	Long-Run Marginal Cost
M&S	Materials and Services
MEM	Ministry of Energy and Mines
MFP	Multifactor Productivity
MFP ^N	Multifactor Productivity Index
MRS	Mandatory Reliability Standards
mTRC	modified TRC
MWh	Megawatt hour
NERA	National Economic Research Associates
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
O&M	Operating and Maintenance
OEB	Ontario Energy Board
OPEB	Other Post-Employment Benefits
Opex	Operating & Maintenance Expenditure
PBR	Performance Base Ratemaking
PBR Plan	Multi-Year Performance Based Ratemaking Plan for the Years 2014 through 2018
PIF	Productivity Improvement Factors
PPA	Power Purchase Agreement
Rate Schedule 1	Residential Conservancy Rate
RNG	Renewable Natural Gas

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ROE	Return on Equity
RRA	Revenue Requirements Application
RS 3808	BC Hydro Application for a Power Purchase Agreement with FBC
RSDM	Rate Stabilization Deferral Mechanism
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCP	Southern Crossing Pipeline
SQIs	Service Quality Indicators
Stanski	Stanski, Henry
STIP	Short Term Incentive Plan
T&D	Transmission and Distribution
TFP	Total Factor Productivity
TRC	Total Resource Cost
UCA	<i>Utilities Commission Act</i>
WACC	Weighted Average Cost of Capital
WACD	Weighted Average Cost of Debt
WAX CAPA	Waneta Capacity Purchase Agreement

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
Application for Approval of a
Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

EXHIBIT LIST

Exhibit No.	Description
<i>COMMISSION DOCUMENTS</i>	
A-1	Letter Dated July 10, 2013 – Appointment of Commission Panel
A-2	Letter Dated July 17, 2013 – Order G-109-13 Establishing a Preliminary Regulatory Timetable, Procedural Conference and Notice of Workshop
A-3	Letter Dated August 14, 2013 - Commission Information Request No. 1 to FortisBC Inc.
A-3-1	Letter Dated August 15, 2013 – Reformatted Commission Information Request No. 1 to FortisBC Inc.
A-4	CONFIDENTIAL Letter Dated August 14, 2013 - Commission Confidential Information Request No. 1 to FortisBC Inc.
A-5	Letter Dated August 23, 2013 – Commission Acceptance of CEC’s late Information Request
A-6	Letter Dated August 23, 2013 – Commission Acceptance of Mr. Stanski’s late Information Request
A-7	Letter Dated August 23, 2013 – Proposed Change to Procedural Conference
A-8	Letter Dated August 23, 2013 – BCUC Requesting Comments on COPE 378’s Late Supplemental Information Request
A-9	Letter Dated August 29, 2013 – Order G-133-13 issuing a Revised Preliminary Regulatory Timetable

Exhibit No.	Description
A-10	Letter Dated August 30, 2013 – BCUC issuing Procedural Conference Items
A-11	Letter Dated September 4, 2013 – Order G-139-13 directing FortisBC Inc. to respond to COPE 378’s Supplemental Information Requests
A-12	Letter Dated September 10, 2013 – Appointment of Commissioner MacMurchy
A-13	Letter Dated September 13, 2013 – Order G-151-13, amending the Regulatory Timetable
A-14	Letter Dated October 4, 2013 – BCUC Requesting comments on Gabana C7-3 submission
A-15	Letter Dated October 4, 2013 – Order G-165-13 Amending the Regulatory Timetable
A-16	Letter Dated October 16, 2013 – Response to Mr. Gabana’s complaint
A-17	Letter Dated October 25, 2013 – Commission Information Request No. 2 on all non-Performance Based Rates Methodology issues
A-18	Letter Dated November 8, 2013 – Commission Information Request No. 2 on Performance Based Rates Methodology issues
A-19	Letter Dated November 25, 2013 – Response to FBC’s Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2
A-20	Letter Dated December 2, 2013 – Order G-206-13 Amending the Regulatory Timetable
A-21	Letter L-73-13 Dated December 12, 2013 – BCUC Response to COPE letter
A-22	Letter Dated December 18, 2013 – Order G-219-13 Amending the Regulatory Timetable
A-23	Letter Dated January 16, 2014 – Commission Information Request No. 1 to BCPSO on Intervener Evidence
A-24	Letter Dated January 16, 2014 – Commission Information Request No. 1 to COPE 378 on Intervener Evidence
A-25	Letter Dated January 16, 2014 – Commission Information Request No. 1 to CEC on Intervener Evidence

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Exhibit No.	Description
A-26	Letter Dated January 16, 2014 – Commission Information Request No. 1 to BCSEA on Intervener Evidence
A-27	Letter Dated January 16, 2014 – Commission Information Request No. 1 to ICG on Intervener Evidence
A-28	Letter Dated January 16, 2014 – Commission Order G-8-14 Amending the Regulatory Timetable
A-29	Letter Dated January 16, 2014 – Commission Letter L-3-14 Providing Scope of Oral Hearing
A-30	Letter Dated January 23, 2014 – Commission Order G-10-14 Amending the Regulatory Timetable
A-31	Letter Dated February 12, 2014 – Commission Information Request No. 2 to BCPSO on Intervener Evidence
A-32	Letter Dated February 12, 2014 – Commission Information Request No. 2 to CEC on Intervener Evidence
A-33	Letter Dated February 12, 2014 – Commission Information Request No. 2 to ICG on Intervener Evidence
A-34	Letter Dated February 19, 2014 – Oral Hearing Information
A-35	Letter Dated February 28, 2014 – CEC IR Response Request for Submission
A-36	Letter Dated March 4, 2014 – Panel’s decision on certain CEC’s IR responses
A-37	Letter Dated March 10, 2014 – Commission Information Request No. 2 to BCSEA
A-38	Letter Dated March 18, 2014 – Final Submissions Regulatory Timetable
A-39	Letter Dated March 27, 2014 – Commission Information Request No. 1 to FBC on FBC Rebuttal Evidence
A-40	Letter Dated April 30, 2014 – Request for comments on CEC’s Request for an Extension of the Deadline for Filing of Argument by Interveners
A-41	Letter Dated April 30, 2014 – Recusal of B. Magnan from Panel

Exhibit No.	Description
A-42	Letter Dated May 8, 2014 – Response to CEC Request for Extension
A-43	Letter Dated June 19, 2014 – Panel Information Request No. 1, Oral Argument and Timetable
A-44	Letter Dated June 27, 2014 – Commission Submitting Oral Argument Topics
A-45	Letter Dated July 10, 2014 – Commission Submitting Oral Argument Clarification

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated August 14, 2013 – Commission Staff filing FortisBC Inc. 2012–13 Revenue Requirements and 2012 Integrated System Plan Order G-110-12 Directive 10 Workforce Action Plan
A2-2	Letter dated August 14, 2013 – Commission Staff filing Commission Staff filing FortisBC Inc. 2012 US GAAP Appendix A – Reconciliation of Financial Statements
A2-3	Letter dated August 14, 2013 – FortisBC Inc. 2012 Application for Approval to Establish Deferral Accounts
A2-4	Letter dated August 14, 2013 – Commission Staff filing FortisBC Holdings Inc. – Statement of Executive Compensation
A2-5	Letter dated August 14, 2013 – Commission Staff filing Ontario Ministry of Energy Agency Review, May 2007
A2-6	Letter dated August 14, 2013 – Commission Staff filing Hydro Ottawa Holding Inc. 2011 Annual Report
A2-7	Letter dated August 14, 2013 – Commission Staff filing Toronto Hydro Corporation 2012 Annual Information Form
A2-8	Letter dated August 14, 2013 – Commission Staff filing Nova Scotia Power 2013 Management Information Circular
A2-9	Letter dated August 14, 2013 – Commission Staff filing Statistics Canada - CANSIM Table 282-0012 Labour force survey estimates, employment by class of worker, North American Industry Classification System and sex annual

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Exhibit No.	Description
A2-10	Letter dated August 14, 2013 – Commission Staff filing Aligning Utility Incentives with Investment in Energy Efficiency A Resource of the National Action Plan for Energy Efficiency, November 2007
A2-11	Letter dated August 14, 2013 – Commission Staff filing International Energy Agency Insights Series 2013 Energy Provider-Delivered Energy Efficiency
A2-12	Letter dated September 4, 2013 – Commission Staff Submissions for the September 5, 2013 Procedural Conference
A2-13	Letter dated October 25, 2013 – Commission Staff filing Pacific Institute for Climate Solutions, September 30, 2013 Media Release: British Columbia should prepare for a different climate future
A2-14	Letter dated October 25, 2013 – Commission Staff filing web article by IT developer – Habanero Consulting Group for Enterprise Solution
A2-15	Letter dated October 25, 2013 – Commission Staff filing American Council for an Energy-Efficient Economy — Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs (September 2009 Report)
A2-16	Letter dated October 25, 2013 – Commission Staff filing BC Hydro Integrated Resource Plan 2013
A2-17	Letter dated October 25, 2013 – Commission Staff filing Navigant Consulting — Review of the Efficiency Maine Trust Triennial Plan (2011–2013)
A2-18	Letter date November 8, 2013 – Commission Staff filing Business Council of British Columbia – Productivity: BC’s Position and Why We Should Care
A2-19	Letter date November 8, 2013 – Commission Staff filing Special Report – TD Economics – Estimating Longer-Term Growth Prospects in Canada’s Provincial Economies
A2-20	Letter date November 8, 2013 – Commission Staff filing Excerpt from Ontario Energy Board Staff Report to the Board on Performance Measurement and Continuous Improvement for Electricity Distributors

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Exhibit No.	Description
A2-21	Letter date November 8, 2013 – Commission Staff filing Report from the 9th International Conference on Probabilistic Methods Applied to Power Systems – Utilizing Bulk Electric System Reliability Performance Index Probability Distributions in a Performance Based Regulation Framework
A2-22	Submitted at Oral Hearing March 12, 2014 – FortisBC and FortisBC Energy Inc. 2014-2018 Performance Based Rates – Staff Witness Aids
A2-23	Submitted at Oral Hearing March 12, 2014 – FortisBC/FEI 2014-2018 PBR Witness Aid - Inflation
A2-24	Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Witness Aid - St. Additions
A2-25	Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – Capital, FBC Scenario 1
A2-26	Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – Capital, FEI Scenario 1
A2-27	Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – ECM, with Cover Page re. Scenarios 1 and 2
A2-28	Submitted at Oral Hearing March 13, 2014 – Extract from Decision of Ontario Energy Board in the Matter of an Application by Enbridge Gas Distribution
A2-29	Submitted at Oral Hearing March 14, 2014 - FBC/FEI 2014-2018 PBR Staff Witness Aid - COPE
A2-30	Submitted at Oral Hearing March 17, 2014 – Response to BCUC Information Request No. 1, Page 161, Submission date September 20, 2013

APPLICANT DOCUMENTS

B-1	FORTISBC INC. (FBC) Letter Dated July 5, 2013 - Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 Volume 1
B-1-1	Letter Dated July 5, 2013 – FBC Submitting Application Appendices Volume 2
B-1-2	CONFIDENTIAL Letter Dated July 5, 2013 – FBC Submitting Confidential page 120

Exhibit No.	Description
B-1-3	CONFIDENTIAL Letter Dated July 5, 2013 – FBC Submitting Confidential Appendix C2
B-1-4	Letter Dated July 25, 2013 – FBC Submitting Errata 1 to the Application
B-1-5	Letter dated September 20, 2013 – FBC Submitting Errata 2 to the Application
B-1-6	Letter dated October 18, 2013 – Evidentiary Update to the Application
B-1-7	Letter Dated December 5, 2013 - FBC Submitting Errata 3 to 2014-18 PBR Plan Application and Responses to BCUC IR No. 1
B-1-8	Letter Dated December 13, 2013 – FBC Submitting Errata 4 Appendix D2
B-1-9	Letter Dated July 16, 2014 - FBC Submitting Application Amendment DSM Expenditure Request
B-2	Letter Dated July 25, 2013 – FBC Submitting Workshop Presentation
B-3	Letter Dated August 22, 2013 – FBC Submitting Response to COPE 378 Late Supplemental Information Requests
B-4	Letter Dated August 27, 2013 – FBC Submitting Further Response for Comment on COPE 378's Late Supplemental Information Request
B-5	Letter Dated September 4, 2013 - FBC Submissions for the September 5, 2013 Procedural Conference
B-6	Letter dated September 20, 2013 – FEI-FBC Joint Procedural Conference Response to Undertaking
B-7	Letter Dated September 20, 2013 - FBC Response to BCUC IR No. 1
B-7-1	CONFIDENTIAL Letter Dated September 20, 2013 - FBC Response to BCUC IR1 Confidential Attachments 220.1 and 222.1
B-8	CONFIDENTIAL Letter Dated September 20, 2013 - FBC Response to BCUC Confidential IR No. 1
B-9	Letter Dated September 20, 2013 - FBC Response to BCMEU IR No. 1
B-9-1	CONFIDENTIAL Letter Dated September 20, 2013 - FBC Response to BCMEU IR No. 1 Confidential Attachments

