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August 8, 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)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-139-14 (the PBR Plan)

Annual Review for 2017 Rates

In accordance with the PBR Plan and Commission Order G-139-15 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2017 Rates Application materials.

Should further information be required, please contact Joyce Martin at 250-368-0319.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to FBC's Annual Review for 2016 Rates Proceeding

FORTISBC INC.

Multi-Year Performance Based Ratemaking Plan

for 2014 through 2019

Annual Review for 2017 Rates

Volume 1 - Application

August 8, 2016

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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 third annual review of the PBR Plan and set FBC's rates for 2017.

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, any 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 2016 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. Overall, FBC proposes to distribute $0.344[2] million in earnings sharing to customers in 2017. FBC has achieved these savings while maintaining an overall high level of service quality as indicated by the results of the Service Quality Indicators (SQIs) approved in the PBR Decision.

The proposed rates for 2017 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 3.60 percent increase over 2016 rates. This equates to an increase of $4.49 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 2016. This is followed by a summary of FBC's proposed revenue requirement and rate changes for 2017 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 2016 estimated earnings sharing and adjustments related to 2015 actuals.
[3] Based on a Residential customer using approximately 12,000 KWh per year.

1. Permanent rates for all customers effective January 1, 2017, resulting in a general increase of 3.60 percent compared to 2016 rates, to be applied to all components of rates for all customer classes.
2. The creation of five non-rate base deferral accounts for the following regulatory proceedings to be financed at FBC's short term interest rate, as described in Section 12.4.1 of the Application:
   - Self-Generation Policy Stage II Application;
   - Net Metering Program Tariff Update Application;
   - BCUC Residential Inclining Block Report;
   - 2017 Demand Side Management Expenditure Schedule; and
   - Transmission Tariff Review.
3. Amortization of the Celgar Interim Period Billing Adjustment deferral account in 2017 as described in Section 12.4.2 of the Application; and
4. Z-factor treatment for the 2017 incremental O&M and capital expenditures related to the Mandatory Reliability Standards (MRS) Assessment Report No. 8, as described in Section 12.2 of the Application.

FBC also requests, pursuant to section 44.2(3), acceptance of a capital expenditure schedule consisting of the capital expenditures for:

1. The Ruckles Substation Rebuild project as described in Appendix C; and
2. The Upper Bonnington Old Units Refurbishment project, as described in Appendix D.

A draft order is included in Appendix E.

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:

1 **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
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
4	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers.	Sections 6.3.4, 7.2.2 and 12.2
5	Review of the Companies' performance with respect to SQIs. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service.	Section 13
6	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs.	FBC does not have any recommendations for new SQIs or the discontinuation of SQIs at this time
7	Assess and make recommendations to the Commission on the scope for future Annual Reviews.	FBC does not have any recommendations at this time

Item	Description	Response or Reference
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.	Deadband was not exceeded for 2015 and is not forecast to be exceeded for 2016.

1.4 EVALUATION OF THE PBR PLAN

FBC is projecting to realize savings in O&M expenditures. FBC's capital expenditures continue to be above the capital formula amount. Overall, the savings achieved result in $0.344 million of earnings sharing that will be returned to customers in 2017, 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 2016, FBC is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $0.803 million lower than the formula amount, representing approximately a 1.5 percent savings. The expected savings, which are in addition to savings embedded in formula O&M by way of the productivity improvement factor, are a result of the Company applying a broad based focus on productivity. While some of the savings are one-time in nature (such as delays in filling vacancies), 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.

1.4.2 Initiatives Undertaken

The following is a discussion of some efficiency and cost savings initiatives that FBC has underway in 2016.

1. ***Sharing of Gas and Electric Contact Centre Staff***
   In 2016, FBC continued to leverage gas and electric contact centre staff to achieve three goals: to maintain or improve service levels to customers, to provide learning and development opportunities for staff, and to reduce operating costs. Integration occurred in two main areas - electric customer service calls and gas billing error correction.

   <u>Electric Customer Service Calls</u>

   As of June 30, to date in 2016, staff in the Prince George contact centre answered approximately 3,200 electric calls, reflecting about 3 percent of the total electric calls received. Although this reflects a relatively small percentage of the total electric calls, use of the Prince George staff reduced the need for staffing at peak times at FBC's Trail contact centre and at the same time ensured that service levels were met. The Prince George staff can answer these calls when there are lower volumes in the gas customer service queue. As a result of this change, Prince George staff had an opportunity to learn more about the electric operations and to have more diverse work. Six fewer Customer Service Representatives (CSRs) are required as compared to having all calls answered in Trail, while maintaining service levels to customers.

Gas Billing Error Corrections

In 2015, six billing analyst roles that were vacant in FEI's Burnaby office were filled by FBC in its Trail office, providing a new opportunity for the six CSRs no longer required as a result of the changes described above. These employees have been in customer service for many years handling customer service calls and billing work related to electric bills. In the ten years since the Trail contact centre opened, there have been very few development opportunities available there and the integration of this work provided a development opportunity for employees in Trail. In 2016, the Trail employees that are performing the gas billing work have been able to find efficiencies in the work and maintain service levels that were in place prior to the transition.

In total, the integration of activities is forecast to produce annual savings for FBC in the amount of $0.317 million.

2. *Training and Development*

The Training and Development Initiative was implemented in 2015 and introduced a company-wide process that improves the ability of the Company to plan and track required training activities, ensuring skills requirements for employee training are addressed efficiently and effectively. All departments are now able to evaluate more effectively the training requirements specific to their group. Further work is being undertaken in 2016 to refine training and competency requirements for individual roles. There are no O&M savings anticipated.

3. *Other Initiatives*

Other initiatives undertaken include:

- Combining the design of service connections for gas and electric customers under one management structure which allows for a better customer experience in the combined service territory and will facilitate customers' ability to construct their projects.
- Improvement of geographic information system (GIS) and the supervisory control and data acquisition (SCADA) system updates.
- Implementation of a new System Control Centre (SCC) phone system to provide for better call handling and improved efficiency.

- Addition of new distribution-focused Load Desk Operators in the SCC to increase productivity by issuing permit and protection guarantees for work without delay.
- The SCC assuming management responsibility for the former City of Kelowna distribution system, which to date has been locally managed, providing for greater consistency throughout all districts.

1.4.3 Overview of Capital Expenditures

FBC is projecting that capital expenditures will be above the formula in 2016. Projected 2016 capital expenditures excluding items forecast outside of the PBR capital formula are $3.142 million higher than the formula amount. This is primarily attributable to a forced relocation of transmission and distribution infrastructure due to the widening of Highway 97 near Kelowna by the Ministry of Transportation and Infrastructure. FBC anticipates that it will continue to be challenged to meet its capital formula for the remainder of the term of the PBR Plan.

1.4.4 Summary

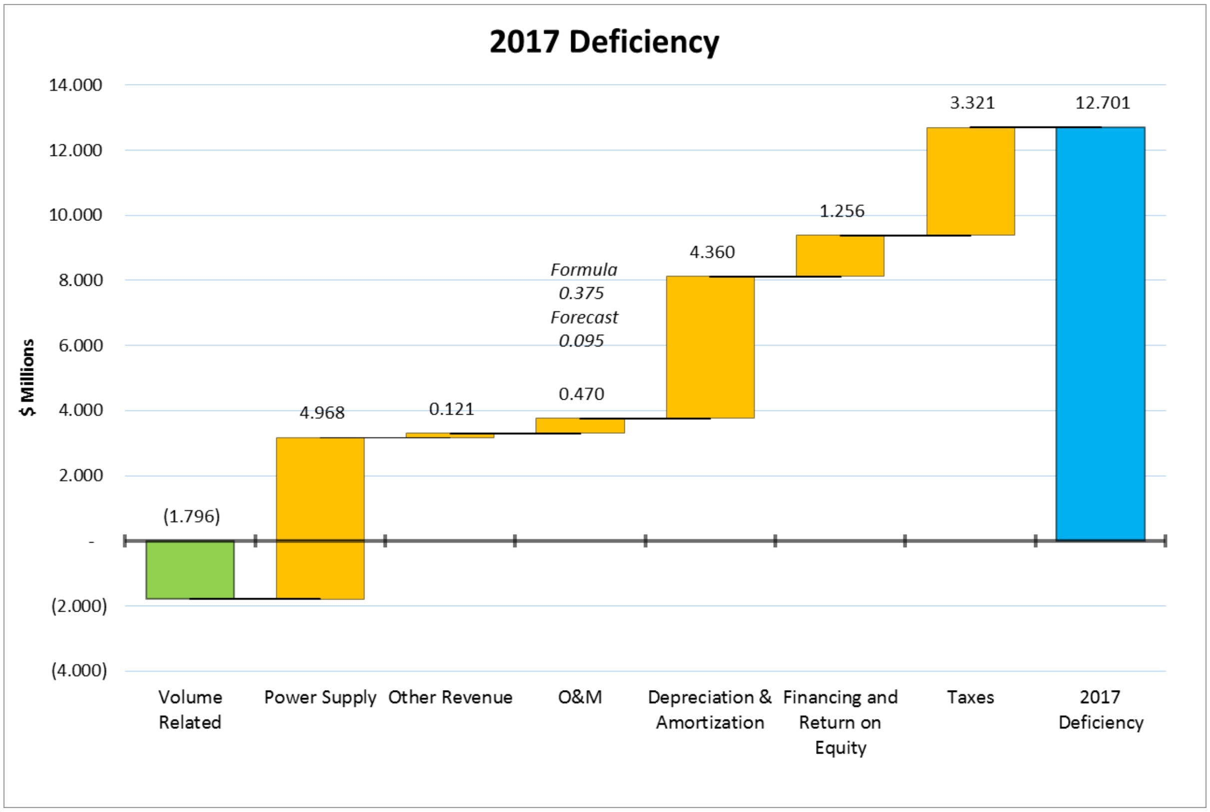
In summary, FBC's experience in 2014 through 2016 has resulted in the realization of earnings sharing on O&M. The first three years of PBR have also shown the challenges of the capital expenditure formula.

1.5 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2017*

The Company is requesting a rate increase of 3.60 percent for 2017 compared to 2016 rates. The rate increase results from a revenue deficiency of $12.701 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 2017 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the 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: 2017 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Load Forecast (Section 3)

In 2017, sales load is forecast to increase by 20 GWh from 2016 due to increased loads for all customer classes with the exception of residential, for which load is lower as a result of lower than forecast customer growth. Based on 2016 rates, FBC's 2017 revenue forecast at existing rates is $352.389 million.

1.5.2 Power Supply (Section 4)

Power Supply expense is forecast to increase in 2017 by $4.968 million, primarily due to higher gross load, and increases to the Brilliant, Waneta Expansion and BC Hydro contract rates.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to decrease in 2017 by approximately $0.121 million, primarily due to reduced connection fees resulting from lower than forecast customer additions, partially offset by higher apparatus and facilities rental revenue due to rate escalation.

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 2017, the formula incorporates an inflation factor (I Factor) of 1.399 percent, a productivity improvement factor (X Factor) of 1.03 percent and a customer growth factor of 0.483 percent for a total increase in formula O&M of 0.854 percent. O&M forecast outside of the formula is $0.095 million higher than Approved 2016. Overall the increase in Gross O&M Expense from 2016 to 2017 is 1.0 percent. The increase in net O&M expense is $0.470 million.

1.5.5 Depreciation and Amortization (Section 7)

Depreciation expense has increased by $1.693 million as a result of additions to rate base. Amortization expense increased by $2.667 million, primarily due to amortization of the Celgar Interim Period Billing Adjustment and the 2016 Flow-through deferral account, partially offset by lower amortization expense related to the pension and OPEB expense variance and amortization of the remaining credit balance in the 2014 Interim Rate Variance deferral account. In total, the 2017 forecast depreciation and amortization expense is higher than 2016 Approved by $4.360 million.

1.5.6 Financing and Return on Equity (Section 8)

FBC has forecast an issuance of long-term debt of $100 million during October 2016, at a forecast rate of 4.0 percent for a term of 30 years, which has been embedded into the long-term 2017 interest expense forecast. FBC is forecasting a short-term debt rate for 2017 of 7.55 percent, an increase from the 2.65 percent rate embedded in the 2016 approved rates due to a lower forecast balance of draws on credit facilities. Overall, interest expense is forecast to increase from 2016 approved by $1.282 million.

2017 rate base is forecast to be slightly lower than 2106 Approved, due to a lower opening plant in service. This reduces the equity return by $0.025 million. In calculating 2017 rates, FBC has utilized its 2016 approved capital structure and return on equity of 40 percent and 9.15 percent, respectively. FBC will update its 2017 rate calculations once a decision is reached in the 2016 FEI 2016 Cost of Capital proceeding.

1.5.7 Taxes (Section 9)

Property taxes are forecast to increase 4.2 percent or $0.645 million from 2016 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 2016. Income taxes are forecast to increase in 2017 by $2.676 million primarily due to an increase in amortization of deferrals and a decrease in deductible temporary tax timing differences associated with capital cost allowance as compared to depreciation.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC's 2015 and June 2016 year-to-date SQI results indicate that the Company's overall performance is meeting service quality standards. In 2015, for those SQIs with benchmarks, four performed better than the approved benchmarks with three performing better than the threshold and within the performance range and one, the All Injury Frequency Rate (AIFR), performing worse than the threshold. In 2016 year-to-date, six performed better than the approved benchmarks with two performing better than the threshold and within the performance range. For the three SQIs that are informational only, performance is generally consistent with or better than recent years' performance. Details of the SQIs are included in Section 13.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factors used for calculating the 2017 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 2017. FBC has used July 2014 through June 2016 inflation data for the 2017 rate change calculations using the CANSIM tables noted above, which are included in Appendix A1 of the Application.

As discussed below, the 2017 inflation factor based on prior year's BC-CPI and BC-AWE is 1.399 percent, and the AC Growth Factor is 0.483 percent.

2.2 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 2016 has been used as a placeholder for the month of June 2016 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 1.627 percent and AWE-BC of 1.212 percent. Applying the 55 percent labour weighting, the calculation of the I-Factor is (1.627 percent x 45 percent) + (1.212 percent x 55 percent) = 1.399 percent.

Table 2-1: I-Factor Calculation

	CANSIM 326-0020 2002=100	*CANSIM 281-0063*	12-Month Average		Year over Year % Change			
	BC CPI Index	BC AWE $	CPI Index	AWE $	CPI %	AWE %	I-Factor %	PBR Year
Jul-14	119.6	892.69						
Aug-14	119.6	902.67						
Sep-14	119.5	898.29						
Oct-14	119.0	904.76						
Nov-14	118.8	906.17						
Dec-14	118.1	895.32						
Jan-15	118.0	911.03						
Feb-15	118.9	909.02						
Mar-15	119.8	905.21						
Apr-15	119.6	903.26						
May-15	120.6	905.28						
Jun-15	120.7	909.59	119.350	903.608				
Jul-15	120.8	913.87						
Aug-15	121.0	906.46						
Sep-15	121.0	911.95						
Oct-15	120.6	913.09						
Nov-15	120.8	910.40						
Dec-15	120.4	925.59						
Jan-16	120.7	905.14						
Feb-16	120.8	913.43						
Mar-16	121.8	915.72						
Apr-16	121.8	920.79						
May-16	122.7	919.11						
Jun-16	123.1	919.11	121.292	914.555	1.627%	1.212%	1.399%	2017

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

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

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

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

	Customer Count	12 Month Average Customers	AC Factor @50%	PBR Year
Jul-14	129,514			
Aug-14	129,537			
Sep-14	129,547			
Oct-14	130,244			
Nov-14	130,500			
Dec-14	130,572			
Jan-15	130,676			
Feb-15	130,729			
Mar-15	130,830			
Apr-15	130,765			
May-15	130,769			
Jun-15	130,810	130,374		
Jul-15	130,846			
Aug-15	130,795			
Sep-15	131,131			
Oct-15	131,209			
Nov-15	131,754			
Dec-15	131,883			
Jan-16	132,080			
Feb-16	132,202			
Mar-16	132,041			
Apr-16	131,955			
May-16	131,603			
Jun-16	132,097	131,633	0.483%	2017

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

Using the I-Factor and Growth Factor as calculated above, and the approved X-Factor of 1.03 percent, a summary of the factors used in the PBR formula for 2017 is provided in Table 2-3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2017
1	Cost Drivers	
2		
3	Customer Growth Factor @ 50%	0.483%
4		
5	Escalators	
6		
7	CPI	1.627%
8	AWE	1.212%
9		
10	Non Labour	45%
11	Labour	55%
12		
13	CPI/AWE Inflation	1.399%
14		
15	Productivity Factor	-1.030%
16		
17	Net Inflation Factor	0.369%

In summary, the formula factor for O&M and capital for 2017 is 100.854 percent, calculated as (1+0.483 percent) x (1+0.369 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. Gross system energy load is a mix of residential, commercial, wholesale, industrial, street lighting and irrigation loads and system losses. The gross load forecast 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)[4], the Advanced Metering Infrastructure (AMI) program and future rate changes. These savings are further explained in Section 3.3 – Demand Side Management and Other Savings.

FBC's load forecast methods, described below, are consistent with those used in prior years and accepted by the Load Forecast Technical Committee in 2011[5], and provide a reasonable estimate of load for 2017. FBC is forecasting an increase in consumption in 2017 when compared to the 2016 Approved forecast. The total normalized gross load is forecast to be approximately 3,559 GWh which is a 19 GWh increase over the 2016 Approved gross load. The increase in 2017 is due to increased loads in the commercial, wholesale, industrial, lighting and irrigation classes which are partially offset by a decrease in residential load. Based on the 2016 rates for each customer class, FBC's 2017 revenue forecast is $352.389 million.

3.2 OVERVIEW OF FORECAST METHODS

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

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

The load forecast for residential customers is based upon forecasts for customer count and UPC rates, consistent with the past method. Specifically, the average UPC is estimated and is then multiplied by the corresponding forecast of the number of customers to derive the load forecast. The load forecasts for commercial, lighting and irrigation are based upon Conference Board of Canada (CBOC)[6] Gross Domestic Product (GDP) regression, trend analysis and 5-

[4] Customer Information Portal (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 expected start date of the CIP program is December 2016.

[5] 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.

[6] Conference Board of Canada, Provincial Outlook Economic Forecast for British Columbia: Winter 2016, published 2/4/2016. The BC GDP forecast is included in Appendix A1.

year average respectively. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

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

In the figures provided below in the load forecast sections, 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 2017 Annual Review the latest calendar year for which full actual data exists is the 2015 calendar year.
- 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, 2017 is the Forecast Year (2017F).
- 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[7], 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 2016 (2016S) and the Seed Year forecast is based on the latest actual years, including 2015.

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 and other savings are forecast on an incremental basis (to savings embedded in historical loads to 2015).

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. Residential energy sales are 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 2017 are summarized in Table 3-1 below.

[7] 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 2017 DSM and Other Savings (GWh)

Line No.	Description	DSM	AMI	CIP	RCR	Rate-Driven	Total
1	Residential	(10)	12	(2)	(10)	(1)	(11)
2	Commercial	(15)				(1)	(16)
3	Wholesale	(2)				(1)	(3)
4	Industrial	(4)					(4)
5	Lighting	(1)					(1)
6	Irrigation						
7	Net	(32)	12	(2)	(10)	(3)	(35)
8	Losses	(3)	(6)				(9)
9	Gross Load	(34)	6	(2)	(10)	(3)	(43)

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 on population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report that has been produced for FBC.

The forecast commercial customer count is determined by a regression of the year-end customer accounts on the provincial GDP 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	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
1	Residential	89,181	93,647	95,502	96,565	97,883	98,795	99,228	111,862	113,431	114,166	115,080	116,031
2	Commercial	10,285	11,010	11,216	11,308	11,419	11,525	11,811	13,662	14,363	14,976	15,167	15,813
3	Wholesale	8	7	7	7	7	7	7	6	6	6	6	6
4	Industrial	37	38	36	33	35	36	39	47	49	50	50	50
5	Lighting	1,905	1,992	1,910	1,874	1,830	1,803	1,739	1,644	1,620	1,590	1,590	1,590
6	Irrigation	997	1,030	1,048	1,066	1,075	1,092	1,091	1,097	1,103	1,095	1,095	1,095
7	**Total**	102,413	107,724	109,719	110,853	112,249	113,258	113,915	128,318	130,572	131,883	132,988	134,585

3.5 *LOAD FORECAST*

A discussion of the forecast for each customer class is provided in Sections 3.5.1 through 3.5.6, and losses and peak load forecasts 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 3,282 GWh in 2017, up 29 GWh from 2016S.

Figure 3-1: Total Net Load (GWh)

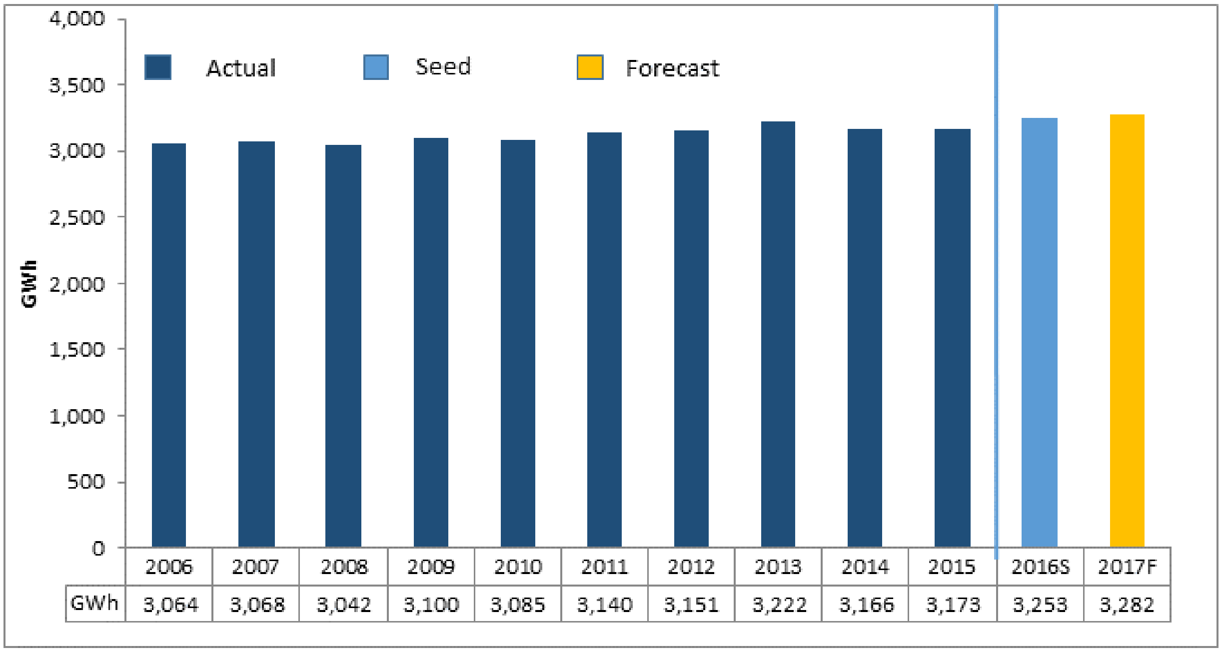


Table 3-3 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2017 the residential customer class is forecast to account for 38 percent of the normalized after-savings gross load.

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

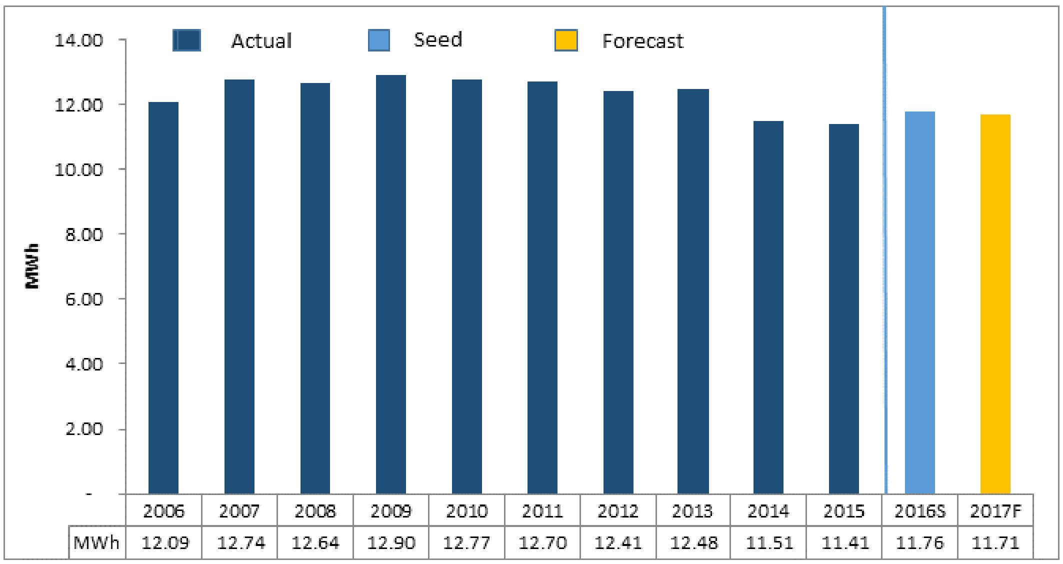
No.	Description	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
	Energy (GWh)												
1	Residential	1,064	1,165	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,348	1,353
2	Commercial	616	650	661	675	660	657	681	788	866	853	868	879
3	Wholesale	979	878	908	908	895	910	899	675	567	580	587	587
4	Industrial	348	314	218	216	234	271	291	352	381	380	393	407
5	Lighting	13	13	13	13	14	13	13	13	16	16	15	14
6	Irrigation	43	48	46	49	40	40	38	40	40	46	41	40
7	Net Load	3,064	3,068	3,042	3,100	3,085	3,140	3,151	3,222	3,166	3,173	3,253	3,282
8	Losses	366	346	309	315	284	307	271	278	270	272	280	278
9	Gross Load	3,430	3,414	3,351	3,416	3,369	3,447	3,422	3,500	3,436	3,446	3,533	3,559
10													
11	System Peak (MW)												
12	Winter Peal	733	704	707	704	726	702	723	698	693	669	728	734
13	Summer Pe	493	520	502	496	566	537	589	600	620	611	589	594

3.5.1 Residential

3.5.1.1 Residential UPC

Normalized historical UPCs are obtained by dividing the normalized residential load by the average customer count in each year. The 2016S before-savings UPC is forecast by averaging the most recent 3 years' normalized historical UPCs (2013, 2014, 2015), and the 2017 before-savings UPC is assumed to remain constant at the 2016S level. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. Incremental savings (that is, savings incremental to those embedded in the historical data to 2015) are then deducted from the before-savings load forecast to determine the after-savings load forecast. The 2016S after-savings UPC forecast is then computed by dividing the 2016S 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 0.05 MWh during 2017.

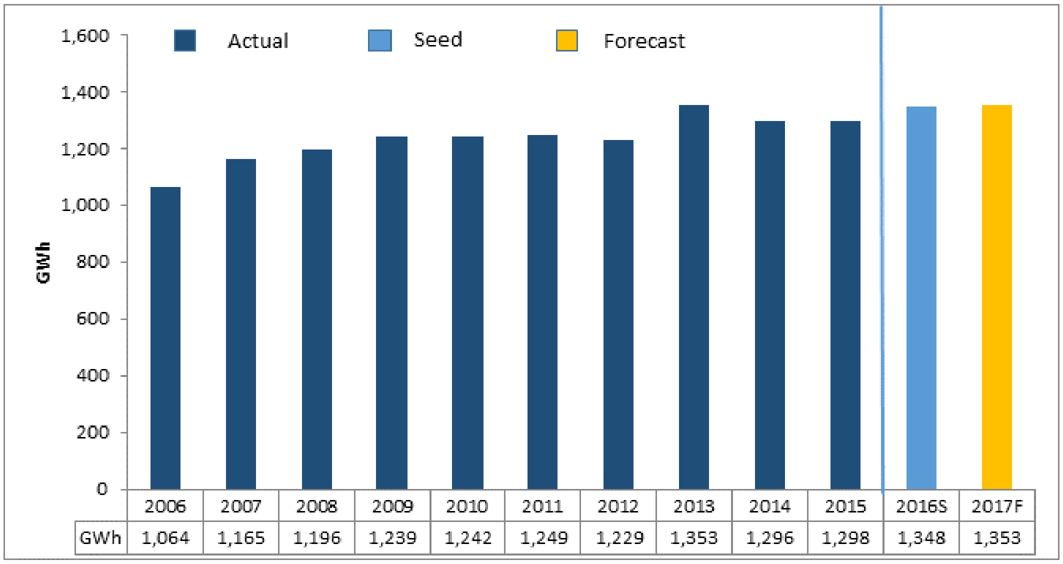
Figure 3-2: Normalized After-Savings Residential UPC (MWh)



3.5.1.2 Residential Load

Consistent with past practice, the total before-savings energy 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 energy is forecast to increase by 5 GWh in 2017.

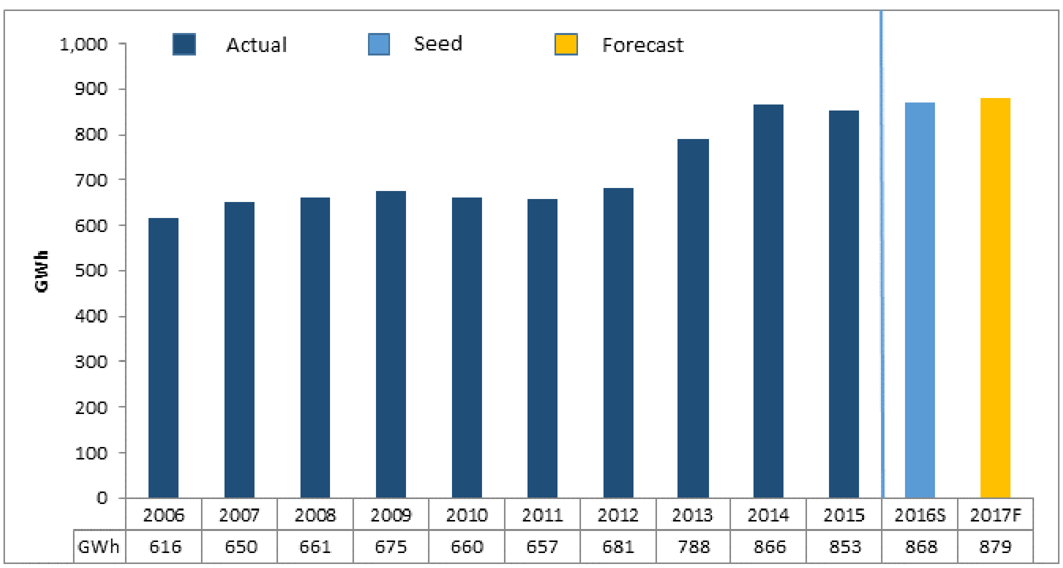
Figure 3-3: Normalized After-Savings Residential Energy (GWh)



3.5.2 Commercial

The commercial class is forecast based on a regression of load on the provincial GDP obtained from the CBOC. As shown in Figure 3-4 below, Commercial after-savings energy is forecast to increase by 11 GWh in 2017.

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

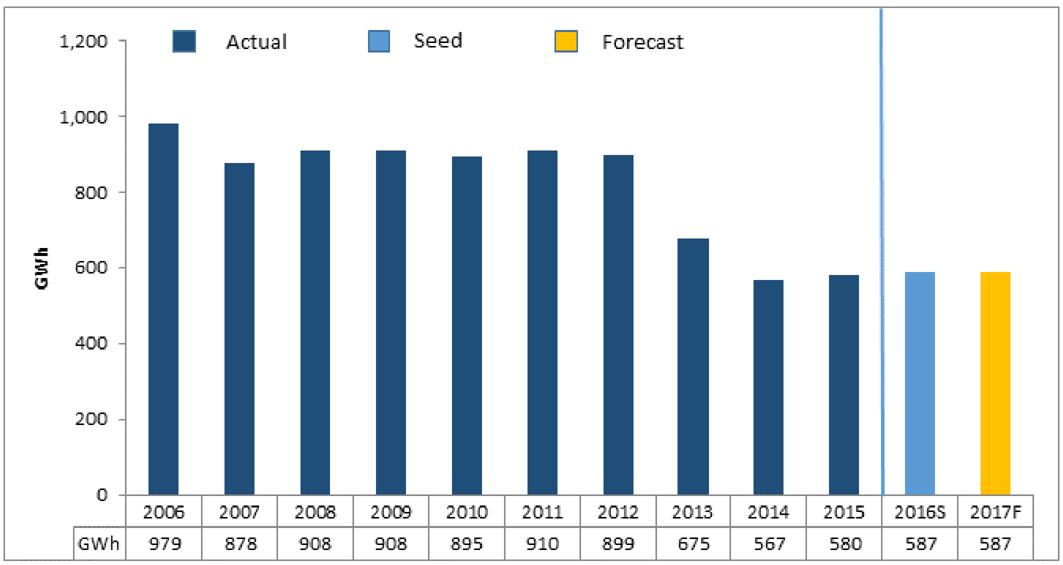


3.5.3 Wholesale

FBC sells wholesale power to municipalities within its service territory that own and operate their own electrical distribution systems. These wholesale customers' load composition is a mix 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 forecast growth projections. As shown in Figure 3-5 below, after-savings wholesale energy is forecast to remain constant in 2017.

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



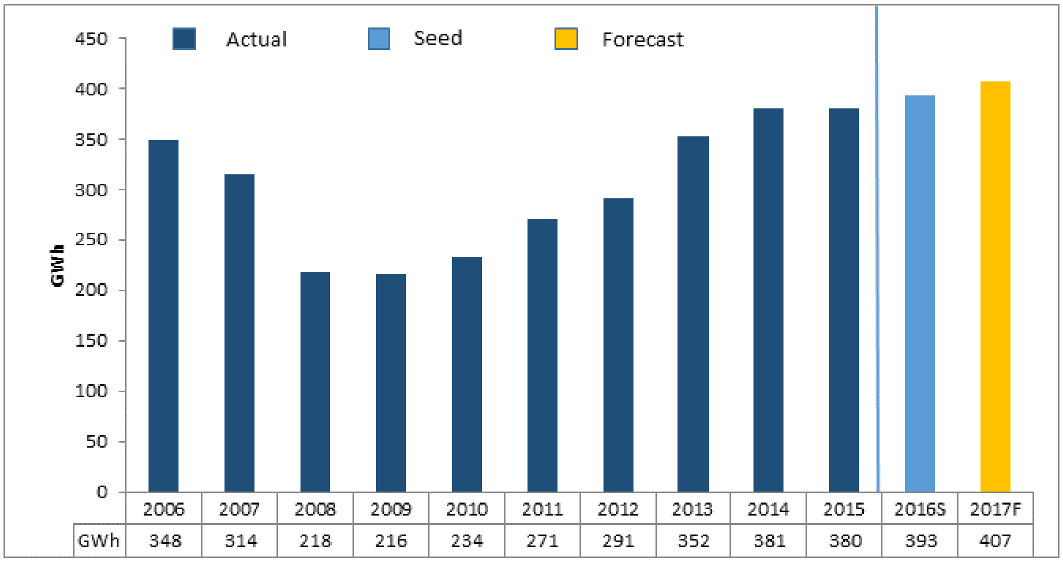
3.5.4 Industrial

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 methodology is utilized because FBC believes that individual industrial customers have the best understanding of what their future energy usage will be. This year FBC received a response from 88 percent (44 of 50) of the surveys sent out. The responding customers also represent approximately 88 percent of the total industrial load.

As shown in Figure 3-6 below, after-savings industrial energy is forecast to increase by 14 GWh in 2017.