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Exhibit No.	Description
B-10	Letter Dated September 20, 2013 - FBC Response to CEC IR No. 1
B-10-1	CONFIDENTIAL Letter Dated September 20, 2013 - FBC Response to CEC IR No. 1 Confidential Attachments
B-11	Letter Dated September 20, 2013 - FBC Response to BCPSO IR No. 1
B-12	Letter Dated September 20, 2013 - FBC Response to BCSEA IR No. 1
B-13	Letter Dated September 20, 2013 - FBC Response to COPE IR No. 1
B-14	Letter Dated September 20, 2013 - FBC Response to Gabana IR No. 1
B-15	Letter Dated September 20, 2013 - FBC Response to ICG IR No. 1
B-16	Letter Dated September 20, 2013 - FBC Response to Stanski IR No. 1
B-17	Letter dated September 24, 2013 – FEI-FBC Response to COPE Request to Amend Timetable
B-18	Letter dated September 27, 2013 – FBC Response to COPE Supplementary IR No. 1
B-19	Letter Dated October 7, 2013 – FBC Response to Mr. Gabana
B-20	Letter Dated November 22, 2013 – FBC Notice of Delay filing responses to BCUC IR No. 2 and CEC IR No. 2
B-21	Letter Dated November 22, 2013 – FBC Response to BCSEA IR No. 2
B-22	Letter Dated November 22, 2013 – FBC Response to ICG IR No. 2
B-23	Letter Dated November 22, 2013 – FBC Response to BCPSO IR No. 2
B-24	Letter Dated November 26, 2013 – FBC Response to BCUC IR No. 2
B-24-1	CONFIDENTIAL Letter Dated November 26, 2013 – FBC Response to BCUC IR No. 2 Confidential Attachment 77.2.1
B-25	Letter Dated November 26, 2013 – FBC Response to CEC IR No. 2
B-26	Letter Dated November 29, 2013 – FBC Submitting Comments Regarding Regulatory Timetable

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Exhibit No.	Description
B-27	Letter Dated December 6, 2013 - FEI-FBC Response to BCUC IR2a - Non PBR Methodology
B-28	Letter Dated December 6, 2013 - FEI-FBC Response to BCPSO IR2a - Non PBR Methodology
B-29	Letter Dated December 6, 2013 - FEI-FBC Response to COPE IR2A - Non PBR Methodology
B-30	Letter Dated December 11, 2013 - FEI-FBC Response to COPE Letter
B-31	Letter Dated December 17, 2013 - FEI-FBC Response to Requests for Extensions to the Regulatory Timetable for Intervener Evidence
B-32	Letter Dated January 6, 2014 – FEI-FBC Rebuttal Evidence Confirmation
B-33	Letter Dated January 13, 2014 – FBC Submission on the Remainder of the Regulatory Timetable
B-34	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to BCPSO
B-35	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to BCSEA
B-36	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to CEC
B-37	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to COPE
B-38	Letter Dated February 12, 2014 – FEI-FBC Submitting IR No. 2 to CEC on Intervener Evidence
B-39	Letter Dated February 27, 2014 – FEI-FBC Submitting Objection to CEC IR Responses on Capital Tracker Mechanism
B-40	Letter Dated February 28, 2014 – FEI-FBC Submitting Witness Panels, Direct Testimony and Notice of Cross Examination

Exhibit No.	Description
B-41	Letter Dated March 3, 2014 – FEI-FBC Submitting Reply regarding Request to Strike CEC IRs
B-42	Letter Dated March 3, 2014 – FBC Submitting Rebuttal Evidence to BCSEA
B-43	Letter Dated March 3, 2014 – FBC Submitting Rebuttal Evidence to ICG
B-44	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to BCPSO
B-45	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to CEC and COPE
B-46	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to COPE
B-47	Letter Dated March 7, 2014 – FEI-FBC Submitting Opening Statement Presentation
B-48	Letter Dated March 10, 2014 – FEI-FBC Supplemental Rebuttal Testimony of Dr. H. Edwin Overcast, Black & Veatch to CEC
B-48-1	Letter Dated March 10, 2014 – FEI-FBC Supplemental Rebuttal Evidence to CEC
B-49	Letter Dated April 11, 2014 - FBC Response to BCSEA IR No. 1 on FBC Rebuttal Evidence
B-50	Letter Dated April 11, 2014 - FBC Response to BCUC IR No. 1 on FBC Rebuttal Evidence
B-51	Letter Dated April 11, 2014 - FBC Response to CEC IR No. 1 on FBC Rebuttal Evidence
B-52	Letter Dated April 29, 2014 - FEI-FBC Submitting Objection to CEC Request for Extension
B-53	Letter Dated June 27, 2014 - FEI-FBC Responses to Panel Information Request No. 1
B-54	Letter Dated July 10, 2014 - FEI-FBC Oral Argument Request for Procedural Confirmation
B-55	Letter Dated July 10, 2014 - FEI-FBC Oral Argument Procedural Confirmation Reply
B2-1	Letter Dated December 6, 2013 - FEI Response to BCUC IR3a - PBR Methodology

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Exhibit No.	Description
B2-2	Letter Dated December 6, 2013 - FEI Response to CEC IR3a - PBR Methodology
B2-3	Letter Dated December 6, 2013 - FBC Response to BCUC IR3a - PBR Methodology
B2-4	Letter Dated December 6, 2013 - FBC Response to BCPSO IR3a - PBR Methodology
B2-5	Letter Dated December 6, 2013 - FBC Response to BCSEA IR3a - PBR Methodology
B2-6	Letter Dated December 6, 2013 - FBC Response to CEC IR3a - PBR Methodology
B2-7	Letter Dated December 6, 2013 - FBC Response to ICG IR3a - PBR Methodology
B2-8	Letter Dated December 6, 2013 - FEI-FBC Response to BCUC IR3 – PBR Methodology
B2-9	Letter Dated December 6, 2013 - FEI-FBC Response to BCPSO IR3 – PBR Methodology
B2-10	Letter Dated December 6, 2013 -FEI-FBC Response to BCSEA IR3 – PBR Methodology
B2-11	Letter Dated December 6, 2013 -FEI-FBC Response to CEC IR3 – PBR Methodology
B2-12	Letter Dated December 6, 2013 -FEI-FBC Response to CEC Supplemental IR3 – PBR Methodology
B2-13	Letter Dated December 6, 2013 -FEI-FBC Response to COPE IR3 – PBR Methodology
B2-13-1	Letter Dated December 11 2013 - FEI-FBC Response to COPE Letter IR 3.G.14
B2-14	Letter Dated December 6, 2013 -FEI-FBC Response to ICG IR3 – PBR Methodology
B2-15	Submitted at Oral Hearing March 12, 2014 – FortisBC Undertaking No. 1 re. Volume 2, Page 362, Line 6 to Page 364, Line 20
B2-16	Submitted at Oral Hearing March 12, 2014 – FortisBC Undertaking No. 2 re. Volume 2, Page 293, Line 25 to Page 296, Line 5
B2-17	Submitted at Oral Hearing March 12, 2014 – Empirical Research In Support Of Incentive Rate Setting, 2012 Update, Report to the Ontario Energy Board Dated September, 2013 by Pacific Economics Group Research

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Exhibit No.	Description
B2-18	Submitted at Oral Hearing March 13, 2014 – FortisBC Undertaking No. 3 re. Volume 2, Page 357, Line 5 to Page 358, Line 7
B2-19	Submitted at Oral Hearing March 13, 2014 – FortisBC Undertaking No. 4 re. Volume 3, Page 406, Line 20 to Page 407, Line 217
B2-20	Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 5 re. Volume 4, Page 603, Lines 16 to 24
B2-21	Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 6 re. Volume 4, Page 606, Lines 13 to 23
B2-22	Submitted at Oral Hearing March 14, 2014 – “FortisBC Materials for Cross-Examination of Ms. Barbara Alexander (COPE)”
B2-23	Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 7 re. Volume 4, Page 607, Lines 4 to 14
B2-24	Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 8 re. Volume 4, Page 822, Lines 5 to 16
B2-25	Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 9 re. Volume 4, Page 674, Line 17 to Page 674, Line 14
B2-26	Submitted at Oral Hearing March 17, 2014 - Evidence Of Russ Bell
B2-27	Submitted at Oral Hearing March 18, 2014 - FortisBC Materials For Cross-examination of Dr. Mark Lowry (CEC)"
B2-28	Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 10 re. Volume 6, Page 1160, Lines 21 to 26
B2-29	Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 11 re. Volume 6, Page 1162, Lines 5 to 14
B2-30	Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 12 re. Volume 6, Page 1249, Line 20 to Page 1250, Line 19
B2-31	Submitted at Oral Hearing March 18, 2014 - CONFIDENTIAL - "Cost Trends of Gas Utility Construction, Cost Trend Tables 1912 to July 1, 2013" from Handy-Whiteman

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Exhibit No.	Description
B2-32	Submitted at Oral Hearing March 18, 2014 - Excel Spreadsheet
B2-33	Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 13 re. Volume 6, Page 1266, Lines 10 to 21
B2-34	Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 14 re. Volume 6, Page 1269, Line 10 to Page 1271, Line 10
B2-35	Submitted March 19, 2014 – FEI-FBC Response to Undertaking No. 15,V6, p1210, SQI Incentive Payments
B2-36	Submitted March 19, 2014 – FEI-FBC Response to Undertaking No. 16, V4, p772 Scenarios

INTERVENOR DOCUMENTS

C1-1	MINISTRY OF ENERGY AND MINES (MEM) Online Registration and Letter dated July 18, 2013 – Request for Intervener Status by Katherine Muncaster
C2-1	IRRIGATION RATEPAYERS GROUP (IRG) Online Registration and Letter dated July 18, 2013 – Request for Intervener Status by Fred Weisberg
C2-2	Letter Dated November 27, 2013 –IRG Submitting Comment regarding FBC’s Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2
C2-3	Letter Dated January 13, 2014 – IRG Submission on the Remainder of the Regulatory Timetable
C2-4	Letter Dated May 2, 2014 - IRG Comments regarding CEC Extension Request
C3-1	BRITISH COLUMBIA PENSIONERS’ AND SENIORS’ ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, BC COALITION OF PEOPLE WITH DISABILITIES, COUNSEL OF SENIOR CITIZENS’ ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCPSO) Letter dated July 22, 2013 – Request for Intervener Status by Tannis Braithwaite, Eugene Kung, Bill Harper and Russ Bell
C3-2	Letter dated August 21, 2013 – BCPSO Submitting Information Request No. 1
C3-3	Letter dated August 28, 2013 – BCPSO Submitting Comments on on COPE 378’s Late Supplemental Information Request

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Exhibit No.	Description
C3-4	Letter dated November 1, 2013 – BCPSO Submitting Information Request No. 2 Non-PBR
C3-5	Letter dated November 15, 2013 – BCPSO Submitting Information Request No. 2 on Performance Based Rates Methodology issues
C3-6	Letter Dated November 27, 2013 – BCPSO Submitting Comment regarding FBC's Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2
C3-7	Letter Dated December 19, 2013 – BCPSO Submitting Evidence
C3-8	Letter Dated January 13, 2014 – BCPSO Submission on the Remainder of the Regulatory Timetable
C3-9	Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to BCSEA
C3-10	Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to CEC
C3-11	Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to COPE
C3-12	Letter Dated January 29, 2014 – BCPSO Submitting Response to BCUC IR No. 1
C3-13	Letter Dated January 29, 2014 – BCPSO Submitting Response to FEI-FBC IR No. 1
C3-14	Letter Dated February 12, 2014 – BCPSO Submitting IR No. 2 to CEC on Intervener Evidence
C3-15	Letter Dated February 26, 2014 – BCPSO Submitting Response to BCUC IR No. 2
C3-16	Letter Dated February 26, 2014 – BCPSO Submitting Response to CEC IR No. 2
C3-16-1	Letter Submitted March 3, 2014 – BCPSO Filing Response to CEC IR No.2.2.3
C3-17	Letter Dated March 3, 2014 – BCPSO Submitting Comments regarding FEI-FBC Objection to CEC IR Responses
C3-18	Letter Dated March 3, 2014 – BCPSO Submitting Witness Panel
C3-19	Letter Dated April 30, 2014 - BCPSO Comments regarding CEC Extension Request