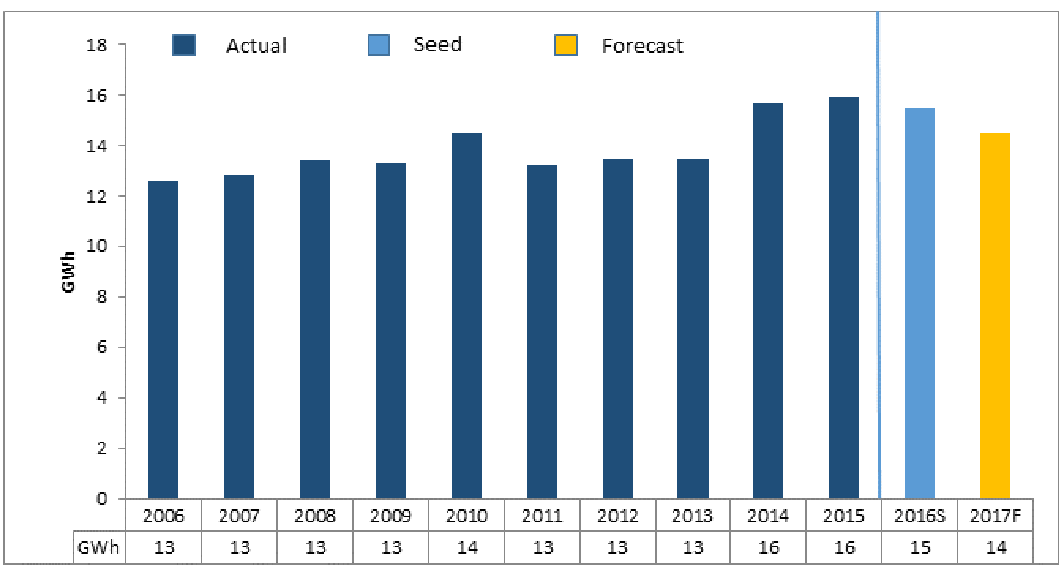
Figure 3-6: After-Savings Industrial Energy (GWh)



3.5.5 Lighting

Consistent with past practice the trend analysis for the most recent five-year period for which FBC has actual data (from 2011 to 2015 in this case) is used to forecast load for this class. As shown in Figure 3-7 below, after-savings lighting energy is forecast to decrease by 1 GWh in 2017.

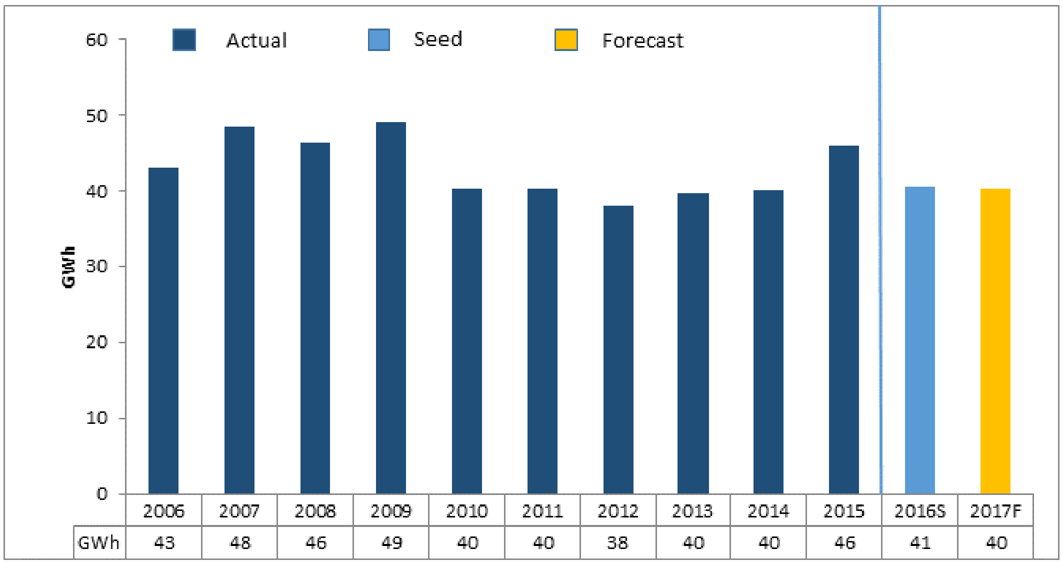
Figure 3-7: After-Savings Lighting Energy (GWh)



3.5.6 Irrigation

The before-savings forecast is developed using a five-year average for the most recent years for which FBC has actual data (from 2011 to 2015 in this case). This method is consistent with past practice. As shown in Figure 3-8 below, after-savings irrigation energy is forecast to decrease by 1 GWh in 2017.

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



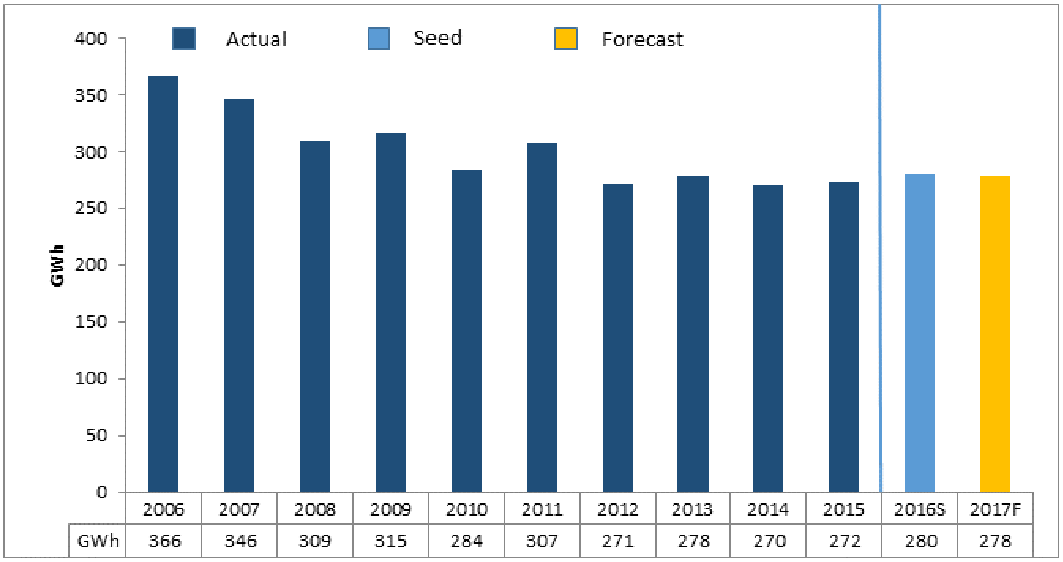
3.5.7 Losses

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, which is explained below. AMI loss reduction is expected to further reduce the losses in the future. Below are the normalized after-savings energy losses from 2011 to 2017. Despite the decrease in system losses due to AMI as described in Section 3.5.7.1 below, the after-savings 2016 losses are forecast to increase by 8 GWh compared to 2015 due to a projected 80 GWh increase in gross load. As shown in Figure 3-9 below, after-savings energy losses are forecast to decrease by 2 GWh in 2017.

Figure 3-9: Normalized After-Savings Energy 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.[8]

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.

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 – 2015,

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

as well as the forecast losses (both with and without the AMI impact) for 2016 – 2019. The 2015 AMI impact to losses related to theft detection and deterrence is 2.4 GWh, which is consistent with the original forecast. The 2015 loss figures are embedded in the 2016 – 2019 loss figures noted in Table 3-4.

Table 3-4: System Losses Before and After AMI, 2012 – 2019

		Before AMI				After AMI	
Line No.	Year	Actuals and Before-Savings Gross Load (GWh)	% of Gross Load	Normalized Actual and Forecast Losses (GWh)	Incremental AMI Impact (GWh)	% of Gross Load	Losses (GWh)
1	2012 Actual	3,421.7	7.92%	271.1			
2	2013 Actual	3,500.0	7.95%	278.1			
3	2014 Actual	3,436.0	7.86%	270.1			
4	2015 Actual	3,445.8	7.91%	272.4			
5	2016 Seed	3,498.2	7.99%	279.5	(2.7)	7.91%	276.8
6	2017 Forecast	3,520.1	7.99%	281.2	(6.7)	7.80%	274.5
7	2018 Forecast	3,530.6	7.98%	291.9	(9.7)	7.71%	272.2
8	2019 Forecast	3,544.8	7.98%	283.0	(12.1)	7.64%	270.9

FBC is beginning to leverage the tamper detection functionality of the AMI system for theft identification, and is also preparing for the full implementation of its energy balancing program in late 2016. FBC expects to have fully implemented its energy balancing theft detection program as described in the AMI CPCN application by Q4 2016.

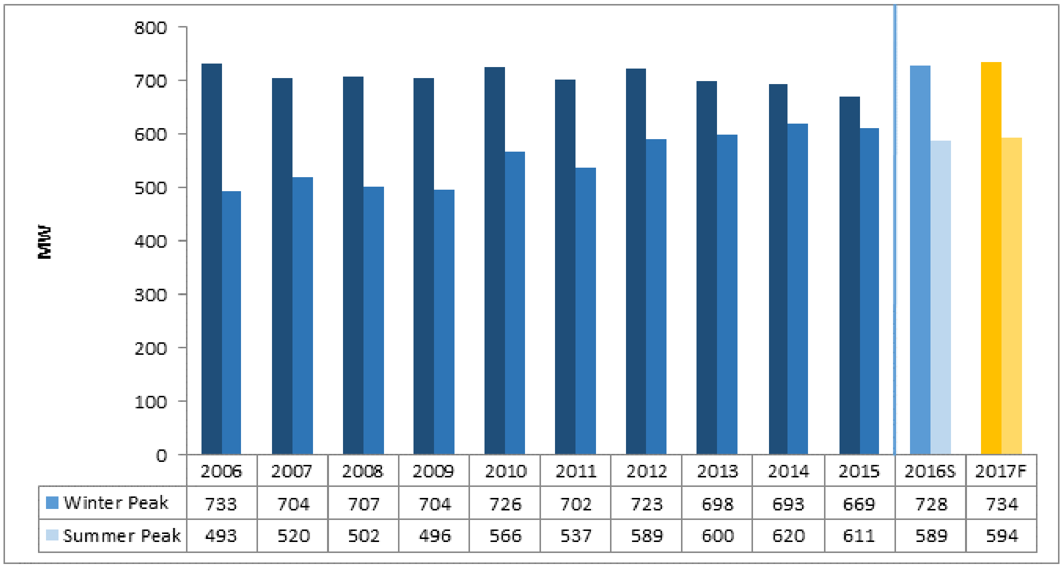
The following discussion of incremental O&M costs related to the AMI-enabled revenue protection program is provided in this section in response to the directive cited above. The incremental O&M expenditures relate primarily to the addition of a Revenue Protection Analyst for managing the development 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 to implement the AMI-enabled energy balancing program include 2016 O&M expenditures of $0.088 million.

With respect to the regulatory treatment of the AMI costs associated with FBC's Revenue Protection Program, these costs, which are incremental to the Revenue Protection program costs included in formula O&M, are forecast and tracked outside of the PBR formula and variances 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 by taking the ten year average of historical peak data. 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 2006-2017 are shown below.

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



3.6 *REVENUE FORECAST*

The forecast of revenues has been developed by applying approved 2016 rates to the forecast billing determinants for each customer class.

Table 3-5 below summarizes the approved, projected and forecast revenue for 2016 and 2017.

Table 3-5: Forecast Sales Revenue at 2016 Approved Rates ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Forecast 2017
1	Residential	$ 184.048	$ 172.322	$ 182.534
2	Commercial	82.385	84.229	83.934
3	Wholesale	46.940	40.444	47.194
4	Industrial	31.020	36.702	32.600
5	Lighting & Irrigation	6.199	6.630	6.127
6	Total	$ 350.593	$ 340.326	$ 352.389

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 energy forecast is 3,559 GWh. Based on net load of 3,282 GWh at the approved 2016 rates, FBC's 2017 revenue forecast is $352.389 million.

When comparing the 2017 forecast to the 2016 Approved there in an increase in gross load of 19 GWh. This increase is due to higher commercial, wholesale, lighting, and irrigation loads which are partially offset by a lower residential load.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2016 Projected and 2017 Forecast power purchase expense (PPE), wheeling expense and water fees.

As shown in Table 4-1 below, the 2017 Forecast power supply cost of $153.930 million represents an increase of 3.3 percent or $4.968 million over the 2016 Approved cost of $148.962 million. The increase in the 2017 Forecast PPE is due to increased gross load as well as increases to the Brilliant, Waneta Expansion, and BC Hydro contract rates. The increase in 2017 Forecast wheeling expense is due to increases in the wheeling nominations and wheeling rates. The 2017 Forecast water fees are consistent with 2016 Approved. 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 2016	Projected 2016	Forecast 2017
1	Power Purchase Expense	$ 133.907	$ 128.439	$ 138.674
2	Wheeling Expense	4.764	4.779	4.928
3	Water Fees	10.291	10.187	10.328
4	Total Power Supply Cost	$ 148.962	$ 143.406	$ 153.930
5				
6	Gross Load (GWh)	3,540	3,426	3,559

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:

a) 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;

b) 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);

c) A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro Rate Schedule 3808 (Order G-60-14);

d) 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);

e) A number of small Independent Power Producer (IPP) contracts; and

f) 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 2017 forecast annual energy and capacity requirements. The nature of FBC's contracted resources, in particular the BC Hydro PPA, provide 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, under the terms of 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 2016/17 ANNUAL ELECTRIC CONTRACTING PLAN

On March 9, 2016, FBC filed its 2016/17 Annual Electric Contracting Plan (AECP) with the Commission. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and annual energy requirements for the operating year commencing October 1, 2016 and ending September 30, 2017, 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.[9] 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 2016 and for 2017 are based on the plan detailed in the 2016/17 AECP, which was generally accepted by the Commission on April 21, 2016, by way of Letter L-8-16[10].

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2016/17 contract year equal to 822 GWh, less any firm market contracts that FBC could enter into, as described in section 5 of the 2016/17 AECP.

During May 2016, FBC entered into eight energy supply contracts (ESCs) with Powerex under the terms of the CEPSA. The eight ESCs provide FBC with 120 GWh of incremental market energy over the winter of 2016/17 and 96 GWh over the winter of 2017/18, both at a lower total cost than if supplied under the PPA. The ESCs were accepted by Order E-11-16 on July 15, 2016, and the associated savings are included in the 2016 Projected PPE and 2017 Forecast PPE. As a result of these contracts, and changes to forecast gross load and forecast CPA entitlement energy storage operations, the Company submitted a PPA nomination for the 2016/17 contract year of 680 GWh on June 27, 2016

4.5 *REVIEW OF 2016 POWER PURCHASE EXPENSE*

As shown in Table 4-2 below, FBC's 2016 gross load (after taking into account demand side management and other customer savings) and PPE are projected to be below the 2016 Approved values by 114 GWh and $5.467 million, respectively. The reduction in power purchase expense in 2016 is primarily due to decreased load from forecast, driven primarily by a warmer than forecast winter and additional market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost.

[9] 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

[10] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-8-16.

Table 4-2: 2016 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Difference
1	Brilliant	$ 38.785	$ 38.775	$ (0.010)
2	BC Hydro PPA	47.545	38.256	(9.289)
3	Waneta Expansion	37.358	37.490	0.132
4	Independent Power Producers	0.195	0.186	(0.009)
5	Market and Contracted Purchases	10.023	13.014	2.991
6	CPA Balancing Pool	-	0.839	0.839
7	Special and Accounting Adjustments	-	(0.121)	(0.121)
8	Total	$ 133.907	$ 128.439	$ (5.467)
9				
10	Gross Load (GWh)	3,540	3,426	(114)

4.6 *2017 POWER PURCHASE EXPENSE FORECAST*

As shown in Table 4-3 below, the 2017 Forecast PPE is approximately $10.235 million greater than the 2016 Projected. The forecast increase from $128.439 million in 2016 to $138.674 million in 2017 is a result of increased gross load, a reduction in market and contracted purchases and correspondingly a greater reliance on 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 2016 Projected PPE and the 2017 Forecast PPE. Reasons for significant variances from the 2016 Projected PPE are further discussed below.

Table 4-3: 2016 and 2017 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2016	Forecast 2017	Difference
1	Brilliant	$ 38.775	$ 39.983	$ 1.208
2	BC Hydro PPA	38.256	48.731	10.476
3	Waneta Expansion	37.490	38.415	0.925
4	Independent Power Producers	0.186	0.204	0.017
5	Market and Contracted Purchases	13.014	11.341	(1.673)
6	CPA Balancing Pool	0.839	-	(0.839)
7	Special and Accounting Adjustments	(0.121)	-	0.121
8	Total	$ 128.439	$ 138.674	$ 10.235
9				
10	Gross Load (GWh)	3,426	3,559	133

The 133 GWh increase in gross load is due to an increased forecast load in 2017, as well as the 2016 Projected gross load being 114 GWh below 2016 Approved due to warmer than expected weather in 2016, as well as reduced customer growth from plan.

The $1.208 million increase from 2016 Projected to 2017 Forecast in the Brilliant expense is due to increases in 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.

The $10.476 million increase from 2016 Projected to 2017 Forecast in BC Hydro PPA expense is due to a greater volume of power forecast to be purchased under the PPA in the 2017 Forecast compared to the 2016 Projected, as well as due to a forecast BC Hydro rate increase of 3.5 percent on April 1, 2017.[11] The BC Hydro rate increase of 3.5 percent as of April 1, 2017, increases the 2017 Forecast expense by $1.690 million, while higher purchased volume increases 2017 Forecast expense by $9.202 million. The volume of PPA purchases included in the 2017 Forecast is 176 GWh higher than the volume included in the 2016 Projected and 36 GWh lower than 2016 Approved. For the 2017 Forecast, and consistent with the 2016 Approved, FBC has included a $1.000 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 for under the BC Hydro PPA. The flexibility under the BC Hydro PPA has created savings of $0.515 million in the 2016 Projected PPE. The Company is required to create additional savings of $0.485 million in 2016 in order to meet the $1.0 million planned savings, which it anticipates doing by the end of the 2016. Any variance in actual savings compared to the $1.000 million planned savings included in the 2016 Approved and 2017 Forecast are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

The $0.925 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, and a forecast increase in capacity available to be purchased in 2017, offset by a $0.858 million increase in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of capacity FBC releases to Powerex and to the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. FBC's forecast of Mid-C forward market prices is based on contracts that have been traded and/or bids and offers from forward contracts on the Intercontinental Exchange Inc. (ICE), which is a global exchange, clearing, financial data and technology company. More electric power is traded on ICE than any other electronic marketplace in the world. The method used to forecast market prices and calculate surplus sales is the same as in the Annual Review for 2016 Rates. Overall, the forecast of market prices has a relatively small effect on the overall PPE. The forecast of surplus sales revenue in 2017, which is included in line 3 of Table 4-3, is approximately $9.129 million.

The $1.673 million reduction in Market and Contracted Purchases is due to a reduction in the volume of contracted market purchases in 2017 and a lower average cost of purchases in 2017. Market and Contracted Purchases for 2016 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 2017 Forecast are based on fixed price contracts executed by the

[11] BC Hydro filed its F2017-F2019 Revenue Requirements application on July 28, 2016, requesting a rate increase of 3.5 percent effective April 1, 2017. (BC Hydro F2017 – F2019 Revenue Requirements, Exhibit B-1-1).

Company. As discussed above, there may be opportunities for additional real-time market purchases in 2017 using the flexibility of the PPA purchases and FBC has reduced its expected purchases under the BC Hydro PPA by $1.000 million to account for this, consistent with the 2016 Approved PPE.

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 2016 Projected PPE, FBC has used a net total of 19 GWh of entitlement energy from storage, at a total cost of $0.839 million. For the 2017 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 2016 Rates. Table 4-4 below shows FBC's Wheeling Expense for 2016 and 2017.

Table 4-4: Wheeling Expense ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Forecast 2017
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,400	2,400	2,430
3	Creston	432	432	432
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.221	$ 4.235	$ 4.374
7	Creston	0.495	0.497	0.507
8	Other	0.048	0.047	0.048
9	Total Wheeling Expense	$ 4.764	$ 4.779	$ 4.928

In 2016 and 2017, ARWA costs are forecast to account for all of FBC's wheeling expense, except for $0.047 million and $0.048 million of OATT and Teck wheeling in 2016 and 2017 respectively.

As shown in Table 4-4 above, 2017 wheeling expense is forecast to increase by $0.149 million over 2016 Projected, which is due to an anticipated ARWA rate increase on October 1, 2016 and an increase to the Okanagan Wheeling nomination starting in October 2017 from 200 MW to 210 MW. The AWRA annual rate increases are based on forecast BC CPI.

4.8 WATER FEES

Water fees are assessed by the Province 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 2016 Projected Water Fees are slightly lower than 2016 Approved, due to a decrease in Plant Entitlement in 2015 compared to the Entitlement assumed in the 2016 Approved Water Fees.

The 2017 water fees are forecast to increase by $0.141 million over 2016 Projected due to a yearly increase in water fee rates, offset by reduced Plant Entitlement in the Previous Year. Water fees are forecast using the same method as in the Annual Review for 2016 Rates.

Table 4-5 below shows FBC's Water Fees for 2016 and 2017.

Table 4-5: Water Fees ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Forecast 2017
1	Plant Entitlement in Previous Year (GWh)	1,649	1,627	1,617
2				
3	Water Fees	$ 10.291	$ 10.187	$ 10.328

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 2016/17 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

5.1 INTRODUCTION AND OVERVIEW

As shown in the table below, FBC is forecasting other revenue for 2017 to be $0.121 million lower than the amounts approved for 2016. The main driver of this decrease is a reduction in connection charges due to a lower number of customer connections than had been forecast for 2016.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Forecast 2017
1	Apparatus and Facilities Rental	$ 4.467	$ 4.482	$ 4.576
2	Contract Revenue	1.808	1.817	1.865
3	Transmission Access Revenue	1.230	1.228	1.179
4	Interest Income	0.034	0.035	0.024
5	Connection Charges	0.496	0.277	0.270
6	Other Recoveries	0.142	0.142	0.142
7	Total	$ 8.177	$ 7.981	$ 8.056

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

5.2 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 2016 Projected is expected to be in line with 2016 Approved. 2017 revenue is forecast to be higher than 2016 Approved due to escalations in unit rental rates.

5.3 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, fluctuates 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 2016 Projected is expected to be in line with 2016 Approved. FBC's 2017 revenue is forecast to be slightly higher than 2016 Approved due to labour and material cost escalations.

The Company also operates and maintains a number of other facilities for third party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between

FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[12] and earn a transfer price profit revenue.

5.4 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 2016 and 2017. The 2016 Projected is expected to be in line with 2016 Approved, while the 2017 Forecast is expected to decrease due to a lower nomination of power to transmit in that year by one of the customers.

5.5 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.

5.6 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 2016 Projected connection charge revenues are expected to be lower than 2016 Approved due to a lower number of customer connections. The 2017 Forecast is expected to be in line with the 2016 Projected.

5.7 OTHER RECOVERIES

Other recoveries are primarily comprised of the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities. The 2016 Projected and 2017 Forecast are expected to be in line with 2016 Approved.

5.8 SUMMARY

FBC has forecast the other revenue components for 2017 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in other revenue are recorded in the Flow-through deferral account.

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

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 2017, the formula O&M is $54.054 million, representing a 0.854 percent increase from the 2016 formula-O&M, entirely due to the formula drivers. O&M expenses forecast outside the formula are $3.478 million, representing an approximate 2.8 percent increase from the amount approved for 2016. Overall, the increase in Gross O&M Expense from 2016 Approved to 2017 Forecast is approximately 1.0 percent.

The components of 2017 O&M expense are shown in Table 6-1 below.

Table 6-1: 2017 O&M Expense

Line No.	Description	2017	Reference
1	Formula O&M	$ 54.054	Table 6.2 Line 6
2	Forecast O&M	3.478	Table 6.3 Line 5
3	Total Gross O&M	57.532	
4	Capitalized Overhead (15%)	(8.630)	Section 11, Sch. 21
5	Net O&M	$ 48.902	

In the subsections below, FBC provides further details on its formula and forecast O&M expenses for 2017.

6.2 *FORMULA O&M EXPENSE*

The formula-driven portion of Base O&M starts from a base of the 2016 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 2017 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.369 percent and one-half of the prior year's customer growth is 0.483 percent.

For 2017, the annual operating and maintenance expense under the formula is calculated as:

2016 Approved formula O&M x [1 + (I Factor – X Factor)] x [1 + (0.5 x customer growth)]

Table 6-2 below shows the calculation of the 2017 Formula O&M.

Table 6-2: Calculation of 2017 Formula O&M

Line No.	Description			Reference
1	2016 Approved Formula O&M	$	53.596	FBC 2016 Rates Compliance Filing Sch 21
2				
3	Net Inflation Factor		0.369%	Section 2 Table 2-3
4	Customer Growth Factor		0.483%	Section 2 Table 2-2
5				
6	2017 Formula O&M	$	54.054	Line 1 x (1 + Line 3) x (1 + Line 4)

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

After calculating the Formula O&M, 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). 2017 FBC also includes a reduction to O&M due to lower annual inspection costs, which in turn is due to capital refurbishment of one of its generating units. These amounts are shown in Table 6-3 below along with a comparison to 2016.

Table 6-3: 2017 Forecast O&M ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Forecast 2017
1	Pension/OPEB (O&M Portion)	$ 3.391	$ 3.391	$ 3.267
2	Insurance Premiums	1.347	1.305	1.327
3	Advanced Metering Infrastructure Project	(1.800)	(1.335)	(1.126)
4	Mandatory Reliability Standards Incremental O&M	0.445	0.455	0.050
5	Upper Bonnington Unit 3 Annual Inspection	-	-	(0.040)
	Forecast O&M	$ 3.383	$ 3.816	$ 3.478

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 2017 are based upon recent actuarial estimates using a range of assumptions at December 31, 2015 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: 2015-2016 Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2016	Forecast 2017
1	O&M	$ 3.391	$ 3.267
2	Capital	3.674	3.539
3	Total Pension & OPEB Expense	**$ 7.065**	**$ 6.806**

Overall, pension and OPEB expense for 2017 is forecast to be $0.259 million lower than what was approved for 2016, of which $0.124 million resides in O&M. This decrease is primarily due to past service contributions to the pension plans improving the funded status of the plans, and an associated reduction in the net interest cost.

The 2016 variance between approved and actual pension and OPEB expense and any 2017 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.

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 2017 insurance premiums are forecast at $1.327 million, a decrease of $0.020 million or 1.5 percent from what was approved for 2016. The 2017 Forecast is calculated by taking the known annual insurance premium of $1.162 which is applicable to the first six months of 2017 and escalating that amount by five percent for the remaining six months[13]. 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 will be 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 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 2015 through 2017 net AMI savings to the net savings forecast in the AMI CPCN application.

[13] $1.162 million/2 = $0.581 million x 1.05 = $0.611 million. $0.581 million + $0.611 million + $0.135 million annual firefighting premium = $1.327 million.

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

Line No.		2014-2015			2016			2017	
1		Actual	Approved	CPCN[(1)]	Projected	Approved	CPCN[(1)]	Forecast	CPCN[(1)]
2		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
3									
4	AMI Costs	2.122	2.341	2.975	1.481	1.481	1.892	1.992	1.925
5	AMI Savings	(1.239)	(1.289)	(2.493)	(2.816)	(3.281)	(3.976)	(3.118)	(3.970)
6	Net AMI Savings	0.883	1.052	0.482	(1.335)	(1.800)	(2.084)	(1.126)	(2.045)
7									
8	[(1)] CPCN estimates adjusted to include reclassification of software from capital pursuant to Order G-13-14								

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

As stated in FBC's Annual Review for 2016 Rates, FBC expected AMI costs and savings to be approximately as forecast in the CPCN Application beginning in 2017 (the first year of fully realized costs and savings). As shown in Table 6-5 above, the 2017 forecast costs are approximately as forecast in the CPCN Application. The 2017 forecast savings of $3.118 million are approximately $0.852 million lower than the CPCN forecast of $3.970 million. This is due to the combination of two factors:

1. 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 savings were based partly on estimates of continuing with manual meter reading. These meter reading cost estimates were materially higher than actual experience in 2013 and 2014 (the last full years of manual meter reading), so savings potential was diminished; and

2. The forecast Remote Connect/Disconnect savings are lower than forecast, in part due to the discontinuation of the $100 meter connection fee for premises that are remotely reconnected following disconnection for vacancy, as accepted by Letter L-1-16.

As directed by the Commission in Order C-7-13, FBC will file a detailed cost/benefit report on AMI costs and savings within six months of completion of the AMI project.

The 2017 Forecast net savings are estimated to be $0.209 million lower than the 2016 Projected, primarily due to additional staff required to implement the AMI-based Revenue Protection program and for technical staff required to maintain the AMI network.

6.3.4 2016 MRS Incremental Operating Expense

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-38-14, 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. As explained in Section 12.2.2, the incremental costs in 2017 for MRS compliance qualify for exogenous factor treatment. This treatment is consistent with the Commission's determination in Order G-202-15 that FBC's 2016 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. For 2017, 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 2016 forecast of incremental O&M expenses was $0.445 million, and the projection for 2016 is close to that, at $0.455 million. The 2016 expenses are being utilized to evaluate and implement changes to procedures and processes to comply with those MRS that came into effect in 2016. For example, the testing and maintenance program for protection systems was modified to comply with Protection and Control standard PRC-005-2 and the operations personnel training program was updated pursuant to Personnel Performance, Training and Qualifications standard PER-005-2.

FBC also assessed the scope and implementation strategy to transition from Version 3 (V3) to Version 5 (V5) of the Critical Infrastructure Protection (CIP) Standards. FBC evaluated processes to address physical and cyber security controls, continuous monitoring, change management and vulnerability assessments. This included assessments of manual versus automated solutions and identifying what solutions are available in the industry. The CIP Transition Guidance adopted by the Commission in Order R-38-15 gives entities the flexibility of when to transition requirements of the CIP standards from V3 to V5. This flexibility has allowed FBC to reduce duplication of effort during the transition phase, which will reduce 2017 O&M expense compared to previous estimates for that year.

FBC forecasts the incremental MRS costs in 2017 to be $1.400 million. Only $0.050 million of this total is O&M Expense, which is required to comply with certain of the CIP V5 standards addressed above and to revised training standards. The incremental capital costs are discussed in Section 7.2. As explained in section 7.2, the 2017 work includes adding hardware and software systems to current infrastructure to meet requirements of the new MRS.

Any variances from the 2016 Projected and 2017 Forecast amounts for MRS compliance will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in 2018.

6.3.5 Annual Inspection Cost for Upper Bonnington Unit 3

FBC will execute the refurbishment of the Upper Bonnington (UBO) generating plant Unit 3 during 2017. Due to the refurbishment of the unit, the Company will not carry out the annual inspection of Unit 3, which is estimated to be a saving of $0.040 million. Unit 3 is the first of the four UBO "Old Units" (Units 1 – 4) which will be refurbished over the period 2017 – 2021 under the UBO Old Units Refurbishment project. The business case for the project is included as Appendix D.

The O&M reduction related to the annual unit inspections is a one-time reduction to O&M Expense in the year that each unit is refurbished; following the refurbishment of the unit, it will once again undergo an annual inspection, and therefore does not impact the level of Base O&M expenditures 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.

6.4 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 $48.902 million.

6.5 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 unit inspections in the Annual Review.

FBC plans a major unit inspection on the Lower Bonnington Unit 1 in November 2016. The work undertaken for the major unit inspection will be dismantling the unit at the coupling, removing the rotor, performing an in depth mechanical and electrical inspection as well as a thorough cleaning of the unit. The unit has no known current issues and it is anticipated that the cost will be approximately $0.300 million. Since actual costs for the unit inspection are not available at this time, these will be reported in the Annual Review for 2018 Rates.

6.6 SUMMARY

Overall the increase in Gross O&M Expense from Approved 2016 to 2017 is approximately 1.0 percent. The formula-driven O&M is increasing at a rate of 0.854 percent, and forecast O&M is slightly higher than Approved 2017. The capitalized overhead rate remains unchanged from 2016.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

The 2017 Rate Base for FBC is forecast to be $1.285 billion. Rate Base is composed of mid-year net plant in service, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital and the generation plant acquisition adjustment[14].

The 2017 Rate Base of FBC includes the full-year impacts of the 2016 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 $48.399 million;
- A $5.973 million plant addition for the last year of the AMI CPCN project; and
- Plant depreciation, net of CIAC amortization, of $44.616 million.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $32.403 million.

Details of the 2017 forecast plant balances can be found in Section 11 Schedules 5 through 9.

7.2 2016 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 2017, the formula capital is $43.240 million, representing a 0.854 percent increase from 2016, entirely due to the formula drivers. Regular capital expenditures forecast outside the formula are $5.297 million. Overall regular capital expenditures are forecast to increase from 2016 to 2017 by 3.7 percent. The components of 2017 regular capital expenditures are shown in Table 7-1 below.

Table 7-1: 2017 Regular Capital Expenditures ($millions)

Line No.	Description			Reference
1	Formula Capital Expenditures	$	43.240	Table 7.2 Line 6
2	Forecast Capital Expenditures		5.297	Table 7.3 Line 4
3	Total Regular Capital Expenditures	$	48.537	

In the subsections below, FBC provides further details on its formula and forecast capital expenditures for 2017.

[14] 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.

7.2.1 Formula Capital Expenditures

The formula-driven portion of regular capital expenditures starts from a base of the 2016 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 2017 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.369 percent, and one-half of the prior year's average customer growth is 0.483 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 2017, the annual capital expenditures under the formula are initially calculated as:

$$2017\ \text{Capital} = 2016\ \text{Capital} \times [(1 + (\text{I Factor} - \text{X Factor})] \times [1 + \text{customer growth}]$$

Table 7-2 below shows the calculation of the resulting 2017 formula capital expenditures.

Table 7-2: Calculation of 2017 Formula Capital Expenditures

Line No.	Description			Reference
1	2016 Approved Formula Capital Expenditures	$	42.874	FBC 2016 Rates Compliance Filing Sch. 4
2				
3	Net Inflation Factor		0.369%	Section 2 Table 2-3
4	Customer Growth Factor		0.483%	Section 2 Table 2-2
5				
6	2017 Formula Capital	$	43.240	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 Mandatory Reliability Standards (MRS) Incremental Capital expenditures related to BC Hydro's Assessment Report No. 8, which qualify for exogenous treatment as discussed in Section 12.2 of the Application. These amounts are shown in Table 7-3 below along with a comparison to 2016.

Table 7-3: 2017 Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Forecast 2017
1	Pension/OPEB (Capital Portion)	$ 3.674	$ 3.674	$ 3.539
2	AMI Sustainment Capital	0.256	0.256	0.408
3	Mandatory Reliability Standards Incremental Capital	-	0.445	1.350
4	Forecast Capital Expenditures	$ 3.930	$ 4.375	$ 5.297

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

- The Pension and OPEB forecast of $3.539 million represents the forecast capital portion of the total Pension and OPEB costs for 2017. These amounts are described in Section 6.3.1.
- AMI Sustainment Capital of $0.408 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. During the implementation of the AMI project, which will be complete in 2016, the related sustainment capital costs were included in the AMI CPCN project costs.
- As discussed in Section 6.3.4 and Section 12.2.2, in Order G-202-15 the Commission determined that FBC's 2016 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. In 2017, FBC continues to treat its forecast cost of adopting MRS pursuant to Order R-38-15 as an Exogenous event under the PBR Plan by tracking the incremental O&M and capital expenditures associated with compliance with Order R-38-15 and flowing them through to rates outside of the O&M and capital formulas.

  MRS Incremental Capital of $1.350 million (in addition to $0.050 million in O&M Expense as described in section 6.3.4) is required in 2017 to comply with recently adopted MRS. As explained in section 6.3.4, during 2016, FBC began assessing and determining the detailed scope and strategy required to implement additions/changes to meet the effective dates of all the standards defined by Order R-38-15. The work is primarily focused on version 5 of the CIP standards.

  As a result of the 2016 effort to date, FBC has estimated a one-time capital expenditure of $1.350 million in 2017. The 2017 work includes adding hardware and software systems to current infrastructure. These expenditures are necessary to meet requirements of the new standards and are related to tasks such as continuous monitoring, change management, vulnerability assessment and cyber security controls. These additions will need to be completed in 2017 in order to manage the timing of compliance activities to minimize costs.

  Additional sustaining capital will be required beyond 2017 for ongoing support for the hardware and software additions, including annual upgrades and minor additions that may be required to the infrastructure and systems implemented as a result of version 5 of the CIP standards.

7.3 CPCN AND SPECIAL PROJECTS CAPITAL EXPENDITURES

Also forecast outside of the formula are any capital expenditures related to approved CPCNs.

The Ruckles Substation Rebuild Project and the Upper Bonnington Old Units Refurbishment Project (UBO Project) were also determined by Order G-80-16 to be outside of the formula capital expenditures and eligible for flow-through treatment, subject to approval of the projects in the Annual Review process preceding the commencement of the project. The project descriptions, justification and costs for the Ruckles Substation Rebuild Project and the UBO Project are provided in Appendix C and Appendix D of the Application, respectively. To facilitate the review and approval of these multi-year projects in this annual review, FBC is seeking Commission acceptance of the capital expenditures for the two projects pursuant to section 44.2 of the *Utilities Commission Act.*

For 2017, FBC is forecasting capital expenditures related to the Kootenay Operations Centre project, the Ruckles Substation Rebuild Project, and the UBO Project. None of these projects is forecast to be included in rate base or affect rates in 2017. Instead, the project costs will enter rate base on January 1 of the year following the in-service date.

Each of these projects is described further below.