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Exhibit No.	Description
C4-1	CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378) Letter dated July 22, 2013 – Request for Intervener Status by Jim Quail and Leigha Worth
C4-2	Letter dated August 21, 2013 – COPE 378 Submitting Information Request No. 1
C4-3	Letter dated August 23, 2013 – COPE 378 Submitting Information Regarding Consultant
C4-4	Letter dated August 22, 2013 – COPE 378 Submitting Late Supplementary Information Requests
C4-5	Letter dated August 28, 2013 – COPE 378 Submitting Comments and Corrected Supplemental Information Request to FBC
C4-6	Letter dated September 20, 2013 – COPE 378 Submitting Application to Amend Regulatory Timetable
C4-7	Letter dated November 13, 2013 – COPE 378 Submitting Information Request No. 2 on Performance Based Rates Methodology issues
C4-8	Letter dated December 10, 2013 – COPE 378 Submitting Responses to FEI (B2-13)-FBC (B-29) Information Request
C4-9	Letter dated December 17, 2013 - COPE 378 Submitting Evidence
C4-10	Letter Dated January 14, 2014 – COPE 378 Late Submission on the Remainder of the Regulatory Timetable
C4-11	Letter Dated January 29, 2014 – COPE 378 Submitting Response to BCUC IR No. 1
C4-12	Letter Dated January 29, 2014 – COPE 378 Submitting Response to FEI-FBC IR No. 1
C4-13	Letter Dated January 29, 2014 – COPE 378 Submitting Response to BCSEA IR No. 1
C4-14	Letter Dated January 29, 2014 – COPE 378 Submitting Response to CEC IR No. 1
C4-14-1	Letter Dated January 30, 2014 – COPE 378 Submitting Updated Response to CEC IR No. 1

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Exhibit No.	Description
C4-15	Letter Dated February 5, 2014 – COPE 378 Submitting Late Responses to Information Requests
C4-16	Letter Dated February 26, 2014 – COPE 378 Submitting Late Response to BCSEA IR No. 2
C4-17	Letter Dated February 26, 2014 – COPE 378 Submitting Late Response to CEC IR No. 2
C4-18	Letter Dated February 28, 2014 – COPE 378 Submitting Comment on FEI-FBC-Objections to CEC IR Responses
C4-19	Letter Dated March 3, 2014 – COPE 378 Submitting Witness Panel
C4-20	Letter Dated April 29, 2014 - COPE 378 Comments regarding CEC Extension Request
C4-21	Letter Dated July 10, 2014 - COPE 378 Submitting Comments regarding Oral Argument Phase
C5-1	BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU) Letter dated July 22, 2013 – Request for Intervener Status by Christopher Weafer
C5-2	Letter dated August 21, 2013 – BCMEU Submitting Information Request No. 1
C6-1	COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC) - Letter dated July 8, 2013 – Request for Intervener Status by Christopher Weafer
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C6-7	Letter Dated November 27, 2013 – CEC Submitting Comment regarding FBC’s Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2

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C6-9	Letter Dated December 20, 2013 – CEC Submitting Evidence
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C6-22	Letter Dated February 26, 2014 – CEC Submitting Response to FEI FBC IR No. 2
C6-23	Letter Dated March 3, 2014 – CEC Submitting Witness Panel
C6-24	Letter Dated March 3, 2014 – CEC Submitting Comments regarding FEI-FBC Objection to CEC IR Responses
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C6-26	Letter Dated April 29, 2014 - CEC Extension Request
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C6-28	Letter Dated July 10, 2014 - CEC Submitting Comments regarding Oral Argument Phase
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C9-1	BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH) Online Registration Dated July 23, 2013 – Request for Intervener Status by Janet Fraser
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C11-2	Letter Dated August 22, 2013 – Stanski Submitting late Information Request No. 1 July 27, 2018

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C12-1	Submitted at Oral Hearing March 11, 2014 – COPE Letter From Jim Quail With Attached Evidence of Barbara R. Alexander Dated December 18, 2013
C12-2	Submitted at Oral Hearing March 11, 2014 – CEC Opening Comments-2014 Through 2018
C12-3	Submitted at Oral Hearing March 12, 2014 – COPE Opening Statement of Barbara R. Alexander on Behalf of COPE Local 378
C12-4	Submitted at Oral Hearing March 12, 2014 – CEC Opening Comments on B&V's Rebuttal Testimony, Mark Lowry Dated 12 March 2014
C12-5	Submitted at Oral Hearing March 14, 2014 – COPE 378 Extracted Reference Exhibits For Cross-Examination Of FortisBC Witness Panel No. 2
C12-6	Submitted at Oral Hearing March 17, 2014 - Extracts From FortisBC Electric Final Argument in the 2012-2013 RRA and ISP Proceeding
C12-7	Submitted at Oral Hearing March 17, 2014 - One-Page Petition with 16 Signatures
C12-8	Submitted March 19, 2014 – COPE Undertaking-Hearing Date March 14, 2014 Volume 5, Page 1010, Line 7 to 12

INTERESTED PARTY DOCUMENTS

D-1	IBEW LOCAL 213 MEMBERS (IBEW) Online Registration and Letter Dated July 24, 2013 – Request for Interested Party Status by Rod Russell
D-2	ALLAN, BEVERLY (ALLAN) Letter Dated July 24, 2013 – Request for Interested Party Status by Beverly Allan

LETTERS OF COMMENT

E-1	Johnson, Colby - Letter of Comment dated July 10, 2013
E-2	Fenton,R and Haidenger, T Letter of Comment dated September 9, 2013– Redacted version on web only
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E-13	Wayling, Kirby Letter of Comment dated September 17, 2013– Redacted version on web only
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E-17	Kokiw, D Letter of Comment dated September 22, 2013– Redacted version on web only
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E-73	Lower Columbia Community Development Team Society Letter of Comment dated December 19, 2013 - Redacted version on web only
E-74	Clyde, D Letter of Comment dated January 22, 2014 – Redacted version on web only
E-75	Stuart, B Letter of Comment dated March 14, 2014 – Redacted version on web only

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E-77	Sommerey, R Letter of Comment dated March 14, 2014 – Redacted version on web only
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E-80	MacNeil, M Letter of Comment dated April 15, 2014 – Redacted version on web only
E-81	Diduch Letter of Comment dated April 24, 2014 – Redacted version on web only



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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 \$0.831² 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.

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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 SQLs. 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 SQLs 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 SQLs.	FBC does not have any recommendations for new SQLs or the discontinuation of SQLs 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

2 **1.4 EVALUATION OF THE PBR PLAN**

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

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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.

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customer-funded, and are therefore offset by Contributions in Aid of Construction (CIAC). However, as recognized during the Annual Review for 2017 Rates⁶, 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 Period⁸.

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

Question:

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.

Response:

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.

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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, BCSPSO 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.” (BCSPSO 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 stated¹³:

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.

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- 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-182-16¹⁴:

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 million¹⁵ 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

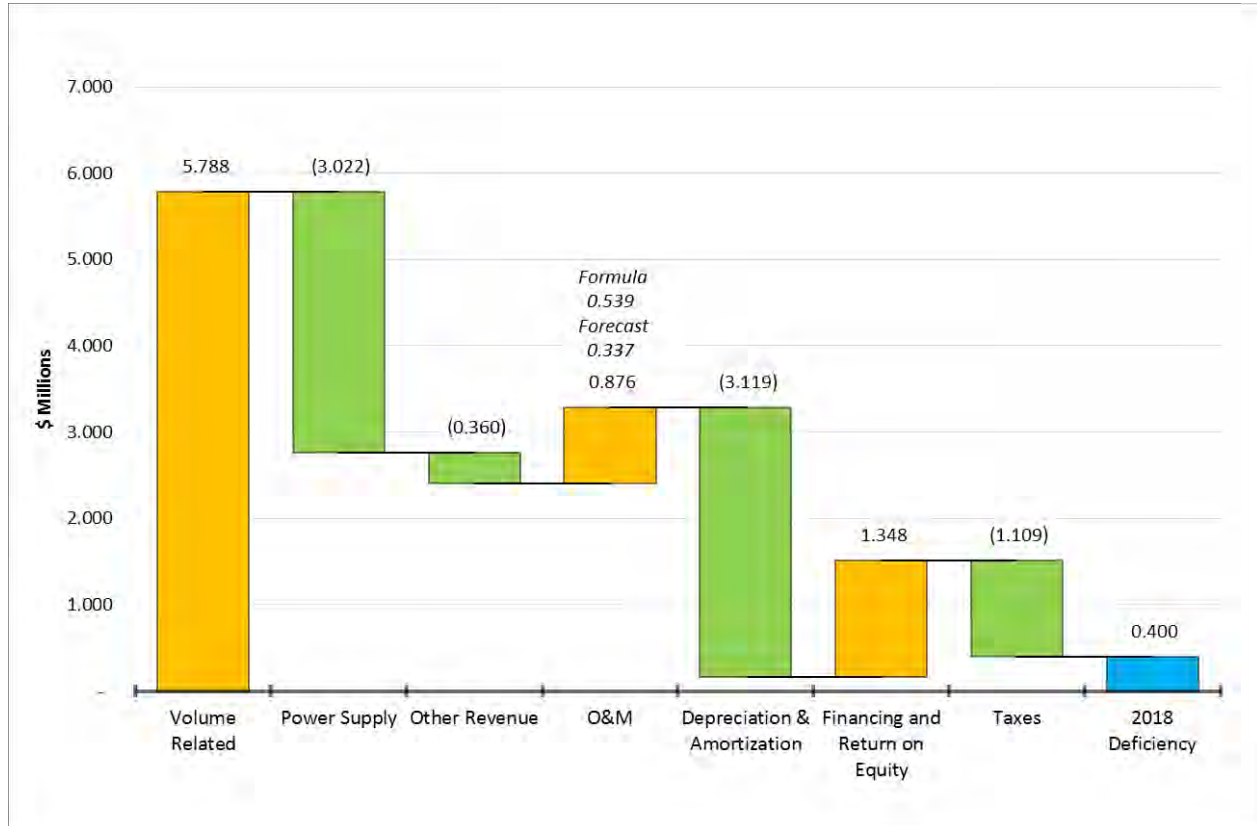
The Company is requesting a rate increase of 0.11 percent for 2018 compared to 2017 rates. The rate increase results from a revenue deficiency of \$0.400 million. The revenue deficiency is due to revenue at existing rates being lower than the forecast cost of service. The forecast cost of service is 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

1 which was fully amortized in 2017, and an increase in deductible temporary differences
2 associated with pensions and OPEBs, partly offset by an overall increase in revenues.

3 **1.6 SERVICE QUALITY INDICATORS (SECTION 13)**

4 FBC's 2016 and June 2017 year-to-date SQI results indicate that the Company's overall
5 performance is representative of a high level of service quality. In 2016, for those SQIs with
6 benchmarks, seven performed at or better than the approved benchmarks with one performing
7 better than the threshold and within the performance range. In 2017 June year-to-date,
8 performance is similar to 2016, with seven of the eight SQIs with benchmarks performing better
9 than the threshold and the one remaining performing better than the threshold and within the
10 performance range. For the three SQIs that are informational only, performance generally
11 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 $[1 + ((AC_{t-1} - AC_{t-2}) / AC_{t-2}) \times 50\%]$.

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 $(1.979 \text{ percent} \times 45 \text{ percent}) + (1.433 \text{ percent} \times 55 \text{ percent}) = 1.679 \text{ percent}$.

1

Table 2-1: I-Factor Calculation

	CANSIM 326-0020 2002=100	CANSIM 281-0063	12-Month Average		Year over Year % Change			PBR Year
	BC CPI Index	BC AWE \$	CPI Index	AWE \$	CPI %	AWE %	I-Factor %	
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

3 **2.2 GROWTH FACTOR CALCULATION SUMMARY**

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

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

1

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

	Customer Count	12 Month Average Customers	AC Factor @50%	PBR Year
Jul-15	130,846	131,662		
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			
Jul-16	132,421	133,317	0.629%	2018
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			

2

3 **2.3 INFLATION AND GROWTH CALCULATION SUMMARY**

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

1

Table 2-3: Summary of Formula Drivers

Line No.	Description	2018
1	<u>Cost Drivers</u>	
2		
3	Customer Growth Factor @ 50%	0.629%
4		
5	<u>Escalators</u>	
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%

2

3

4 In summary, the formula factor for O&M and capital for 2017 is 101.282 percent, calculated as
5 (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 2011¹⁷. 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 available¹⁸, 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.