- Order C-2-16 granted a CPCN for the construction of a new Kootenay Operations Centre (or KOC) located in the Castlegar area. The KOC project will replace certain facilities in the Kootenay area that are at end of life and improve operational efficiency and emergency preparedness within the Kootenay region. The 2016 and 2017 expenditures are forecast to be $6.717 million and $14.416 million, respectively, with the total project cost forecast to be $21.910 million[15]. The expected in-service date is September 2017.
- The Ruckles Substation Rebuild Project involves rebuilding the existing substation in Grand Forks. The project is required to eliminate the risk of damage and environmental and employee safety concerns due to the substation's location in the Kettle River flood zone, to address safety and reliability risks presented by obsolete equipment including the risk of arc flash hazard, and to address system reliability concerns and capacity constraints. The Ruckles Substation Rebuild Project will be completed in the winter of 2018 at a cost of $8.288 million ($2.143 million in 2017). The project business plan is included as Appendix C.
- The UBO Units Refurbishment Project involves the refurbishment of the more than 100 year old generating Units 1 – 4 (the Old Units), at an estimated cost of $31.783 million ($5.898 million in 2017). These units are at end of life and can no longer be operated in a safe, reliable, and environmentally responsible manner. This four-year project will extend the life of the Old Units for an additional twenty years or more, and will reduce the safety and environmental risks associated with failures of the aged equipment. The project business plan is included as Appendix D.

[15] Including land purchased in 2014 for $0.777 million.

7.4 2016 PLANT ADDITIONS

The 2017 Plant Additions are comprised of FBC's 2017 regular capital expenditures from section 7.2 above plus the AMI CPCN capital additions, 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.

Table 7-4: Reconciliation of Capital Expenditures to Plant Additions ($millions)

Line No.	Description			Reference
1	Formula Capital Expenditures	$	43.240	Table 7-2
2	Forecast Capital Expenditures		5.297	Table 7-3
3	Total Regular Capital Expenditures	$	48.537	
4				
5	Capitalized Overhead		8.630	Table 6-1
6	Direct Overhead		5.000	
7	AFUDC		-	
8	Cost of Removal charged to Accumulated Depreciation		(2.541)	Section 11, Sch. 5, Line 21
9	Total Regular Additions to Plant		59.626	
10				
11	Special Projects and CPCN Capital Expenditures		21.279	
12	Special Projects and CPCN AFUDC		1.179	Section 11, Sch. 5, Line 28
13	Special Projects and CPCN Cost of Removal		-	Section 11, Sch. 5, Line 29
14	Change in Special Projects and CPCN Work in Progress		(16.485)	Section 11, Sch. 5, Line 31
15	Special Projects and CPCN Additions to Plant		5.973	
16				
17	2017 Plant Additions	$	65.599	

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. 2017 CIAC additions are forecast at $6.027 million. The year-end CIAC balances net of accumulated amortization are $111.698 million in 2016 (projected) and $114.036 million forecast in 2017.

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 2017 are the rates that have been approved by Order G-202-15 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 2017 depreciation expense is calculated as $56.046 million.

7.7 RATE BASE DEFERRED CHARGES

The forecast mid-year balance of unamortized deferred charges in rate base for FBC is approximately $12.392 million in 2017 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 2017.

Based on amortizing the opening deferral account balances using the approved amortization periods, the 2017 amortization expense for rate base deferral accounts is calculated as $4.714 million.[16]

7.8 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other 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-billed 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[17].

[16] Section 11; Schedule 11 Line 16 Column 6.

[17] For example, the revenue lag shown in Section 11, Schedule 14, Line 3 Column 3 for the residential class, of which 13.5 percent are billed monthly and 86.5 percent bimonthly, is calculated as:

Consumption lag	= (0.135 x 15.2 days) + (0.865 x 30.4 days)	=	28.4
Processing lag		=	1.0
Clearing lag	= (0.135 x 17 days) + (0.865 x 22 days)	=	21.3
Total revenue lag		=	50.7 days

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.

The impact on working capital due to the AMI Project will result 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) is used as a baseline in order to identify future changes. Beginning in 2016 customers may 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. FBC will record the first annual impact in the deferral account after the required information is available on December 31, 2016.

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 on a monthly average basis, based on 2016 actual amounts.

7.9 SUMMARY

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

8. FINANCING AND RETURN ON EQUITY

8.1 *INTRODUCTION AND OVERVIEW*

FBC has prepared this Application using its 2015 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 FortisBC Energy Inc. (FEI). A decision on FEI's approved capital structure and ROE for 2016 is anticipated during the course of this proceeding and FBC will update its rate calculations in an evidentiary update after the decision is issued. The 2017 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 2017 (which is equal to its after-tax weighted average cost of capital) is 5.98 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. Pursuant to Order G-75-13, the Commission approved a benchmark ROE of 8.75 percent for FEI, the benchmark utility in BC, effective January 1, 2013 until December 31, 2015, with an Automatic Adjustment Mechanism (AAM) in place. Order G-47-14 further approved, for FBC, a capital structure of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE.

The AAM was not triggered for 2014 or 2015, such that the ROE percentage remained as approved in Orders G-75-13 and G-47-14. FBC has therefore prepared this Application using an ROE of 9.15 percent and a common equity percentage of 40 percent. As part of Order G-75-13, the Commission directed FEI as the benchmark utility to file a cost of capital application no later than November 2015, for determination of cost of capital for periods beyond December 31, 2015. That application was filed and a decision is expected to be received before the proceeding relating to this Application is final. Any changes to the ROE as a result of that proceeding will be reflected in an evidentiary update to this proceeding.

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 has forecast an issuance of long-term debt of $100 million during October 2016, at a forecast rate of

4.0 percent for a term of 30 years, which has been embedded into the long-term 2017 Weighted Average Cost of Debt. The proceeds of this issuance are expected to be used to repay unfunded debt; 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 of the debt issuance will depend on future market conditions and the balance of the unfunded debt.

Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are 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 and prime lending rate margin loans, both drawn on its $150 million operating credit facility, which matures in May 2019. 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 new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained. FBC currently expects to issue long term debt in 2016 for the repayment of maturing debt as well as other capital requirements. The forecast issue rate for 2016 is approximately 4.0 percent based on a 30-year GOC rate of 2.08 percent and an indicative spread of 1.93 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 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 arising from the Company's April 2016 renewal of its operating credit facility agreement and its current credit ratings.

Also included in the Company's short-term interest rate are borrowings using the Prime Lending Rate. Based on the pricing arising from the April 2016 extension of FBC's operating credit facility agreement and its current credit ratings, there is no prime rate margin associated with Prime Rate Margin borrowings.

As a result, the forecast weighted average short-term rate, prior to including standby fees and financing fees, has increased from the 2016 projected rate of 1.90% to a 2017 forecast rate of 2.00%.

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

Table 8-1: Short Term Interest Rate Forecast[18]

Line No.	Description	Projected 2016	Forecast 2017
1	3 month T-Bills[(1)]	0.49%	0.59%
2	Spread to CDOR	0.35%	0.35%
3	Acceptance Fee Rate	1.00%	1.00%
4	Bankers' Acceptance Rate	1.84%	1.94%
5			
6	Prime Rate [(1)]	2.60%	2.65%
7	Prime Rate Margin	0.00%	0.00%
8	Prime Lending Rate	2.60%	2.65%
9			
10	Weighted Average Short-term Rate[(2)]	1.90%	2.00%
11			
12	add: Standby Fee on Undrawn Credit[(3)]	0.16%	2.14%
13	Short-term Interest Rate applied to debt balance	2.06%	4.14%
14	add: Financing fees[(4)]	0.43%	3.41%
15	FBC Short-term Interest Rate	2.49%	7.55%

Notes:

1 3 month T-Bill and Prime rate for 2016 based on a composite of actual historical rates up to March 31, 2016 and forecast rates for the remainder of the year.

2 Representative of the weighted average of BA rate and the Prime Lending Rate.

3 Amounts undrawn on the credit facility are subject to a Standby fee, which is estimated to be 20 basis points in 2016 and 2017. 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.

4 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.

While the 2016 Projected to 2017 Forecast weighted average short-term rate is relatively stable, the all-in short-term interest rate has increased primarily due to a lower balance of draws on the credit facilities (short-term debt) in 2017 Forecast as compared to 2016 Projected. Included in short-term interest expense are standby fees and financing fees. When the absolute dollar amount of standby fees and financing fees are converted into a 2017 short-term interest rate,

[18] The 2016 approved short term rate for FBC was 2.65%, inclusive of standby fees and financing fees.

the rate increases compared to 2016 as a result of dividing these fees over the lower forecast balance of 2017 short-term debt.

8.3.4 Interest Expense Forecast

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

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 2017 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 2017 (which is equal to its after-tax weighted average cost of capital) is 5.98 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2017

Line No.	Description	Weight	Pre-Tax Rate	After-Tax Rate
1	Short Term Debt	0.86%	7.55%	5.59%
2	Long Term Debt	59.14%	5.18%	3.83%
3	Common Equity	40.00%	12.36%	9.15%
4				
5	Weighted Average	100.00%	8.07%	5.98%

8.4 *SUMMARY*

FBC's capital structure and ROE have been forecast for 2017 at the same percentages as approved for 2015 and the ROE will be updated once a decision is reached on the benchmark 2016 ROE. FBC's financing costs on rate base are primarily determined by embedded rates on long-term debt, with one maturity forecast to be refinanced at a lower rate in 2016. While the calculated short-term debt rate is forecast to increase in 2017, this increase 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 2017, 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 consistent basis with prior years. In 2017 property taxes are forecast to increase 4.2 percent from 2016 Approved, while income tax is forecast to increase by 32.2 percent compared to 2016 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 2017 of $16.052 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 2016	Projected 2016	Forecast 2017
1	Generating Plant	$ 2.995	$ 3.006	$ 3.113
2	Transmission and Distribution	6.139	6.269	6.328
3	Substation Equipment	3.651	3.688	3.806
4	Land and Buildings	0.707	0.696	0.729
5	In-Lieu	1.915	1.915	2.076
6	Total Property Taxes	$ 15.407	$ 15.574	$ 16.052
7				
8	Forecast Change from Approved 2016			4.2%
9	Forecast Change from Projected 2016			3.1%

As shown in the table above, in 2017 property taxes are forecast to increase by 4.2 percent from 2016 Approved, and to increase 3.1 percent compared to 2016 Projected. In general, the increase from 2016 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 0.6 percent;

    c) Rural rates are expected to decrease by 0.7 percent;

    d) Tax rates on First Nations are expected to increase 1.5 percent; and

e) Other rates are expected to increase by 3.75 percent.

4. ***Changes in Revenues to Calculate Grants In Lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 10.6 percent 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 the increases that BC Assessment was proposing at the time the forecast was developed. These include:

   a) A 1.5 percent increase in assessed values for distribution lines and transmission lines;

   b) A 2.08 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

   c) A 1.77 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 2.0 percent increase in the assessed value for right of ways to a 5.0 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 increase in 2017 by $2.676 million or 32.2 percent compared to 2016 Approved. This increase is primarily due to an increase in amortization of deferrals and a decrease in deductible temporary tax timing differences associated with capital cost allowance as compared to depreciation, in particular related to AMI computer software and hardware assets.

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

9.4 SUMMARY

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

10. EARNINGS SHARING

The PBR Decision (at pages 120-121) stated that the inclusion of symmetric earnings sharing is beneficial to both FBC and its customers and approved an earnings sharing mechanism where gains and losses are shared equally between FBC and customers. For 2017, FBC is proposing to distribute a $0.344 million pre-tax credit ($0.254 million after tax) as shown in Table 10-1 below. This amount is composed of:

- 2016 projected sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth; and
- The true-up of the 2015 projected earnings sharing to actual.

Table 10-1: Summary of Earnings Sharing to be Returned in 2017 ($ millions)

Line No.	Description	After-tax Amount	Reference
1	2016 Projected Sharing	$ (0.187)	Table 10-2, Line 46
2	Actual Customer Growth Adjustment	0.005	Table 10-3, Line 18
3	2015 Projected vs. Actual Ending Balance True-Up	(0.072)	Table 10-4, Line 3
4			
5	2017 After-Tax Amount Returned to Customers	$ (0.254)	
6	2017 Pre-Tax Amount Returned to Customers	$ (0.344)	

Each of these items is discussed in the sections below.

10.1 *2016 PROJECTED SHARING*

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

Formula-driven O&M less actual base O&M[19] x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[20]) 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 2016 formula-driven O&M savings at $0.803 million, and 2016 capital expenditures in excess of the formula by $3.142 million. The calculation of the 2016 Projected earnings sharing is set out in Table 10-2 below.

19 Excluding items that are reforecast outside of the formula.
20 Ibid .

Table 10-2: Calculation of 2016 Projected Earnings Sharing ($ millions)

Line No.	Description					Reference
1	Approved Formula O&M	$ 53.596				G-139-14
2						
3	Actual/Projected Gross O&M	56.610				
4						
5	Less: O&M Tracked Outside of Formula					
6	Pension/OPEB (O&M Portion)	3.391				
7	Insurance Premiums	1.305				
8	Advanced Metering/Infrastructure Costs/Savings	(1.335)				
9	MRS Incremental O&M	0.455				
10	Total	3.816				Sum of Lines 6 - 9
11						
12	Actual/Projected Base O&M	52.794				Line 3 - Line 10
13						
14	O&M Subject to Sharing	(0.803)				Line 12 - Line 1
15			Annual Capital Expenditures			
16			2014	2015	2016	
17						
18	Cumulative Formula Capital Expenditures	127.451	42.193	42.384	42.874	G-139-14
19						
20	Cumulative Total Regular Capital Expenditures	147.794	49.061	49.043	49.690	Note 1
21						
22	Less: Capital Expenditures Tracked Outside of Formula					
23	Cumulative Pension and OPEB	14.323	6.396	4.253	3.674	
24						
25	Actual/Projected Base Capital Expenditures	133.471	42.665	44.791	46.016	Line 20 - Line 23
26	Deadband Adjustment	-	-	-	-	Adjustment to stay within deadband
27	Actual/Projected Base Capital Expenditures for ESM Calculation	133.471	42.665	44.791	46.016	Line 25 + Line 26
28						
29	Actual/Projected Cumulative Base Capital Expenditure Variance	6.020	0.472	2.408	3.142	Line 27 - Line 18
30						
31	Single Year Deadband % Variance (After Adjustment)		0.97%	5.16%	6.75%	Line 29 / (Line 18 + Line 23)
32	Two Year Cumulative Deadband % Variance (After Adjustment)			6.13%	11.91%	Line 31, sum of two years
33						
34	Equity Component of Rate Base	40.00%	40.00%	40.00%	40.00%	G-139-14
35	Approved Return on Equity	9.15%	9.15%	9.15%	9.15%	G-75-13/G-47-14
36	After Tax Capital Expenditures Subject to Sharing	0.220	0.017	0.088	0.115	Product of Lines 29, 34 & 35
37						
38	Tax Rate	26.00%				G-139-14
39						
40	Before Tax Capital Expenditures Subject to Sharing	0.298				Line 36 ÷ (1 - Line 38)
41						
42	Total Before Tax Sharing Account	(0.505)				Line 14 + Line 40
43	Sharing Percentage	50.00%				G-139-14
44						
45	2016 Projected Earnings Sharing (Pre-Tax)	$ (0.253)				Line 42 x Line 43
46	2016 Projected Earnings Sharing (After-Tax)	$ (0.187)				Line 45 x (1- Line 38)
47						
48	Note 1: 2014 and 2015 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. 2016 is Projected results.					

10.2 *ACTUAL CUSTOMER GROWTH ADJUSTMENT*

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

> FEI and FBC are approved to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the actual customer additions. This positive or negative variance in earned return resulting from the Growth Term shall be recovered from or returned to customers in the subsequent year through the earnings sharing mechanism.

FBC has calculated the resulting adjustment of $0.007 million debit ($0.005 million debit after-tax) for 2015 as shown in Table 10-3 below based on its actual customer additions.

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

Line No.	Description		Reference
1	Average Customers 2015	131,016	
2	Average Customers 2014	129,525	
3	Growth in Average Customers	1,491	Line 1 - Line 2
4	Average Customer Growth	1.151%	Line 3 / Line 2
5		50%	G-139-14
6	Average Customer Growth to be recast in Formula	0.576%	
7	2015 Net Inflation Factor	0.271%	G-202-15 Compliance Filing, Section 11, Schedule 3, Line 9, Column 4
8	2014 Reforecast Formulaic Capital	$ 42.209	Annual Review for 2016 Rates, Table 10-1, Line 9
9	2015 Reforecast Formulaic Capital	$ 42.567	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2015 Year Formulaic Capital	$ 42.384	G-202-15 Compliance Filing, Section 11, Schedule 4, Line 11, Column 4
11			
12	Increase in Capital Requirements from Actual Growth	$ 0.183	Line 9 - Line 10
13	Mid-Year	$ 0.091	Line 12 / 2
14			
15	Equity Cost Component	3.66%	G-139-14
16	Debt Cost Component	3.54%	G-139-14
17	Earned Return on Incremental Capital Requirements (Pre-Tax)	$ 0.007	Line 13 x (line 15 + Line 16)
18	Earned Return on Incremental Capital Requirements (After-Tax)	$ 0.005	Line 17 x 0.74

10.3 *TRUE-UP FOR 2015 ACTUAL EARNINGS SHARING*

In FBC's 2015 Annual Report to the Commission, FBC calculated the final 2015 earnings sharing based on the final 2015 results. The final amount of earnings sharing for 2015 was $0.356 million (after-tax), which was $0.072 million higher than the $0.284 million projected for 2015 as shown in Table 10-4 below. As a result, FBC is increasing its 2017 earnings sharing by the after-tax amount of $0.072 million as shown in Table 10-1 above.

Table 10-4: Calculation of 2015 Actual Earnings Sharing True-Up ($ millions)

Line No.	Description	After-tax Amount	Reference
1	2015 Actual Earnings Sharing Account Ending Balance	$ (0.356)	2015 Annual Report to BCUC
2	2015 Projected Earnings Sharing Account Ending Balance	(0.284)	FBC Annual Review for 2016 Rates Compliance Filing Schedule 12, Line 21, Column 2
3	2017 After-Tax Amount Returned to Customers	$ (0.072)	

10.4 SUMMARY OF EARNINGS SHARING

After calculating the 2016 projected earnings sharing and including the adjustments described above, FBC proposes to distribute $0.344 million to customers in 2017 as a reduction in 2017 revenue requirements through amortization of the projected 2017 after-tax balance of $0.254 million in the Earnings Sharing deferral account.

As part of the Annual Review for 2018 Rates, the earnings sharing for 2016 will be subject to similar true-ups to those described above, which account for the actual O&M and capital expenditure amounts for 2016, as well as impacts, if any, associated with non-performance of Service Quality Indicators, based on final 2016 results.

11. FINANCIAL SCHEDULES

SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2017
($000,000s)

Line No.	Particulars	2017 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	(1.796)		
3	Change in Other Revenue	0.121	(1.675)	
4				
5	**POWER SUPPLY**			
6	Power Purchases (net of customer growth and volume)	4.767		
7	Wheeling	0.165		
7	Water Fees	0.037		
8			4.968	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	0.553		
12	Capitalized Overhead Change	(0.083)	0.470	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions	1.693	1.693	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.200)		
19	Deferrals	2.867	2.667	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	1.249		
23	Financing Ratio Changes	0.053		
24	Rate Base Growth	(0.045)	1.256	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes Changes	0.645		
28	Other Income Taxes Changes	2.676	3.321	
29				
30				
31	Revenue Deficiency (Surplus)		$ 12.701	Schedule 16, Line 7, Column 4
32				
33	Revenue at Existing Rates		352.389	Schedule 16, Line 7, Column 3
34	Rate Change		3.60%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 1,865,084	$ 1,912,643	$ 47,559	Schedule 6.1, Line 14, Column 3
2	Opening Balance Adjustment	-	-	-	
3	Net Additions	54,339	60,399	6,060	Schedule 6.1, Line 14, Column 4+5+6
4	Plant in Service, Ending	1,919,423	1,973,042	53,618	
5					
6	Accumulated Depreciation Beginning	$ (507,239)	$ (553,121)	$ (45,882)	Schedule 7.1, Line 14, Column 5
7	Opening Balance Adjustment	-	-	-	
8	Net Additions	(46,625)	(48,305)	(1,680)	Schedule 7.1, Line 14, Column 6+7+8+9
9	Accumulated Depreciation Ending	(553,863)	(601,426)	(47,563)	
10					
11	CIAC, Beginning	$ (166,764)	$ (176,357)	$ (9,593)	Schedule 9, Line 1, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(9,593)	(6,027)	3,566	Schedule 9, Line 1, Column 4
14	CIAC, Ending	(176,357)	(182,384)	(6,027)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 61,171	$ 64,660	$ 3,489	Schedule 9, Line 3, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	3,489	3,689	200	Schedule 9, Line 3, Column 4
19	Accumulated Amortization Ending - CIAC	64,660	68,349	3,689	
20					
21	Net Plant in Service, Mid-Year	$ 1,253,057	$ 1,252,702	$ (355)	
22					
23	Adjustment for timing of Capital additions	$ -	$ 2,987	$ 2,987	
24	Capital Work in Progress, No AFUDC	6,532	8,387	1,855	
25	Unamortized Deferred Charges	18,316	12,392	(5,924)	Schedule 11, Line 16, Column 8
26	Working Capital	2,009	2,959	951	Schedule 13, Line 15, Column 3
27	Utility Plant Acquistion Adjustment	5,865	5,679	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,285,779	$ 1,285,106	$ (673)	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	Reference	2014	2015	2016	2017	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Cost Drivers for Formulaic Capital and O&M**						
2	CPI		0.473%	0.879%	0.980%	1.627%	
3	AWE		2.277%	1.646%	2.050%	1.212%	
4	Labour Split						
5	Non Labour		45.000%	45.000%	45.000%	45.000%	
6	Labour		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%	1.399%	
8	Productivity Factor		-1.030%	-1.030%	-1.030%	-1.030%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.435%	0.271%	0.539%	0.369%	
10							
11	Average Customer Growth		0.326%	0.181%	0.613%	0.483%	
12	Inflation Factor	(1 + Line 9) x (1 + Line 11)	100.758%	100.452%	101.155%	100.854%	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 4

Line No.	Particulars	CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base	$ 41,875			
3	**2014**				
4	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
5	Formula Capex	42,193			
6	**2015**				
7	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
8	Formula Capex	42,384			
9	**2016**				
10	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
11	Formula Capex	$ 42,874			
12	**2017**				
13	Net Inflation Factor	100.854%			Schedule 3, Line 12, Column 6
14	Formula Capex	$ 43,240		$ 43,240	
15					
16					
17	**Capital Tracked Outside of Formula**				
18	Pension & OPEB (Capital Portion)		$ 3,539		
19	Advanced Metering Infrastructure Sustainment Capital		408		
20	Mandatory Reliability Standards Incremental Capital		1,350		
21	Kootenay Operations Centre		13,405		
22	Ruckles Substation Rebuild		2,078		
23	Upper Bonnington Old Units Refurbishment		5,796		
24	Total		$ 26,576	$ 26,576	
25					
26	**Total Capital Expenditures before CIAC**			$ 69,816	

Schedule 5

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars		2017	Cross Reference
	(1)		(2)	(3)
1	**CAPITAL EXPENDITURES**			
2				
3	Formula Capital Expenditures	$	43,240	Schedule 4, Line 14, Column 4
4	Forecast Capital Expenditures		5,297	Schedule 4, Lines 18 to 20, Column 3
5	Total Regular Capital Expenditures	$	48,537	
6				
7	**CPCN and Special Projects**			
8	Kootenay Operations Centre	$	13,405	Schedule 4, Line 21, Column 3
9	Flow-Through Capital Projects		7,874	Schedule 4, Lines 22+23, Column 3
10	Total CPCN and Special Projects	$	21,279	
11				
12	**Total Capital Expenditures**	$	69,816	
13				
14				
15	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
16				
17	Regular Capital Expenditures	$	48,537	
18	Add - Capitalized Overheads		8,630	Schedule 20, Line 28, Column 4
19	Add - Direct Overheads		5,000	
20	Add - AFUDC		-	
21	Less: Removal costs		(2,541)	Schedule 7.1, Line 14, Column 8
22	Gross Capital Expenditures		59,626	
23	Change in Work in Progress		-	
24	**Total Additions to Plant**	$	59,626	
25				
26				
27	**CPCN and Special Projects**	$	21,279	
28	Add - AFUDC		1,179	
29	Less: Removal costs		-	
30	Gross Capital Expenditures		22,458	
31	Change in Work in Progress		(16,485)	
32	**Total Additions to Plant**	$	5,973	
33				
34	**Grand Total Additions to Plant**	$	65,599	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	12-31-16	CPCNs	Additions	Retirements	12-31-17	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**Hydraulic Production Plant**						
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	15,562	-	340	(10)	15,892	
4	332	Reservoirs, Dams & Waterways	33,955	-	828	(30)	34,754	
5	333	Water Wheels, Turbines and Gen.	96,860	-	42	-	96,902	
6	334	Accessory Equipment	43,059	-	382	(390)	43,052	
7	335	Other Power Plant Equipment	45,982	-	531	(130)	46,383	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	1,287	
9			$ 237,667	$ -	$ 2,124	$ (560)	$ 239,232	
10		**Transmission Plant**						
11	350	Land Rights-R/W	$ 9,206	$ -	$ 197	$ -	$ 9,403	
12	350.1	Land Rights-Clearing	8,436	-	197	-	8,633	
13	353	Station Equipment	201,432	-	13,183	(200)	214,415	
14	355	Poles Towers & Fixtures	108,934	-	3,345	(90)	112,189	
15	356	Conductors and Devices	103,960	-	2,755	(120)	106,595	
16	359	Roads and Trails	1,121	-	-	-	1,121	
17			$ 433,090	$ -	$ 19,677	$ (410)	$ 452,357	
18		**Distribution Plant**					-	
19	360	Land Rights-R/W	$ 4,576	$ -	$ -	$ -	$ 4,576	
20	360.1	Land Rights-Clearing	10,456	-	-	-	10,456	
21	362	Station Equipment	272,296	-	-	(340)	271,956	
22	364	Poles Towers & Fixtures	218,057	-	18,854	(580)	236,331	
23	365	Conductors and Devices	299,545	-	5,628	(600)	304,573	
24	368	Line Transformers	136,134	-	2,814	(1,290)	137,658	
25	369	Services	9,521	-	-	-	9,521	
26	370	Meters	443	-	-	-	443	
27	370.1	AMI Meters	33,637	629	844	-	35,110	
28	371	Installation on Customers' Premises	938	-	-	-	938	
29	373	Street Lighting and Signal System	12,001	-	-	(70)	11,931	
30			$ 997,604	$ 629	$ 28,140	$ (2,880)	$ 1,023,494	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	12-31-16	CPCNs	Additions	Retirements	12-31-17	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**General Plant**						
2	389	Land	$ 12,354	$ -	$ -	$ -	$ 12,354	
3	390	Structures - Frame & Iron	337	-	-	-	337	
4	390.1	Structures - Masonry	45,170	-	713	-	45,884	
5	391	Office Furniture & Equipment	6,900	-	159	-	7,059	
6	391.1	Computer Equipment	97,537	101	5,880	(110)	103,408	
7	391.2	AMI Software	8,391	475	-	-	8,866	
8	392	Transportation Equipment	26,087	-	1,982	(1,170)	26,899	
9	394	Tools and Work Equipment	14,262	-	713	(70)	14,905	
10	397	Communication Structures & Equipment	29,335	-	238	-	29,572	
11	397.1	AMI Communications Structure & Equipment	3,908	4,768	-	-	8,676	
12			$ 244,281	$ 5,344	$ 9,685	$ (1,350)	$ 257,959	
13								
14		**Total Plant in Service**	$ 1,912,643	$ 5,973	$ 59,626	$ (5,200)	$ 1,973,042	
15								
16		Cross Reference		Schedule 5 Line 32 Column 2	Schedule 5 Line 24 Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12-31-16	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12-31-17	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**Hydraulic Production Plant**									
2	330	Land Rights	$ 962	2.60%	$ (488)	$ 25	$ -	$ -	$ -	$ (463)	
3	331	Structures and Improvements	15,562	1.29%	5,373	201	(10)	(16)	-	5,549	
4	332	Reservoirs, Dams & Waterways	33,955	1.78%	6,639	604	(30)	(38)	-	7,175	
5	333	Water Wheels, Turbines and Gen.	96,860	1.79%	14,937	1,734	-	(2)	-	16,669	
6	334	Accessory Equipment	43,059	2.28%	10,178	982	(390)	(18)	-	10,752	
7	335	Other Power Plant Equipment	45,982	2.05%	13,972	943	(130)	(24)	-	14,760	
8	336	Roads, Railroads and Bridges	1,287	1.47%	363	19	-	-	-	382	
9			$ 237,667		$ 50,973	$ 4,507	$ (560)	$ (97)	$ -	$ 54,823	
10		**Transmission Plant**									
11	350	Land Rights-R/W	$ 9,206	0.00%	$ (183)	$ -	$ -	$ -	$ -	$ (183)	
12	350.1	Land Rights-Clearing	8,436	1.23%	2,035	104	-	-	-	2,138	
13	353	Station Equipment	201,432	2.45%	66,684	4,935	(200)	(858)	-	70,561	
14	355	Poles Towers & Fixtures	108,934	2.53%	25,596	2,756	(90)	(211)	-	28,051	
15	356	Conductors and Devices	103,960	2.52%	19,238	2,620	(120)	(174)	-	21,564	
16	359	Roads and Trails	1,121	2.88%	273	32	-	-	-	305	
17			$ 433,090		$ 113,643	$ 10,447	$ (410)	$ (1,244)	$ -	$ 122,436	
18		**Distribution Plant**									
19	360	Land Rights-R/W	$ 4,576	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
20	360.1	Land Rights-Clearing	10,456	1.23%	2,079	129	-	-	-	2,207	
21	362	Station Equipment	272,296	2.57%	59,998	6,998	(340)	-	-	66,656	
22	364	Poles Towers & Fixtures	218,057	2.67%	52,176	5,822	(580)	(733)	-	56,685	
23	365	Conductors and Devices	299,545	2.89%	88,268	8,657	(600)	(219)	-	96,106	
24	368	Line Transformers	136,134	2.74%	31,146	3,730	(1,290)	(109)	-	33,477	
25	369	Services	9,521	0.50%	6,648	48	-	-	-	6,696	
26	370	Meters	443	6.68%	84	30	-	-	-	113	
27	370.1	AMI Meters	34,266	5.00%	2,014	1,713	-	(33)	-	3,695	
28	371	Installation on Customers' Premises	938	0.00%	938	-	-	-	-	938	
29	373	Street Lighting and Signal System	12,001	4.65%	3,120	558	(70)	-	-	3,608	
30			$ 998,233		$ 246,470	$ 27,684	$ (2,880)	$ (1,095)	$ -	$ 270,180	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12-31-16	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12-31-17	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**General Plant**									
2	389	Land	$ 12,354	0.00%	$ (11)	$ -	$ -	$ -	$ -	$ (11)	
3	390	Structures - Frame & Iron	337	0.56%	283	2	-	-	-	285	
4	390.1	Structures - Masonry	45,170	2.77%	18,366	1,251	-	(9)	-	19,608	
5	391	Office Furniture & Equipment	6,900	1.68%	5,648	116	-	(2)	-	5,762	
6	391.1	Computer Equipment	97,638	7.21%	76,991	7,040	(110)	(55)	-	83,866	
7	391.2	AMI Software	8,866	10.00%	1,456	887	-	-	-	2,343	
8	392	Transportation Equipment	26,087	6.01%	8,538	1,568	(1,170)	(26)	-	8,910	
9	394	Tools and Work Equipment	14,262	2.49%	10,557	355	(70)	(9)	-	10,833	
10	397	Communication Structures & Equipment	29,335	5.49%	19,793	1,610	-	(3)	-	21,400	
11	397.2	AMI Communications Structure & Equipment	8,676	6.67%	413	579	-	-	-	991	
12			$ 249,625		$ 142,035	$ 13,407	$ (1,350)	$ (105)	$ -	$ 153,987	
13											
14	108	Total Accumulated Depreciation	$ 1,918,616		$ 553,121	$ 56,046	$ (5,200)	$ (2,541)	$ -	$ 601,426	
15											
16		Cross Reference	Schedule 6.1 Line 14 Columns 3+4								

SCHEDULE NOT APPLICABLE

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	12-31-16	Adjustment	Additions	Retirements	12-31-17	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**	$ 176,357	$ -	$ 6,027	$ -	$ 182,384	
2							
3	**Amortization**	(64,660)	-	(3,689)	-	(68,349)	
4							
5	**Net CIAC**	$ 111,698	$ -	$ 2,338	$ -	$ 114,036	

SCHEDULE NOT APPLICABLE

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	12-31-16	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12-31-17	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Energy Policy								
2	Demand Side Management	$ 20,472	$ -	$ 7,610	$ (1,979)	$ (3,257)	$ 22,846	$ 21,659	
3		$ 20,472	$ -	$ 7,610	$ (1,979)	$ (3,257)	$ 22,846	$ 21,659	
4									
5	Preliminary and Investigative Charges								
6	Preliminary and Investigative Charges[1]	$ 200	$ -	$ -	$ -	$ -	$ 200	$ 200	Note 1
7		$ 200	$ -	$ -	$ -	$ -	$ 200	$ 200	
8									
9	Other								
10	Right of Way Reclamation (Pine Beetle Kill)	$ 346	$ -	$ -	$ -	$ (173)	$ 173	$ 260	
11	Deferred Debt Issue Costs	5,032	-	-	(178)	(202)	4,651	4,841	
12	Accounting Treatment of non-AMI Meters	3,245	-	-	-	(1,082)	2,163	2,704	
13	Pemsion and OPEB Liability	(16,999)	-	(546)	-	-	(17,545)	(17,272)	
14		$ (8,376)	$ -	$ (546)	$ (178)	$ (1,457)	$ (10,557)	$ (9,466)	
15									
16	**Total Rate Base Deferral Accounts**	$ 12,296	$ -	$ 7,064	$ (2,157)	$ (4,714)	$ 12,489	$ 12,392	
17									
18	Note 1: Gross additions for Preliminary and Investigative Charges are net of transfers to Construction Work in Progress. Additions of $215,000 - transfers of $215,000 = $0								

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 12

Line No.	Particulars	12-31-16	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12-31-17	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	Revenue and Power Supply Variances	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Note 1
4									
5	Flow-Through Account	$ 6,445	$ -	$ -	$ -	$ (6,445)	$ -	$ 3,223	
6									
7	Non-Controllable Items								
8	Pension & Other Post Retirement Benefits (OPEB) Variance	$ (2,492)	$ -	$ -	$ -	$ 2,182	$ (309)	$ (1,400)	
9		$ (2,492)	$ -	$ -	$ -	$ 2,182	$ (309)	$ (1,400)	
10									
11	Regulatory Compliance								
12	2014-2019 Performance Based Ratemaking Application	$ 739	$ -	$ -	$ -	$ (246)	$ 493	$ 616	
13	Annual Reviews 2015 - 2019 Rates	151	-	150	(39)	(151)	111	131	
14	Self-Generation Policy Application, Stage II	74	-	-	-	(74)	-	37	
15	Net Metering Program Tariff Update	56	-	-	-	(56)	-	28	
16	BCUC Residential Inclining Block Rate Report	74	-	-	-	(74)	-	37	
17	2017 Demand Side Management Expenditure Schedule Application	56	-	-	-	(56)	-	28	
18	Transmission Tariff Review	74	-	-	-	(74)	-	37	
19		$ 1,223	$ -	$ 150	$ (39)	$ (730)	$ 604	$ 913	
20									
21	Other								
22	2014-2019 Earnings Sharing Account	$ (254)	$ -	$ -	$ -	$ 254	$ -	$ (127)	
23	2014 Interim Rate Variance	(12,547)	-	-	-	12,547	-	(6,274)	
24	2016 FEI Return on Equity Decision	-	-	-	-	-	-	-	
25		$ (12,802)	$ -	$ -	$ -	$ 12,802	$ -	$ (6,401)	
26									
27	Residual								
28	City of kelowna Acquisition Legal & Regulatory Costs	$ 2	$ -	$ -	$ -	$ (2)	$ -	$ 1	
29	BC Hydro Application for Power Purchase Agreement with FBC	71	-	-	-	(71)	-	35	
30		$ 73	$ -	$ -	$ -	$ (73)	$ -	$ 36	
31									
32									
33	**Total Deferral Accounts at Short Term Interest**	$ (7,552)	$ -	$ 150	$ (39)	$ 7,736	$ 294	$ (3,629)	
34									
35	Financing Costs at STI	$ (174)	$ -	$ (74)	$ 19	$ 174	$ (55)	$ (115)	
36									
37	Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term								