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Figure 3-1: Total Net Load (GWh)

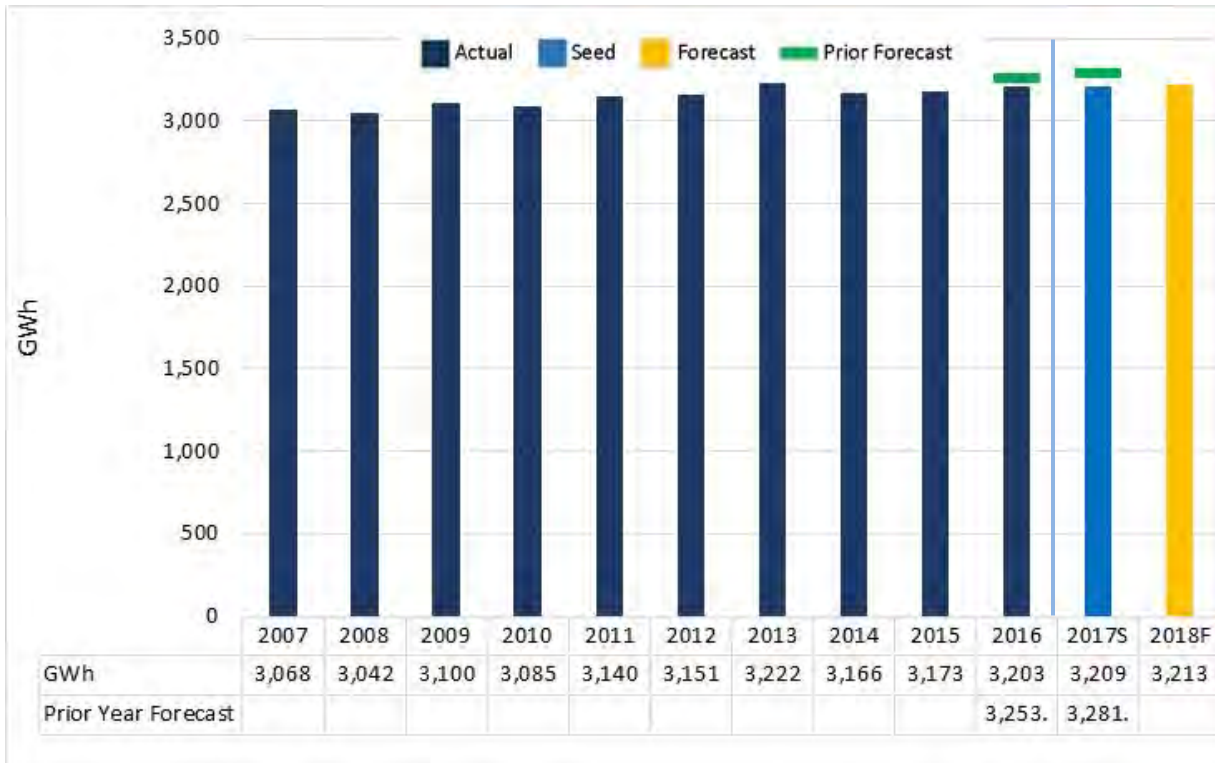


Table 3-3 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2018 the residential customer class is forecast to account for 37 percent of the normalized after-savings gross load.

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

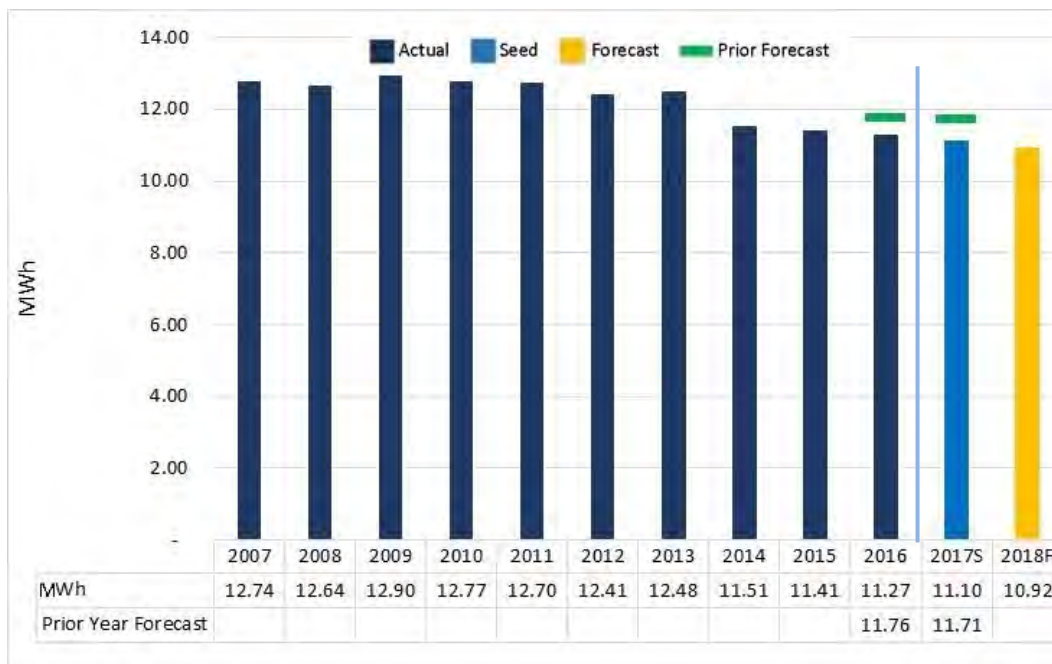
No.	Description	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Energy (GWh)													
1	Residential	1,165	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,290	1,280
2	Commercial	650	661	675	660	657	681	788	866	853	901	908	912
3	Wholesale	878	908	908	895	910	899	675	567	580	574	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
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)

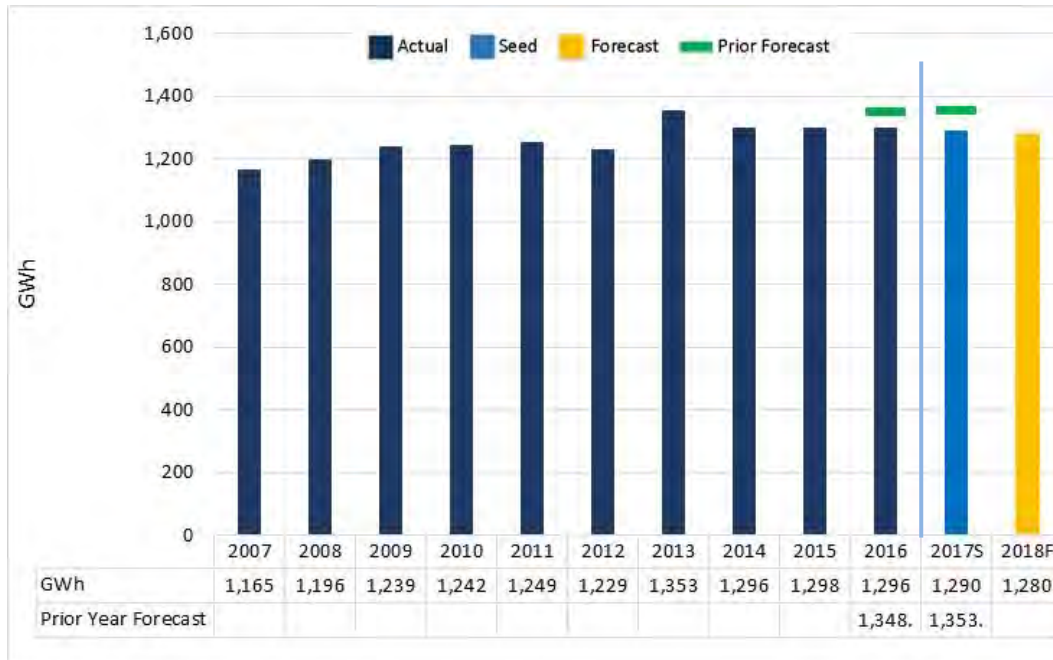


3.5.1.2 Residential Load

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.

1

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



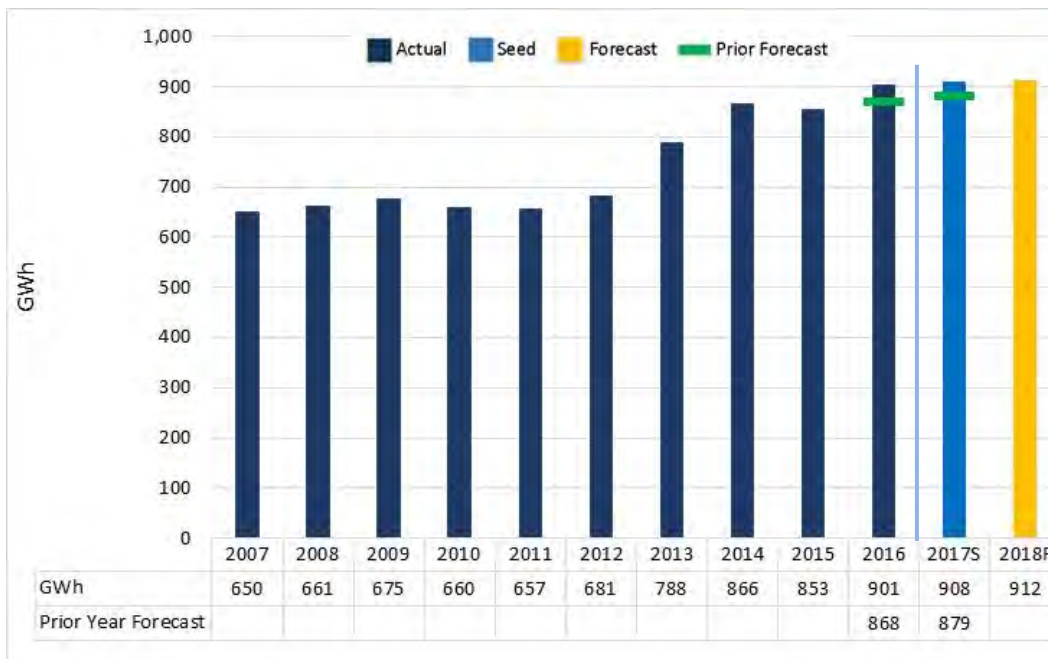
2

3 **3.5.2 Commercial**

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

7

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



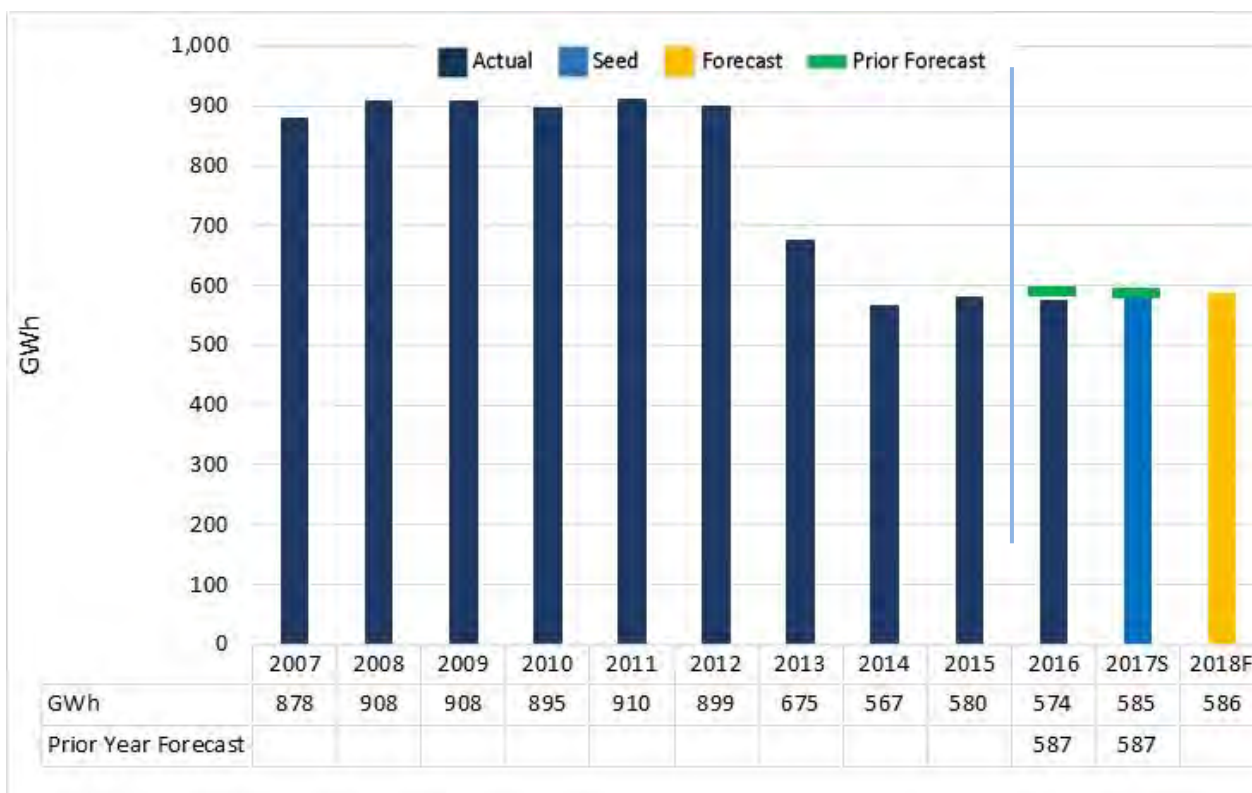
8

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)



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

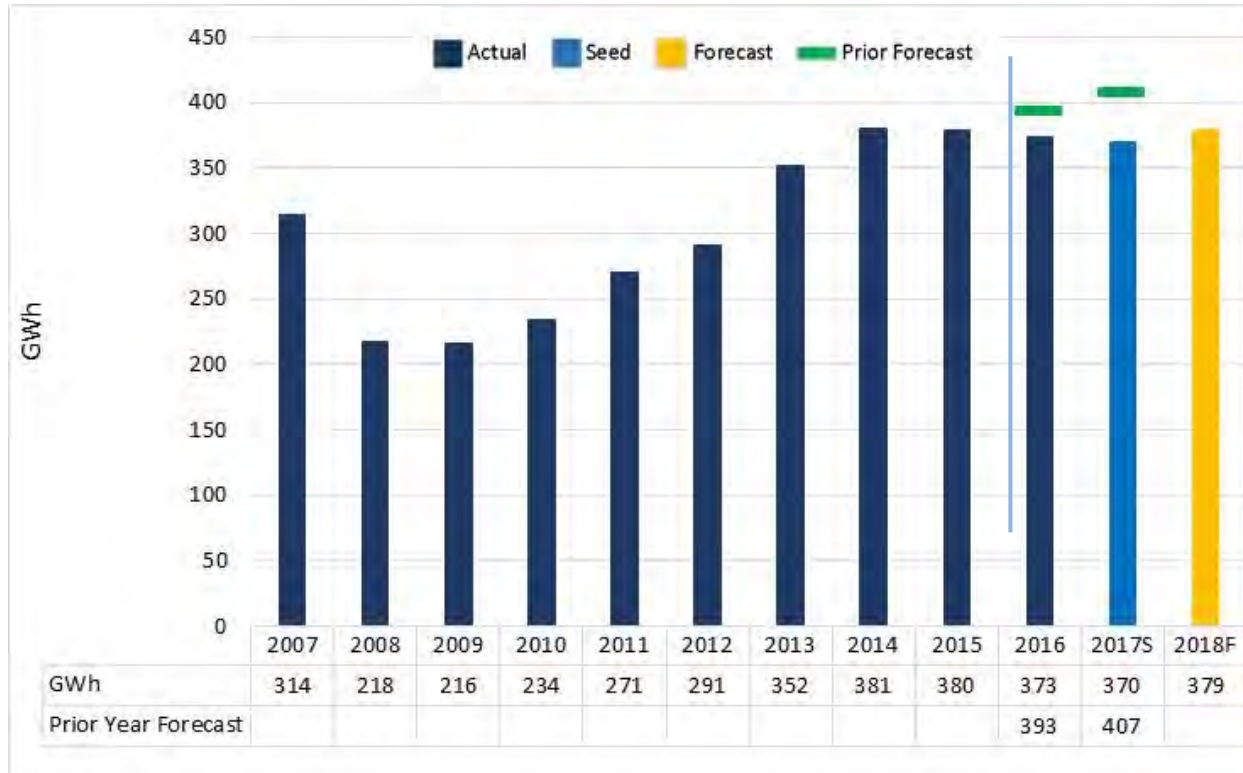
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understanding of what their future energy usage will be. This year FBC received a response from 80 percent (40 of 50) of the surveys sent out. The responding customers represent approximately 89 percent of the total industrial load.

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)

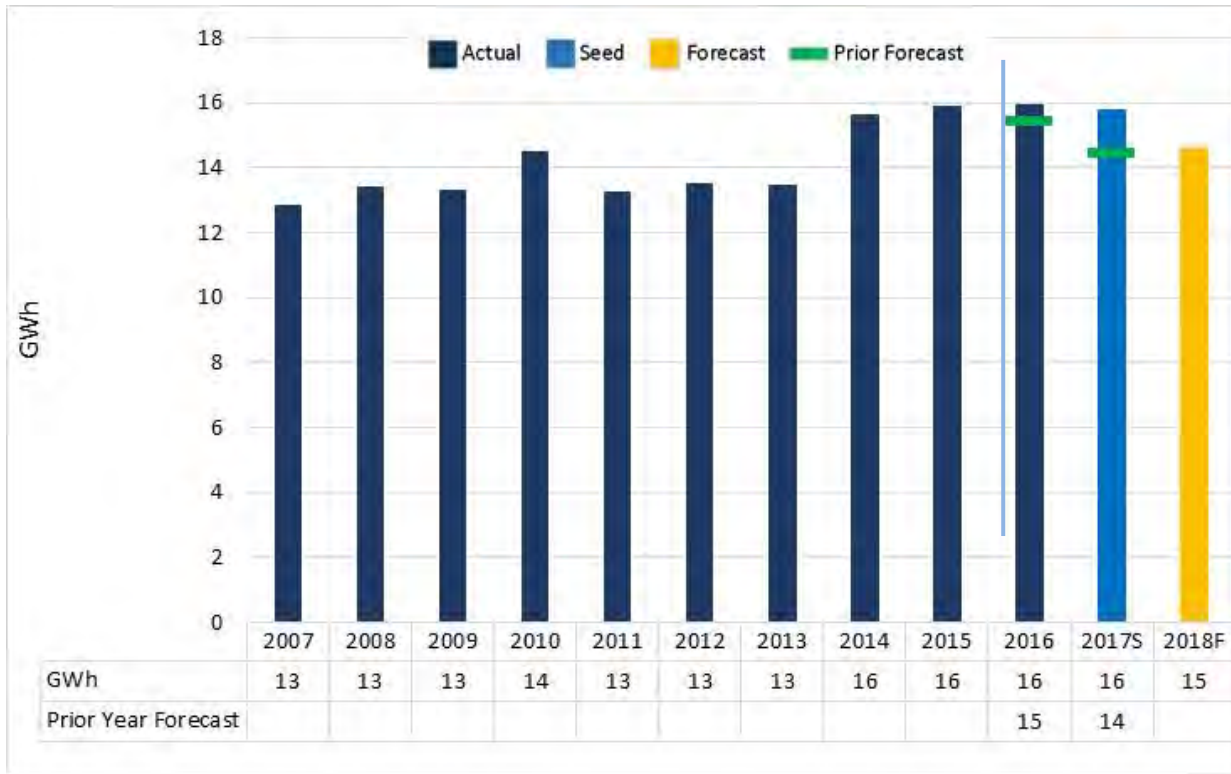


3.5.5 Lighting

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.

1

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

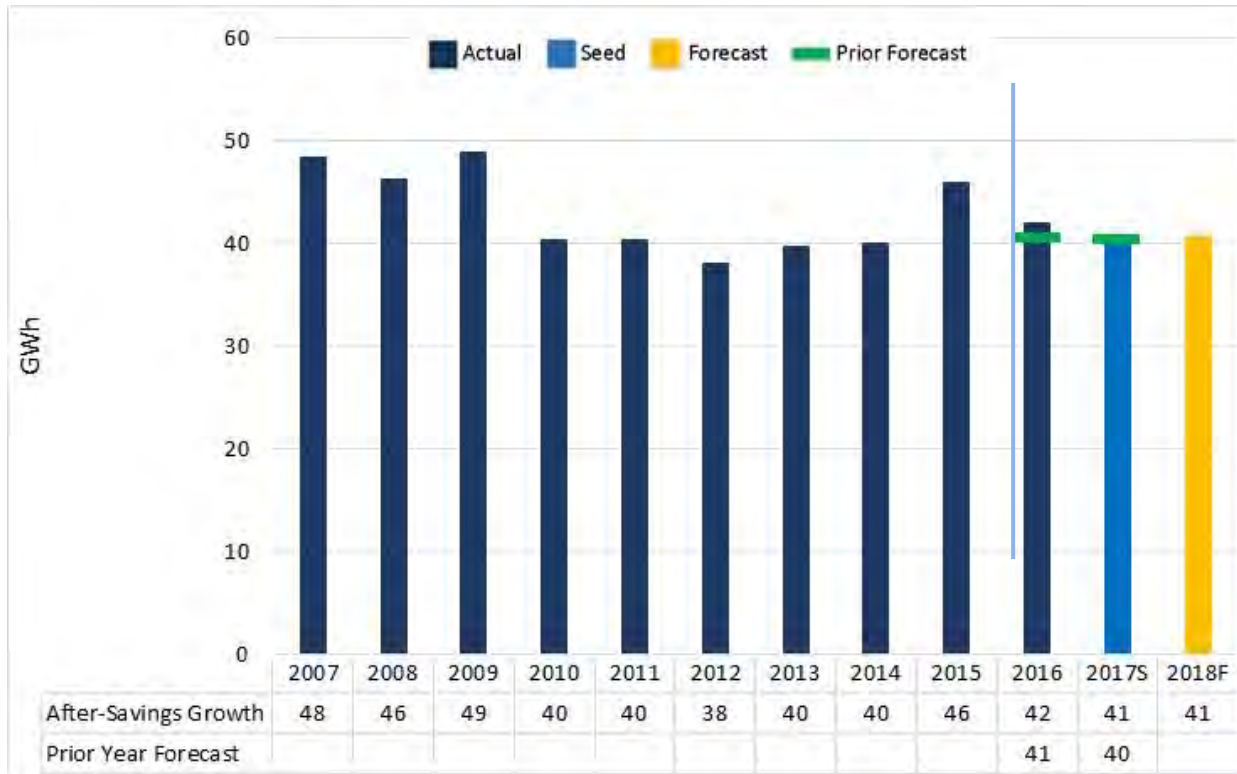


2

3 **3.5.6 Irrigation**

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

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



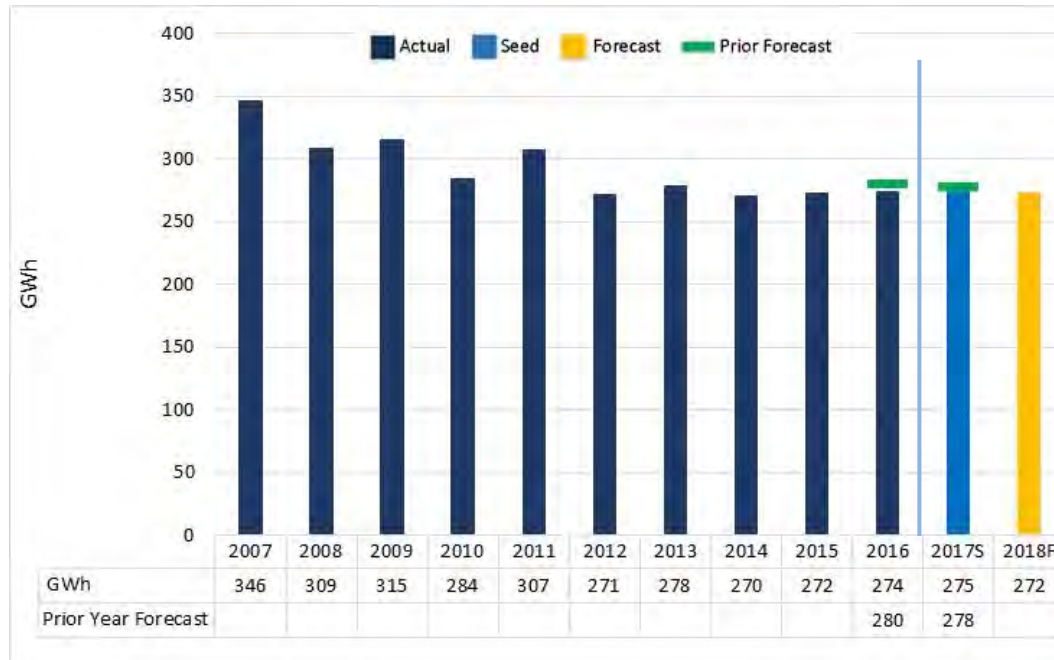
3.5.7 Losses

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)



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.