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	12-31-16	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12-31-17	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	Preliminary and Investigative Charges								
4	CPCN Projects Preliminary Engineering	$ 1,722	$ -	$ (1,119)	$ -	$ -	$ 603	$ 1,162	
5		$ 1,722	$ -	$ (1,119)	$ -	$ -	$ 603	$ 1,162	
6									
7	Regulatory Compliance								
8	2016 Long Term Electric Resource Plan	$ 321	$ -	$ 120	$ (31)	$ -	$ 410	$ 365	
9	2017 Rate Design Application	185	-	650	(169)	-	666	426	
10		$ 506	$ -	$ 770	$ (200)	$ -	$ 1,076	$ 791	
11									
12	Other								
13	US GAAP Pension and OPEB Transitional Obligation	$ 3,555	$ -	$ (827)	$ -	$ -	$ 2,728	$ 3,141	
14	Advanced Metering Infrastructure Radio-Off Shortfall	73	-	100	(26)	-	$ 147	110	
15	Celgar Interim Period Billing Adjustment	6,301	-	-	-	(6,301)	-	3,150	
15		$ 9,928	$ -	$ (727)	$ (26)	$ (6,301)	$ 2,875	$ 6,402	
16									
17	Residual								
18	Transmission Customer Rate Design	$ 69	$ -	$ -	$ -	(69)	$ -	$ 35	
19		$ 69	$ -	$ -	$ -	$ (69)	$ -	$ 35	
20									
21	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ 12,225	$ -	$ (1,076)	$ (226)	$ (6,370)	$ 4,553	$ 8,389	
22									
23	Financing Costs at WACD	$ 335	$ -	$ 446	$ (116)	$ (335)	$ 330	$ 333	
24									
25	**Deferral Accounts Financed at AFUDC**								
26									
27	Energy Policy								
28	On Bill Financing (OBF) Participant Loans	$ 11	$ -	$ (5)	$ 1	$ -	$ 8	$ 10	
29									
30	**Total Deferral Accounts at AFUDC**	$ 11	$ -	$ (5)	$ 1	$ -	$ 8	$ 10	
31									
32	Financing Costs at AFUDC	$ 1	$ -	$ -	$ -	$ (1)	$ -	$ 1	
33									
34	**Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
35									
36	**Total Non Rate Base Deferral Accounts (including financing)**	$ 4,896	$ -	$ (559)	$ (361)	$ 1,204	$ 5,181	$ 5,038	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 5,343	$ 5,549	$ 206	Schedule 14, Line 40, Column 5
3					
4	Add: Funds Unavailable				
5	Customer Loans	990	800	(190)	
6	Employee Loans	349	310	(39)	
7	Uncollectible Accounts	697	1,520	823	
8	Inventory (average monthly investment)	531	580	49	
9					
10	Less: Funds Available				
11	Average Customer Deposits	(4,500)	(4,440)	60	
12	Average Provincial Sales Tax	(741)	(710)	31	
13	Average Goods and Services Tax	(659)	(650)	9	
14					
15	Total	$ 2,009	$ 2,959	$ 949	

CASH WORKING CAPITAL Schedule 14
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2017 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	$ 189,113	50.7	$ 9,588		
4	Commercial Tariff Revenue	86,960	49.6	4,313		
5	Wholesale Tariff Revenue	48,895	33.2	1,623		
6	Industrial Tariff Revenue	33,775	33.2	1,121		
7	Other Tariff Revenue	6,348	48.2	306		
8						
9	**Other Revenue**					
10	Apparatus and Facilities Rental	4,576	27.4	125		
11	Contract Revenue	1,865	43.6	81		
12	Transmission Revenue	1,179	15.2	18		
13	Interest Income	24	15.2	0		
14	Other Utility Income	412	44.7	18		
15						
16	Total	$ 373,146		$ 17,195	46.1	
17						
18	**EXPENSES**					
19	Power Purchases	$ 138,674	41.7	5,783		
20	Wheeling	4,928	40.2	198		
21	Water Fees	10,328	(1.0)	(10)		
22	Operating Labour					
23	Salaries and Wages	16,982	5.3	90		
24	Employee Benefits	13,481	13.2	178		
25	Contracted Labour	12,632	50.6	639		
26	Rental of T&D Facilities	3,372	48.6	164		
27	Office Lease	600	(15.2)	(9)		
28	Materials	508	45.6	23		
29	Insurance	1,327	(182.5)	(242)		
30	Interest	40,187	85.2	3,424		
31	Property Taxes	16,052	1.4	22		
32	Income Tax	10,986	15.2	167		
33						
34	Total	$ 270,058		$ 10,427	(38.6)	
35						
36	Net Lag (Lead) Days				7.5	
37						
38	Total Expenses				$ 270,058	
39						
40	Cash Working Capital				$ 5,549	

SCHEDULE NOT APPLICABLE

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast at Existing Rates	2017 Forecast Revised Revenue	2017 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,262	3,282		3,282	20	Schedule 17, Line 7, Column 3
3							
4	**REVENUE**						
5	Sales	$ 340,511	$ 352,389	$ -	$ 352,389	$ 11,878	
6	Deficiency (Surplus)	10,082	-	12,701	12,701	2,619	
7	Total	350,593	352,389	12,701	365,090	14,497	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	148,962	153,930	-	153,930	4,968	Schedule 19, Line 29, Column 3
11	O&M Expense (net)	48,432	48,902	-	48,902	470	Schedule 20, Line 29, Column 4
12	Depreciation & Amortization	51,694	56,053	-	56,053	4,359	Schedule 21, Line 11, Column 3
13	Property Taxes	15,407	16,052	-	16,052	645	Schedule 22, Line 7, Column 3
14	Other Revenue	(8,177)	(8,056)	-	(8,056)	121	Schedule 23, Line 8, Column 3
15	Utility Income Before Income Taxes	94,275	85,507	12,701	98,208	3,933	
16							
17	Income Taxes	8,310	7,684	3,302	10,986	2,676	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 85,965	$ 77,824	$ 9,399	$ 87,222	$ 1,258	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,285,779	$ 1,285,106		$ 1,285,106	$ (673)	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.69%	6.06%		6.79%	0.10%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,367	1,353	(14)	
3	Commercial	871	879	9	
4	Wholesale	579	587	8	
5	Industrial	393	407	14	
6	Lighting & Irrigation	52	55	3	
7	Total	3,262	3,282	20	
8					
9	**REVENUE AT EXISTING RATES**				
10	Residential	$ 184,048	$ 182,534	$ (1,514)	
11	Commercial	82,385	83,934	1,549	
12	Wholesale	46,940	47,194	254	
13	Industrial	31,020	32,600	1,580	
14	Lighting & Irrigation	6,199	6,127	(72)	
15	Total	$ 350,593	$ 352,389	$ 1,796	

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved Revenue	2017 Forecast Revenue at Existing Rates	2017 Forecast Effective Increase	2017 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 184,048	$ 182,534	$ 6,579	$ 189,113	115,595	1,353	
2	Commercial	82,385	83,934	3,025	86,960	15,517	879	
3	Wholesale	46,940	47,194	1,701	48,895	6	587	
4	Industrial	31,020	32,600	1,175	33,775	50	407	
5	Lighting & Irrigation	6,199	6,127	221	6,348	2,685	55	
6								
7	Total	$ 350,593	$ 352,389	$ 12,701	$ 365,090	133,853	3,282	
8								
9	**Effective Increase**				3.60%			

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 19

Line No.	Particulars		2016 Approved		2017 Forecast		Change	Cross Reference
	(1)		(2)		(3)		(4)	(5)
1	**POWER PURCHASES**							
2	Gross Load (GWh)		3,540		3,559		19	
3								
4	**Power Purchase Expense**							
5	Brilliant	$	38,785	$	39,983	$	1,198	
6	BC Hydro PPA		47,545		48,731		1,186	
7	Waneta Expansion		37,358		38,415		1,057	
8	Independent Power Producers		195		204		9	
9	Market and Contracted Producers		10,023		11,341		1,318	
10	Balancing Pool		-		-		-	
11	Total	$	133,907	$	138,674	$	4,767	
12								
13	**WHEELING**							
14	**Wheeling Nomination (MW months)**							
15	Okanagan Point of Interconnection		2,400		2,430		30	
16	Creston		432		432		-	
17								
18	**Wheeling Expense**							
19	Okanagan Point of Interconnect	$	4,221	$	4,374	$	153	
20	Creston		495		507		12	
21	Other		48		48		-	
22	Total	$	4,764	$	4,928	$	165	
23								
24	**WATER FEES**							
25	Plant Entitlement Use in previous year (GWh)		1,649		1,617		(32)	
26								
27	Water Fees	$	10,291	$	10,328	$	37	
28								
29	Total	$	148,962	$	153,930	$	4,968	

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 20

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base O&M	$ 60,159			
3	Less: O&M tracked outside of Formula	(7,810)			
4	O&M Subject to Formula	52,349			
5	**2014**				
6	Net Inflation Factor	100.758%			Schedule 3, Line 12, Column 3
7	Formula O&M	52,746			
8	**2015**				
9	Net Inflation Factor	100.452%			Schedule 3, Line 12, Column 4
10	Formula O&M	52,984			
11	**2016**				
12	Net Inflation Factor	101.155%			Schedule 3, Line 12, Column 5
13	Formula O&M	$ 53,596			
14	**2017**				
15	Net Inflation Factor	100.854%			Schedule 3, Line 12, Column 6
16	Formula Capex	$ 54,054		$ 54,054	
17					
18	**O&M Tracked Outside of Formula**				
19	Pension & OPEB (O&M Portion)		$ 3,267		
20	Insurance Premiums		1,327		
21	Advanced Metering Infrastructure Costs/Savings		(1,126)		
22	Mandatory Reliability Standards Incremental O&M		50		
23	Upper Bonnington Unit 3 Annual Inspection		(40)		
24	Total		$ 3,478	3,478	
25					
26	**Total Gross O&M**			$ 57,532	
27					
28	Capitalized Overhead - 15% of Total Gross O&M			(8,630)	
29	**Net O&M Expense**			$ 48,902	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 21

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 54,353	$ 56,046	$ 1,693	Schedule 7.1, Line 14, Column 6
3					
4	**Amortization**				
5	Rate Base deferrals	$ 4,630	$ 4,714	$ 84	Schedule 11, Line 16, Column 6
6	Non-Rate Base deferrals	(3,986)	(1,204)	2,782	Schedule 12.1, Line 36, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(3,489)	(3,689)	(200)	Schedule 9, Line 3, Column 4
9		(2,659)	7	2,667	
10					
11	Total	$ 51,694	$ 56,053	$ 4,360	

PROPERTY AND SUNDRY TAXES Schedule 22
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 2,995	$ 3,113	$ 118	
2	Transmission and Distribution	6,139	6,328	189	
3	Substation Equipment	3,651	3,806	155	
4	Land and Buildings	707	729	22	
5	1% In-Lieu of Municipal Taxes	1,915	2,076	161	
6					
7	Total	$ 15,407	$ 16,052	$ 645	

OTHER REVENUE Schedule 23

FOR THE YEAR ENDING DECEMBER 31, 2017

($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 4,467	$ 4,576	$ 108	
2	Contract Revenue	1,808	1,865	57	
3	Transmission Access Revenue	1,230	1,179	(51)	
4	Interest Income	34	24	(10)	
5	Connection Charge	496	270	(226)	
6	Other Recoveries	142	142	-	
7					
8	Total	$ 8,177	$ 8,056	$ (121)	

INCOME TAXES Schedule 24
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved	2017 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 85,965	$ 87,222	$ 1,257	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(38,906)	(40,187)	(1,282)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(23,407)	(15,768)	7,639	Schedule 24, Line 29, Column 3
4	Accounting Income After Tax	$ 23,652	$ 31,267	$ 7,615	
5					
6	1 - Current Income Tax Rate	74.00%	74.00%	0.00%	
7	Taxable Income	$ 31,962	$ 42,253	$ 10,291	
8					
9	Current Income Tax Rate	26.00%	26.00%	0.00%	
10	Income Tax - Current	$ 8,310	$ 10,986	$ 2,676	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 8,310	$ 10,986	$ 2,676	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 54,353	$ 56,046	$ 1,693	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	644	3,510	2,866	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	7,065	6,806	(259)	
22					
23	Deductions:				
24	Capital Cost Allowance	(67,576)	(64,245)	3,331	Schedule 25, Line 19, Column 6
25	CIAC Amortization	(3,489)	(3,689)	(200)	Schedule 21, Line 8, Column 3
26	Pension & OPEB Contributions	(5,720)	(5,433)	287	
27	Overheads Capitalized Expensed for Tax Purposes	(8,547)	(8,630)	(83)	Schedule 20, Line 28, Column 4
28	All Other	(322)	(319)	3	
29	Total	$ (23,407)	$ (15,768)	$ 7,639	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Schedule 25

Line No.	Class	CCA Rate	31-12-2016 UCC Balance	Adjustments	2017 Additions	2017 CCA	31-12-2017 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 196,972	$ -	$ -	$ 7,879	$ 189,093
2	1(b)	6%	16,705	-	589	1,020	16,274
3	2	6%	16,530	-	-	992	15,538
4	3	5%	1,030	-	-	51	978
5	6	10%	5	-	-	1	5
6	8	20%	3,353	-	720	743	3,331
7	9	25%	-		-	-	-
8	10	30%	4,694	-	1,637	1,654	4,678
9	12	100%	-	-	-	-	-
10	13	manual	89	-	-	75	14
11	14.1	5%	-	-	162	4	158
12	17	8%	96,911	-	1,871	7,828	90,955
13	42	12%	3,936	-	4,506	743	7,699
14	45	45%	17	-	-	8	9
15	46	30%	9,175	-	-	2,752	6,422
16	47	8%	443,038	-	37,602	36,947	443,693
17	50	55%	3,610	-	5,686	3,549	5,747
18							
19	Total		$ 796,065	$ -	$ 52,774	$ 64,245	$ 784,595

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 Approved Earned Return	2017 Amount	2017 Ratio	2017 Average Embedded Cost	2017 Cost Component	2017 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 36,587	$ 760,000	59.14%	5.18%	3.06%	$ 39,353	$ 2,765	Schedule 27, Line 11, Column 6
2	Short Term Debt	2,319	11,064	0.86%	7.55%	0.06%	835	(1,484)	
3	Common Equity	47,060	514,043	40.00%	9.15%	3.66%	47,035	(25)	
4									
5	Total	$ 85,965	$ 1,285,106	100.00%		6.79%	$ 87,222	$ 1,256	
6									
7	Cross Reference		Schedule 2 Line 29 Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Series G	28-08-1993	28-08-2023	$ 25,000	8.800%	$ 2,200	
2	Series I	01-12-1997	01-12-2021	25,000	7.810%	1,953	
3	Series 1 - 05	09-11-2005	09-11-2035	100,000	5.600%	5,600	
4	Series 1 - 07	04-07-2007	04-07-2047	105,000	5.900%	6,195	
5	MTN - 09	02-06-2009	02-06-2039	105,000	6.100%	6,405	
6	MTN - 10	24-11-2010	24-11-2050	100,000	5.000%	5,000	
7	MTN - 14	28-10-2014	28-10-2044	200,000	4.000%	8,000	
8	MTN - 16 (forecast)	15-10-2016	tbd	100,000	4.000%	4,000	
9	Total			$ 760,000		$ 39,353	
10							
11	Average Embedded Cost				5.18%		

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 related to regulatory matters, and the amortization of one existing deferral account. FBC also reports on three of its existing deferral accounts, including requesting the disposition of the Celgar Interim Period Billing Adjustment deferral account and reporting on the calculation of the balance in the Flow-through deferral account 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, as described below.

12.2.1 Mandatory Reliability Standards

FBC will continue to incur incremental O&M and capital requirements in 2017 and future years related to complying with the changes to BC's MRS program approved by Order R-38-15. Consistent with Order G-202-15, these costs qualify for exogenous factor treatment under the PBR Plan.

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

> In Section 6.3.6, FBC identified incremental O&M Expense in 2016 and future years (and incremental capital expenditures in 2017) related to MRS that qualify as exogenous events. By Order R-38-15 dated July 24, 2015, the Commission adopted 34 reliability standards and the NERC (North American Electric Reliability Corporation) Glossary of Terms as recommended for adoption by BC Hydro in MRS Assessment Report No. 8. In that Order, the Commission also identified that one standard is pending and two standards are held in abeyance. The Commission accepted BC Hydro's recommendation of adoption given that the major portion of costs identified by the entities relate to the implementation of new cyber security requirements, new modelling and testing requirements for generators and synchronous condensers, and an overhaul of the protection system maintenance program requirements.
>
> This event and the costs required as a result of the adoption of the reliability standards meet the exogenous factor criteria identified above.
>
> - The costs are entirely attributed to complying with the changes to BC's MRS program approved by Order R-38-15, which is an event outside the control of FBC. These changes were developed by regulatory bodies in the U.S., assessed for adoption by BC Hydro and then adopted by the BCUC. FBC is legally obligated to comply with the new reliability standards.
> - As described in section 6.3.6, the costs are directly and solely attributable to complying with the changes to the BC MRS program approved on July 24, 2015. These costs have not been previously incurred and were not known at the time the 2013 base O&M was determined and therefore were not included in the 2013 base O&M used to determine the O&M expense included in the PBR formula.
> - The costs to comply with the reliability standards that were approved by Order R-38-15 could not have been foreseen at the time the 2013 base was set as the new standards were either non-existent or under preliminary development at the time.
> - FBC will manage its costs to comply with the reliability standards in a prudent manner and the Commission will have the opportunity to review the costs in subsequent annual reviews.
> - The forecast O&M costs of $0.445 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.

Although FBC has updated its forecast costs as set out below, the description above remains true for FBC's incremental costs to comply with changes to BC's MRS program approved by Order R-38-15.

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.

FBC has updated its forecast of incremental costs associated with complying with Assessment Report No. 8 as described in Sections 6.3.4 and 7.2.2 of the Application. For 2017, FBC forecasts incremental costs of $1.400 million, comprised of $0.050 million in incremental O&M expense and an incremental $1.350 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 Order G-202-15. 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 two sections, 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 below, none of which impact the accounting policies or rate forecasts for 2017.

12.3.1.1 Revenue Recognition

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers* and the amendments in this update created Accounting Standard Codification (ASC) Topic 606. 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. This standard was originally effective for annual and interim periods beginning on or after December 15, 2016. In August 2015, FASB issued ASU No. 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. ASU No. 2015-14 defers the effective date of ASU No. 2014-09 by one year to annual and interim periods beginning after December 15, 2017, which is January 1, 2018 for FBC.

Three ASU's were issued in 2016 to clarify implementation guidance in ASC Topic 606. ASU No. 2016-08, *Principal versus Agent Considerations*, was issued in March 2016, ASU No. 2016-10, *Identifying Performance Obligations and Licensing*, was issued in April 2016 and ASU No. 2016-12, *Narrow-Scope Improvements and Practical Expedients,* was issued in May 2016. The effective date of these updates is the same as the effective date and transition requirements of ASU No. 2014-09.

ASU No. 2014-09 is not expected to significantly change current practice for rate-regulated operations that use published tariff rates to recognize revenue upon delivery of electricity to a customer meter. FBC is revisiting its revenue contracts associated with commodity exchange arrangements, capacity sales agreements and any bundled arrangements. FBC is also revisiting the accounting treatment of contributions in aid of construction under ASU No. 2014-09. Any long-term sale arrangements will need to be aggregated and documented to determine whether the terms result in changes to how revenue is recognized under ASU No. 2014-09. There are various situations that could arise which could change the timing of when revenue is recognized, resulting in revenue being deferred on the balance sheet. FBC has not yet selected a transition method and is assessing the impact that the adoption of this standard, and all related ASUs, will have on its consolidated financial statements and related disclosures. FBC plans to have this assessment substantially complete by the end of 2016 and will provide an update in the Annual Review for 2018 rates.

12.3.1.2 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 and early adoption is permitted. 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. FBC has building operating leases which could potentially be recorded 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 is assessing the impact that the adoption of this standard will have on its consolidated financial statements and related disclosures and will provide an update in the Annual Review for 2018 rates.

12.3.1.3 Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In January 2016, FASB issued a proposed ASU, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (net benefit cost). Currently, it is not known when a final standard will be issued and FASB has not set an effective date for the standard.

As approved by the BCUC, FBC capitalizes net benefit costs related to pension and other post-retirement benefits (OPEB) to property, plant and equipment with the balance expensed as operating costs in the income statement. The proposed ASU would allow only the service cost component of net benefit costs to be eligible for capitalization, while the other components would not be eligible to be capitalized. This proposed standard could result in a decrease in the amount of pension and OPEB costs currently allocated to capital and an increase in the net benefit costs currently recognized in the income statement. Rate-regulated entities have commented on the proposed ASU and are proposing that rate-regulated entities be allowed to continue to capitalize all components of net benefit costs related to pension and OPEB to property, plant and equipment. FBC will monitor the progress of this standard and provide an update in the Annual Review for 2018 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 return equal to the WACC. 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 $5.038 million in 2017.

In the following sections, FBC requests approval of five new deferral accounts, all of which are related to regulatory requirements. FBC also provides additional information for three of its previously approved deferral accounts.

12.4.1 New Deferral Accounts

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.

12.4.1.1 Self-Generation Policy, Stage II

In Order G-60-14, the Commission directed FBC to initiate a consultation process in its service area and to file a Self-Generation Policy (SGP) application. FBC filed its SGP application on January 9, 2015. The Commission determined that the review of the Application would proceed by way of a two-staged approach. In Order G-27-16, the Commission made certain findings on the High Level Policy Statement and Supporting Policies contained in the SGP application (the Stage I Decision) to guide the development of a comprehensive Self-Generation Policy and GBL Guidelines (Stage II Application).

FBC expects to file its Stage II application on September 30, 2016, and will incur incremental costs primarily consisting of legal fees, public consultation costs, Commission expenses and Intervener funding. Although the scope of this proceeding is not known at this time, FBC estimates these costs on a preliminary basis at $0.100 million ($0.074 million after tax).

FBC is seeking approval of a deferral account attracting a STI return, to capture costs related to the Stage II Application in 2016. FBC proposes to amortize the costs over one year, in 2017.

12.4.1.2 Net Metering Program Tariff Update Application

On April 15, 2016, FBC filed a Net Metering Program Tariff Update Application and the Commission established a written public hearing for its review. FBC will incur incremental costs primarily consisting of legal fees, Commission expenses and Intervener funding, estimated at $0.075 million ($0.056 million after tax).

FBC is seeking approval of a deferral account attracting a STI return, to capture costs related to the Net Metering Program Tariff Update. FBC proposes to amortize the costs over one year, in 2017.

12.4.1.3 BCUC Residential Inclining Block (RIB) Rate Report

In July, 2015, the Commission was requested to report to the provincial government on certain issues regarding the residential inclining block rates of BC Hydro and FBC (FBC's Residential Conservation Rate). To date, FBC has made submissions in the initial phase of this proceeding and has responded to Information Requests from the Commission. On July 15, 2016, the Commission commenced a public comment process for residential customers in communities without access to natural gas. FBC expects to incur incremental costs related to this filing which are estimated on a preliminary basis at $0.100 million ($0.074 million after tax).

FBC is seeking approval of a deferral account attracting a STI return, to capture costs related to the BCUC RIB Rate Report. FBC proposes to amortize the costs over one year, in 2017.

12.4.1.4 2017 Demand Side Management Expenditure Schedule

FBC intends to file an application for approval of its 2017 DSM Expenditure Schedule in August, 2016. A written public hearing is anticipated for the review of this application and FBC will incur incremental costs primarily consisting of legal fees, Commission expenses and Intervener funding. These costs have been estimated at $0.075 million ($0.056 million after tax).

FBC is seeking approval of a deferral account attracting a STI return, to capture costs related to the 2017 DSM Expenditure Schedule. FBC proposes to amortize the costs over one year, in 2017.

12.4.1.5 Transmission Tariff Review

FBC expects to file an application to update its Transmission Tariff in the fall of 2016 and will incur incremental costs primarily consisting of legal fees, stakeholder consultation costs, Commission expenses and Intervener funding. Although the scope of this proceeding is not known at this time, FBC estimates these costs on a preliminary basis at $0.100 million ($0.074 million after tax).

FBC is seeking approval of a deferral account attracting a STI return, to capture costs related to the Transmission Tariff Review. FBC proposes to amortize the costs over one year, in 2017.

12.4.2 Existing Deferral Accounts

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

12.4.2.1 Celgar Interim Period Billing Adjustment

The Stage IV Decision in FBC's Application for Approval of Stepped and Stand-by Rates for Transmission Customers (Order G-149-15) retroactively set a Stand-by Demand Limit and a Stand-by Billing Demand for Zellstoff Celgar Limited Partnership (Celgar), and directed FBC and Celgar to negotiate an agreement as to the appropriate billing charges during the period during which Celgar's rates were interim. On October 22, 2015, FBC and Celgar filed an executed settlement agreement in respect of the billing charges. The Commission issued Order G-214-15 (the Stage V decision) on December 24, 2015, approving the establishment of a deferral account to recover from ratepayers the refund amount ($8.514 million before tax) and associated carrying costs. The deferral account is to be amortized within five years of the date of the Order (2020).

FBC proposes to amortize this account fully during 2017, in order to partially offset the amortization of the remaining credit balance ($12.457 million after tax) of the 2014 Interim Rate Variance account.

12.4.2.2 2016 FEI Return on Equity Decision Deferral

On October 2, 2015, FEI filed an application to set its Common Equity Component and Return on Equity (ROE) for 2016. The regulatory review process is complete and FEI is awaiting a decision. Once a decision is received, FBC will calculate the impact, if any, on 2016 revenue requirements that results from the change FEI's ROE (as the benchmark utility). FBC will file an Evidentiary Update to request approval to capture the amount of the impact in the deferral account that was approved for this purpose in Order G-202-15. Order G-202-14 stated:

> Approval is granted for FBC to establish a deferral account to capture the difference between the rate impact of Directive No. 1 above and any future rate impact resulting from setting the Benchmark rate in the FortisBC Energy Inc. (FEI) Application for a Common Equity Component and Return on Equity for 2016 proceeding.

12.4.2.3 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 and accepted in the determination of 2015 rates pursuant to Order G-107-15.

Table 12-1: Variances Captured in the Flow-through Deferral Account[21]

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

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

In accordance with the method set out above, the calculation of the 2016 projected Flow-through amount of $3.472 million debit is shown in Table 12-2 below. To calculate the amount to be distributed to customers, FBC has also included an adjustment for the difference between the projected ending 2015 deferral account credit balance of $(0.561 million) embedded in 2016 rates and the actual ending 2015 deferral account debit balance of $2.412 million, a difference of $2.973 million debit.

[21] 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.

Table 12-2: 2016 Flow-through Deferral Account Additions ($ millions)

Line No.	Description	Approved 2016	Projected 2016	Variance
1	Revenue	$ (350.593)	$ (340.326)	$ 10.267
2				
3	Power Purchase Expense	133.907	128.439	(5.468)
4				
5	Wheeling	4.764	4.779	0.015
6				
7	Water Fees	10.291	10.187	(0.104)
8				
9	O&M Tracked Outside of Formula			
10	Insurance Premiums	1.347	1.305	(0.042)
11	Advanced Metering Infrastructure Project	(1.800)	(1.335)	0.465
12	Mandatory Reliability Standards Incremental O&M	0.445	0.455	0.010
13				
14	Property Tax	15.407	15.574	0.167
15				
16	Depreciation and Amortization	51.694	51.323	(0.371)
17				
18	Other Revenue	(8.177)	(7.981)	0.196
19				
20	Interest Expense	38.906	38.497	(0.409)
21				
22	Income Tax	8.310	7.056	(1.254)
23				
24	2015 After-Tax Flow-Through Addition to Deferral Account			3.472
25				
26	2015 Ending Deferral Account Balance True-Up			$ 2.973
27	2017 After-Tax Amortization			$ 6.445

The variance in revenue is due to loads being lower than approved for residential and wholesale loads, largely due to warmer than normal weather, and to a lower industrial load. The variance in power purchase is primarily due to decreased load from forecast and additional market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost. Variances in wheeling and water fees are shown in Section 4, other revenue are shown in Section 5, O&M tracked outside of formula are shown in Section 6, and Property Taxes are shown in Section 9. The variance in depreciation expense is primarily due to a lower value of depreciable assets arising from the delay in AMI project expenditures in 2014 and 2015. The variance in interest expense is due to both the short-term debt balance and interest rates being lower than forecast. Finally, the variance in income taxes is due to the income tax impacts of each of the aforementioned items, the variance between the projected and approved tax timing differences, and an adjustment between the prior year's tax provision and the actual tax return.

A true-up of $2.973 million between the projected and final 2015 deferral account balance is primarily the result of lower revenue in the second half of 2015, primarily due to lower than forecast residential loads. Similarly, an adjustment to include the difference between the projected and final actual amounts for 2016 subject to flow-through will be recorded in the deferral account in 2017 and amortized in 2018 rates.

12.5 SUMMARY

FBC has updated the costs associated with the MRS exogenous event, which affects rates in 2017. In this section, FBC has also requested approval of five new deferral accounts related to regulatory proceedings and requested the disposition of the Celgar Interim Period Billing Adjustment deferral account.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

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

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

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

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

In the subsections below, FBC reports on its 2015 and June 2016 year-to-date performance as measured against the SQI benchmarks and thresholds. Both 2015 and June 2016 year-to-date SQI results indicate that the Company's overall performance is meeting service quality standards. In 2015, for the eight SQIs with benchmarks, four performed at or better than the approved benchmarks with three performing better than the threshold and one, the All Injury Frequency Rate (AIFR) performing worse than the threshold. For the three SQIs that are informational only, performance is generally consistent with or better than recent years' performance.

June 2016 year-to-date performance is similar to 2015 with an improving trend, with six of the eight SQIs with benchmarks performing at or better than the approved benchmarks and the two remaining 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 2015 and June year-to-date performance for 2016 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 2015 and June year-to-date results for 2016 are also provided for the three informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2015 Results	2016 June YTD Results
	Safety SQIs				
Emergency Response Time	Percent of calls responded to within two hours	93%	90.6%	92%	98%
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	2.52	1.88
	Responsiveness to the Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	72%	76%	77%
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.39	0.48
Meter Reading Accuracy	Number of scheduled meters that were read	97%	94%	96%	98%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	71%	70%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.1	8.2
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	2.7%	3.3%
	Reliability SQIs				
System Average Interruption Duration Index (SAIDI) - Normalized	3 year average of SAIDI (average of cumulative customer outage time)	2.22	2.62	2.15	2.12

Performance Measure	Description	Benchmark	Threshold	2015 Results	2016 June YTD Results
System Average Interruption Frequency Index (SAIFI) - Normalized	3 year average of SAIFI (average customer outage)	1.64	2.50	1.49	1.52
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.1%	1.6%

In the following sections, FBC reviews each SQI's individual performance in 2015 and 2016. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

Emergency Response Time

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

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

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

The 2015 result was 92 percent which was within the performance range with the benchmark at 93 percent and the threshold at 90.6 percent. The 2015 result was impacted by widespread outages due to a windstorm in June, and higher trouble call volumes in July and August. The June 2016 year-to-date result is 98 percent, which is better than the benchmark level set at 93 percent. Performance indicates that, overall, trouble calls and/or unplanned system interruptions are being addressed in a prompt and timely manner.

The Company's 2009 to 2015 annual and 2016 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the types of outage described above and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Results	92%	95%	92%	91%	94%	91%	92%	98%
Benchmark	n/a	n/a	n/a	n/a	n/a	93%	93%	93%
Threshold	n/a	n/a	n/a	n/a	n/a	90.6%	90.6%	90.6%

All Injury Frequency Rate

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

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

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

The 2015 annual (calendar year) AIFR result was 1.54, resulting in a three-year rolling average of 2.52 in 2015 which was above (i.e. worse than) the threshold of 2.39. In 2015, there was an improved trend in the second half of the year, with only one recordable incident compared to six observed during the first half of the year. The annual result demonstrates an improvement in 2015 which has continued into the first half of 2016 where the AIFR for January 1 to June 30, 2016 was 0.88. As of June 30, 2016, there were zero Medical Treatment and 2 Lost Time injuries. This compares to the June annual year-to-date AIFR result of 2.55 in 2015 and 1.35 in 2014.

The three year rolling average of annual results including 2016 June year-to-date results is 1.88, which is between the benchmark of 1.64 and threshold of 2.39. The recent AIFR results are reflective of FBC's efforts to continue its focus on safety.

Safety continues to be a core value for FBC and prevention of injury remains a key focus. FBC continues to focus and reinforce fundamentals of safe work planning, hazard identification and proper body positioning with all employees. FBC has in place 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 meets the requirements of the Occupational Health and Safety Regulations. An independent qualified auditor is used to assess the Company's Health and Safety programs in consideration of this initiative. In 2015, FBC achieved a 92 percent overall audit score and retained the COR certification.

As a part of the Company's focus on continual improvement, FBC launched the Target Zero safety program in January 2016. This program provides a structured format for employees at all levels to participate in corporate safety, enabling the Company to better understand the current state of the safety culture and prioritize and implement initiatives that are relevant to employees. Aspects of the program include:

- Targeted and relevant safety communications to increase safety awareness with employees;
- Annual safety performance analysis developed for all departments;
- Safety action plans created by each department on an annual basis that form the blueprint for each department's continual safety improvement. The results are reviewed on a quarterly basis;
- An employee safety perception survey that allows the Company to better understand the current state of its safety culture and prioritize and implement initiatives that are relevant to employees; and
- An employee based safety program that brings together employees from all areas of the company to develop and implement safety initiatives that enables direct employee input to drive continual improvement.

The Company's 2009 to 2015 and 2016 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	June 2016 YTD
Annual Results	1.41	1.72	1.48	1.72	2.82	3.21	1.54	0.88
Three year rolling average	2.00	2.00	1.54	1.64	2.01	2.58	2.52	1.88
Benchmark	n/a	n/a	n/a	n/a	n/a	1.64	1.64	1.64
Threshold	n/a	n/a	n/a	n/a	n/a	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 appear to be anomalous in nature. As seen in the historical results, FBC's 2015 annual AIFR result is materially improved over 2013 and 2014 and has returned to pre-2013 levels. The June 2016 year-to-date annual result is also consistent with a return to pre-2013 levels.

It is also important to note that the increase in the AIFR results began in 2013 while FBC was not under PBR and in 2014 when the PBR was still subject to Commission approval.[22] In 2015, when FBC was continuously under PBR, the annual AIFR result was better than the benchmark. This, together with the June 2016 year to date annual result, is evidence that the 2015 three-year average AIFR result above threshold cannot be attributed to cost-cutting or efficiency measures put in place under PBR.

FBC remains committed to maintaining its focus on safety and is investing in enhancements to its safety program as evidenced by the launch of the Target Zero safety program in 2016. 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 2015 result was 76 percent and was within the performance range with the benchmark at 78 percent and the threshold at 72 percent. June 2016 year-to-date performance is 77 percent and also within the performance range.

Based on feedback from customers, FBC has introduced initiatives to target areas where improvements can be made in order to improve the overall FCR score. These initiatives include:

- Improve up-front messaging to identify alternative channels (in addition to hours of operation messaging);
- Refresher training in collections and billing policies and procedures;
- Call handling and soft skill training in explaining complex issues to customers; and
- One-on-one coaching for CSRs with calls "not resolved".

The benchmark was set at the same level as the FEI benchmark, as there were no previous FBC results that could be used to establish the level of performance at the time of setting the benchmark. FCR performance has been between the benchmark and threshold for three

[22] The PBR Decision was issued on September 15, 2014.

consecutive years, with the June 2016 year-to-date FCR levels consistent with results from 2015 (76 percent) but showing an improvement since the start of PBR Plan (77 percent June 2016 year-to-date versus 73 percent in 2014 and 2013. The initiatives described above will continue through 2016.

The Company's 2009 to 2015 annual and 2016 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Annual Results	n/a	n/a	n/a	n/a	73%	73%	76%	77%
Benchmark	n/a	n/a	n/a	n/a	n/a	78%	78%	78%
Threshold	n/a	n/a	n/a	n/a	n/a	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 2015 result was 0.39 which was better than the benchmark of 5.0. The June 2016 year-to-date performance is 0.48 which is also better than the benchmark. No significant billing issues have arisen in 2016.

The 2015 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2015 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)	0.00
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	98.82%	(100%-PA)*100	=(100%-98.82%)*100	1.18
Billing Service Quality Indicator; Target < 5.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0+0+1.18) /3	**0.39**

The Company's 2014 and 2015 annual and 2016 year-to-date results are provided below. As this SQI was tracked starting during 2013, the 2013 results do not reflect a full year.