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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

Line No.	Year	Before AMI			After AMI		
		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)

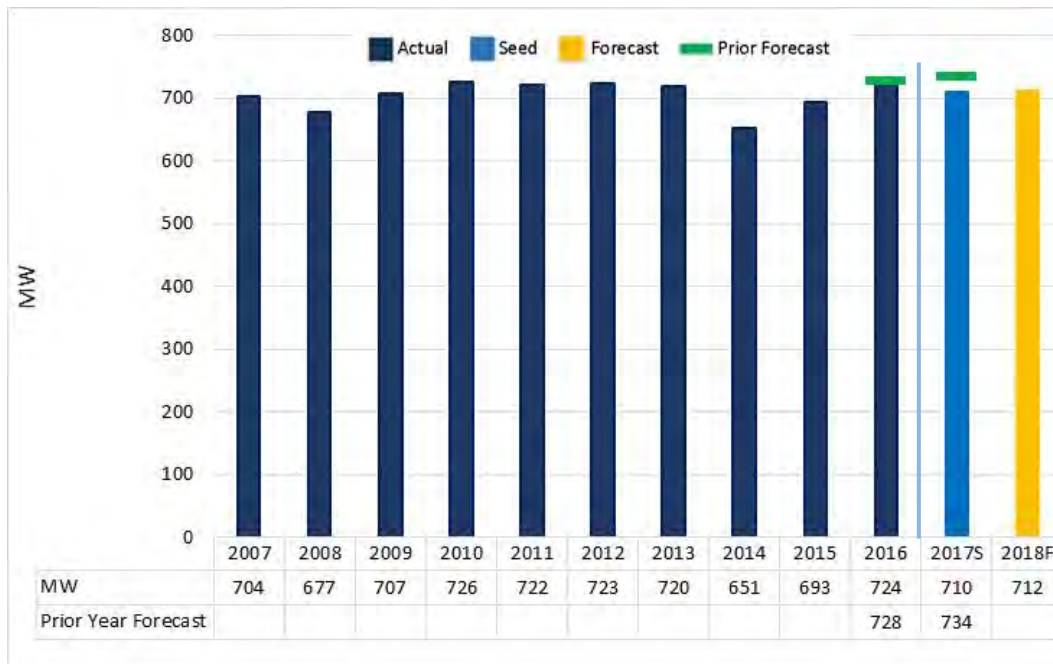
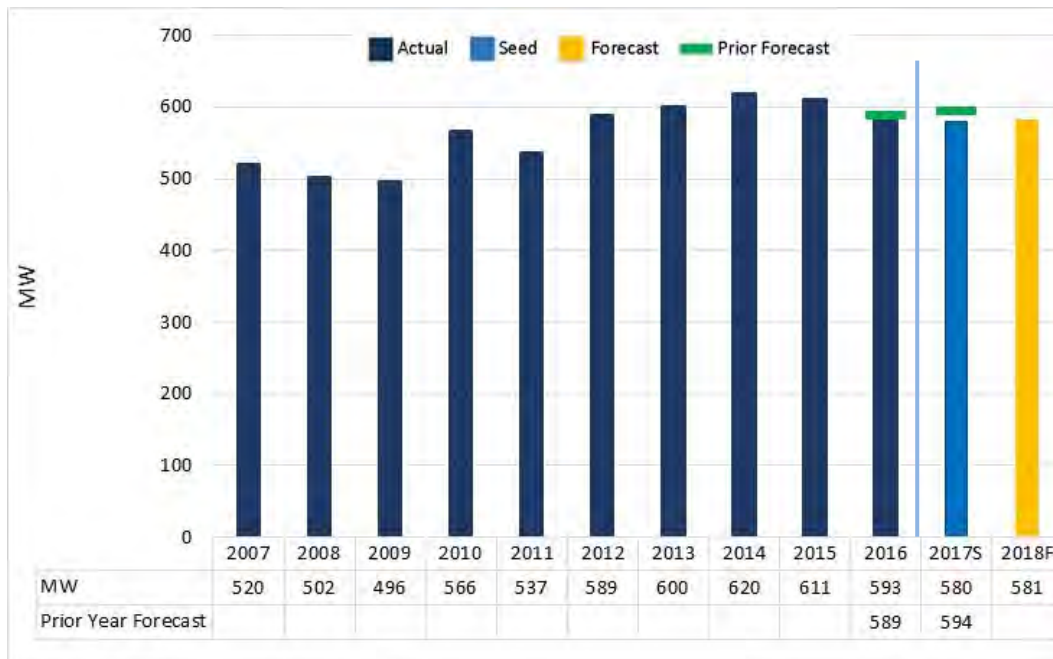


Figure 3-11: After-Savings Summer Peaks (MW)



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 is 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	<u>\$ 151.472</u>	<u>\$ 145.783</u>	<u>\$ 148.450</u>
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 (AECF) with the Commission. The purpose of the AECF 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-6-17²¹.

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 CEPSCA 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	<u>\$ 136.216</u>	<u>\$ 130.437</u>	<u>\$ (5.779)</u>
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	<u>\$ 130.437</u>	<u>\$ 133.071</u>	<u>\$ 2.634</u>
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.

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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, 2018²² 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 CEPSPA. Revenue under the CEPSPA 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	<u>\$ 4.928</u>	<u>\$ 5.017</u>	<u>\$ 5.171</u>

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 ARWA 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 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

Policy²³ 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.

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- 1 variable components. Variances in other revenue are recorded in the Flow-through deferral
- 2 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:

$$2017 \text{ Approved formula O\&M} \times [1 + (\text{I Factor} - \text{X Factor})] \times [1 + (0.5 \times \text{customer growth})]$$

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	<u>\$ 54.764</u>	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	<u>\$ 3.478</u>	<u>\$ 3.418</u>	<u>\$ 3.815</u>

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.

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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	
		Actual	Approved	CPCN ⁽¹⁾	Projected	Approved	CPCN ⁽¹⁾	Forecast	CPCN ⁽¹⁾
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
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)

⁽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

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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&M²⁶.

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.

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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.

1 **6.5 SUMMARY**

2 Overall the increase in Gross O&M Expense from Approved 2017 to 2018 is approximately
3 1.790 percent. The formula-driven O&M is increasing at a rate of 1.282 percent, and forecast
4 O&M is 9.689 percent higher than Approved 2017. The capitalized overhead rate remains
5 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 adjustment²⁷.

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	<u>\$ 47.754</u>	

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	<u>\$ 43.809</u>	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

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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	4 Forecast Capital Expenditures	<u>\$ 5.297</u>	<u>\$ 5.296</u>	<u>\$ 3.945</u>

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 below²⁸.

- 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	<u>\$ 47.754</u>	
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	<u>(2.577)</u>	Section 11, Sch. 5, Line 22
9	Total Regular Additions to Plant	<u>59.656</u>	
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	<u>(5.391)</u>	Section 11, Sch. 5, Line 32
15	Special Projects and CPCN Additions to Plant	<u>25.287</u>	
16			
17	2018 Plant Additions	<u>\$ 84.943</u>	

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.

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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		Approved			Actual			Meter Read to Billing	
		Monthly	Bimonthly	Proportion Billed		Consumption Lag	Proportion Billed		Consumption Lag	Processing Lag	
				Monthly	Bimonthly		Monthly	Bimonthly			
		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											
9		Billing to Collection		Approved			Actual			Approved	Actual
10		Monthly	Bimonthly	Proportion Billed		Clearing Lag	Proportion Billed		Clearing Lag	Total Lag Days	
11		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
12											
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.

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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	<u>\$ 359</u>		<u>\$ 16</u>	46.0	
13						
14	EXPENSES	<u>\$ 260.017</u>		<u>\$ 260.017</u>	(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				<u>\$ 5.272</u>	
21						
22	Cash Working Capital in 2016 Rates				<u>\$ 5.343</u>	2016 Rates Compliance Filing, Section 11, Schedule 14, Line 40
23						
24	Reduction in Cash Working Capital				<u>\$ (0.071)</u>	

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	<u>100.00%</u>	<u>7.97%</u>	<u>\$ (0.006)</u>	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:

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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 No.	Description	Projected		Actual			
		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

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

3
4 FBC continues to monitor uncollectible accounts the same way it always has, through monthly
5 internal reporting, trend analysis, account risk analytics, and a dedicated collections team with
6 assistance from collection agencies when necessary. Some additional changes that have been
7 made in the last few years to ensure potential uncollectible accounts are identified in a timely
8 manner. These include shortening the timeline for sending payment reminder notices, using
9 reminder calls on overdue payments more frequently, and the implementation of AMI meters
10 with the ability to remotely disconnect and reconnect meters. These changes have all resulted
11 in an improvement to collection timelines. It should also be noted that FBC has security
12 deposits in place for all customers with lack of credit history, which could be applied against
13 accounts if determined to be uncollectible.

14 **7.9 SUMMARY**

15 FBC's rate base includes the impact of both formula-driven capital expenditures and those
16 capital expenditures that are forecast outside of the formula and CPCNs and Special Projects,
17 adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts
18 for all of its rate base deferral accounts in its financial schedules in Section 11. Finally, the rate
19 base includes other working capital, composed of customer deposits and loans and other
20 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.

1

Table 8-1: Short Term Interest Rate Forecast³⁰

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.

2

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

12 **8.3.4 Interest Expense Forecast**

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

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

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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	<u>\$ 16.052</u>	<u>\$ 15.888</u>	<u>\$ 16.684</u>
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.

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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.

1 **9.4 SUMMARY**

2 FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing
3 enacted legislation for income taxes and forecast changes for property tax rates and
4 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&M³¹ x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures³²) 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 .

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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
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
11		Sum of Lines 6 - 9
12	Actual/Projected Base O&M	52.872
13		Line 3 - Line 10
14	O&M Subject to Sharing	(1.200)
15		Line 12 - Line 1
16		
17		
18		
19		
20		
21		
22		
23		
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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

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

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

5 **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

7 **10.3 TRUE-UP FOR 2016 ACTUAL EARNINGS SHARING**

8 In FBC's 2016 Annual Report to the Commission, FBC calculated the final 2016 earnings
9 sharing based on the final 2016 results. The final amount of earnings sharing for 2015 was
10 \$0.610 million (after-tax), which was \$0.356 million higher than the \$0.254 million projected for
11 2016 as shown in Table 10-4 below. As a result, FBC is increasing its 2018 earnings sharing by
12 the after-tax amount of \$0.356 million as shown in Table 10-1 above.

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1 **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
2	3 2016 Earnings Sharing Account True-Up	<u>\$ (0.356)</u>	

3 **10.4 SUMMARY OF EARNINGS SHARING**

4 After calculating the 2017 projected earnings sharing and including the adjustments described
5 above, FBC proposes to distribute \$0.831 million to customers in 2018 as a reduction in 2018
6 revenue requirements through amortization of the projected 2018 opening after-tax balance of
7 \$0.615 million in the Earnings Sharing deferral account.

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

1 11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

2

3

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August 10, 2017

Section 11

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

Schedule 1

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%	

FORTISBC INC.

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Section 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 Acquisition Adjustment	5,679	5,493	(186)	
28					
29	Mid-Year Utility Rate Base	\$ 1,285,408	\$ 1,321,793	\$ 36,386	

FORTISBC INC.

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Section 11

**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%	

FORTISBC INC.

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Section 11

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

Schedule 4

Line No.	Particulars (1)	CapEx (2)	Forecast CapEx (3)	Total CapEx (4)	Cross Reference (5)
1	<u>2013</u>				
2	Base	\$ 41,875			
3	<u>2014</u>				
4	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
5	Formula Capex	42,193			
6	<u>2015</u>				
7	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
8	Formula Capex	42,384			
9	<u>2016</u>				
10	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
11	Formula Capex	\$ 42,874			
12	<u>2017</u>				
13	Net Inflation Factor	100.886%			Schedule 3, Line 12, Column 6
14	Formula Capex	\$ 43,254			
15	<u>2018</u>				
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	

FORTISBC INC.

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Section 11

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

Schedule 5

Line No.	Particulars (1)	2018 (2)	Cross Reference (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	<u>\$ 47,754</u>	
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	<u>\$ 29,945</u>	
12			
13	Total Capital Expenditures	<u>\$ 77,699</u>	
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	<u>(2,577)</u>	Schedule 7.1, Line 14, Column 8 - Row 30
23	Gross Capital Expenditures	<u>\$ 59,656</u>	
24	Change in Work in Progress	-	
25	Total Additions to Plant	<u>\$ 59,656</u>	
26			
27			
28	CPCN and Special Projects	\$ 29,945	
29	Add - AFUDC	2,114	
30	Less: Removal costs	<u>(1,381)</u>	
31	Gross Capital Expenditures	<u>30,678</u>	
32	Change in Work in Progress	<u>(5,391)</u>	
33	Total Additions to Plant	<u>\$ 25,287</u>	
34			
35	Grand Total Additions to Plant	<u>\$ 84,943</u>	Schedule 6.1, Line 14 , Columns 5+6

FORTISBC INC.

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Section 11

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

Schedule 6

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	

FORTISBC INC.

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Section 11

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

Schedule 6.1

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			<u>\$ 249,302</u>	<u>\$ 1,597</u>	<u>\$ 19,875</u>	<u>\$ 8,456</u>	<u>\$ (5,880)</u>	<u>\$ 273,350</u>	
13									
14		Total Plant in Service	<u>\$ 1,966,584</u>	<u>\$ 11,268</u>	<u>\$ 25,287</u>	<u>\$ 59,656</u>	<u>\$ (11,064)</u>	<u>\$ 2,051,731</u>	
15									
16		Cross Reference			Schedule 5 Line 33 Column 2	Schedule 5 Line 25 Column 2			

FORTISBC INC.

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Section 11

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

Schedule 7

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			<u>\$ 242,144</u>		<u>\$ 54,914</u>	<u>\$ 4,593</u>	<u>\$ (1,093)</u>	<u>\$ (1,135)</u>	<u>\$ -</u>	<u>\$ 57,278</u>	
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			<u>\$ 470,457</u>		<u>\$ 124,567</u>	<u>\$ 11,345</u>	<u>\$ (860)</u>	<u>\$ (1,606)</u>	<u>\$ -</u>	<u>\$ 133,446</u>	
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			<u>\$ 1,019,763</u>		<u>\$ 267,364</u>	<u>\$ 28,397</u>	<u>\$ (3,231)</u>	<u>\$ (1,110)</u>	<u>\$ -</u>	<u>\$ 291,419</u>	

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Section 11

**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			<u>\$ 270,774</u>		<u>\$ 145,010</u>	<u>\$ 14,141</u>	<u>\$ (5,880)</u>	<u>\$ (107)</u>	<u>\$ -</u>	<u>\$ 153,164</u>	
13											
14	108	Total Accumulated Depreciation	<u>\$ 2,003,138</u>		<u>\$ 591,854</u>	<u>\$ 58,476</u>	<u>\$ (11,064)</u>	<u>\$ (3,958)</u>	<u>\$ -</u>	<u>\$ 635,308</u>	
15											
16		Cross Reference	Schedule 6.1								
17			Line 14								
18			Columns 3+4+5								

FORTISBC INC.

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Section 11

Schedule 8

SCHEDULE NOT APPLICABLE

FORTISBC INC.

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Section 11

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

Schedule 9

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	<u>\$ 118,894</u>	<u>\$ -</u>	<u>\$ 2,207</u>	<u>\$ -</u>	<u>\$ 121,101</u>	

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Schedule 10

SCHEDULE NOT APPLICABLE

FORTISBC INC.

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Section 11

**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	<u>Benefits Matching Accounts</u>								
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		<u>\$ 28,986</u>	<u>\$ -</u>	<u>\$ 7,900</u>	<u>\$ (2,054)</u>	<u>\$ (4,982)</u>	<u>\$ 29,849</u>	<u>\$ 29,417</u>	
8	<u>Other Accounts</u>								
9	Pension and OPEB Liability	(17,541)	-	132	-	-	(17,409)	(17,475)	
10		<u>\$ (17,541)</u>	<u>\$ -</u>	<u>\$ 132</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ (17,409)</u>	<u>\$ (17,475)</u>	
11									
12	Total Rate Base Deferral Accounts	<u>\$ 11,445</u>	<u>\$ -</u>	<u>\$ 8,032</u>	<u>\$ (2,054)</u>	<u>\$ (4,982)</u>	<u>\$ 12,440</u>	<u>\$ 11,942</u>	

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.

FORTISBC INC.

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Section 11

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

Schedule 12

Line No.	Particulars	12/31/17 (2)	Opening Bal./ Transfer/Adj. (3)	Gross Additions (4)	Less Taxes (5)	Amortization Expense (6)	12/31/18 (7)	Mid-Year Average (8)	Cross Reference (9)
	(1)								
1	Deferral Accounts Financed at Short Term Interest Rate								
2									
3	<u>Forecast Variance Accounts</u>								
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		<u>\$ (7,470)</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 7,391</u>	<u>\$ (80)</u>	<u>\$ (3,775)</u>	
8	<u>Benefit Matching Accounts</u>								
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		<u>\$ 675</u>	<u>\$ -</u>	<u>\$ 175</u>	<u>\$ (46)</u>	<u>\$ (475)</u>	<u>\$ 329</u>	<u>\$ 502</u>	
19	<u>Other Accounts</u>								
20	2014-2019 Earnings Sharing Account	\$ (615)	\$ -	\$ -	\$ -	\$ 615	\$ -	\$ (307)	
21		<u>\$ (615)</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 615</u>	<u>\$ -</u>	<u>\$ (307)</u>	
22									
23	Total Deferral Accounts at Short Term Interest	<u>\$ (7,410)</u>	<u>\$ -</u>	<u>\$ 175</u>	<u>\$ (46)</u>	<u>\$ 7,531</u>	<u>\$ 250</u>	<u>\$ (3,580)</u>	
24									
25	Financing Costs at STI	<u>\$ (362)</u>	<u>\$ -</u>	<u>\$ (98)</u>		<u>\$ 362</u>	<u>\$ (98)</u>	<u>\$ (230)</u>	
26									
27	Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term.								

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Section 11

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

Schedule 12.1

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	<u>Benefit Matching Accounts</u>								
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		<u>\$ 1,126</u>	<u>\$ -</u>	<u>\$ 1,125</u>	<u>\$ (280)</u>	<u>\$ (209)</u>	<u>\$ 1,762</u>	<u>\$ 1,444</u>	
12									
13	<u>Other Accounts</u>								
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		<u>\$ 2,855</u>	<u>\$ -</u>	<u>\$ (707)</u>	<u>\$ (226)</u>	<u>\$ -</u>	<u>\$ 1,922</u>	<u>\$ 2,388</u>	
17									
18									
19	Total Deferral Accounts at Weighted Average Cost of Debt	<u>\$ 3,981</u>	<u>\$ -</u>	<u>\$ 418</u>	<u>\$ (506)</u>	<u>\$ (209)</u>	<u>\$ 3,684</u>	<u>\$ 3,832</u>	
20									
21	Financing Costs at WACD	<u>\$ 488</u>	<u>\$ -</u>	<u>\$ 207</u>		<u>\$ (488)</u>	<u>\$ 207</u>	<u>\$ 347</u>	
22									
23	Deferral Accounts Financed at AFUDC								
24									
25	<u>Benefit Matching Accounts</u>								
26	On Bill Financing (OBF) Participant Loans	\$ 8	\$ -	\$ (5)	\$ -	\$ -	\$ 4	\$ 6	
27									
28	Total Deferral Accounts at AFUDC	<u>\$ 8</u>	<u>\$ -</u>	<u>\$ (5)</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 4</u>	<u>\$ 6</u>	
29									
30	Financing Costs at AFUDC	<u>\$ 1</u>	<u>\$ -</u>	<u>\$ 1</u>		<u>\$ (1)</u>	<u>\$ 1</u>	<u>\$ 1</u>	
31									
32	Deferral Accounts Non-Interest Bearing	<u>\$ 50</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 50</u>	<u>\$ 50</u>	
33									
34	Total Non Rate Base Deferral Accounts (including financing)	<u>\$ (3,244)</u>	<u>\$ -</u>	<u>\$ 698</u>	<u>\$ (551)</u>	<u>\$ 7,194</u>	<u>\$ 4,096</u>	<u>\$ 426</u>	

FORTISBC INC.

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Section 11

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

Schedule 13

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)	

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Section 11

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

Schedule 14

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	<u>\$ 365,156</u>		<u>\$ 16,763</u>	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	<u>Operating Labour</u>					
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	<u>\$ 264,240</u>		<u>\$ 10,358</u>	(39.2)	
36						
37	Net Lag (Lead) Days				6.7	
38						
39	Total Expenses			\$ 264,240		
40						
41	Cash Working Capital			<u>\$ 4,850</u>		

FORTISBC INC.

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Section 11

Schedule 15

SCHEDULE NOT APPLICABLE

FORTISBC INC.

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Section 11

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

Schedule 16

Line No.	Particulars	2017 Approved (2)	2018 Forecast			Change (6)	Cross Reference (7)
			at Existing Rates (3)	Revised Revenue (4)	at Revised Rates (5)		
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

FORTISBC INC.

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Section 11

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

Schedule 17

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)	

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Section 11

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

Schedule 18

Line No.	Particulars	2017 Approved Revenue (2)	2018 Forecast			Average Number of Customers (6)	GWh (7)	Cross Reference (8)
			Revenue at Existing Rates (3)	Effective Increase (4)	Revenue at Revised Rates (5)			
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	<u>\$ 362,128</u>	<u>\$ 356,340</u>	<u>\$ 400</u>	<u>\$ 356,740</u>	<u>135,855</u>	<u>3,213</u>	
9								
10	Effective Increase				<u>0.11%</u>			

FORTISBC INC.

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Section 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)	

FORTISBC INC.

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Section 11

**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	<u>2013</u>				
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	<u>2014</u>				
6	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
7	Formula O&M	52,746			
8	<u>2015</u>				
9	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
10	Formula O&M	52,984			
11	<u>2016</u>				
12	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
13	Formula O&M	\$ 53,596			
14	<u>2017</u>				
15	Net Inflation Factor	100.886%			Schedule 3, Line 12, Column 6
16	Formula Capex	\$ 54,071			
17	<u>2018</u>				
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	

FORTISBC INC.

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Section 11

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

Schedule 21

Line No.	Particulars (1)	2017 Approved (2)	2018 Forecast (3)	Change (4)	Cross Reference (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)	

FORTISBC INC.

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Section 11

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

Schedule 22

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	<u>\$ 16,052</u>	<u>\$ 16,684</u>	<u>\$ 632</u>	

FORTISBC INC.

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Section 11

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

Schedule 23

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	

FORTISBC INC.

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Section 11

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

Schedule 24

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)	

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Section 11

**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

FORTISBC INC.

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Section 11

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

Schedule 26

		(\$000s)							
Line No.	Particulars	2017 Approved Earned Return	2018				Earned Return Change	Cross Reference	
			Amount	Ratio	Average Embedded Cost	Cost Component			Earned Return
	(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	<u>\$ 87,237</u>	<u>\$ 1,321,793</u>	<u>100.00%</u>		<u>6.70%</u>	<u>\$ 88,584</u>	<u>\$ 1,348</u>	
6									
7	Cross Reference		Schedule 2 Line 29 Column 3						

FORTISBC INC.

August 10, 2017

Section 11

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

Schedule 27

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			<u>\$ 735,000</u>		<u>\$ 38,203</u>	
10							
11	Average Embedded Cost				<u>5.20%</u>		

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.

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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.

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- 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.

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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 Checklist³³. 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.

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

4 **12.4.1 New Deferral Accounts**

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

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

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

1

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.

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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.

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Item	Consideration	Regulatory Proceeding Costs	2018 Joint Pole Use Audit
IV a)	Address: 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 intervenor 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.

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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.

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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.

1

2

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 directed³⁶

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 reached 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.

1 **Table 12-4: Variances Captured in the Flow-through Deferral Account³⁷**

	FEI	FBC
<u>Delivery Revenues (FEI):</u>		
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
<u>Revenues and Power Supply (FBC):</u>		
Revenue variances	N/A	Flow-through deferral
Power purchase variances	N/A	Flow-through deferral
Water fees variances	N/A	Flow-through deferral
<u>Gross O&M:</u>		
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
<u>Capitalized Overhead:</u>		
Capitalized overhead variances	N/A - no variance	N/A - no variance
<u>Property Tax:</u>		
Property tax variances	Flow-through deferral	Flow-through deferral
<u>Depreciation and Amortization:</u>		
Depreciation variances	Flow-through deferral	Flow-through deferral
Amortization of deferrals	N/A - no variance	N/A - no variance
<u>Other Revenues (FEI)/Other Income (FBC):</u>		
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
<u>Wheeling (FBC)/Transportation costs (FEI):</u>		
Transportation and wheeling variances	Flow-through deferral	Flow-through deferral
<u>Income Tax:</u>		
Income tax variances	Flow-through deferral	Flow-through deferral
<u>Interest Expense/Cost of Debt:</u>		
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

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

3
4 In accordance with the method set out in the table above, the calculation of the 2017 projected
5 Flow-through amount of \$6.215 million credit is shown in Table 12-5 below. To calculate the
6 amount to be distributed to customers, FBC has also included an adjustment for the difference
7 between the projected ending 2016 deferral account debit balance of \$3.078 million embedded
8 in 2017 rates and the actual ending 2016 deferral account debit balance of \$2.191 million, a
9 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.

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

3 **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)

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

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1 of the aforementioned items, the variance between the projected and approved tax timing
2 differences, partially offset by an adjustment between the prior year's tax provision and the
3 actual tax return.

4 A true-up of \$0.886 million between the projected ending 2016 Flow-Through deferral account
5 balance embedded in 2017 rates and the actual ending 2016 deferral account balance is the
6 result of higher revenue on construction work performed for a third party in addition to lower
7 loads in the last half of 2016 due to warmer than normal weather and reduced residential and
8 industrial loads. Similarly, an adjustment to include the difference between the projected and
9 final actual amounts for 2017 subject to flow-through will be recorded in the deferral account in
10 2018 and amortized in 2019 rates.

11 **12.5 SUMMARY**

12 FBC has updated the costs associated with the MRS exogenous event(s) which affect rates in
13 2018 and proved updates on certain accounting related matters. In this section, FBC has also
14 requested approval of five non-rate base deferral accounts and included information on two
15 existing deferral accounts.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

SQLs 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, SQLs 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 SQLs covering safety, responsiveness to customer needs, and reliability. Eight of the SQLs 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 SQLs 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 SQLs, 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 SQL benchmarks and thresholds. Both 2016 and June 2017 year-to-date SQL results indicate that the Company's overall performance is meeting service quality standards. In 2016, for the eight SQLs 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 SQLs 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 SQLs with benchmarks performing at or better than the approved benchmarks and the one remaining SQL, 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%

1
2 In the following sections, FBC reviews each SQI's individual performance in 2016 and 2017.
3 Discussion is also provided for the informational SQIs.

4 **13.2.1 Safety Service Quality Indicators**

5 Emergency Response Time

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

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

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

17 The 2016 result was 97 percent which was better than the benchmark of 93 percent. The June
18 2017 year-to-date result is 93 percent, which meets the benchmark level set at 93 percent. The
19 2017 year-to-date performance has been impacted by two major events: a heavy snowfall on
20 February 6, and a windstorm on May 24. During these two outage events, the high number of
21 trouble calls has contributed to the lower 2017 year-to-date performance versus the same
22 period in 2016.