Table 13-6: Historical Billing Index Results

Description	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
Annual Results	n/a	n/a	n/a	n/a	0.10	2.34	0.39	0.48
Benchmark	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0
Threshold	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0

Meter Reading Accuracy

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

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

The 2015 result was 96 percent, lower than the benchmark but above the threshold. This was due to staffing challenges as the Company transitioned from manual to automated meter reading[23]. In addition, several meter reading routes had to be estimated during August due to forest fires destroying advanced metering routers and limiting road access for meter readers.

[23] As of June 30, 2016, more than 95% of FBC's meter fleet is being ready by the AMI system.

The June 2016 year-to-date performance shows a return to previous levels of 98 percent, which is better than the benchmark.

The Company's 2009 to 2015 and 2016 year-to-date results are provided below. Historically, there has been little variation in performance other than in 2013, which saw a significant drop in performance (to 51 percent) as the result of the six-month IBEW labour disruption.

Table 13-7: Historical Meter Reading Accuracy Results

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

Telephone Service Factor (Non-Emergency)

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

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

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

The 2015 result was 71 percent which was better than the benchmark of 70 percent. The June 2016 year-to-date performance is 70 percent which is equal to the benchmark.

The Company's 2009 to 2015 annual and 2016 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	June 2016 YTD
Annual Results	70%	70%	70%	70%	70%	48%	71%	70%
Benchmark	n/a	n/a	n/a	n/a	n/a	70%	70%	70%
Threshold	n/a	n/a	n/a	n/a	n/a	68%	68%	68%

Customer Satisfaction Index

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

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage. Over the last several years, customer concerns about tiered electricity prices, collection policies and advanced metering have contributed to an overall erosion of CSI scores as evident in Table 13-9 below. Recent index scores compare favourably with the 2014 result, with several service attributes showing marked improvement.

The 2015 result was 8.1 and consistent with the 8.1 score in 2014. In addition, the June 2016 year-to-date average index score is up to 8.2 from 8.1 for the same period last year. Customer attitudes about the Company's field services increased by four points from 8.7 to 9.1. Attitudinal improvements were also seen in overall satisfaction and perceived accuracy of meter reading. On a year-to-date basis, overall satisfaction rose from 7.7 for June 2015 year-to-date to 8.0 for June 2016 year-to-date. Accuracy of meter reading scores increased from 7.5 in 2015 to 7.7 for June 2016 year-to-date.

The Company's 2009 to 2015 annual and 2016 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

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

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 2015 result was 2.7 percent, consistent with prior years' results except for 2014. The June 2016 year-to-date result is 3.3 percent and is comparable to that achieved in the last few years.

The Company's 2009 to 2015 annual and 2016 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 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	June 2016 YTD
Annual Results	2.2%	1.9%	1.7%	1.9%	2.0%	12.4%	2.7%	3.3%
Benchmark	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

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 per 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 2015 result was 2.15 which was better than the benchmark. In addition, the June 2016 year-to-date result is 2.12 which is better than the benchmark of 2.22. A further explanation of outages impacting 2016 year-to-date SAIDI results is included in the SAIFI section below.

The Company's 2009 to 2015 and 2016 year-to-date results are provided below. From 2009 to 2015, 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	June 2016 YTD
Three year rolling average results	2.40	2.51	2.33	2.22	1.94	2.09	2.15	2.12
Benchmark	n/a	n/a	n/a	n/a	n/a	2.22	2.22	2.22
Threshold	n/a	n/a	n/a	n/a	n/a	2.62	2.62	2.62

System Average Interruption Frequency Index (SAIFI) – Normalized

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

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

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

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

The 2015 result was 1.49 which was better than the benchmark. In addition, the June 2016 year-to-date result is 1.52, which is better than the benchmark of 1.64.

FBC has not experienced any major events during the first six months of 2016. January to April 2016 reliability was better than the historical three year average, with no significant weather events. In May 2016, the SAIDI and SAIFI metrics were higher than the historical results due to a windstorm that caused significant damage to the transmission and distribution system in the Kootenay area. The May windstorm affected 8,500 customers and resulted in 17,000 customer hours of interruption, with customer restoration efforts extending into May 19 due to the extent of damage to the distribution system.

The Company's 2009 to 2015 and 2016 year-to-date results are provided below. From 2009 to 2015, 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	June 2016 YTD
Three year rolling average results	1.87	1.96	1.71	1.64	1.31	1.39	1.49	1.52
Benchmark	n/a	n/a	n/a	n/a	n/a	1.64	1.64	1.64
Threshold	n/a	n/a	n/a	n/a	n/a	2.50	2.50	2.50

Generator Forced Outage Rate

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

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

The 2015 result for GFOR was 0.1 percent. The GFOR for June 2016 year-to-date is 1.6 percent and is mainly attributable to failure of the over hundred-year-old Upper Bonnington Unit 3 transformer. This transformer was not repairable and was replaced; the repairs took just under a month.

The Company's 2009 to 2015 annual and 2016 year-to-date results are provided below. The 2013 and 2014 results are higher than the other years due to forced outages arising from fires at the Corra Linn and South Slocan generating plants. Also shown is the comparable data from the Canadian Electricity Association (CEA), demonstrating that FBC's performance has, other than 2013, been much lower than the industry average.

Table 13-13: Historical Generator Forced Outages

	2009	2010	2011	2012	2013	2014	2015	June 2016 YTD
FBC	0.9%	0.1%	0.1%	0.5%	5.2%	1.7%	0.1%	1.6%
CEA	1.8%	3.9%	5.0%	4.9%	4.9%	6.3%[24]	tbd	

13.3 REVIEW OF 2015 PERFORMANCE OF SERVICE QUALITY INDICATORS

Based on the SQI performance reviewed above, FBC believes that its overall performance is meeting service quality standards. For the reasons discussed below, FBC does not believe that the AIFR results warrant any penalty to the Company.

For 2015, four of the SQIs with benchmarks performed at or better than the approved benchmarks with three performing better than the threshold. The AIFR is the only SQI with performance below the threshold. To summarize the AIFR results discussed above, FBC's final calendar year AIFR result in 2015 was 1.54, resulting in a three-year rolling average for 2015 of 2.52 which was above the threshold of 2.39. .FBC does not believe that a penalty is warranted, for the following reasons.

- In 2015, there was an improved trend in the second half with only one recordable incident compared to six observed during the first half of the year. The calendar year result demonstrates an improvement in 2015 which has continued into the first half of 2016 where the AIFR for January 1 – June 30, 2016 was 0.88. The recent AIFR results are reflective of FBC's efforts to continue its focus on safety.
- As discussed above, the historical AIFR results show that the performance that was worse than the -benchmark is due solely to the 2013 and 2014 calendar year results. The 2015 calendar year result and 2016 year-to-date results are consistent with a return to pre-2013 levels. This supports the conclusion that the performance that was worse than the -benchmark AIFR results began prior to the PBR term.
- FBC has not received any economic gain due to the AIFR results. There is no evidence that the AIFR results are due to cost-cutting or efficiency measures put in place under PBR.
- FBC has taken measures to ameliorate the AIFR results. FBC has undertaken a comprehensive review of its Safety Management system. FBC has initiated the Target Zero safety program in 2016.

FEI believes the evidence is clear that there has been no serious degradation of service and no penalty is warranted.

[24] The final CEA report is generally available in the third quarter of the following year. The previous number for 2014 was from the draft report. For 2015 the number will be reported when the final CEA number is available.

13.4 *SUMMARY*

In summary, FBC's 2015 results and June 2016 year-to-date SQI results indicate that the Company's overall performance meets service quality standards. In 2015, for the eight SQIs with benchmarks, four performed at or better than the approved benchmarks with three performing better than the threshold. One, the AIFR, performed inferior to the threshold and FBC has provided a discussion of why the performance does not warrant a penalty in Section 13.3 above. For the three SQIs that are informational only, performance is generally consistent with or better than recent years' performance.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: CANSIM Table 326-0020

Government of Canada / Gouvernement du Canada
Canada

Statistics Canada

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Table 326-0020[1, 2]
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[16]	All-items	Food[17]	Shelter[18]	Household operations, furnishings and equipment	Clothing and footwear	Transportation	Gasoline	Health and personal care	Recreation, education and reading	Alcoholic beverages and tobacco products	All-i exclu food ene
2014 July	119.6	130.2	114.5	112.5	101.0	129.0	197.3	112.4	116.2	135.6	113.
2014 August	119.6	129.9	114.4	113.4	99.5	128.5	192.7	112.8	117.0	135.6	113.
2014 September	119.5	129.7	114.5	113.6	102.9	127.8	190.7	112.8	115.6	136.3	113.
2014 October	119.0	129.8	114.1	113.2	103.9	126.9	178.8	112.3	113.7	135.8	113.
2014 November	118.8	130.6	114.2	113.5	102.2	126.0	171.6	113.9	112.2	136.3	113.
2014 December	118.1	131.1	114.1	113.0	98.4	123.6	155.6	113.1	111.8	135.4	112.
2015 January	118.0	132.2	114.0	113.3	99.6	121.8	140.5	113.6	111.2	137.0	112.
2015 February	118.9	133.1	114.0	113.9	101.6	123.7	154.9	113.7	113.1	136.8	113.
2015 March	119.8	133.5	114.0	114.5	105.6	126.2	168.2	113.0	114.0	136.9	113.
2015 April	119.6	132.7	113.7	114.8	106.5	126.1	165.8	113.0	113.3	137.1	113.
2015 May	120.6	134.4	114.0	114.7	104.3	128.1	176.6	114.0	116.6	137.2	114.
2015 June	120.7	134.7	113.9	114.9	101.0	128.7	180.8	113.9	118.4	137.4	114.
2015 July	120.8	134.8	113.9	115.3	99.6	128.4	182.1	113.7	119.9	137.3	114.
2015 August	121.0	134.6	114.1	115.1	102.2	127.8	178.9	113.8	120.6	137.9	114.
2015 September	121.0	135.6	114.0	115.4	108.0	125.2	162.1	114.4	119.6	139.5	115.
2015 October	120.6	135.2	114.4	114.9	108.2	125.6	160.0	114.0	116.4	137.6	114.
2015 November	120.8	136.2	114.5	113.7	106.5	127.2	167.4	114.7	115.3	139.0	114.
2015 December	120.4	137.0	114.6	114.1	101.8	126.6	162.5	113.9	115.1	137.8	114.
2016 January	120.7	139.5	114.4	114.7	101.4	125.9	148.0	114.6	114.6	140.1	114.
2016 February	120.8	137.9	114.4	115.8	103.4	125.0	140.3	115.1	116.0	140.2	115.
2016 March	121.8	138.1	114.7	117.1	106.0	126.9	150.8	114.9	117.8	141.1	116.
2016 April	121.8	137.3	115.0	117.2	105.3	127.7	153.8	115.9	116.7	141.2	116.
2016 May	122.7	137.7	115.3	117.3	105.3	130.3	161.4	115.5	119.6	140.9	117.
2016 June	123.1	137.0	115.8	117.3	103.6	131.7	166.9	116.4	120.9	141.1	117.

Table A1-2: CANSIM Table 281-0063

Government of Canada Gouvernement du Canada
Canada

Statistics Canada

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

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

monthly

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

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

Selected items [Add/Remove data]

Geography – British Columbia
Estimate – Average weekly earnings including overtime for all employees (dollars)[4]

North American Industry Classification System (NAICS)[14]	Industrial aggregate excluding unclassified businesses [11-91N][1, 2]	Goods producing industries [11-33N][1]	Forestry, logging and support [11N][1]	Mining, quarrying, and oil and gas extraction [21]	Utilities [22]	Construction [23]	Manufacturing [31-33]	Service producing industries [41-91N][1]	
2014 July	892.69[A]	1,147.91[A]	1,244.97[A]	1,760.15[B]	1,691.20[A]	1,118.17[A]	999.93[A]	843.26[A]	68
2014 August	902.67[A]	1,155.15[A]	1,144.61[A]	1,954.02[B]	1,876.24[A]	1,135.32[A]	1,022.57[A]	853.28[A]	69
2014 September	898.29[A]	1,162.28[A]	1,103.10[A]	1,998.27[A]	1,745.52[A]	1,136.66[A]	1,026.63[A]	846.29[A]	68
2014 October	904.76[A]	1,161.32[A]	1,152.62[A]	2,005.71[A]	1,726.06[A]	1,146.65[A]	1,010.79[A]	855.08[A]	67
2014 November	906.17[A]	1,150.20[A]	1,111.75[A]	1,939.69[A]	1,729.29[A]	1,140.03[A]	1,009.81[A]	857.64[A]	67
2014 December	895.32[A]	1,144.46[A]	1,153.41[A]	1,942.84[B]	1,646.87[A]	1,144.81[A]	986.96[A]	848.10[A]	68
2015 January	911.03[A]	1,168.95[A]	1,209.82[A]	1,890.75[B]	1,690.57[A]	1,169.65[A]	1,016.90[A]	863.65[A]	68
2015 February	909.02[A]	1,148.89[A]	1,197.83[A]	1,888.41[A]	1,700.44[A]	1,123.40[A]	1,044.74[A]	863.40[A]	68
2015 March	905.21[A]	1,147.75[A]	1,204.89[A]	1,984.66[A]	1,668.65[A]	1,124.51[A]	1,035.26[A]	859.68[A]	69
2015 April	903.26[A]	1,154.70[A]	1,213.84[A]	1,799.08[A]	1,630.94[A]	1,134.35[A]	1,046.13[A]	853.98[A]	68
2015 May	905.28[A]	1,145.30[A]	1,185.21[A]	1,755.97[A]	1,572.08[A]	1,127.07[A]	1,061.40[A]	858.86[A]	69
2015 June	909.59[A]	1,154.75[A]	1,223.83[A]	1,764.35[A]	1,806.19[A]	1,138.82[A]	1,043.36[A]	860.48[A]	69
2015 July	913.87[A]	1,151.50[A]	1,174.14[A]	1,707.48[A]	1,653.21[A]	1,141.88[A]	1,032.94[A]	868.09[A]	70
2015 August	906.46[A]	1,130.18[A]	1,205.83[A]	1,725.26[A]	1,700.13[A]	1,130.15[A]	1,014.75[A]	863.57[A]	70
2015 September	911.95[A]	1,144.29[A]	1,247.21[A]	1,708.33[A]	1,577.58[A]	1,129.23[A]	1,041.00[A]	866.01[A]	68
2015 October	913.09[A]	1,152.73[A]	1,269.45[A]	1,739.84[A]	1,614.48[A]	1,109.45[A]	1,077.46[A]	867.28[A]	68
2015 November	910.40[A]	1,154.79[A]	1,273.15[A]	1,799.40[A]	1,605.43[A]	1,117.30[A]	1,057.17[A]	862.79[A]	69
2015 December	925.59[A]	1,163.74[A]	1,331.62[A]	1,776.77[A]	1,567.11[A]	1,116.86[A]	1,055.00[A]	880.23[A]	71
2016 January	905.14[A]	1,152.15[A]	1,289.79[A]	1,900.85[A]	1,694.18[A]	1,120.10[A]	1,050.69[A]	858.73[A]	69
2016 February	913.43[A]	1,146.10[A]	1,321.72[A]	1,845.96[A]	1,645.40[A]	1,112.78[A]	1,046.51[A]	870.74[A]	71
2016 March	915.72[A]	1,152.94[A]	1,256.44[A]	1,881.80[A]	1,822.15[A]	1,116.38[A]	1,044.59[A]	870.51[A]	70
2016 April	920.79[A]	1,157.19[A]	1,280.93[A]	1,758.81[A]	1,860.00[A]	1,123.83[A]	1,093.66[A]	875.07[A]	71
2016 May	919.11[A]	1,149.32[A]	1,220.80[A]	1,734.56[A]	1,790.02[A]	1,116.13[A]	1,060.70[A]	875.66[A]	72

Table A1-3: Conference Board of Canada Forecast Gross Domestic Product

Key Economic Indicators: British Columbia

(Forecast Completed: February 4, 2016)

	2015Q1	2015Q2	2015Q3	2015Q4	2016Q1	2016Q2	2016Q3	2016Q4	2017Q1	2017Q2	2017Q3	2017Q4	2015	2016	2017
GDP at market prices ($ millions)	241,042	246,608	248,823	249,342	252,670	256,278	259,327	262,613	265,298	268,234	271,367	274,498	246,454	257,722	269,849
	0.4	*2.3*	*0.9*	*0.2*	*1.3*	*1.4*	*1.2*	*1.3*	*1.0*	*1.1*	*1.2*	*1.2*	*3.9*	*4.6*	*4.7*
GDP at market prices (2007 $ millions)	226,369	227,598	228,594	229,713	231,623	233,618	235,300	237,318	239,604	241,381	243,210	244,927	228,068	234,465	242,281
	–0.1	*0.5*	*0.4*	*0.5*	*0.8*	*0.9*	*0.7*	*0.9*	*1.0*	*0.7*	*0.8*	*0.7*	*2.3*	*2.8*	*3.3*
GDP at basic prices (2007 $ millions)	206,408	207,322	208,229	209,249	210,905	212,637	214,083	215,834	218,042	219,790	221,587	223,284	207,802	213,365	220,676
	0.4	*0.4*	*0.4*	*0.5*	*0.8*	*0.8*	*0.7*	*0.8*	*1.0*	*0.8*	*0.8*	*0.8*	*2.3*	*2.7*	*3.4*
Consumer price index (2002 = 1.0)	1.189	1.203	1.209	1.206	1.212	1.220	1.226	1.229	1.236	1.245	1.251	1.255	1.202	1.222	1.247
	0.2	*1.2*	*0.5*	*–0.3*	*0.5*	*0.7*	*0.5*	*0.3*	*0.6*	*0.7*	*0.5*	*0.3*	*1.1*	*1.6*	*2.1*
Implicit price deflator— GDP at market prices (2007 = 1.0)	1.065	1.084	1.088	1.085	1.091	1.097	1.102	1.107	1.107	1.111	1.116	1.121	1.081	1.099	1.114
	0.6	*1.8*	*0.5*	*–0.3*	*0.5*	*0.6*	*0.5*	*0.4*	*0.1*	*0.4*	*0.4*	*0.4*	*1.5*	*1.7*	*1.3*
Wages and salary per employee ($ 000s)	45.854	45.997	45.783	46.033	46.278	46.509	46.822	47.175	47.507	47.769	48.132	48.532	45.917	46.696	47.985
	0.9	*0.3*	*–0.5*	*0.5*	*0.5*	*0.5*	*0.7*	*0.8*	*0.7*	*0.6*	*0.8*	*0.8*	*2.1*	*1.7*	*2.8*
Primary household income ($ millions)	176,331	178,137	179,281	181,906	183,545	185,025	187,071	189,211	191,565	193,813	196,389	199,042	178,914	186,213	195,202
	1.2	*1.0*	*0.6*	*1.5*	*0.9*	*0.8*	*1.1*	*1.1*	*1.2*	*1.2*	*1.3*	*1.4*	*4.6*	*4.1*	*4.8*
Household disposable income ($ millions)	151,260	153,099	154,798	157,060	158,503	159,877	161,990	163,789	165,841	167,874	170,046	172,312	154,054	161,040	169,018
	0.9	*1.2*	*1.1*	*1.5*	*0.9*	*0.9*	*1.3*	*1.1*	*1.3*	*1.2*	*1.3*	*1.3*	*5.6*	*4.5*	*5.0*
Household net savings rate (per cent)	–2.0	–1.7	–1.8	–1.2	–1.3	–1.5	–1.3	–1.3	–1.2	–1.0	–0.9	–0.8	–1.7	–1.3	–1.0
Population (000s)	4,666	4,672	4,683	4,704	4,718	4,734	4,751	4,767	4,784	4,801	4,818	4,834	4,681	4,742	4,809
	0.0	*0.1*	*0.2*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.4*	*0.4*	*0.3*	*0.3*	*1.0*	*1.3*	*1.4*
Employment (000s)	2,286	2,289	2,315	2,341	2,346	2,352	2,363	2,374	2,391	2,406	2,423	2,439	2,308	2,359	2,415
	0.3	*0.1*	*1.1*	*1.1*	*0.2*	*0.2*	*0.5*	*0.4*	*0.7*	*0.7*	*0.7*	*0.6*	*1.3*	*2.2*	*2.4*
Labour force (000s)	2,428	2,438	2,468	2,503	2,506	2,510	2,518	2,526	2,539	2,553	2,567	2,581	2,459	2,515	2,560
	0.4	*0.4*	*1.2*	*1.4*	*0.1*	*0.2*	*0.3*	*0.3*	*0.5*	*0.5*	*0.5*	*0.6*	*1.4*	*2.3*	*1.8*
Labour force participation rate (per cent)	63.0	63.0	63.5	64.2	64.0	63.9	63.9	63.9	64.0	64.1	64.3	64.4	63.4	63.9	64.2
Unemployment rate (per cent)	5.8	6.1	6.2	6.5	6.4	6.3	6.1	6.0	5.9	5.7	5.6	5.5	6.1	6.2	5.7
Retail sales ($ millions)	69,247	70,542	71,167	71,724	72,413	73,007	73,725	74,485	75,213	75,794	76,520	77,331	70,670	73,407	76,214
	2.0	*1.9*	*0.9*	*0.8*	*1.0*	*0.8*	*1.0*	*1.0*	*1.0*	*0.8*	*1.0*	*1.1*	*6.6*	*3.9*	*3.8*
Housing starts (number of units, 000s)	30,241	32,434	29,516	33,593	32,605	33,709	32,187	32,172	32,356	32,505	32,848	33,297	31,446	32,668	32,752
	3.6	*7.3*	*–9.0*	*13.8*	*–2.9*	*3.4*	*–4.5*	*0.0*	*0.6*	*0.5*	*1.1*	*1.4*	*10.9*	*3.9*	*0.3*
Net interprovincial migration (000s)	10.8	15.9	25.3	18.4	16.5	20.1	21.1	19.3	19.2	19.3	16.3	14.0	17.6	19.3	17.2
Net international migration (000s)	7.3	16.4	44.4	30.6	31.1	31.8	32.8	34.0	36.7	37.9	38.9	39.8	24.7	32.4	38.3

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

(continued…)

Appendix A-2

Load Forecast Tables

Table of Contents

1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. Tables 2.1 to 5.2 show ten years of historical data and the before-savings and after-savings forecast for 2016 and 2017. Table 5.3 shows the DSM and Other-Savings that were deducted from the before-savings forecast to provide the after-savings forecast for 2017. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2010 to 2015 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2010. Finally Table 6.4 shows the system load factor from the years 2010 to 2015 and the forecast load factor for 2016 and 2017.

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

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

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

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	370,078	309,284	305,670	255,581	240,065	237,225	274,816	260,925	231,742	267,853	310,004	366,727	3,429,970
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
Before-Savings													
2016S	377,141	324,121	312,283	263,268	250,376	246,844	291,612	286,127	240,639	266,119	309,609	382,732	3,550,870
2017F	382,209	328,858	316,866	267,569	254,571	250,910	296,023	290,541	244,674	270,408	314,164	387,962	3,604,756
After-Savings													
2016S	376,306	323,247	311,274	262,228	249,246	245,572	290,057	284,433	238,888	264,134	307,365	380,169	3,532,919
2017F	378,989	325,685	313,575	264,367	251,347	247,524	292,202	286,560	240,688	266,063	309,421	382,729	3,559,150

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	323,051	272,294	272,267	230,781	218,543	215,584	247,266	235,858	211,010	241,560	274,833	320,453	3,063,500
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
Before-Savings													
2016S	341,351	294,605	286,986	244,322	233,613	230,046	269,331	264,618	224,624	247,330	284,008	345,967	3,266,800
2017F	345,980	298,918	291,202	248,289	237,500	233,813	273,401	268,691	228,365	251,296	288,190	350,732	3,316,375
After-Savings													
2016S	340,935	294,086	286,341	243,589	232,767	229,068	268,165	263,291	223,184	245,732	282,234	343,989	3,253,380
2017F	343,742	296,576	288,772	245,841	235,002	231,192	270,600	265,664	225,129	247,821	284,457	346,734	3,281,531

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

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	129,951	99,060	100,792	76,647	67,004	65,050	81,435	70,346	60,882	78,885	93,787	140,556	1,064,394
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
Before-Savings													
2016S	151,688	122,855	124,998	98,983	85,086	84,784	115,219	102,928	75,465	100,228	126,793	163,621	1,352,649
2017F	152,922	123,854	126,015	99,789	85,778	85,474	116,157	103,766	76,079	101,044	127,824	164,952	1,363,653
After-Savings													
2016S	151,535	122,679	124,781	98,748	84,825	84,486	114,858	102,530	75,040	99,736	126,230	162,981	1,348,428
2017F	152,156	123,073	125,215	99,020	85,037	84,725	115,392	102,940	75,152	99,994	126,653	163,676	1,353,032

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2006	54,810	52,105	49,302	47,269	49,149	52,078	52,684	51,555	49,179	48,978	52,736	56,451	616,295
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
Before-Savings													
2016S	78,882	71,989	67,701	67,005	74,688	72,725	75,391	77,163	72,507	66,425	69,577	80,021	874,074
2017F	80,799	73,739	69,346	68,633	76,502	74,492	77,223	79,038	74,268	68,038	71,267	81,966	895,311
After-Savings													
2016S	78,748	71,795	67,449	66,697	74,320	72,302	74,903	76,603	71,881	65,728	68,800	79,158	868,384
2017F	79,845	72,718	68,276	67,521	75,342	73,272	75,918	77,633	72,772	66,440	69,556	80,140	879,433

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	104,740	87,653	86,284	70,910	67,094	65,924	77,822	79,281	66,626	76,585	98,120	97,957	978,996
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
Before-Savings													
2016S	74,552	63,006	58,723	40,657	37,296	34,333	43,092	41,994	37,332	41,480	51,129	64,973	588,567
2017F	74,681	63,115	58,825	40,727	37,360	34,392	43,167	42,067	37,396	41,552	51,218	65,085	589,585
After-Savings													
2016S	74,480	62,935	58,648	40,590	37,225	34,258	43,001	41,895	37,228	41,363	50,994	64,816	587,434
2017F	74,507	62,943	58,651	40,565	37,198	34,226	42,985	41,875	37,198	41,339	50,985	64,829	587,301

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2006	32,169	31,766	34,606	34,204	31,283	27,474	26,731	23,420	24,749	30,771	27,229	23,877	348,279
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
Before-Savings													
2016S	34,019	34,700	33,448	34,822	31,768	31,422	27,551	33,381	31,572	33,804	33,159	35,058	394,704
2017F	35,369	36,155	34,901	36,286	33,083	32,672	28,777	34,669	32,872	35,269	34,531	36,435	411,020
After-Savings													
2016S	33,974	34,638	33,373	34,732	31,668	31,309	27,425	33,234	31,410	33,622	32,958	34,838	393,181
2017F	35,126	35,894	34,628	36,002	32,792	32,366	28,455	34,318	32,499	34,868	34,104	35,982	407,035

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2006	1,043	984	1,064	1,034	1,061	1,033	1,021	1,029	1,014	1,144	1,102	1,062	12,591
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
Before-Savings													
2016S	1,319	1,325	1,274	1,334	1,369	1,376	1,333	1,380	1,270	1,321	1,296	1,390	15,987
2017F	1,319	1,325	1,274	1,334	1,369	1,376	1,333	1,380	1,270	1,321	1,296	1,390	15,987
After-Savings													
2016S	1,311	1,309	1,252	1,306	1,335	1,336	1,286	1,325	1,208	1,250	1,217	1,303	15,437
2017F	1,223	1,223	1,168	1,224	1,256	1,258	1,206	1,245	1,126	1,166	1,131	1,216	14,442

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	338	726	219	716	2,953	4,026	7,573	10,227	8,560	5,196	1,858	551	42,945
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
Before-Savings													
2016S	890	730	840	1,521	3,407	5,406	6,744	7,772	6,479	4,072	2,054	903	40,819
2017F	890	730	840	1,521	3,407	5,406	6,744	7,772	6,479	4,072	2,054	903	40,819
After-Savings													
2016S	889	729	838	1,516	3,394	5,377	6,692	7,703	6,417	4,032	2,035	894	40,516
2017F	885	725	834	1,509	3,378	5,344	6,644	7,654	6,381	4,014	2,028	892	40,288

2.9 SYSTEM PEAK (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2006	719	666	582	523	561	415	493	490	474	541	638	733	733	493
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	707	502
2009	707	643	624	507	481	415	496	446	564	514	660	704	704	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	702	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	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	669	611
Before-Savings														
2016S	673	621	570	494	442	493	585	563	459	514	639	686	731	590
2017F	683	631	578	501	449	500	593	572	466	521	649	696	741	599
After-Savings														
2016S	673	621	569	493	441	491	583	561	457	511	637	683	728	589
2017F	680	627	575	497	445	495	588	566	460	515	643	689	734	594

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential	89,181	93,647	95,502	96,565	97,883	98,795	99,228	111,862	113,431	114,166	115,080	116,031
Commercial	10,285	11,010	11,216	11,308	11,419	11,525	11,811	13,662	14,363	14,976	15,167	15,813
Wholesale	8	7	7	7	7	7	7	6	6	6	6	6
Industrial	37	38	36	33	35	36	39	47	49	50	50	50
Lighting	1,905	1,992	1,910	1,874	1,830	1,803	1,739	1,644	1,620	1,590	1,590	1,590
Irrigation	997	1,030	1,048	1,066	1,075	1,092	1,091	1,097	1,103	1,095	1,095	1,095
Total Direct	102,413	107,724	109,719	110,853	112,249	113,258	113,915	128,318	130,572	131,883	132,988	134,585

3.2 CUSTOMER ADDITIONS

Customer Additions	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential	2,311	4,466	1,855	1,063	1,318	912	433	12,634	1,569	735	914	951
Commercial	273	725	206	92	111	106	286	1,851	701	613	191	645
Wholesale	-	(1)	-	-	-	-	-	(1)	-	-	-	-
Industrial	(2)	1	(2)	(3)	2	1	3	8	2	1	-	-
Lighting	69	87	(82)	(36)	(44)	(27)	(64)	(95)	(24)	(30)	-	-
Irrigation	17	33	18	18	9	17	(1)	6	6	(8)	-	-
Total Direct	2,668	5,311	1,995	1,134	1,396	1,009	657	14,403	2,254	1,311	1,105	1,596

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

MWh/Customer	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential	12.09	12.74	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.76	11.71

5. ENERGY

5.1 NORMALIZED AFTER-SAVINGS ENERGY

Energy (GWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential	1,064	1,165	1,196	1,239	1,242	1,249	1,229	1,353	1,296	1,298	1,348	1,353
Commercial	616	650	661	675	660	657	681	788	866	853	868	879
Wholesale	979	878	908	908	895	910	899	675	567	580	587	587
Industrial	348	314	218	216	234	271	291	352	381	380	393	407
Lighting	13	13	13	13	14	13	13	13	16	16	15	14
Irrigation	43	48	46	49	40	40	38	40	40	46	41	40
Net	3,064	3,068	3,042	3,100	3,085	3,140	3,151	3,222	3,166	3,173	3,253	3,282
Losses	366	346	309	315	284	307	271	278	270	272	280	278
Gross	3,430	3,414	3,351	3,416	3,369	3,447	3,422	3,500	3,436	3,446	3,533	3,559
System Peak (MWh)												
Winter Peak	733	704	707	704	726	702	723	698	693	669	728	734
Summer Peak	493	520	502	496	566	537	589	600	620	611	589	594

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE ENERGY

Wholesale (GWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016S	2017F
BCH Lardeau	11	9	7	6	10	8	6	6	6	6	7	7
BCH Kingsgate	3	3	3	4	3	3	5	5	5	5	5	5
City of Grand Forks	41	41	41	41	41	41	41	41	39	41	42	41
City of Nelson	81	86	107	109	90	88	80	83	81	83	87	84
City of Penticton	351	348	346	346	341	344	341	348	342	348	349	351
District of Summerland	96	98	92	78	97	96	95	98	94	97	98	99
City of Kelowna	318	293	312	324	314	329	332	94	-	-	-	-
City of Princeton	78	-	-	-	-	-	-	-	-	-	-	-
Total	979	878	908	908	895	910	899	675	567	580	587	587

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

	2017
DSM	-32
AMI	+12
CIP	-2
RCR	-10
Rate-driven	-3

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

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2010	2011	2012	2013	2014	2015
Actual						
Residential	97,883	98,795	99,228	98,906	113,431	114,166
Commercial	11,419	11,525	11,811	12,077	14,363	14,976
Wholesale	7	7	7	6	6	6
Industrial	35	36	39	39	49	50
Lighting	1,830	1,803	1,739	1,641	1,620	1,590
Irrigation	1,075	1,092	1,091	1,097	1,103	1,095
Total	112,249	113,258	113,915	113,766	130,572	131,883
Forecast						
Residential	98,264	99,663	101,320	103,279	113,229	114,855
Commercial	11,667	11,714	11,837	12,130	13,739	14,531
Wholesale	7	7	7	7	6	6
Industrial	34	35	36	36	48	49
Lighting	1,891	1,836	1,830	1,830	1,742	1,620
Irrigation	1,048	1,081	1,075	1,075	1,091	1,103
Total	112,911	114,336	116,105	118,357	129,855	132,164
Variance (customers)						
Residential	(381)	(868)	(2,092)	(4,373)	202	(689)
Commercial	(248)	(189)	(26)	(53)	624	445
Wholesale	-	-	-	(1)	-	-
Industrial	1	1	3	3	1	1
Lighting	(61)	(33)	(91)	(189)	(122)	(30)
Irrigation	27	11	16	22	12	(8)
Total	(662)	-1,078	-2,190	-4,591	717	(281)
Variance (%)						
Residential	-0.4%	-0.9%	-2.1%	-4.4%	0.2%	-0.6%
Commercial	-2.2%	-1.6%	-0.2%	-0.4%	4.3%	3.0%
Wholesale	0.0%	0.0%	0.0%	-16.7%	0.0%	0.0%
Industrial	2.9%	2.8%	7.7%	7.7%	2.0%	2.0%
Lighting	-3.2%	-1.8%	-5.2%	-11.5%	-7.5%	-1.9%
Irrigation	2.6%	1.0%	1.5%	2.0%	1.1%	-0.7%
Total	-0.6%	-1.0%	-1.9%	-4.0%	0.5%	-0.2%

6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Energy (GWh)	2010	2011	2012	2013	2014	2015
Normalized						
Residential	1,242	1,249	1,229	1,274	1,296	1,298
Commercial	660	657	681	699	866	853
Wholesale	895	910	899	904	567	580
Industrial	234	271	291	291	381	380
Lighting	14	13	13	13	16	16
Irrigation	40	40	38	40	40	46
Net	3,085	3,140	3,151	3,222	3,166	3,173
Gross	3,369	3,447	3,422	3,500	3,436	3,446
Forecast						
Residential	1,248	1,261	1,264	1,276	1,402	1,397
Commercial	682	671	696	709	813	808
Wholesale	915	940	926	935	581	593
Industrial	291	233	250	255	389	371
Lighting	15	12	14	14	13	14
Irrigation	50	45	44	43	42	40
Net	3,199	3,162	3,193	3,233	3,240	3,224
Gross	3,509	3,472	3,502	3,543	3,519	3,499
Variance (GWh)						
Residential	(6)	(12)	(35)	(3)	(106)	(99)
Commercial	(22)	(14)	(16)	(10)	53	45
Wholesale	(20)	(30)	(27)	(31)	(14)	(13)
Industrial	(57)	38	41	36	(9)	9
Lighting	(1)	1	(0)	(0)	3	2
Irrigation	(10)	(4)	(6)	(3)	(2)	6
Net	(114)	(22)	(43)	(11)	(75)	(51)
Gross	(140)	(25)	(81)	(43)	(83)	(53)
Variance (%)						
Residential	-0.5%	-1.0%	-2.9%	-0.2%	-8.2%	-7.6%
Commercial	-3.4%	-2.1%	-2.3%	-1.4%	6.1%	5.3%
Wholesale	-2.2%	-3.4%	-3.0%	-3.4%	-2.5%	-2.2%
Industrial	-24.5%	13.9%	14.1%	12.4%	-2.2%	2.3%
Lighting	-3.6%	10.4%	-3.5%	-1.5%	18.2%	12.7%
Irrigation	-23.8%	-10.8%	-14.9%	-8.7%	-4.9%	12.1%
Net	-3.7%	-0.7%	-1.4%	-0.3%	-2.4%	-1.6%
Gross	-4.2%	-0.7%	-2.4%	-1.2%	-2.4%	-1.5%

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

1 ## 6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential	1,242	1,249	1,229	1,353	1,296	1,298	1,348	1,353
Commercial	660	657	681	788	866	853	868	879
Wholesale	895	910	899	675	567	580	587	587
Industrial	234	271	291	352	381	380	393	407
Lighting	14	13	13	13	16	16	15	14
Irrigation	40	40	38	40	40	46	41	40
Net	3,085	3,140	3,151	3,222	3,166	3,173	3,253	3,282
Losses	284	307	271	278	270	272	280	278
Gross	3,369	3,447	3,422	3,500	3,436	3,446	3,533	3,559
System Peak								
Winter Peak (MW)	726	702	723	698	693	669	728	734
Summer Peak (MW)	566	537	589	600	620	611	589	594

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Growth Year over Year	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential		1%	-2%	10%	-4%	0%	4%	0%
Commercial		0%	4%	16%	10%	-1%	2%	1%
Wholesale		2%	-1%	-25%	-16%	2%	1%	0%
Industrial		16%	7%	21%	8%	0%	4%	4%
Lighting		-9%	2%	0%	16%	2%	-3%	-6%
Irrigation		0%	-6%	4%	1%	15%	-12%	-1%
Net		2%	0%	2%	-2%	0%	3%	1%
Losses		8%	-12%	3%	-3%	1%	3%	-1%
Gross		2%	-1%	2%	-2%	0%	3%	1%
System Peak								
Winter Peak (MW)		-3%	3%	-3%	-1%	-3%	9%	1%
Summer Peak (MW)		-5%	10%	2%	3%	-1%	-4%	1%

Customer Count	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential	97,883	98,795	99,228	111,862	113,431	114,166	115,080	116,031
Commercial	11,419	11,525	11,811	13,662	14,363	14,976	15,167	15,813
Wholesale	7	7	7	6	6	6	6	6
Industrial	35	36	39	47	49	50	50	50
Lighting	1,830	1,803	1,739	1,644	1,620	1,590	1,590	1,590
Irrigation	1,075	1,092	1,091	1,097	1,103	1,095	1,095	1,095
Total Direct	112,249	113,258	113,915	128,318	130,572	131,883	132,988	134,585

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Growth Year over Year	2010	2011	2012	2013	2014	2015	2016S	2017F
Residential		1%	0%	13%	1%	1%	1%	1%
Commercial		1%	2%	16%	5%	4%	1%	4%
Wholesale		0%	0%	-14%	0%	0%	0%	0%
Industrial		3%	8%	21%	4%	2%	0%	0%
Lighting		-1%	-4%	-5%	-1%	-2%	0%	0%
Irrigation		2%	0%	1%	1%	-1%	0%	0%
Total Direct		1%	1%	13%	2%	1%	1%	1%

6.4 SYSTEM LOAD FACTOR

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

Year	Energy (MWh)	Peak (MW)	Load Factor
2010	3,368,701	726	0.53
2011	3,447,280	722	0.55
2012	3,421,657	723	0.54
2013	3,499,975	720	0.56
2014	3,435,977	693	0.57
2015	3,445,816	669	0.59
2016S	3,532,919	728	0.55
2017F	3,559,150	734	0.55

Appendix A-3

Load Forecast Methodology

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1. LOAD FORECAST METHODOLOGY

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

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2017 Annual Review the latest calendar year for which full actual data exists is the 2015 calendar year.
- 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, 2017 is the Forecast Year (2017F).
- 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 2016 (2016S) and the Seed Year forecast is based on the latest actual years, including 2015.