23 The Company's 2009 to 2016 annual and 2017 year-to-date emergency response time results
24 are provided below. While the results have been relatively consistent, variables such as the

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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:

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

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.

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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

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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%	$(100\% - \text{PA}) * 100$	$=(100\% - 98.82\%) * 100$
Billing Service Quality Indicator ; Target < 5.0		$(\text{Accuracy PA} + \text{Timeliness PA} + \text{Completion PA}) / 3$	$=(0 + 0 + 1.18) / 3$

1

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

4 **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

5

6 **Meter Reading Accuracy**

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

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

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

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

17 **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%

18

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

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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 indicators. 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 SQL, 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:

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

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 Slokan 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

FORTISBC INC.

APPENDIX A1 – STATISTICS CANADA AND CBOC REPORTS



1

Table A1-1: CANSIM Table 326-0020

Government of Canada / Gouvernement du Canada | Canada.ca | Services | Département des Statistiques Canada

Statistics Canada

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Table 326-0020^{2,3}
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 ^{1a}	All-items	Food ^{1b}	Shelter ^{1c}	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

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FORTISBC INC.

APPENDIX A1 – STATISTICS CANADA AND CBOC REPORTS



1

Table A1-2: CANSIM Table 281-0063

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Departments

Statistics Canada

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Table 281-0063

31-33, 33-33, 33-34

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

Data table

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

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Geography = British Columbia

Estimate = Average weekly earnings including overtime for all employees (dollars)¹

North American Industry Classification System (NAICS) ³¹	Industrial aggregate excluding unclassified businesses [11-91N] ^{31,32}	Goods producing industries [11-33N] ³¹	Forestry, logging and support [11N] ³²	Mining, quarrying, and oil and gas extraction [21]	Utilities [22]	Construction [23]	Manufacturing [31-33]	Service-producing industries [41-91] ³²
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 ^a	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 ^a	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	1,191.25 ^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	1,682.37 ^a	1,121.94 ^a	1,093.56 ^a	889.97 ^a
2017 May	939.99 ^a	1,176.34 ^a	1,186.44 ^a	1,859.52 ^a	1,778.63 ^a	1,127.34 ^a	1,091.63 ^a	894.20 ^a

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FORTISBC INC.

APPENDIX A1 – STATISTICS CANADA AND CBOC REPORTS

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

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APPENDIX A2
LOAD FORECAST TABLES

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.



APPENDIX A2

LOAD FORECAST TABLES

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and all other savings (RCR¹, CIP², AMI³, 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



APPENDIX A2
LOAD FORECAST TABLES

1 **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

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3 **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

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5 **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

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APPENDIX A2
LOAD FORECAST TABLES

1 **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

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3 **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

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APPENDIX A2
LOAD FORECAST TABLES

1 **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

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3 **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

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APPENDIX A2
LOAD FORECAST TABLES



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

APPENDIX A2
LOAD FORECAST TABLES



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 LOSSES⁴

Energy (GWh)	2012	2013	2014	2015	2016	2017S	2018F
Demand 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.

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LOAD FORECAST TABLES



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.

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LOAD FORECAST TABLES



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.



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LOAD FORECAST TABLES

1 **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%

2

3

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%

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LOAD FORECAST TABLES

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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LOAD FORECAST METHODS

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 year¹. 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 R² 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.

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LOAD FORECAST METHODS

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: Irrigation 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

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.

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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.

$$\text{Normalized Energy}_t = \text{Energy}_t - \text{HDD Slope}_t \times (\text{HDD}_t - \text{Normal HDD}_t)$$

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

and

$$\text{Normalized Energy}_t = \text{Energy}_t - \text{CDD Slope}_t \times (\text{CDD}_t - \text{Normal CDD}_t)$$

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

$$\text{After Savings Load}_t = \text{Before Savings Load}_t - \text{Savings}_t$$

1.2.1 Residential

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

$$\text{Before Savings Load}_t = \text{UPC}_t \times \text{Average Customer Count}_t$$

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

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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:

$$\text{Average Customer Count}_t = 0.5 \times (\text{Year End Customer Count}_{t-1} + \text{Year End Customer Count}_t)$$

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

$$\text{Year End Customer Count}_{t-1} = \text{Prior Year Actual}$$

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

$$\text{Year End Customer Count}_t = b_0 + b_1 \times \text{Population}_t$$

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

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1.2.2 Commercial

The expected before-savings commercial load in year t was forecast based on the provincial GDP supplied by the CBOC⁴. The relationship was estimated from the following equation.

$$\text{Before Savings Load}_t = b_0 + b_1 \times \text{GDP}_t + b_2 \times \text{Princeton Event}_t + b_3 \times \text{CoK Event}_t$$

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 b_0 , b_1 , b_2 , and b_3 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.

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LOAD FORECAST METHODS

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



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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

FORTISBC INC.

APPENDIX B – PRIOR YEAR DIRECTIVES

Decision No.	Directive No. or Page No.	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

FORTISBC INC.

APPENDIX B – PRIOR YEAR DIRECTIVES

Decision No.	Directive No. or Page No.	Reference	Description / Details	Status	Section in this Application
G-107-15 – FBC ANNUAL REVIEW FOR 2015 RATES					
6.	15	n/a	<i>Advanced Metering Infrastructure (AMI) Theft Reduction</i> 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	<i>Capital Expenditures Exceeding the Deadband</i> 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	<i>Ruckles Substation Rebuild Project:</i> 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

FORTISBC INC.

APPENDIX B – PRIOR YEAR DIRECTIVES

Decision No.	Directive No. or Page No.	Reference	Description / Details	Status	Section in this Application
9.	21	6	<i>Upper Bonnington Old Units Refurbishment Project:</i> 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 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 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	<i>Telephone Abandon Rate:</i> 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 indicators.	Completed	Section 13.2.2
11.	30	8	<i>Uncollectible Accounts:</i> 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	<i>Advanced Metering Infrastructure Radio-Off Report:</i> 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

APPENDIX C

FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

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.



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FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

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



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FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

1 estimate for the conversion. FBC and Interfor have reached an agreement whereby FBC will
2 contribute a portion of Interfor's costs of conversion.

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

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

12 **1.3.2 Procurement**

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

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

17 An RFQ for the station construction was issued to four vendors for competitive quotes on June
18 6, 2017. Contractor estimates have been reviewed and the contract was awarded on July 14,
19 2017 to Martech Electrical Systems Ltd.

20 **1.3.3 Environmental Planning**

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

24 **1.3.4 Permits and Approvals**

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

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

APPENDIX C

FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

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.

APPENDIX C

FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

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.



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FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

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.



APPENDIX C

FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

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.

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FBC RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

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

APPENDIX D
FBC UBO REFURBISHMENT PROJECT STATUS REPORT



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.

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FBC UBO REFURBISHMENT PROJECT STATUS REPORT



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.

APPENDIX D
FBC UBO REFURBISHMENT PROJECT STATUS REPORT



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 4², 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.

APPENDIX D
FBC UBO REFURBISHMENT PROJECT STATUS REPORT



1.4.2 Construction and Commissioning

During the demolition of the UBO switchgear structure, FBC was required to construct a containment area to manage silica 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.

APPENDIX D

FBC UBO REFURBISHMENT PROJECT STATUS REPORT



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			

APPENDIX D
FBC UBO REFURBISHMENT PROJECT STATUS REPORT



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		

1

2 **2.1 SCHEDULE PERFORMANCE TO DATE**

3 Engineering has been progressing favourably, and is largely completed, with the exception of
4 integration engineering and commissioning documentation. The majority of the procurement is
5 now complete as most contracts are now in place and expected delivery dates are on-schedule.
6 Many of the supply agreements are for all four units in order to standardize equipment.

7 The dismantling of Unit 3 began as scheduled at the end of June 2017. FBC prepared the unit
8 for handover to Voith Hydro for the generator rewind. In July 2017, Voith started work on the
9 rewind and FBC began removal of old equipment and installation of new equipment. This work
10 is expected to be completed in early October 2017.

11 Demolition of the old switchgear structure was substantially completed in March 2017, with the
12 remaining section to be demolished in Q3 2017.

13 **2.2 SCHEDULE PROJECTION GOING FORWARD**

14 For the remainder of 2017, engineering resources will be focused on providing construction and
15 commissioning support for Unit 3, updating documentation from Unit 3 for use on Unit 4,

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FBC UBO REFURBISHMENT PROJECT STATUS REPORT



1 finalizing the condition assessment report for Unit 4, and creating performance and technical
2 specifications for Unit 4 that were not needed for Unit 3.

3 FBC expects to complete these items prior to year-end, slightly ahead of schedule.

4 The outstanding procurement items were identified in section 1.3.2. The procurement of the
5 generator step-up transformer for Unit 1 is also ahead of schedule.

6 Construction for Unit 3 remains on target. Reassembly is expected to begin in September 2017,
7 with unit alignment completed in early October 2017. Commissioning is expected to begin in
8 October 2017 and be complete by mid-December 2017. FBC expects to return Unit 3 to service
9 December 13, 2017.

10 Construction for the remaining units is scheduled as follows:

- 11 • Unit 4: February 2018 – November 2018
- 12 • Unit 2: February 2019 – November 2019
- 13 • Unit 1: February 2020 – November 2020
- 14 • Plant wrap-up: December 2020 – April 2021

15 **2.3 SCHEDULE DIFFICULTIES AND VARIANCES**

16 Based on progress to date, FBC has advanced the dismantling start date for the remaining units
17 from March, as originally scheduled, to February of the respective year in order to provide
18 additional schedule contingency. The project schedule remains on target.

19 **2.4 PROJECT SCOPE CHANGE SUMMARY**

20 Throughout detailed engineering, FBC has made minor adjustments in order to address some
21 unforeseen challenges and issues. These adjustments do not represent significant scope
22 deviations and do not have a major financial or schedule impact.

23 Any engineering deviations from the original scope are captured and documented through
24 FBC's change management procedures.

25 Scope changes to date include floor modifications for removal and disposal of asbestos and
26 other minor issues identified during demolition of the old switchgear structure, and the
27 requirement for one additional tail race gate in order to work through high tail water during
28 freshet, at an aggregate cost of approximately \$0.115 million. The overall project schedule is
29 not affected.



APPENDIX D
FBC UBO REFURBISHMENT PROJECT STATUS REPORT

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	Percentag e 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



APPENDIX D
FBC UBO REFURBISHMENT PROJECT STATUS REPORT

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentag e 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%	

1

2 In summary, the total project forecast remains per the original budget. While there are instances where forecast costs are higher than
3 budgeted, they have been offset by reductions in contingency and forecast removal costs.

4

APPENDIX D
FBC UBO REFURBISHMENT PROJECT STATUS REPORT



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.

APPENDIX D

FBC UBO REFURBISHMENT PROJECT STATUS REPORT



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

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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

FORTISBC INC.

BRITISH COLUMBIA UTILITIES COMMISSION ORDER G-220-13 COMPLIANCE FILING
REPORT ON RADIO-OFF AMI METER OPTION PARTICIPATION AND COSTS



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FORTISBC INC.

BRITISH COLUMBIA UTILITIES COMMISSION ORDER G-220-13 COMPLIANCE FILING
REPORT ON RADIO-OFF AMI METER OPTION PARTICIPATION AND COSTS



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

FORTISBC INC.

BRITISH COLUMBIA UTILITIES COMMISSION ORDER G-220-13 COMPLIANCE FILING
REPORT ON RADIO-OFF AMI METER OPTION PARTICIPATION AND COSTS



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.

FORTISBC INC.

BRITISH COLUMBIA UTILITIES COMMISSION ORDER G-220-13 COMPLIANCE FILING
REPORT ON RADIO-OFF AMI METER OPTION PARTICIPATION AND COSTS



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.

FORTISBC INC.



BRITISH COLUMBIA UTILITIES COMMISSION ORDER G-220-13 COMPLIANCE FILING
REPORT ON RADIO-OFF AMI METER OPTION PARTICIPATION AND COSTS

1 With the stabilization of Radio-off Option customer counts experienced in the three months
2 ending in August 2016, finalized manual meter reading routes have been created to maximize
3 efficiencies. Average monthly costs during the period of June to August 2016 were \$25,800 per
4 month.

5 **2.3 *MANUAL METER READING REVENUE***

6 Radio-off Option manual meter read fee revenues collected under Electric Tariff Rate Schedule
7 81 were \$42,000 in 2015 and are \$180,400 to date in 2016.

8 During the three months ending in August 2016, total Radio-off manual meter reading fee
9 revenue was \$74,900.

FORTISBC INC.

BRITISH COLUMBIA UTILITIES COMMISSION ORDER G-220-13 COMPLIANCE FILING
REPORT ON RADIO-OFF AMI METER OPTION PARTICIPATION AND COSTS



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



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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 intervenor registration, one round of information requests, a workshop, FBC's 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;

Order G-xx-xx

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