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 and wholesale load classes are normalized because the associated regression results showed significant results with high R^2 values for these load classes.

Results of the residential and wholesale regressions are provided in the tables below.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	35,599	47,465	55,035	51,841
Slope HDD	198	125	-	99
Slope CDD	-	-	202	-
Adjusted R2	0.79	0.78	0.86	0.91

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

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	10,493	28,245	31,168	33,074
Slope HDD	94	58	-	42
Slope CDD	-	-	109	-
Adjusted R2	0.95	0.95	0.97	0.94

Steps for weather (temperature) normalization are described 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), fall (September to October), and summer (June to August). Thus all monthly 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 2015:
   (a) obtain the month's HDD (or CDD) information from Environment Canada;
   (b) calculate the deviation from the 10-year average (2005-2014) HDD (CDD) as found in Step 2;
   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and
   (d) add the normalization adder to the month's load (residential or wholesale).

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

Normalized energy$_t$ = Energy$_t$ –HDD slope$_t$*(HDD$_t$ – Normal HDD$_t$) for t = spring, fall, and winter; and

Normalized energy$_t$ = Energy$_t$ –CDD slope$_t$*(CDD$_t$ – Normal CDD$_t$) for t = summer.

[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.

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, the Residential Conservation Rate (RCR), Customer Information Portal (CIP), Advanced Metering Infrastructure Project (AMI), and rate-driven impacts. Note that the RCR, the CIP, and AMI 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:

$$\text{Before-savings Load}_t = \text{UPC}_t\text{*Average Customer Count}_t,$$

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

The before-savings UPC for 2017F was forecast at 11.80[4] (MWh per customer per year) as the average of historical normalized UPCs in the previous three years 2013-2015. This value was then assumed to remain constant since there is no significant trend in the UPC at this point in time.

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

$$\text{Average Customer Count}_t = 0.5\text{*(Year-end Count}_t + \text{Year-end Count}_{t-1}\text{)}$$

The year-end customer count was based on the least squares regression model below.

$$\text{Year-end Customer}_t = b_0 + b_1\text{*Population}_t$$

Population$_t$ is the population data supplied by BC Stats that is customized to the Company's direct service area.

Table A3-3: Results of Residential Regression

Regression of RES on Load Drivers	
Regression	**Residential**
Start Year	2011
End Year	2015
R2	0.90
Adjusted R2	0.87
df	3
Intercept	33,787
Slope Population	0.33

4 The 2016S before-savings UPC of 11.80 (MWh) is calculated by integrating COK load in 2013. The following values were used in calculating the average: 2013 12.48, 2014 11.51, 2015 11.41 (MWh).

1.2.2 Commercial

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

$$\text{Before-savings Load}_t = b_0 + b_1{*}\text{GDP}_t + b_2{*}\text{Princeton Event}_t + b_3{*}\text{CoK Event}_t$$

Princeton Event$_t$ is a binary variable for the PLP integration event in 2007, CoK$_t$ is a binary variable for the City of Kelowna integration event in 2013 and coefficients b0, b1, b2, and b3 are obtained from an OLS regression analysis on the 2001 to 2015 data.

Table A3-4: Results of Commercial Regression

Regression of COM on Load Drivers	
Regression	GEN
Start Year	2001
End Year	2015
R2	0.98
Adjusted R2	0.98
df	11
Intercept	78,275
Slope GDP	3.52
Slope PLP Event	45,287
Slope CoK Event	130,726

1.2.3 Wholesale

The Company forecasts its wholesale load using the growth rates from load surveys from all wholesale customers. 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 (88 percent of customers accounting for 88 percent of 2015 load).

1.2.5 Irrigation

The before-savings irrigation load for 2017F was developed using a 5-year average of actual loads in 2011-2015.

1.2.6 Lighting

The before-savings street lighting forecast for 2017F was based on a trend analysis of lighting loads from 2011 to 2015.

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 2017 DSM Expenditure Schedule application, which will be filed in August, 2016. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.
- The RCR forecast is a result of analysis performed for the Residential Conservation Rate Information Report submitted to the Commission in November 2014.
- AMI savings are the incremental sales that occur due to an increase in paying marijuana grow operations that are offset by loss reductions due to closing illegal marijuana grow sites. The estimates and forecasts of incremental savings are based on the theft reduction information provided as part of the AMI CPCN Application as adjusted by the Commission determination provided in Order C-7-13.
- CIP savings refer to potential savings due to the implementation of the Customer Information Portal, which allows customers to view historic billing and consumption data.
- Rate-Driven impacts are price elasticity savings given as a percentage of the before-savings loads. The current price elasticity estimate of -0.05 is consistent with BC Hydro.

RCR, CIP, and AMI are forecast for the residential class only. 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 (2006-2015) of historic peak data. The historic peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-Generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. A separate forecast of 16 MW a month was completed for those customers and was then added to the forecast. Seasonal peaks were used for both the winter and the summer. The twelve monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July respectively.

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

Appendix B

PRIOR YEAR DIRECTIVES

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-139-14 – FBC MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
1.	80	29, 30, 31	***Benchmarking Study:*** The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018. In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	Not yet started	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.	2	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.	2	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
5.	2	5	FBC must report these incremental costs and savings in each of the annual reviews during the Performance Based Ratemaking term.	Ongoing during term of PBR	Section 6.3.3

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-107-15 – FBC ANNUAL REVIEW FOR 2015 RATES					
6.	15	Appendix A	***Advanced Metering Infrastructure (AMI) Theft Reduction*** The Commission Panel directs FBC to include, in its next and subsequent annual PBR reports, the impact of AMI on losses through theft deterrence. This directive will improve regulatory efficiency in the review of FBC's proposed actions (and FBC's incentives to undertake these actions while under PBR) related to the reduction of theft related costs. The information to be submitted should include: (i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and (ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.	Ongoing during term of PBR	Section 3.5.7.1
G-120-15 – FEI-FBC PBR CAPITAL EXCLUSION CRITERIA					
7.	17	4	***Capital Expenditures Exceeding the Deadband*** Should the dead-band for annual capital expenditures approved in the PBR Plans be exceeded FBC or FEI are directed to include in its next Annual Review filing, recommendations as to any adjustment to base capital (re-basing) for Commission approval.	Capital expenditures are not forecast to exceed the deadband	Section 1.4.3
G-202-15 – FBC ANNUAL REVIEW FOR 2015 RATES					
8.	28	11	***Use of FEI Employees to Perform FBC Work:*** The Panel directs FBC to work with FEI to provide information on their capabilities for the individual tracking of service quality of FEI employees and an outline of additional costs if individual tracking was put in place in the future.	Completed	Appendix B2

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-214-15 –Application for Approval of Stepped and Stand-By Rates for Transmission Customers Stage V					
9.	16	2	***Celgar Interim Period Billing Adjustment Deferral Account::*** The request to create the Celgar Interim Period Billing Adjustment deferral account to recover from customers the Refund Amount, Continued Interest and carrying costs is approved: • The balance in the Deferral Account is to be financed at FBC's weighted average cost of debt; • FBC must propose a means for recovery as part of the the Annual Review for 2017 Rates; • **The Deferral account must be fully amortized** within **five years of the date of the Order.**	Completed	Section 12.4.2
G-44-16 – FBC Annual Review for 2016 Rates – All Injury Frequency Rate Compliance Filing					
10.	3	2	***2015 Service Quality:*** FBC is directed to address its 2015 service quality and/or penalities in its next Annual Review filing.	Completed	Section 13.3

As described in section 1.4.2 of the Application, FBC has achieved cost efficiencies through the sharing of certain services between the FBC call centre in Trail and the FEI call centre in Prince George. In its decision on FBC's Annual Review for 2016 Rates, the Commission issued the following directive regarding the sharing of call centre services between FEI and FBC[1]:

> The primary concern raised by COPE was that success was being claimed in spite of the lack of individual tracking of service quality. The Panel notes that this issue was not specifically addressed by FBC in its Reply Submission in spite of COPE's claim that FEI/FBC has the necessary information needed to track the service quality of FBC employees. The Panel considers it useful if this issue was explored more thoroughly in the 2017 Annual Review. **Accordingly, the Panel directs FBC to work with FEI to provide information on their capabilities for individual tracking of service quality of FEI employees and an outline of additional costs if individual tracking was put in place in the future.**

Both FBC and FEI track the service quality of individual Customer Service Representatives (CSRs). The activities to track service quality are described below and were in use by both FBC and FEI prior to the sharing of services between the two utilities' call centres.

Both FBC and FEI monitor employee performance on an ongoing basis. All customer calls are recorded for training purposes. Leaders in each of FBC's and FEI's contact centres review the recorded calls and provide coaching to employees on a daily basis.

FBC and FEI also track quality through feedback from customers. Each day, the records of all calls are submitted to a third party survey company, which produces random samples and then contacts customers to request feedback on the interaction. Some customers will provide feedback and others will decline. The tracking of the survey results at an individual CSR level is done on a monthly basis as part of the ongoing coaching program. Employees receive the customer feedback provided by the surveys and are able to review the actual call recordings in support of that feedback. The managers then work with the employee to reinforce positive feedback and to support the employee in improving any negative feedback.

Due to the small sample size on a per-CSR basis, the data has a high margin of error. Therefore, the data on an individual CSR basis can only be used as anecdotal information.

Of a total of 98,700 electric calls taken in the period of January to June 2016, a total of 522 completed surveys were received. Based on feedback from customers, year-to-date in 2016, 95% of electric customers surveyed were "very satisfied" or "somewhat satisfied" with the level of service provided by the CSRs. From January to June 2016, the Prince George office took approximately 3,200 (3 percent) of the 98,700 electric calls received. Out of the 522 completed customer surveys, twenty were related to calls taken in Prince George. Nineteen of these customers (95 percent) rated their satisfaction with the level of service provided by the CSR as

[1] G-202-15, page 28.

"very satisfied" or "somewhat satisfied". The single customer who expressed dissatisfaction indicated the high price of the bill as the reason for the dissatisfaction.

Based on the above, FBC concludes that its customers are receiving a high quality of service from the CSRS in both the Trail and Prince George contact centres.

The costs of FBC's service quality monitoring activities as described above are included in FBC's Base O&M expense. Performance monitoring and improvement activities are the same for FBC and FEI and predate the sharing of services between the two utilities' call centres. There are no incremental costs specifically related to the performance monitoring of the shared employees. As identified in section 1.4.2 of the Application, the sharing of services has resulted in a net reduction to O&M expense of $0.317 million which is shared with customers by way of the Earnings Sharing Mechanism.

Appendix C

RUCKLES SUBSTATION REBUILD PROJECT BUSINESS CASE

FORTISBC INC.

Appendix C
Ruckles Substation Rebuild Project

Business Case

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1. PROJECT SUMMARY

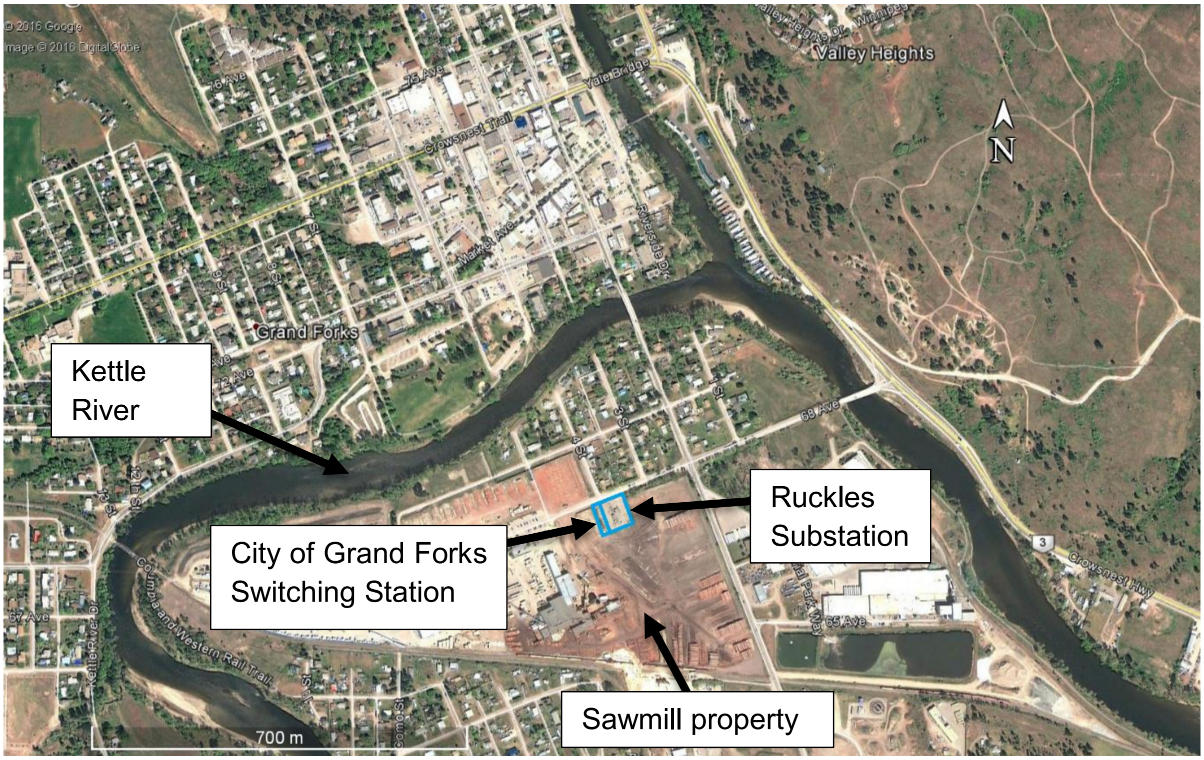
The Ruckles Substation Rebuild Project (Ruckles Project) is the proposed rebuilding of the existing FortisBC Inc. (FBC) Ruckles Substation on the existing substation site, and is necessary to continue to safely and reliably supply electricity to the City of Grand Forks' municipal electric utility, an industrial sawmill and the surrounding FBC service area. The Ruckles Project will address the reliability, environmental and employee safety risks due to its location within the flood zone of the Kettle River, will eliminate the risk of arc flash associated with the existing 4 kV switchgear, will replace obsolete protection, control and metering equipment with equipment that meets current FBC standards, and will increase the capacity of the substation and improve customer reliability. The estimated capital cost of the Ruckles Project in as-spent dollars (including AFUDC and removal costs) is $8.288 million. Final construction and commissioning of the Ruckles Project is scheduled to be completed by the winter of 2018. FBC believes that the Ruckles Project is necessary for continued safe and reliable service and is in the public interest.

1.1 BACKGROUND

The Ruckles Substation was built in 1972 and is located on 68th Avenue in Grand Forks B.C., on the south side of the Kettle River, adjacent to an industrial sawmill. The station is supplied by two FBC transmission lines (9 Line and 10 Line) and provides both a 4 kilovolt (kV) and a 13 kV distribution supply source for the area. The substation 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).

The following figure shows the Ruckles Substation property location. As shown in the figure, the property is surrounded by the Kettle River on three sides. On the south and east side of the substation is the sawmill property, to the north is a municipal roadway, and on the west side is the City of Grand Forks municipal electric utility's switching station.

Figure 1-1: Geographic Location of Ruckles Substation



2. PROJECT NEED

There are four primary drivers for the Ruckles Project.

1. There are employee safety, environmental and customer supply reliability risks as a result of the location of the Ruckles Substation and the high voltage infrastructure and associated protection and control equipment within the flood zone of the Kettle River;
2. There is an employee safety and reliability risk resulting from the arc flash potential associated with the switching equipment that provides the 4kV source of supply to the City of Grand Forks municipal electric utility and the sawmill;
3. The existing substation protection, control and metering equipment is obsolete and presents safety and reliability risks in the event of failures; and
4. FBC customers in the Grand Forks area are exposed to potentially lengthy outages as the Ruckles substation does not meet FBC's planning criteria for backup during contingency operations.

Each of these issues is explained in more detail in the following sections.

2.1 RELIABILITY, SAFETY AND ENVIRONMENTAL RISKS ASSOCIATED WITH THE SUBSTATION LOCATION WITHIN THE KETTLE RIVER FLOOD ZONE

The Ruckles Substation site was purchased in 1954 from the City of Grand Forks. In the mid-2000s, the sawmill that surrounds most of the substation raised the grade of its adjacent wood pole storage area by approximately one metre using crushed rock. As a result, the substation site is now effectively located in a depression relative to the surrounding terrain. The substation has been subject to flooding during spring runoff on several occasions, which has resulted in damage to equipment. To better understand the possible extent of the flooding risk to FBC assets and the electric service it provides to customers, FBC asked Golder Associates (Golder) to conduct a flood assessment of the Ruckles Substation. Golder's conclusions were as follows:

- According to the floodplain mapping, a 1 in 20 year event and a 1 in 200 year event would result in flood waters up to elevations of about 514.0 metres and 514.5 metres respectively; and
- Based on topographic survey data of the substation site elevation, the substation would be under about 2.0 metres of water for the 1 in 20 year event and 2.5 metres of water for the 1 in 200 year event.

The flood assessment completed by Golder is included in Appendix C-2 – Golder Associates Flood Assessment. Flooding to the level of a 1 in 20 event would have a major impact on existing substation equipment, including:

- **Damage to high voltage equipment and resulting safety, environmental and reliability risks** – flooding of the switchyard can lead to significant damage to electrical equipment, most notably power transformers and circuit breakers. Any damage to this equipment would impact FBC's ability to serve its customers in a safe and reliable manner and could result in employee safety hazards and environmental risks. Repairing and/or replacing this equipment would take considerable time (several months to a year depending on the equipment and failure mode);
- **Damage to protection and control equipment** – flooding of the control building can lead to significant water damage to protection and control devices which would impair their ability to reliably monitor, protect and operate high voltage equipment. Repairs to these devices are impractical as they are obsolete (no direct spares are available) and therefore would require redesign and replacement. Replacing this equipment could take between 4-6 weeks; and
- **Loss of supply** – flooding may lead to a necessary de-energization of the substation, or a sudden loss of supply if the flooding is rapid. Depending on the timing and magnitude of the flood, and depending on customer demand, it may be possible to transfer some FBC direct customer load to other nearby substations. If the flooding is rapid and widespread, it would be challenging to offload the substation as some field work is required for switching procedures. Failure to transfer the substation loads would result in loss of service to customers. There is no alternate substation source of supply for the 4 kV City of Grand Forks municipal electrical utility and sawmill loads.

In March 2007, FBC re-graded the ground surface in order for the surface water to flow away from the substation equipment. In addition, two sump pits located in the southwest part of the substation can direct water into a containment pond within the southeast corner of the substation. The containment pond is shown below.

Figure 2-1: Ruckles Substation Water Containment Pond

Periodic flooding has been experienced at the substation site, although 1 in 20 flood levels have not yet occurred. Despite the addition of the containment pond and re-grading activities, some damage to station equipment has occurred even at these lower flood elevations. Below are photographs of the high-water mark left during a flood event that occurred in 2011. A 1 in 20 year flood would result in water levels over 1 metre higher than the 2011 event. For reference, the switchgear panels are approximately 2 metres tall, and would be mostly submerged in a 1 in 20 year event.

Figure 2-2: High Water Marks on Control Room Switchgear

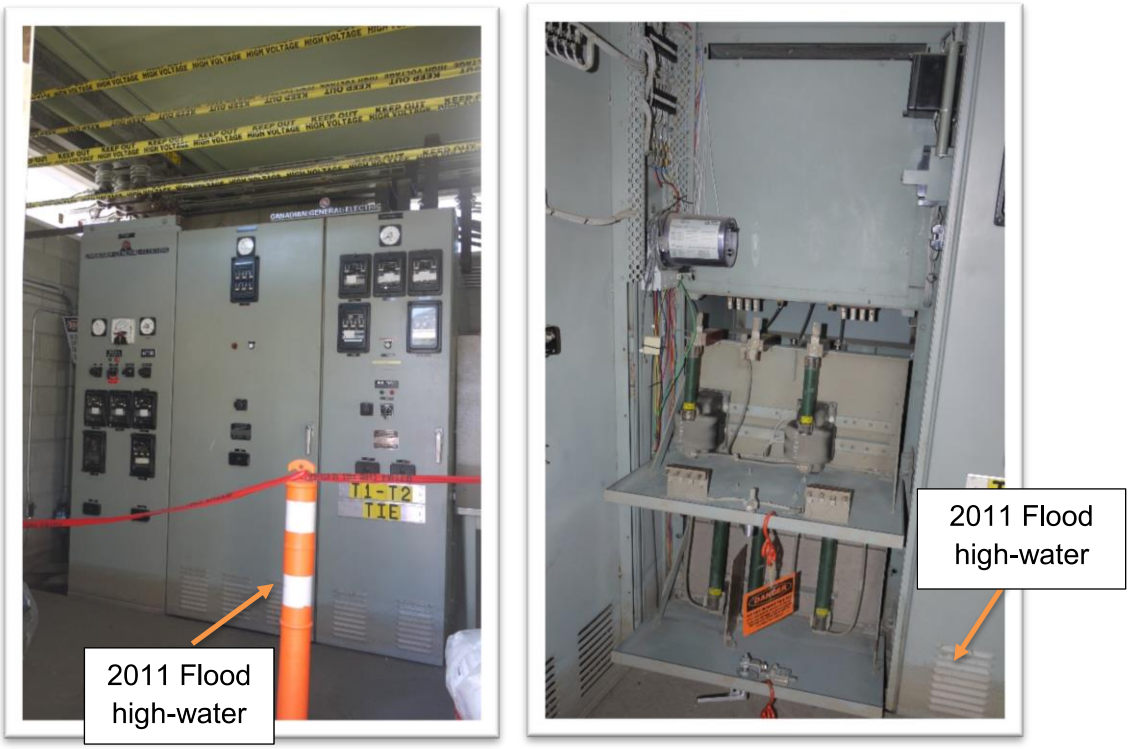


Figure 2-3 shows the water containment pond in use. While the use of the containment pond mitigates the impact of low-level flooding by pumping pooled water which has drained into the station site to the containment pond, it is insufficient to mitigate the impact of even a 1 in 20 year flood event.

Figure 2-3: Ruckles Water Containment Pond during Low Level Flood Conditions

The presence of water in close proximity to high voltage equipment could result in equipment failures. A failure would result in high voltage fault currents flowing through the flood waters and energization of the flood waters and surrounding areas. Further, stations are designed with a crushed rock insulating ground cover to protect personnel from risks associated with a fault; however, in flood scenarios where the ground is saturated above the gravel layer, the insulating nature of the rock becomes ineffective. Any personnel in the vicinity during a high-voltage fault would be exposed to a risk of serious injury.

In addition to the employee safety risk noted above, there is also an environmental risk due to the potential for flooding. As shown in Figure 2-4 below by the absence of containment walls, the transformers at the Ruckles Substation do not have oil containment. For substation power transformers 63 kV and above, it is FBC's current practice to install oil containment, given the large volume of insulating oil contained in the units. In the FBC standard oil containment system, any liquid that accumulates in the containment pit (such as spilled oil or natural rainwater) drains into a "petro-pipe", a device which allows water to pass into the surrounding soil but becomes a plug when it comes in contact with hydrocarbons, preventing oil from being discharged. Given that the installation of oil containment is FBC and industry standard practice, and given the proximity of the substation to the Kettle River, oil containment is necessary for Ruckles Substation to mitigate the release of oil into the environment.

In the event of flooding, an oil containment system may not mitigate the release of oil into the environment without additional modifications to the site. Since the top of the standard containment would be approximately 150 mm above the existing grade, it is likely that flood water would enter the containment pit. In the event that a leak occurs during flood conditions or if oil had previously accumulated, the "petro-pipe" would become a plug, causing the leaking oil and flood water to accumulate in the containment pit, increasing the risk of oil being released into the environment. Given the high probability of flood water accumulating in an oil containment system, any containment system should be designed to withstand a Kettle River flood event. Simply extending the height of the oil containment walls to withstand the maximum flood levels without also raising the surrounding grade and transformer elevation is not a viable solution; the result would be an approximately 2 metre high watertight wall entirely surrounding the transformer which would block access for maintenance or replacement.

Figure 2-4: Flooding in Transformer Area

In summary, the station requires civil modifications to raise the equipment above the Kettle River flood level in order to mitigate employee safety, environmental and supply reliability risks as a result of the location of the Ruckles Substation within the flooding zone. Alternatively, the substation would need to be relocated in order to mitigate the risks caused by flooding.

2.2 ARC FLASH RISK ASSOCIATED WITH EXISTING 4KV EQUIPMENT

Arc flash occurs when a short circuit current flows through air. Arc flash incidents release considerable amounts of energy in a very short period of time, resulting in explosive, high temperature events with potentially severe consequences to employees and equipment. Consistent with practices at the time, the Ruckles Substation was constructed with non-arc-resistant metal-clad switchgear. This type of switchgear presents an extreme risk of serious injury or fatality if a fault occurs within the switchgear when employees are inside or nearby.

FBC undertook an Arc Flash Detection program (accepted by Order G-195-10 regarding FBC's 2011 Capital Expenditure Plan) to mitigate the arc flash hazard at various substations. The program included the installation of arc flash detector relays in legacy metal-clad installations. These relays trip either the transformer high-side circuit breaker or low-side main breaker, as applicable. The installation of these relays allows for safer conditions for employees working near metal-clad switchgear until the legacy switch-gear can be replaced with arc resistant equipment.

Following approval of the program, FBC completed an arc flash study assessing each site in order to determine the work required to reduce the arc flash hazard and to define areas within the substation where additional personal protective equipment is required. In most instances, barriers were introduced in order to maintain sufficient distance such that personal protective equipment and fire-resistant clothing was sufficient to withstand the incident energy. In other instances, arc flash relays were installed, high voltage fuses were reduced to a smaller size, or equipment was replaced to mitigate the arc flash hazard.

Currently, the Ruckles Substation has the highest arc flash hazard of any FBC distribution substation. This is due to the fact that Ruckles is the only remaining FBC substation which provides a 4 kV customer supply[1]. The incident energy[2] of the switchgear is 141.5 cal/cm^2 in the front and 948.0 cal/cm^2 at the back. For comparison, the arc flash energy released during a fault at Ruckles is roughly equivalent to between 10 to 20 kg of TNT[3].

Given that the switchgear could be inoperable during flooding, it was not practical to install arc-flash detection relays in the switchgear at Ruckles in order to mitigate the arc-flash hazard.

Operating practices specific to the Ruckles Substation must be followed by employees to ensure their safety (as demonstrated by the station signage shown in Figure 2-5 below). However, these practices are only a temporary mitigation measure and are not an acceptable permanent solution. The preferred solution is to redesign the substation to remove the safety hazard. As a result, replacement of the existing switchgear with modern protection and control equipment is required.

Figure 2-6 shows the warning barrier outlining the zone where additional personal protective equipment is required.

[1] In general, as rated operating voltage decreases, the arc flash hazard increases due to the higher current which flows during fault events.

[2] Incident energy is a measure of thermal energy at a working distance from an arc fault. The incident energy for 2nd degree burn of human skin is equal to 1.2 cal/cm^2.

[3] While the nature and properties of an arc flash differ from a chemical explosion, the resulting effect is comparable.

Figure 2-5: Arc Flash Warning Signage Outside Substation

Figure 2-6: Arc Flash Warning Barrier around Switchgear

2.3 PRESENCE OF OBSOLETE PROTECTION, CONTROL AND METERING EQUIPMENT PRESENTS RELIABILITY AND SAFETY RISKS

The protection, control and metering equipment at the Ruckles Substation is below current FBC standards. This presents several shortcomings including:

- The presence of obsolete electromechanical protection and metering devices which can fail at any time and which cannot be repaired as no spare parts are available;
- The station is entirely manually operated with no communications facilities for remote monitoring or control of switching equipment; this unnecessarily lengthens customer outage responses;
- There is no remote monitoring of station alarms; consequently, FBC's System Control Centre operators are not aware of equipment trouble until damage resulting in a customer outage occurs; and
- None of the protection devices have recording capabilities to capture information during fault events to assist with troubleshooting.

Installation of this standard equipment would bring the equipment at the Ruckles Substation up to the Company's standards for new substation construction. Further, the installation of this equipment would be consistent with the modifications made to existing substations in the recent Distribution Substation Automation Program[4] (approved by Order C-11-07[5]).

Installation of a standard package of modern protection, monitoring and data collection equipment is required in order to gather and analyse data to aid in the restoration of power outages, improve reliability and power quality for customers by enabling remote monitoring and operation and automated load and power quality metering, and to provide immediate indication of critical substation alarms which is important to reduce the potential for equipment damage and the associated risks to employee and public safety.

2.4 SYSTEM RELIABILITY CONCERNS RESULTING FROM LIMITED TRANSFORMER CAPACITY

The Ruckles Project is also supported by the need to address system reliability concerns resulting from limited substation transformer capacity in the Grand Forks area. The City of Grand Forks and surrounding area are served by three substations: Ruckles Substation (RUC), Grand Forks Terminal (GFT), and Christina Lake Substation (CHR).

[4] At the time of filing the Distribution Substation Automation Program application, the Ruckles Substation was still being considered for future rebuild or replacement and consequently was excluded from the scope of that program.

[5] In its decision associated with Order C-11-07 approving the program, the Commission concluded that "replacing the existing legacy technology with new electronic technology is appropriate."

The Ruckles Substation load is served by two transformers (RUC T1 and RUC T2).

Details related to RUC T1 are:

- Year of manufacture: 1972 (44 years old)
- Voltage: 63 kV – 13 kV / 4.3 kV
- Capacity[6]: 10/15 MVA (ONAN 55°C/ONAF 65°C)[7]

RUC T1 has a dual voltage output and provides both a 13 kV and 4 kV supply. RUC T1 provides the station's only 13 kV source, which feeds two distribution feeders. One of the 13 kV feeders provides a wholesale source to the City of Grand Forks municipal electric utility, while the other 13 kV feeder serves FBC direct customers in the area surrounding the City of Grand Forks utility service area. RUC T1 previously had the capability to provide a redundant 4 kV source for the RUC T2 transformer should it become inoperable, through the use of interconnecting 4 kV switchgear; however, this interconnecting switchgear has been disconnected to limit the arc flash hazard within the substation.

Details related to RUC T2 are:

- Year of manufacture: 1961 (55 years old)
- Voltage: 63 kV – 2.5 kV / 4.3 kV
- Capacity: 7.5/10 MVA (ONAN 55°C/ONAF 55°C)

RUC T2 operates at 4 kV and has two feeders: one dedicated to the neighbouring sawmill and the other provides a wholesale electricity source to the City of Grand Forks electric utility. Note that both the RUC T2 transformer and associated switchgear are older than the 1972 construction date of the Ruckles Substation; this is because they were relocated to that site in 1991 from a previous substation.

Table 2-1 shows the peak load forecast for the distribution voltage power transformers at Ruckles Substation, Grand Forks Terminal, and Christina Lake Substation.

[6] As RUC T1 is a dual secondary winding transformer, the capacity of the transformer is split between both voltages. For example, the capacity of RUC T1 at 13 kV is 5/8 MVA.
[7] ONAN = Oil Natural Air Natural cooled rating at specified temperature rise, ONAF = Oil Natural Air Forced cooled rating at specified temperature rise.

Table 2-1: Load Forecast for Grand Forks Area Power Transformers

Station	Transformer Capacity	2017		2035	
		Summer	Winter	Summer	Winter
RUC T1 (13 kV)	15 MVA	7.1 MVA	9.1 MVA	8.0 MVA	11.0 MVA
RUC T2 (4 kV)	10 MVA	8.9 MVA	8.3 MVA	10.0 MVA	10.0 MVA
GFT T3	20 MVA	7.8 MVA	10.1 MVA	8.8 MVA	12.1 MVA
CHR T1	5 MVA	4.4 MVA	4.6 MVA	4.9 MVA	5.5 MVA

Based on FBC planning criteria, in the event of a loss of a transformer or a loss of a distribution feeder, the remaining distribution feeders in the area should be capable of supplying 80% of peak load of the de-energized transformer[8] and feeder[9], respectively. The distribution planning criteria were provided as Appendix H "Distribution Planning Manual" of the 2012 Long Term Capital Plan (2012 LTCP). No issue was raised with respect to the Distribution Planning Manual and the Commission found the 2012 LTCP to be in the public interest in Order G-110-12.

Based on this contingency planning requirement, the total load on RUC T1 during an outage of GFT T3 during peak conditions is forecast to be 100 percent of the RUC T1 load plus 80 percent of the GFT T3 load, or 13.3 MVA (Summer) and 17.2 MVA (Winter) in 2017, the latter of which would exceed the 15 MVA capacity of RUC T1. The results of the analysis are shown in Table 2-2.

Table 2-2: Ruckles Contingency Loading

Line	Ruckles Loading	Contingency	Capacity	2017		2035	
				Summer	Winter	Summer	Winter
1	RUC T1		15 MVA	13.3 MVA	17.2 MVA	15.0 MVA	20.7 MVA

Due to the limited capacity of RUC T1, FBC is unable to sufficiently backup GFT T3 load in the event of a transformer outage. Consequently, a failure of GFT T3 would require the installation of an FBC mobile substation (which can take 12 to 24 hours or more) to restore service to all customers. Additional 63/13 kV transformation capacity at the Ruckles Substation would allow FBC to ensure consistent application of FBC's customer reliability planning criteria that are employed in other areas of the FBC system.

[8] For a single transformer substation with no distribution interconnections with other substations this contingency criteria does not apply for practicality reasons.

[9] For substations with a single radial feeder this contingency criteria does not apply for practicality reasons.

2.5 SUMMARY OF PROJECT OBJECTIVES

To summarize, the objectives of the Ruckles Project are as follows:

- Address station flooding risks in order to prevent equipment damage, station outages and related employee safety and environmental risks;
- Remove 4 kV non-arc-resistant metal-clad switchgear to address personnel safety risks associated with the arc flash hazard;
- Install new protection, control and metering systems consistent with equipment standards at all other FBC distribution substations to address obsolete equipment and to improve both reliability and safety; and
- Increase 63/13 kV transformation capacity at the Ruckles Substation in order to maintain backup capabilities for nearby distribution feeders and transformers to minimize the potential duration of customer outages.

3. PROJECT ALTERNATIVES

FBC evaluated three options to address the project objectives. This section reviews each of the options and compares their advantages/disadvantages, relative costs and rate impacts. The three options considered are:

1. Option 1 – Do Nothing. Under this option, no modifications would be made to the substation equipment or site.
2. Option 2 – Full Rebuild on Existing Site. This option would involve raising the existing site above the flood plain and constructing a new transformer foundation with oil containment in a new location within the existing substation site. A new 63/13 kV 40MVA transformer would be installed, along with two 13 kV/4 kV 5 MVA step-down transformers to accommodate 4kV load requirements. New high voltage equipment including circuit breakers, disconnect switches and ancillary equipment would be constructed on raised foundations above anticipated flood levels.
3. Option 3 – New Ruckles Substation on East Side of Highway 3. This option would involve constructing a new substation on the east side of Highway 3 outside of the Kettle River flood plain and preferably near the existing 9 Line and 10 Line transmission lines. A new 63/13 kV 40 MVA transformer would be installed, along with two 13/4 kV 5 MVA step-down transformers to accommodate 4 kV load requirements. This option would also require either a new interconnection between the new station and the existing City of Grand Forks switching station or the relocation of the City of Grand Forks switching station.

FBC evaluated and rejected another potential substation site located on the northeast corner of the sawmill property as the project costs associated with this location were higher than Option 3.

3.1 OPTION 1: DO NOTHING

The Do Nothing Option would involve no modifications to the substation equipment or site.

Advantages:

- No advantages.

Disadvantages:

- Would not reduce the risk of equipment damage or risk of loss of supply due to station flooding;
- Would not address the environmental risk associated with the lack of oil containment;
- Would not eliminate the arc flash hazard to FBC personnel presented by the existing 4 kV switchgear;

- Would not address obsolete protection, control and metering equipment issues; and
- Would not allow for an increase in 63/13 kV transformation capacity to backup nearby distribution feeders and transformers.

3.2 OPTION 2: FULL REBUILD ON EXISTING SITE

The Full Rebuild on Existing Site Option would include, but is not limited to, the following:

- Raise existing station finished grade above the Kettle River flood plain;
- Construction of a new transformer foundation and transformer oil containment system at the existing site on the east side of the station;
- Installation of a new 63/13 kV 40 MVA transformer (designation RUC T3);
- Installation of two new 13/4 kV 5 MVA transformers (designation RUC T4, RUC T5);
- Construction of a new 13 kV distribution structure in the northeast corner of the station with a new main low voltage breaker and four feeder breakers[10];
- Construction of a new 63 kV A-frame structure with a new 63kV breaker (designation RUC CB1);
- Installation of a mobile substation connection;
- Construction of new control building in northeast corner of substation; and
- Incoming transmission line and distribution feeder egress modifications to accommodate new equipment locations; and
- Relocation of CAP1 capacitor bank.

The capital cost of Option 2 is estimated to be approximately $8.288 million, inclusive of removal and financing costs.

Option 2 has a NPV of revenue requirements of $11.279 million and a levelized rate increase of 0.20 percent. The revenue requirements impact is calculated over 50 years based on the depreciable life of the assets (48 years) plus two preceding years during the planning/construction phase and assuming the Company's current capital structure and cost of capital.

[10] An existing 13 kV breaker would be reused and renamed RUC DB4. The existing breaker is currently in operation at Ruckles Substation however it would need to be retrofitted from 48VDC to 125VDC operation.

Advantages:

- Mitigates the risk of equipment damage and of loss of supply due to station flooding by increasing the elevation of all major high voltage equipment in yard;
- Addresses environmental risks by providing FBC standard oil containment;
- Eliminates the arc flash hazard by removing the 4 kV non arc-resistant metal-clad switchgear;
- Eliminates obsolete equipment, improves safety and reliability and brings the Ruckles Substation to current day standards consistent with all other FBC distribution substations by installing new protection, control and metering equipment; and
- Increases 63/13 kV transformation capacity at Ruckles Substation in order to maintain backup capabilities for nearby distribution feeders and transformers.

Disadvantages:

- Construction within an existing facility location which is still interconnected with the electric power system is generally more complex than construction within a new site or property that is not interconnected to the power system until the project is put in service. With respect to the Ruckles Project, there is a need to maintain 4 kV and 13 kV sources of supply during construction.

3.3 OPTION 3: NEW RUCKLES SUBSTATION (EAST OF HIGHWAY 3)

The new Ruckles Substation Option (East of Highway 3) would include, but is not limited to, the following:

- Construction of a new substation on the east side of Highway 3, outside of the Kettle River flood plain;
- Installation of a new 63/13 kV 40 MVA transformer;
- Installation of a transformer oil containment system;
- Installation of two new 13/4 kV 5 MVA transformers;
- Construction of a new 13 kV distribution bus;
- Installation of a new 63 kV breaker and a new 13 kV breaker for transformer protection;
- Installation of three new 13 kV breakers for feeder protection;
- Installation of a mobile substation connection;
- Installation of a new main low voltage breaker and two new feeder breakers for the 4.3kV loads;
- Construction of new control building;

- Transmission and distribution modifications; and
- Relocation of CAP1 capacitor bank.

The capital cost of Option 3 is estimated to be approximately $9.962 million, inclusive of removal and financing costs.

Option 3 has a NPV of revenue requirements of $12.370 million and a levelized rate increase of 0.22 percent. The revenue requirements impact is calculated over 50 years based on the depreciable life of the assets (47 years) plus three preceding years during the planning/construction phase and assuming the Company's current capital structure and cost of capital.

Advantages:

- Mitigates the risk of equipment damage and of loss of supply due to station flooding by relocating the substation;
- Addresses environmental risks by providing FBC standard oil containment;
- Eliminates the arc flash hazard by removing the 4 kV non arc-resistant metal-clad switchgear;
- Eliminates obsolete equipment, improves safety and reliability and brings the Ruckles Substation to current day standards consistent with all other FBC distribution substations by installing new protection, control and metering equipment; and
- Construction would be less complex given it would be an undeveloped site.

Disadvantages:

- May require the relocation of or interconnections back to the City of Grand Forks Switching Station;
- Uncertainty surrounding acquisition and rezoning of land for construction of the substation; and
- Uncertainty surrounding Rights of Way acquisition for the required transmission and distribution interconnections.

3.4 OPTION SUMMARY AND RECOMMENDATION

Table 3-1 below summarizes the analysis of the three options. The financial analysis of Options 2 and 3 can be found in Appendix C-4.

Table 3-1: Summary of Options Analysis

Criteria	Option 1 Do Nothing	Option 2 Ruckles Rebuild on Existing Site	Option 3 New Station East of Highway 3
Preliminary Capital Cost Estimate ($2016, incl. Removal)[11]	$ -	$7.595 million	$8.675 million
Preliminary Capital Cost Estimate (As-spent, incl. Removal and AFUDC[12])	$ -	$8.288 million	$9.962 million
PV of Incremental Revenue Requirement (50 years)	$ -	$11.279 million	$12.370 million
Levelized % Increase on Rate (50 years)	0%	0.20%	0.22%
Addresses Station Flooding Hazards	No	Yes, civil modifications	Yes, station relocation
Addresses Arc-Flash Hazards	No	Yes, eliminates	Yes, eliminates
Addresses Obsolete Equipment Issues	No	Yes, replacement	Yes, replacement
Addresses Reliability Issues	No	Yes, additional capacity	Yes, additional capacity
Requires New Lands and Rights of Way	No	No	Yes
Constructability	N/A	More complex, must work around existing energized equipment	Less complex, site will be in a new location without existing energized equipment
Decision	Rejected	Accepted	Rejected

Option 2 is the preferred option as it is the most cost-effective alternative and achieves all of the project objectives. While construction will be more complex than on an undeveloped site, FBC has considerable experience completing projects within an existing substation site and the risks associated with construction can be mitigated. For Option 3, the risks associated with obtaining new land and rights-of-way outweigh any benefit of less complex construction given the uncertainty in the cost and time to secure new property rights. When including the potential cost of new property rights, the net present value over 50 years for Option 3 is $12.370 million, which is approximately $1.091 million more than the net present value of Option 2 at $11.279 million.

The following section describes the selected option in more detail.

[11] The as-spent amount is escalated from the 2016 amount at a rate of two percent annually.
[12] AFUDC is calculated only on as-spent amounts.

4. PROJECT DESCRIPTION

4.1 PROJECT SCOPE

The scope of the Ruckles Project includes, but is not limited to:

- Rebuild existing station to current FBC standards;
- Raise existing site above the 200 year flood level[13];
- Provide new 40 MVA, 63/13 kV transformer with OLTC;
- Provide new 5 MVA 13/4.3 kV step down transformer & containment for City of Grand Forks supply;
- Provide new 5 MVA 13/4.3 kV step down transformer & containment for the sawmill supply;
- Provide new 63 kV A-frame for line connection;
- Provide 63 kV, 1200 amp breaker and line disconnect;
- Provide 4 bay distribution structure;
- Provide 13 kV main breaker;
- Provide 3 new feeder breakers and egress;
- Re-use one existing breaker (change from 48 VDC to 125 VDC);
- Provide mobile substation access, 63 kV and 13 kV connections & switches;
- Relocate existing CAP1 capacitor bank;
- Provide new station AC/DC station service;
- Provide temporary mobile substation connection for construction;
- Provide new control building;
- Provide new station duct & cable trench system;
- Provide new standard Class II metering and protection;
- Provide new SCADA control and communications infrastructure;
- Provide CAP1 unbalance protection;

[13] As discussed in Section 2.1, the difference in elevation between the 1 in 20 and 1 in 200 flood levels is relatively small. Accordingly, FBC considers it appropriate to design the station to the more conservative 1 in 200 flood level (approximately 0.5 metre higher).

- Realign station feeders as needed to interface with existing;
- Complete station ground grid study;
- Complete station geotechnical study;
- Provide new station ground grid & interconnect with existing;
- Realign 63 kV line to new station A-frame;
- Provide new revenue class metering in station (three feeders);
- Demolish all remaining existing structures & equipment; and
- Salvage existing 48 VDC station service equipment.

Preliminary drawings showing the single line diagram and general arrangement are included in Appendix C-1 as Figure 1 – Option 2 Single Line Diagram and Figure 2 – Option 2 General Arrangement.

4.2 CONSTRUCTION AND OPERATING SCHEDULE

Final construction and commissioning is expected to be complete by the winter of 2018, assuming the Ruckles Project is approved by December 31, 2016. A detailed Project schedule is attached as Appendix C-3 - Execution Schedule.

4.3 PROJECT RISKS

Potential risks to the Ruckles Project identified to date include the following:

- Unforeseen environmental or archaeological discoveries during the construction phase. The risk of such occurrences is considered to be low, based on FBC's previous construction experience at the Ruckles Substation and the historical use of the land for industrial purposes.
- Availability of labour and materials. The risk of such occurrence is considered to be low given the economic climate at this time. Any external labour requirements will likely be easily met given the availability of qualified labour in the market. With respect to materials, FBC believes that the risk of financial and schedule pressures is low. The likelihood and probability of material lead-times and prices changing significantly is low given the current state of the economy. FBC has partially mitigated the risk of any financial or schedule pressures by developing preliminary equipment specifications and obtaining quotes from vendors. Any residual risk will be managed through the use of project planning and contractual performance guarantees.
- An unexpected increase in the cost and time required to complete construction while maintaining the 4 kV and 13 kV sources of supply. This risk is considered to be medium. While there are challenges associated with maintaining two voltage sources during

construction, FBC Engineering, Operations and Project Management developed preliminary designs and staging plans in order to mitigate any construction- or operation-related challenges, which has reduced significantly the risk of cost and delays resulting from construction challenges. As noted above, FBC has extensive experience in substation construction on existing sites with electrified equipment. Any residual risk will be managed through more detailed project pre-planning upon project approval.

4.4 PROJECT COST ESTIMATE

The Ruckles Project is estimated at a capital cost of $8.288 million in as-spent dollars (including $0.428 million of AFUDC and $0.301 million of removal costs). The cost estimate for the Project has been developed to a Class 3 degree of accuracy as defined in the AACE International Recommended Practice No. 10S-90.

Table 4-1 below summarizes the total estimated project capital costs. The as-spent amount is escalated from the 2016 amount at a rate of two percent annually.

Table 4-1: Summary of Estimated Project Capital Costs ($000s)

Project Component	2016 $	As-Spent $
Line Work	231	241
Civil & Site	1,644	1,688
Buildings	184	191
Structures & Buswork	410	427
Station Equipment & Apparatus	2,503	2,602
Communications & SCADA	30	32
Protection, Control & Metering	260	270
Design	611	627
Commissioning	127	132
Project Management	527	545
Subtotal - Construction	6,527	6,754
Cost of Removal	289	301
Project Contingency	779	806
Subtotal – Construction & Removal	7,595	7,860
AFUDC	n/a	428
TOTAL PROJECT COST	7,595	8,288

5. CONSULTATION

As the Ruckles Project is entirely contained within the existing substation footprint, no public consultation was conducted. FBC has discussed the Ruckles Project with the City of Grand Forks municipal electric utility on a number of occasions. Following the most recent discussions, the City of Grand Forks municipal electric utility indicated that they understand the basis on which FBC is proposing the Ruckles Project and do not have a concern with FBC proceeding with the Ruckles Project at this time.

During the construction phase of the Ruckles Project, some customers may experience outages associated with necessary equipment replacements or circuit reconfigurations. FBC will strive to minimize both the number and duration of any outages and will as much as possible provide advance notice to any affected customers.

5.1 FIRST NATIONS CONSULTATION

FBC believes Aboriginal Rights and Title will not be affected by the Ruckles Project and hence First Nation Consultation is not required. All of the planned construction activities for the project are on FBC's existing substation property.

Appendix C-1

SINGLE-LINE DIAGRAM AND GENERAL ARRANGEMENT DRAWINGS

Figure 1: Option 2 Single Line Diagram

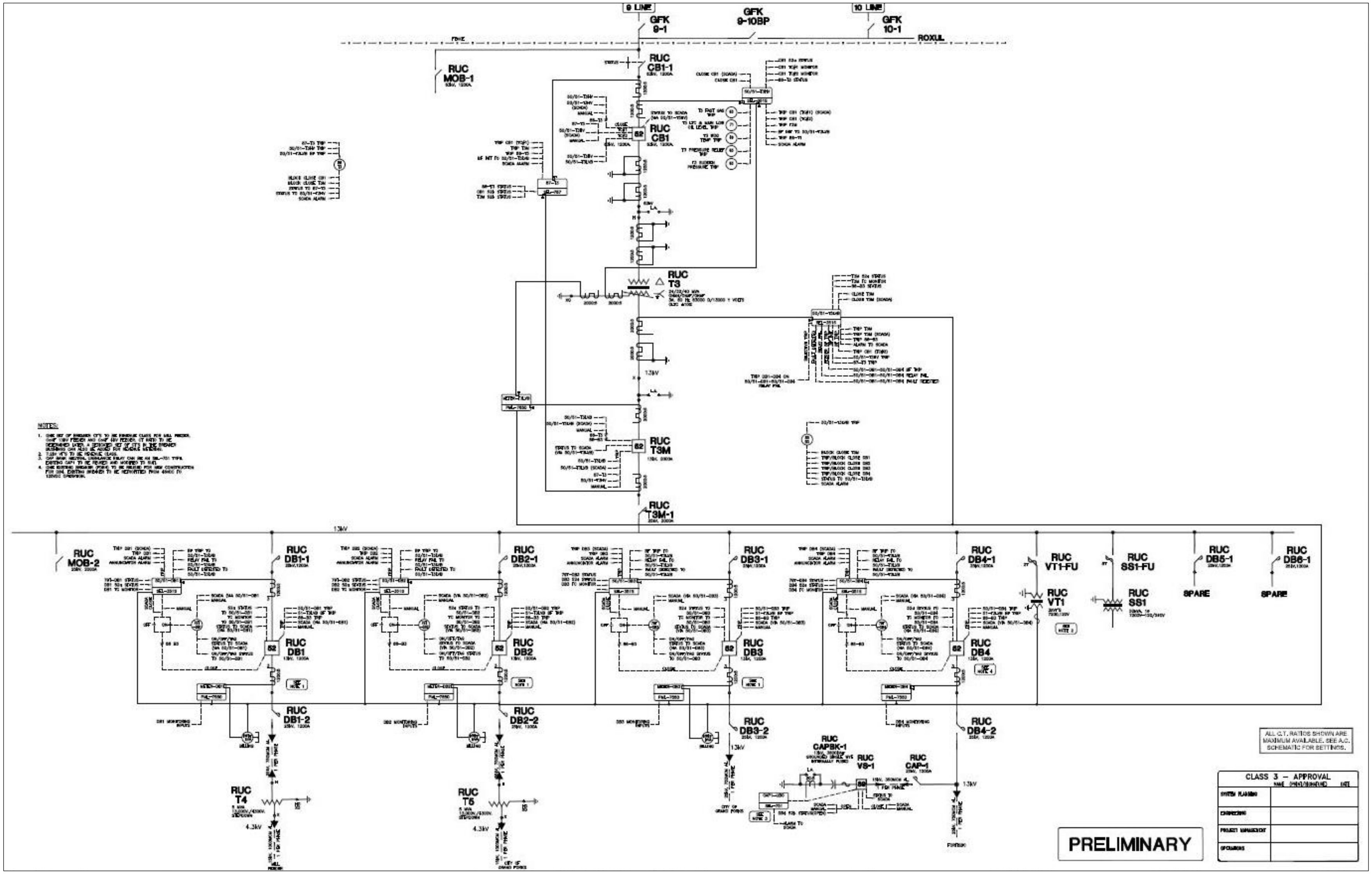
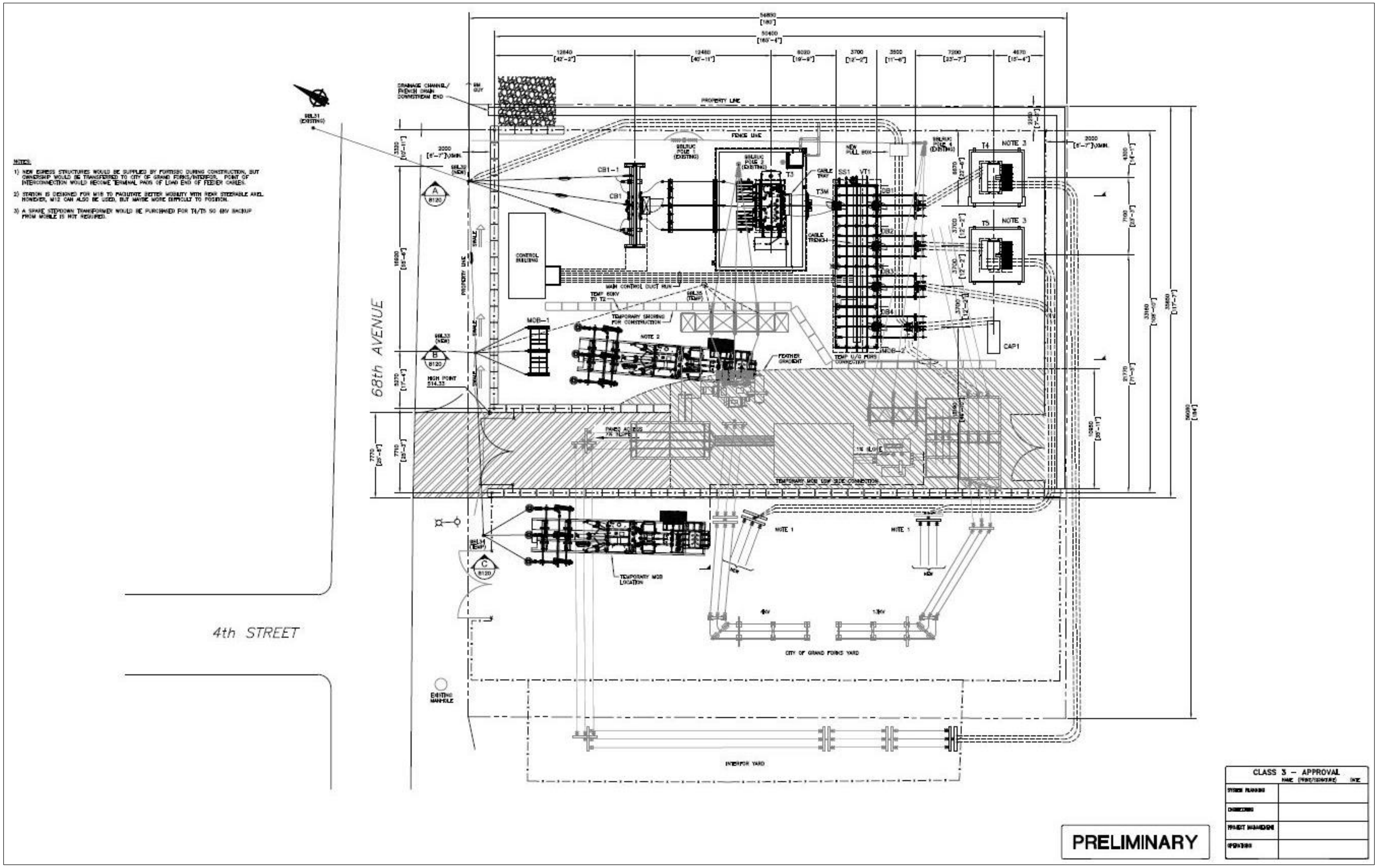


Figure 2: Option 2 General Arrangement



Appendix C-2

GOLDER ASSOCIATES FLOOD REPORT

Golder Associates

TECHNICAL MEMORANDUM

DATE November 2, 2012 **REFERENCE No.** 1214940231-TM-Rev0

TO John McIntosh, P.Eng.
FortisBC Inc.

FROM Gerald Imada, P.Eng. **EMAIL** gimada@golder.com

FLOOD ASSESSMENT, RUCKLES SUBSTATION, 68TH AVENUE, GRAND FORKS, BC

As requested, Golder Associates Ltd. (Golder) has conducted a flood assessment at the above referenced site. The purpose of the assessment was to determine whether the Ruckles Substation was at risk from flooding.

Background Information and Existing Site Conditions

The following presents a brief summary of background information provided by FortisBC together with observations made during an inspection of the site on September 28, 2012.

- The Ruckles Substation is located on the south side of 68th Avenue about 150 m west of the intersection of 68th Avenue and 2nd Street. The Kettle River is located about 100 m to the north of the substation.
- Visual observations indicate the ground surface within substation is relatively flat-lying. A survey conducted by McElhanney Associates Professional Land Surveyors in October, 2007 indicates the geodetic ground surface elevation within the substation is about 512.0 m.
- The substation is located within a "manmade" depression as the site grade along the south and west sides of the substation was noted to be about 1 m higher and along the east side, 2 to 3 m higher.
- The soil conditions observed in a 3 m deep trench excavated on the Interfor property immediately northwest of the substation consisted of up to 2 m of sand and gravel fill underlain by native gravel in which the trench was terminated at about 3 m below the existing ground surface. No groundwater was observed in the trench at the time of the inspection. It is inferred that the substation is underlain by similar subsurface conditions.
- It is understood that the Ruckles Substation has on several occasions been subject to flooding.
- In March of 2007, re-grading of the ground surface was carried out to promote surface water to flow away from the existing transformers and building. Some of the water was directed into two sump pits located within the southwest part of the substation and then pumped into a containment pond located within the southeast corner of the substation.

Flood Assessment

Floodplain Mapping for the Kettle and Granby Rivers (Grand Forks Area) was obtained from the Ministry of Environment Water Stewardship Division's website. A copy of the mapping is attached for your information. Based on the floodplain mapping, the following presents our comments regarding current substation site.

- According to the floodplain mapping, a 1 in 20 year event and 1 in 200 year event would have the flood waters up to elevations of about 514.0 and 514.5 m, respectively at the substation.
- Based on the 2007 McElhanney survey data, the substation would be under about 2.0 m of water for the 1 in 20 year event and 2.5 m of water for the 1 in 200 year event.
- According to the City of Grand Forks Floodplain Management Amendment Bylaw No. 1756, 2004, the designated flood is the 1 in 200 year event. The designated flood level is the 1 in 200 year event plus freeboard.

We trust the information contained in this letter meets your requirements at this time. If you have any questions please contact the undersigned.

Gerald Imada, P.Eng.
Principal, Senior Geotechnical Engineer

GI/cfh

Attachment: Floodplain Mapping Plan of Kettle & Granby Rivers

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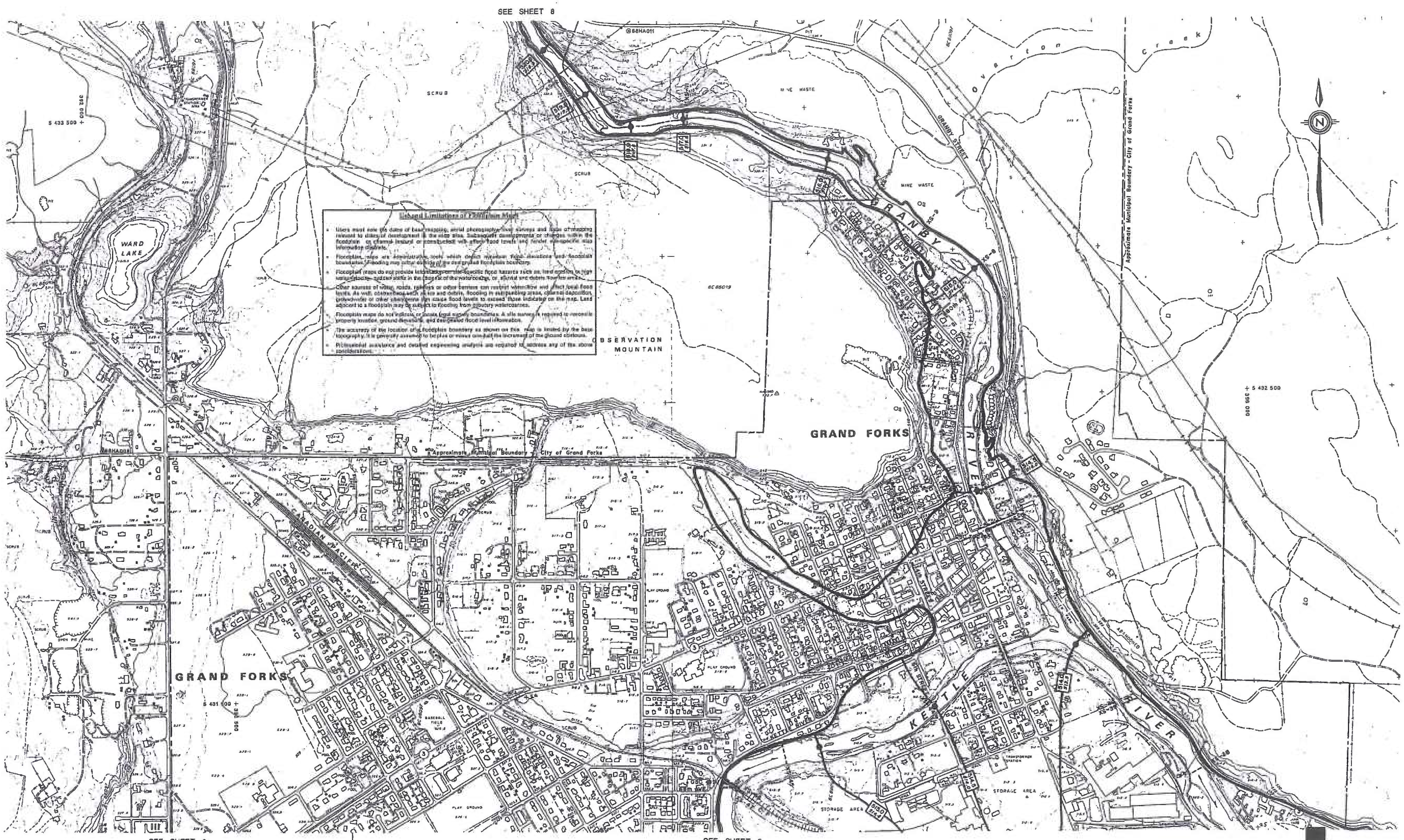


Acres International Limited
Vancouver, B.C., Canada

NOTES

Produced by: Acres International Limited, 4th Floor, 845 Cambie St., Vancouver, B.C. V6B 2P4 (Dec. 1991)

Survey: River survey done by Surveys Section, Water Management Branch, Project 90 23 F035, 1990.
a) Horizontal control based on provincial network.
b) Elevations are in metres and are referred to Geodetic Survey of Canada datum. (◎ indicates Survey Monument).

Mapping: Base mapping done by Map Production Division, Surveys and Resource Mapping Branch, Project 87-034, 1988 Air Photography, NAD 27.
a) Contour interval 1 metre and greater; spot elevations shown to 0.1 metres, with accuracy to ± 0.3 metres, except where noted.
b) Grid origin referred to U.T.M. Projection Zone 11.

FLOODPLAIN DATA

1. The floodplain areas as depicted on this map have been designated pursuant to the Canada/British Columbia Floodplain Mapping Agreement (1988) by the Minister of the Environment for Canada and the Minister of Environment, Lands and Parks for British Columbia.

   Flooding may still occur outside of the designated floodplain areas. The Ministers do not assume any liability by reason of the designation or failure to designate areas on this map.
2. The Designated Flood has a statistical frequency of occurrence of once every 200 years.
3. The flood levels were computed using a standard step method modelling technique, assuming open water flow conditions.
4. The floodplain limits assume the absence of all dykes.
5. The floodplain limits and flood levels include an allowance for freeboard.
6. The floodplain limits are not established on the ground by legal survey.
7. The floodplain limits are not delineated for side streams and tributaries.
8. The required setback of buildings from the natural boundaries of lakes and watercourses to allow for the passage of floodwaters and possible bank erosion is not shown. This information is available either through local municipalities or the Ministry of Environment, Lands and Parks.
9. MAPS AVAILABLE FROM SURVEYS AND RESOURCE MAPPING BRANCH, MAPS B.C. MAP AND AIR PHOTO SALES, VICTORIA, B.C.

LEGEND

DESIGNATED FLOODPLAIN LIMIT

FLOOD LEVEL

RIVER

200 Year Frequency

20 Year Frequency

(METRES G S C DATUM)

KEY MAP

Scale 1 : 250 000

REVISIONS

No.	DESCRIPTION	DATE
	REPLACES DRAWING 5015, SHEETS 1 TO 7, DATED NOVEMBER, 1973.	

ISSUE OF MAPPING
DATE SEPT. 30, 1992

DRAWN V. W.
CHECKED M. N. – P.
RIVER SURVEY
DESIGNED M. N. – P.

ENVIRONMENT CANADA INLAND WATERS / ENVIRONNEMENT CANADA EAUX INTÉRIEURES

BRITISH COLUMBIA MINISTRY OF ENVIRONMENT / COLOMBIE-BRITANNIQUE MINISTÈRE DE L'ENVIRONNEMENT

CANADA BRITISH COLUMBIA FLOODPLAIN MAPPING AGREEMENT / L'ACCORD CANADA COLOMBIE-BRITANNIQUE SUR LA CARTOGRAPHIE DES PLAINES D'INONDATION

FLOODPLAIN MAPPING
KETTLE & GRANBY RIVERS
GRAND FORKS AREA

100m 0 100 200 300 400 500m
Scale in metres

ENGINEER
RECOMMENDED
APPROVED

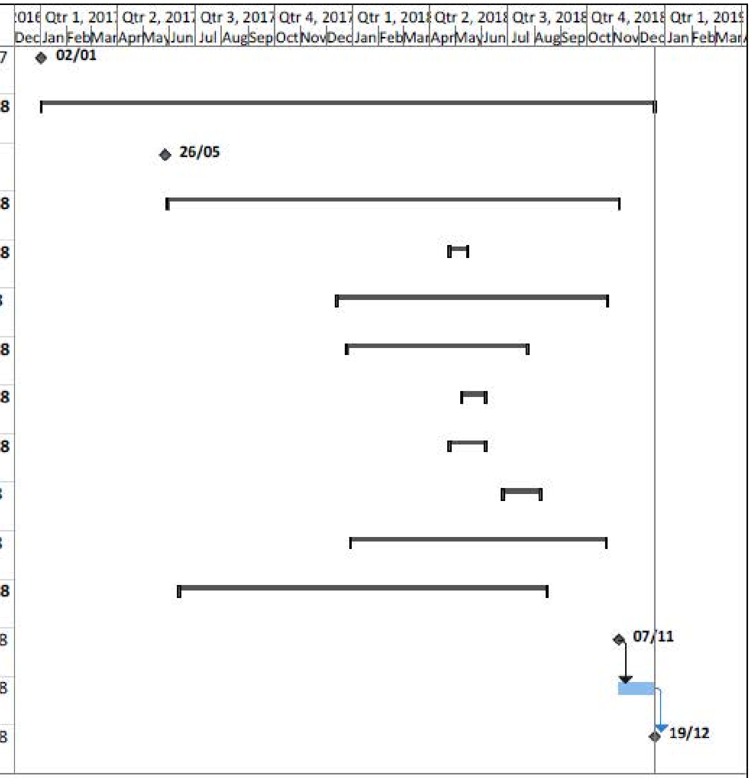
FILE No. 320-0000
N.T.S. MAP No. 82E/1, 2
SCALE 1 : 5 000
NEGATIVE No.
DRAWING No. 90-34-7
REV.
SHEET 7 of 9

DDfimg

Appendix C-3

EXECUTION SCHEDULE

ID	Task Mode	Task Name	Duration	Start	Finish
1		Project Approval	0 days	Mon 02/01/17	Mon 02/01/17
2		**Engineering and Procurement**	**513 days**	**Mon 02/01/17**	**Wed 19/12/18**
6		Construction Start	0 days	Fri 26/05/17	Fri 26/05/17
7		**Civil and Site**	**378 days**	**Mon 29/05/17**	**Wed 07/11/18**
41		**Buildings**	**15 days**	**Tue 24/04/18**	**Mon 14/05/18**
47		**Structures and Buswork**	**226 days**	**Thu 14/12/17**	**Thu 25/10/18**
57		**Station Equipment and Apparatus**	**151 days**	**Mon 25/12/17**	**Mon 23/07/18**
69		**Communications and SCADA**	**20 days**	**Tue 08/05/18**	**Mon 04/06/18**
71		**Protection, Control and Metering**	**30 days**	**Tue 24/04/18**	**Mon 04/06/18**
77		**Commissioning**	**31 days**	**Tue 26/06/18**	**Tue 07/08/18**
80		**Equipment Removal**	**213 days**	**Fri 29/12/17**	**Tue 23/10/18**
91		**Line Work**	**308 days**	**Mon 12/06/17**	**Wed 15/08/18**
99		Construction Completed	0 days	Wed 07/11/18	Wed 07/11/18
100		Project Close-Out	30 days	Thu 08/11/18	Wed 19/12/18
101		Project Completed	0 days	Wed 19/12/18	Wed 19/12/18



Project: RUC Upgrade 2 yr schedu
Date: Mon 25/07/16

Task	External Tasks	Manual Task	Finish-only
Split	External Milestone	Duration-only	Deadline
Milestone	Inactive Task	Manual Summary Rollup	Progress
Summary	Inactive Milestone	Manual Summary	Manual Progress
Project Summary	Inactive Summary	Start-only	

Page 1

Appendix C-4

REVENUE REQUIREMENTS ANALYSIS

FortisBC Inc.
Ruckles Substation: Option 2 - Rebuild on Existing Site
August 2016
($000s), unless otherwise stated

Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2036	2046	2056	2066
1	**Cost of Service**																			
2	Power Purchase Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation & Maintenance	Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Property Taxes	Line 22	-	-	147	149	161	164	167	171	174	177	181	184	188	191	214	259	313	379
5	Depreciation Expense	Line 46	-	-	164	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
6	Income Taxes	Line 79	-	(102)	(35)	(25)	(13)	(3)	7	15	23	30	37	43	48	53	72	81	75	62
7	Earned Return	Line 65	-	-	547	547	537	526	516	506	495	485	475	465	454	444	382	280	177	74
8	**Incremental Annual Revenue Requirement**	Sum of Line 2 to Line 7	**-**	**(102)**	**824**	**822**	**836**	**839**	**841**	**843**	**844**	**844**	**844**	**843**	**841**	**839**	**820**	**771**	**716**	**667**
9	PV of Revenue Requirement (After-tax WACC of 5.97%)	Line 8 / (1 + Line 67)^Yr	-	(91)	692	652	625	592	561	530	501	473	446	420	396	373	257	135	70	37
10	**Total PV of Annual Revenue Requirement**	**Sum of Line 9**	***11,279***																	
11																				
12	2016 Approved Revenue Requirement (G-202-15 Compliance Filing)		350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593
13	% Increase on 2016 Rate	Line 8 / Line 12	0.00%	-0.03%	0.24%	0.23%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.23%	0.22%	0.20%	0.19%
14																				
15	PV of Annual 2016 Approved Revenue Requirement	Line 12 / (1 + Line 67)^Yr	330,826	312,174	294,574	277,965	262,293	247,505	233,551	220,383	207,958	196,233	185,169	174,729	164,878	155,582	109,835	61,476	34,409	19,259
16	Total PV of 2016 Approved Revenue Requirement	Sum of Line 15	5,545,388																	
17	**Levelized % Increase (50 yrs) on 2016 Rate**	**Line 10 / Line 16**	**0.20%**																	
18																				
19	**Property Taxes**																			
20	General, School and Other		-	-	147	150	153	156	159	162	165	169	172	176	179	183	206	251	306	373
21	1% in Lieu of General Municipal Tax[1]	1% of Line 8	-	-	-	(1)	8	8	8	8	8	8	8	8	8	8	8	8	7	7
22	**Total Property Taxes**	Line 20 + Line 21	-	-	147	149	161	164	167	171	174	177	181	184	188	191	214	259	313	379
23	1 - Calculation is based on the second preceding year, e.g. 2019 is based on 2017 revenue																			
24																				
25	**Capital Spending**																			
26	Project Capital Spending[2]		2,064	5,496	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	AFUDC		65	363	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Annual Capital Spending & AFUDC	Sum of Line 26 to 29	2,129	5,859	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Cost of Removal		14	287	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total Annual Project Cost - Capital	Line 28 + Line 29	2,143	6,146	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																				
32	**Total Project Cost (incl. AFUDC)**	**Sum of Line 28**	**7,988**																	
33	**Net Project Cost (incl. AFUDC and Removal)**	**Sum of Line 30**	**8,288**																	
34	2 - First year of analysis includes all prior year spending																			
35																				
36	**Gross Plant in Service (GPIS)**																			
37	GPIS - Beginning[3]	Preceding Year, Line 41	-	-	7,988	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359
38	Additions to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Retirements		-	-	(628)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Net Addition to Plant	Sum of Line 38 to 39	-	-	(628)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	GPIS - Ending	Line 37 + Line 40	-	-	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359
42	3 - Addition in 2018 (when work complete and in-service) is shown in the opening balance of 2019 (CPCN addition to plant to Jan 1 of following year)																			
43																				
44	**Accumulated Depreciation**																			
45	Accumulated Depreciation - Beginning	Preceding Year, Line 49	-	-	-	764	613	462	310	159	7	(144)	(296)	(447)	(599)	(750)	(1,659)	(3,174)	(4,688)	(6,203)
46	Depreciation Expense[4]	Line 37 @ 2.06%	-	-	(164)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)	(151)
47	Retirements		-	-	628	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Cost of Removal		-	-	301	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Accumulated Depreciation - Ending	Sum of Line 45 to 48	-	-	764	613	462	310	159	7	(144)	(296)	(447)	(599)	(750)	(902)	(1,810)	(3,325)	(4,840)	(6,355)
50	4 - Depreciation & Amortization Expense calculation is based on opening balance x composite depreciation rate; The composite rate of all assets addition to plant is 2.06%																			
51																				

FortisBC Inc.
Ruckles Substation: Option 2 - Rebuild on Existing Site
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Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2036	2046	2056	2066
52	**Rate Base and Earned Return**																			
53	Gross Plant in Service - Beginning	Line 37	-	-	7,988	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359
54	Gross Plant in Service - Ending	Line 41	-	-	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359	7,359
55																				
56	Accumulated Depreciation - Beginning	Line 45	-	-	-	764	613	462	310	159	7	(144)	(296)	(447)	(599)	(750)	(1,659)	(3,174)	(4,688)	(6,203)
57	Accumulated Depreciation - Ending	Line 49	-	-	764	613	462	310	159	7	(144)	(296)	(447)	(599)	(750)	(902)	(1,810)	(3,325)	(4,840)	(6,355)
58																				
59	Net Plant in Service, Mid-Year	(Sum of Lines 53 to Line 57) / 2	-	-	8,056	8,048	7,897	7,745	7,594	7,442	7,291	7,139	6,988	6,836	6,685	6,533	5,625	4,110	2,595	1,081
60	Cash Working Capital	Line 41 x FBC CWC/Closing GPIS %	-	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
61	**Total Rate Base**	**Sum of Line 59 to 60**	**-**	**-**	**8,063**	**8,056**	**7,904**	**7,753**	**7,601**	**7,450**	**7,298**	**7,147**	**6,996**	**6,844**	**6,693**	**6,541**	**5,632**	**4,118**	**2,603**	**1,088**
62																				
63	Equity Return	Line 61 x ROE x Equity %	-	-	295	295	289	284	278	273	267	262	256	250	245	239	206	151	95	40
64	Debt Component	[5]	-	-	252	252	247	243	238	233	228	224	219	214	209	205	176	129	81	34
65	**Total Earned Return**	**Line 63 + Line 64**	**-**	**-**	**547**	**547**	**537**	**526**	**516**	**506**	**495**	**485**	**475**	**465**	**454**	**444**	**382**	**280**	**177**	**74**
66	Return on Rate Base %	Line 65 / Line 61	0.00%	0.00%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
67	After- Tax Weighted Average Cost of Capital (WACC)	[6]	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%
68	5 - Line 61 x (LTD Rate x LTD% + STD Rate x STD %)																			
69	6 - ROE Rate x Equity Component + [(STD Rate x STD Portion) + (LTD Rate x LTD Portion)] x (1- Income Tax Rate)]																			
70																				
71	**Income Tax Expense**																			
72	Earned Return	Line 65	-	-	547	547	537	526	516	506	495	485	475	465	454	444	382	280	177	74
73	Deduct: Interest on debt	Line 64	-	-	(252)	(252)	(247)	(243)	(238)	(233)	(228)	(224)	(219)	(214)	(209)	(205)	(176)	(129)	(81)	(34)
74	Add: Depreciation Expense		-	-	164	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
75	Deduct: Capital Cost Allowance	Line 87	-	(290)	(558)	(517)	(479)	(444)	(411)	(381)	(353)	(327)	(302)	(280)	(260)	(240)	(152)	(71)	(33)	(15)
76	Taxable Income After Tax	Sum of Line 72 to 75	-	(290)	(99)	(71)	(38)	(8)	19	44	66	86	105	122	137	150	206	232	214	176
77	Income Tax Rate		26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%
78																				
79	**Total Income Tax Expense**	Line 76 / (1 - Line 77) x Line 77	**-**	**(102)**	**(35)**	**(25)**	**(13)**	**(3)**	**7**	**15**	**23**	**30**	**37**	**43**	**48**	**53**	**72**	**81**	**75**	**62**
80																				
81	**Capital Cost Allowance**																			
82	Opening Balance	Proceeding Year, Line 88	-	-	7,571	7,012	6,495	6,016	5,573	5,162	4,781	4,429	4,102	3,800	3,519	3,260	2,059	957	445	207
83	Additions to Plant		-	7,988	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84	Add: Cost of Removal		-	301	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85	Less: AFUDC		-	(428)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	Net Addition for CCA	Sum of Line 83 through 85	-	7,860	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	**CCA (Composite CCA Rate @ 7.37%)**	**[Line 82 + (Line 86/2)] x CCA Rate**	**-**	**(290)**	**(558)**	**(517)**	**(479)**	**(444)**	**(411)**	**(381)**	**(353)**	**(327)**	**(302)**	**(280)**	**(260)**	**(240)**	**(152)**	**(71)**	**(33)**	**(15)**
88	Closing Balance	Line 82 + Line 86 + Line 87	-	7,571	7,012	6,495	6,016	5,573	5,162	4,781	4,429	4,102	3,800	3,519	3,260	3,019	1,907	886	412	192

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Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2036	2046	2056	2066
1	**Cost of Service**																			
2	Power Purchase Expense		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Operation & Maintenance	Line 18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Property Taxes	Line 22	-	-	-	150	152	166	169	172	175	179	182	185	189	192	215	260	314	380
5	Depreciation Expense	Line 46	-	-	-	206	170	170	170	170	170	170	170	170	170	170	170	170	170	170
6	Income Taxes	Line 79	-	-	(116)	(25)	(21)	(7)	5	17	27	36	45	52	59	65	90	102	95	80
7	Earned Return	Line 65	-	-	-	660	657	645	634	622	611	599	588	576	565	553	484	368	253	136
8	**Incremental Annual Revenue Requirement**	Sum of Line 2 to Line 7	**-**	**-**	**(116)**	**991**	**958**	**974**	**978**	**981**	**983**	**984**	**984**	**984**	**983**	**981**	**959**	**900**	**832**	**767**
9	PV of Revenue Requirement (After-tax WACC of 5.97%)	Line 8 / (1 + Line 67)^Yr	-	-	(97)	786	717	688	652	617	583	551	520	490	462	435	301	158	82	42
10	**Total PV of Annual Revenue Requirement**	Sum of Line 9	***12,370***																	
11																				
12	2016 Approved Revenue Requirement (G-202-15 Compliance Filing)		350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593
13	% Increase on 2016 Rate	Line 8 / Line 12	0.00%	0.00%	-0.03%	0.28%	0.27%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.27%	0.26%	0.24%	0.22%
14																				
15	PV of Annual 2016 Approved Revenue Requirement	Line 12 / (1 + Line 67)^Yr	330,826	312,174	294,574	277,965	262,293	247,505	233,551	220,383	207,958	196,233	185,169	174,729	164,878	155,582	109,835	61,476	34,409	19,259
16	Total PV of 2016 Approved Revenue Requirement	Sum of Line 15	5,545,388																	
17	**Levelized % Increase (50 yrs) on 2016 Rate**	**Line 10 / Line 16**	**0.22%**																	
18																				
19	**Property Taxes**																			
20	General, School and Other		-	-	-	150	153	156	159	162	165	169	172	176	179	183	206	251	306	373
21	1% in Lieu of General Municipal Tax[1]	1% of Line 8	-	-	-	-	(1)	10	10	10	10	10	10	10	10	10	10	9	8	8
22	**Total Property Taxes**	Line 20 + Line 21	-	-	-	150	152	166	169	172	175	179	182	185	189	192	215	260	314	380
23	1 - Calculation is based on the second preceding year, e.g. 2019 is based on 2017 revenue																			
24																				
25	**Capital Spending**																			
26	Project Capital Spending[2]		2,500	5,803	383	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	AFUDC		76	334	571	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Annual Capital Spending & AFUDC	Sum of Line 26 to 29	2,576	6,137	953	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Cost of Removal		67	213	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total Annual Project Cost - Capital	Line 28 + Line 29	2,643	6,349	970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																				
32	**Total Project Cost (incl. AFUDC)**	**Sum of Line 28**	**9,666**																	
33	**Net Project Cost (incl. AFUDC and Removal)**	**Sum of Line 30**	**9,962**																	
34	2 - First year of analysis includes all prior year spending																			
35																				
36	**Gross Plant in Service (GPIS)**																			
37	GPIS - Beginning[3]	Preceding Year, Line 41	-	-	-	9,666	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974
38	Additions to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Retirements		-	-	-	(1,692)	-	-	-	-	-	-	-	-	-	-	-	-	-	(9,666)
40	Net Addition to Plant	Sum of Line 38 to 39	-	-	-	(1,692)	-	-	-	-	-	-	-	-	-	-	-	-	-	(9,666)
41	GPIS - Ending	Line 37 + Line 40	-	-	-	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	(1,692)
42	3 - Addition in 2018 (when work complete and in-service) is shown in the opening balance of 2019 (CPCN addition to plant to Jan 1 of following year)																			
43																				
44	**Accumulated Depreciation**																			
45	Accumulated Depreciation - Beginning	Preceding Year, Line 49	-	-	-	-	1,782	1,611	1,441	1,271	1,101	930	760	590	420	249	(772)	(2,475)	(4,177)	(5,879)
46	Depreciation Expense[4]	Line 37 @ 2.13%	-	-	-	(206)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)
47	Retirements		-	-	-	1,692	-	-	-	-	-	-	-	-	-	-	-	-	-	9,666
48	Cost of Removal		-	-	-	296	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Accumulated Depreciation - Ending	Sum of Line 45 to 48	-	-	-	1,782	1,611	1,441	1,271	1,101	930	760	590	420	249	79	(942)	(2,645)	(4,347)	3,617
50	4 - Depreciation & Amortization Expense calculation is based on opening balance x composite depreciation rate; The composite rate of all assets addition to plant is 2.13%																			
51																				

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Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2036	2046	2056	2066
52	**Rate Base and Earned Return**																			
53	Gross Plant in Service - Beginning	Line 37	-	-	-	9,666	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974
54	Gross Plant in Service - Ending	Line 41	-	-	-	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	7,974	(1,692)
55																				
56	Accumulated Depreciation - Beginning	Line 45	-	-	-	-	1,782	1,611	1,441	1,271	1,101	930	760	590	420	249	(772)	(2,475)	(4,177)	(5,879)
57	Accumulated Depreciation - Ending	Line 49	-	-	-	1,782	1,611	1,441	1,271	1,101	930	760	590	420	249	79	(942)	(2,645)	(4,347)	3,617
58																				
59	Net Plant in Service, Mid-Year	(Sum of Lines 53 to Line 57) / 2	-	-	-	9,711	9,670	9,500	9,330	9,160	8,989	8,819	8,649	8,479	8,309	8,138	7,117	5,414	3,712	2,010
60	Cash Working Capital	Line 41 x FBC CWC/Closing GPIS %	-	-	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	(2)
61	**Total Rate Base**	**Sum of Line 59 to 60**	**-**	**-**	**-**	**9,719**	**9,679**	**9,509**	**9,338**	**9,168**	**8,998**	**8,828**	**8,657**	**8,487**	**8,317**	**8,147**	**7,125**	**5,423**	**3,720**	**2,008**
62																				
63	Equity Return	Line 61 x ROE x Equity %	-	-	-	356	354	348	342	336	329	323	317	311	304	298	261	198	136	73
64	Debt Component	[5]	-	-	-	304	303	297	292	287	281	276	271	266	260	255	223	170	116	63
65	**Total Earned Return**	**Line 63 + Line 64**	**-**	**-**	**-**	**660**	**657**	**645**	**634**	**622**	**611**	**599**	**588**	**576**	**565**	**553**	**484**	**368**	**253**	**136**
66	Return on Rate Base %	Line 65 / Line 61	0.00%	0.00%	0.00%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
67	After- Tax Weighted Average Cost of Capital (WACC)	[6]	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%
68	5 - Line 61 x (LTD Rate x LTD% + STD Rate x STD %)																			
69	6 - ROE Rate x Equity Component + [(STD Rate x STD Portion) + (LTD Rate x LTD Portion)] x (1- Income Tax Rate)]																			
70																				
71	**Income Tax Expense**																			
72	Earned Return	Line 65	-	-	-	660	657	645	634	622	611	599	588	576	565	553	484	368	253	136
73	Deduct: Interest on debt	Line 64	-	-	-	(304)	(303)	(297)	(292)	(287)	(281)	(276)	(271)	(266)	(260)	(255)	(223)	(170)	(116)	(63)
74	Add: Depreciation Expense		-	-	-	206	170	170	170	170	170	170	170	170	170	170	170	170	170	170
75	Deduct: Capital Cost Allowance	Line 87	-	-	(329)	(632)	(584)	(538)	(497)	(458)	(423)	(390)	(360)	(332)	(307)	(283)	(175)	(78)	(35)	(16)
76	Taxable Income After Tax	Sum of Line 72 to 75	-	-	(329)	(70)	(59)	(20)	15	47	77	103	127	149	168	185	256	291	271	228
77	Income Tax Rate		26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%	26%
78																				
79	**Total Income Tax Expense**	Line 76 / (1 - Line 77) x Line 77	**-**	**-**	**(116)**	**(25)**	**(21)**	**(7)**	**5**	**17**	**27**	**36**	**45**	**52**	**59**	**65**	**90**	**102**	**95**	**80**
80																				
81	**Capital Cost Allowance**																			
82	Opening Balance	Proceeding Year, Line 88	-	-	-	8,653	8,020	7,437	6,898	6,402	5,943	5,520	5,130	4,770	4,437	4,131	2,729	1,480	922	672
83	Additions to Plant		-	-	9,666	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84	Add: Cost of Removal		-	-	296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85	Less: AFUDC		-	-	(980)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	Net Addition for CCA	Sum of Line 83 through 85	-	-	8,982	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	**CCA (Composite CCA Rate @ 7.73%)**	**[Line 82 + (Line 86/2)] x CCA Rate**	**-**	**-**	**(329)**	**(632)**	**(584)**	**(538)**	**(497)**	**(458)**	**(423)**	**(390)**	**(360)**	**(332)**	**(307)**	**(283)**	**(175)**	**(78)**	**(35)**	**(16)**
88	Closing Balance	Line 82 + Line 86 + Line 87	-	-	8,653	8,020	7,437	6,898	6,402	5,943	5,520	5,130	4,770	4,437	4,131	3,848	2,554	1,402	887	656

Appendix D

UPPER BONNINGTON OLD UNITS REFURBISHMENT PROJECT BUSINESS CASE

FORTISBC INC.

Appendix D
Upper Bonnington Old Units Refurbishment Project

Business Case

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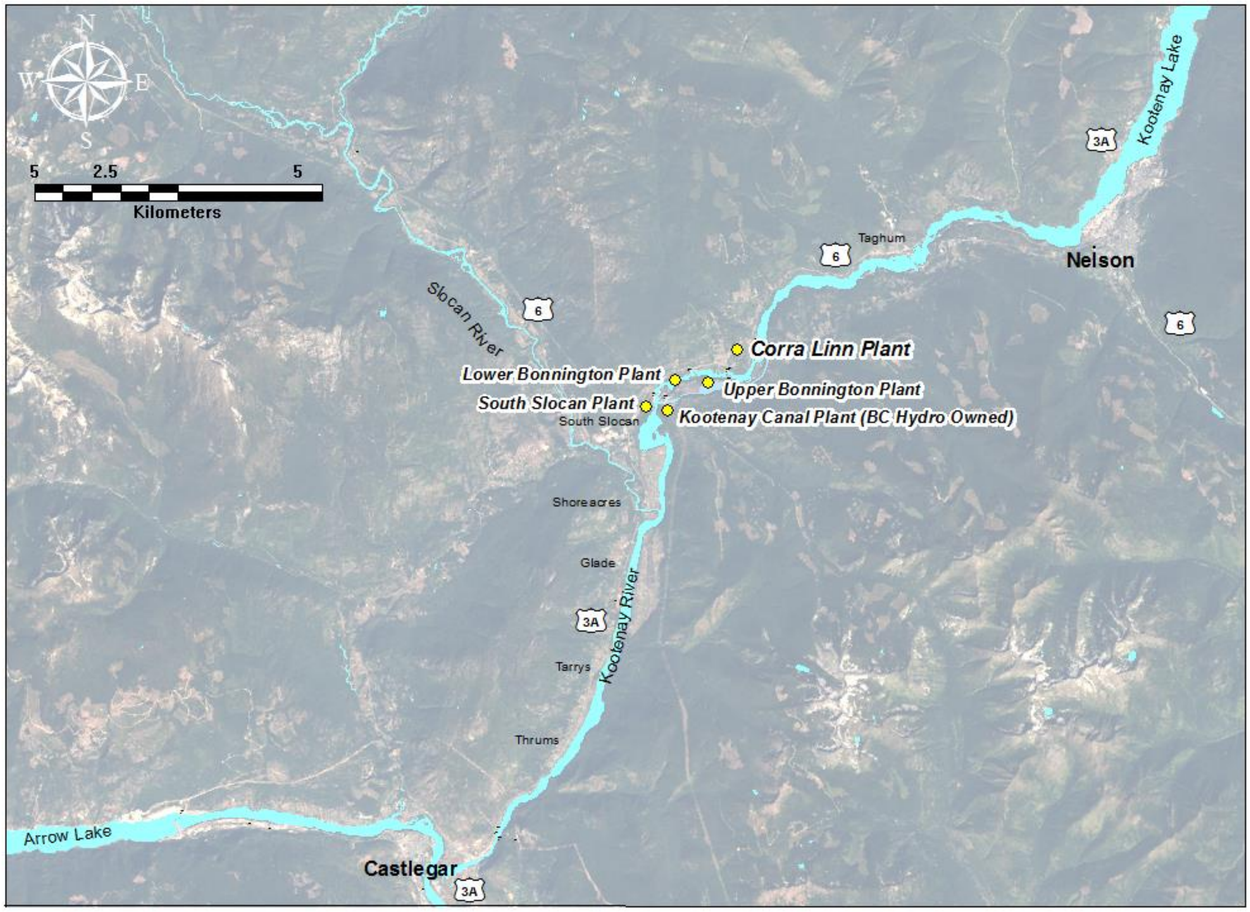
1. PROJECT SUMMARY

The Upper Bonnington Old Units Refurbishment Project (the UBO Project) involves the replacement or refurbishment of various components of four of the generation plant's six units, which are at end of life and can no longer be operated in a safe, reliable, and environmentally responsible manner. The four Old Units (Units 1 to 4) were not included in the Upgrade and Life Extension (ULE) program, which refurbished the remaining 11 of FBC's 15 generating units, although certain components of Unit 3 have been repaired or replaced due to failure in the last three years. The UBO Project, which will be executed over the period 2017 – 2021, will extend the productive life of the Old Units for the next twenty years or more and has an estimated total capital cost of $31.783 million (including financing and removal costs). The UBO Project is comprised of four smaller projects (one for each of the four generation units) in addition to project completion work on elements common to the four units. Capital costs for the four units range from $5.412 million to $9.579 million per unit. Additional capital expenditures beyond the initial 20-year timeframe would increase the productive life to 40 years, however FBC is not seeking approval of those expenditures at this time.

1.1 *BACKGROUND*

FBC owns four hydro-electric generating plants on the Kootenay River with an aggregate capacity of 225 megawatts: the Corra Linn, Upper Bonnington (UBO), Lower Bonnington, and South Slocan plants. The four plants, which are shown in Figure 1-1 below, were commissioned during the period 1907 to 1940.

Figure 1-1: FBC Owned Generating Plants



The UBO plant is located approximately 17 kilometres downstream from the City of Nelson and houses four of the oldest generating units owned by FBC. The UBO plant is comprised of six generating units. Units 1 through 4, each with a nameplate rating of 5.7 megawatts (MW), were commissioned between 1907 and 1916, and are commonly referred to as the "Old Plant" or "Old Units". Two additional units, Unit 5 and Unit 6, were installed in 1940, then with nameplate ratings of 18.4 MW.

The Corra Linn, Lower Bonnington, and South Slocan generating plants house an additional nine generating units.

Between 1998 and 2011, the Company undertook the ULE program, which was primarily a refurbishment program to extend the productive life of eleven units of the fifteen units in FBC's generating plants on the Kootenay River: the nine at Corra Linn, Lower Bonnington and South Slocan, and Units 5 and 6 at UBO. The four UBO Old Units have not undergone life extension work.

FBC has recognized the need to extend the productive life of the Old Units since the inception of the ULE program. Upon completion of the ULE program in 2011, FBC stated the following about the Old Units:

> The Company will continually assess the ability of these generating units to provide reliable service, and will present an application to the Commission to rebuild the generating units when it is apparent that they can no longer be operated without significant capital investments or an increasing operating and maintenance costs.[1]

As explained in the following section, the Old Units are at end of life and in need of refurbishment.

[1] FBC 2012-2013 Revenue Requirements Application, Exhibit B-1, Tab 6, page 15.

2. PROJECT NEED

The requirement to refurbish the four Old Units at UBO is driven by the age and condition of the units. Originally commissioned more than 100 years ago, the Old Units are at end of life, and have begun to experience equipment failures.

The age and condition of the Old Units result in risks to:

- Reliability: In addition to the increasing likelihood of equipment failure, many of the components are obsolete, and any forced outages resulting from their failure would be prolonged by the lack of available replacements;
- Safety: Certain operations require employees to work in close proximity to moving or energized equipment, which increase the risks of injuries; and
- Environment: Oil containment systems are aged or absent, increasing the risk of a release into the environment. Some of the unit components contain asbestos materials.

In FBC's view, the risks posed by the age and condition of the Old Units are increasing. There is an acute need to address the condition of the Old Units as clearly demonstrated by the following condition assessment.

2.1 *OLD UNITS CONDITION ASSESSMENT*

The Company seeks to extend the service life of its assets as long as it is economic to do so through effective condition monitoring and maintenance programs. The Company's approach is to actively monitor the condition of its assets, perform routine maintenance, refurbish deteriorating assets, and only replace deteriorating assets when refurbishment is no longer operationally feasible or economic.

The Old Units have reached end of life and must undergo refurbishment. FBC's assessment of the Old Units is summarized below and is supported by the following third-party reports:

- The 2009 Upper Bonnington Generator 1 Inspection Report, conducted by HDR, Inc. (formerly HDR|DTA) (HDR Generator 1 Inspection Report), included as Appendix D-1;
- The 2013 Upper Bonnington Generating Station Unit 3 Repair Option Review, prepared by Engen Services Ltd. (Engen Unit 3 Review), included as Appendix D-2; and
- The 2015 Upper Bonnington Generating Station Unit 1 Turbine Component Mechanical Inspection, prepared by Engen Services Ltd. (Engen Unit 1 Turbine Inspection), included as Appendix D-3.

The HDR Generator 1 Inspection Report is a condition assessment of the Unit 1 generator main electrical components and its findings are representative of the condition of the other Old Units' main electrical components based on a similar vintage design and construction. The Engen

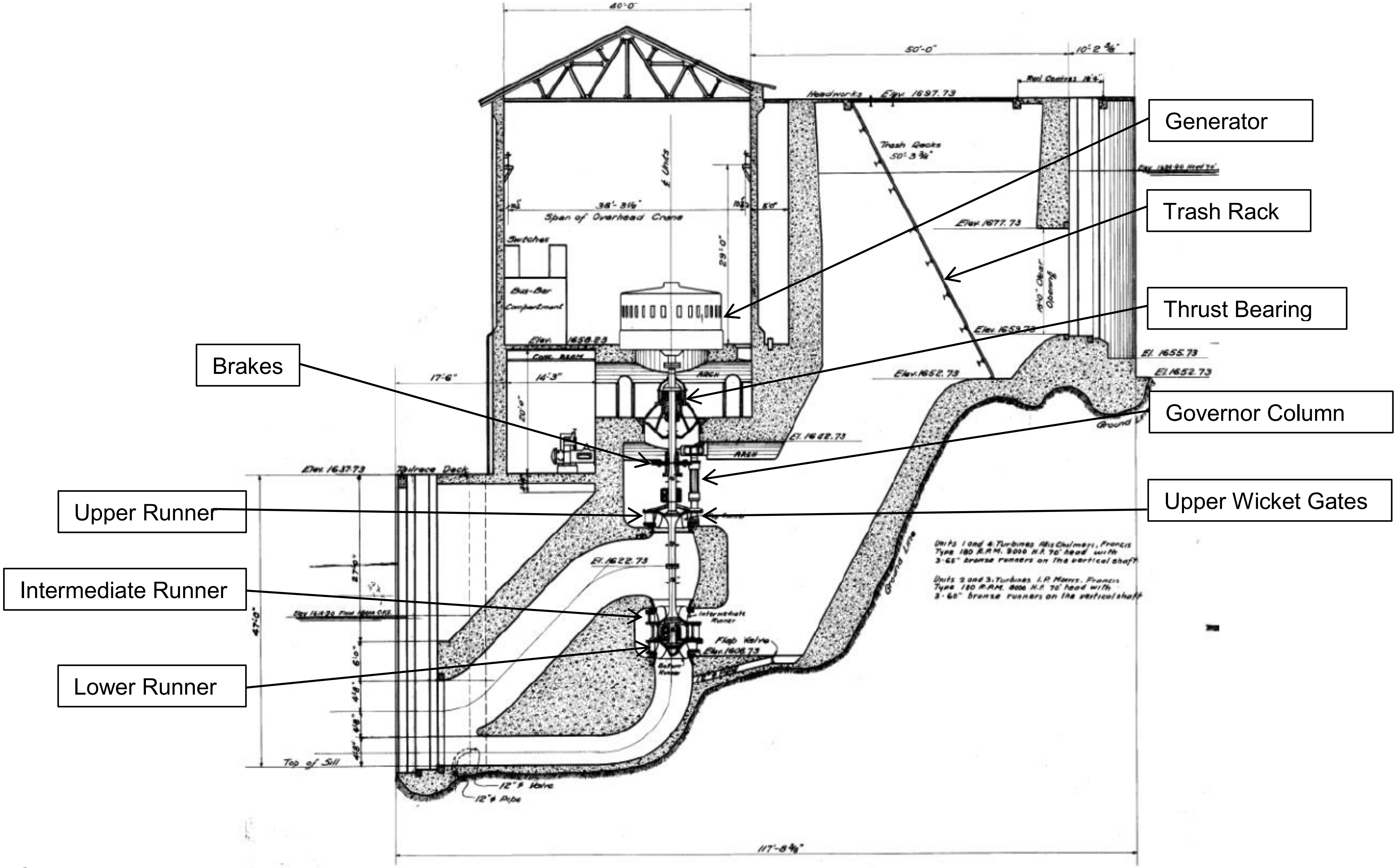
Unit 3 Review and the Engen Unit 1 Turbine Inspection, while specific to the units identified, are also representative of the condition of the remaining Old Units based on their common vintage and operating duty. In general, in addition to the increasing risk of failure due to the age and condition of the components, many are simply obsolete and cannot be easily repaired or replaced. This increases the complexity of ongoing maintenance and is likely to extend the duration of outages in the event of component or equipment failure.

The Company's determination that the Old Units have reached their end of life is also supported by the recent damage to the lower turbine area of Unit 3, which was discovered while the unit was dewatered for its annual inspection in 2013, and the failure of the T3 transformer in 2016. Further, a recent inspection completed in July 2016 revealed damage to Unit 4, which is similar to the damage found in Unit 3 in 2013.

The following is a summary of the assessed condition of the major components which will be addressed by the UBO Project. In general, all of the smaller sub-components and systems are of similar vintage, exhibit deteriorated condition and have reached end of life.

For reference in the condition assessment discussion that follows, a typical unit cross-section is provided in Figure 2-1 below. For clarity the turbine is comprised of three separate runners, the upper, intermediate, and lower runners.

Figure 2-1: Typical Generating Unit Cross Section

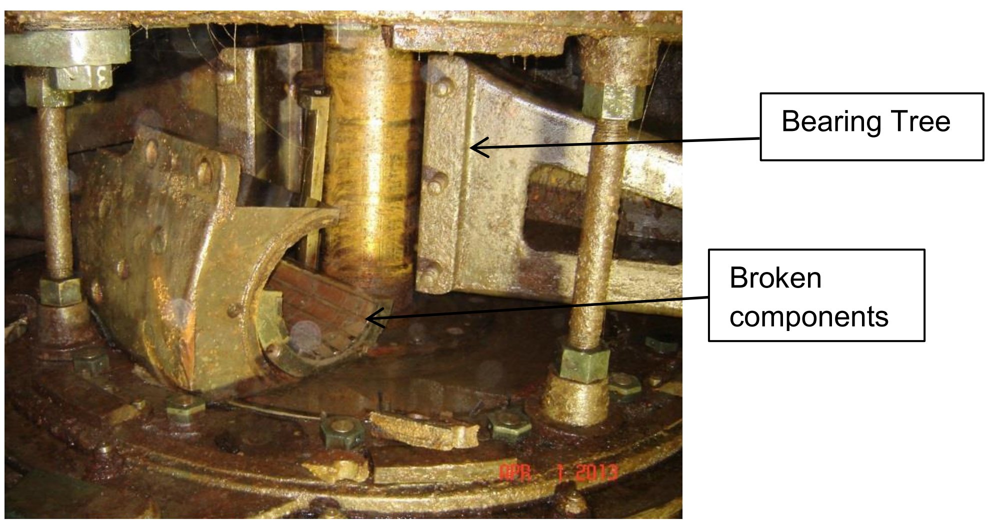


2.1.1.1 Turbine Shaft, Bearings, and Brakes

The damage to Unit 3, which was discovered during the annual inspection in 2013, was caused by a failure of the lower turbine guide bearing and the supporting concrete for the bearing tree. The failure resulted from severe machine imbalance, due to worn and deteriorated components, which caused excessive vibration, which in turn led to breaking up of the bearing components and subsequently damage to the adjacent components. Figures 2-2 and 2-3 below show the damage found.

Figure 2-2: UBO Unit 3 Damage to the Concrete and Lower Bearing Tree

Figure 2-3: UBO Unit 3 Failed Lower Turbine Guide Bearing



The turbine brakes consist of a large shaft mounted brake wheel with a beam type brake lever and an air cylinder operator. The Engen Unit 1 Turbine Inspection identified that the brake shoe support on this unit is heavily corroded, the brake shoes were found misaligned (see Figure 2-4 below) and the brake support beam bent. Corrosion leads to pitting of the braking surfaces which substantially reduces the effectiveness of the braking system, and consequently its ability to slow or stop the unit when required. A failure of the braking system can result in significant equipment damage due to over-speeding.

Figure 2-4: UBO Unit 1 Turbine Brake and Shoe Misalignment

The antiquated design of the existing brake systems poses an operational risk due to its deteriorated condition. The brake systems are located in a confined space, high up in the water passage. Accessing the brake system requires a scaffold and ladders, all within the confined space environment. The brake shoes themselves weigh approximately 200 pounds and must be hoisted on the roof of the water passage above the scaffold in order to be maintained. This situation creates a safety hazard for FBC personnel.

Figure 2-5 provides a picture of the heavy corrosion evident in the upper turbine bearing and distributor assembly.

Figure 2-5: UBO Unit 1 Upper Turbine Bearing and Distributor Assembly Heavily Corroded

The Engen Unit 3 Review identified a number of deteriorated components, including lower generator shaft runout[2] and wear, packing and seals worn to a level that also indicates excessive turbine runout, worn lower runner seals, and pitting on all the bearing diameters and on the seal diameter.

In July 2016, an annual inspection on Unit 4 revealed damage to the upper bearing tree embedded anchor. The damage found was similar to that which occurred at Unit 3 in 2013. FBC is currently assessing the damage and the repairs required on Unit 4 in order to return it to service.

The conditions described above have the potential to cause excess vibration and machine imbalance resulting in uncontrolled turbine rotation, runaway (over-speed), damage to the turbine and the potential un-controlled release of water resulting in flooding of the powerhouse." In addition, all of the listed scenarios pose a safety risk to FBC operating personnel working inside the power plant building.

2.1.1.2 Turbine Runners and Seals

The Engen Unit 1 Turbine Inspection noted that Unit 1 operates the original 1914 Allis-Chalmers turbine which was subject to a major overhaul in the 1980s that addressed cavitation[3] and seal damage. The report described that the obsolete runner design consists of turbine blade inlets that by design are very thin and through the process of cavitation, flow and particle induced erosion, are showing signs of washout and horizontal cracking (shown in Figure 2-6 below). The as-found cavitation is 1/8 inch deep extending from the blade inlet suction side down to the blade fillet with heavy erosion of the seal clearance exceeding acceptable levels, resulting from loss of material in the bronze material surrounding the band seal.

[2] Turbine runout is a technical term and is the degree to which a shaft or coupling deviates from the center of rotation or centerline. Excessive runout causes imbalance, which leads to increased vibration in the units, which causes excessive stresses on the moving parts, leading to failure.

[3] Cavitation is the formation of bubbles or voids in a liquid. Under certain conditions these voids implode when near to a metal surface and due to the excessive forces generated during implosion, cause wear to the metal surface.

Figure 2-6: UBO Unit 1 Cracking and Erosion of the Turbine Blade Inlet Pressure Side

Since the blades are very thin and the extent of cavitation significant, the consequences of increased cavitation is a reduction in turbine performance and eventual blade failure due to the extensive damage observed.

The Engen Unit 1 Turbine Inspection recommended replacement of the Unit 1 turbine because extensive buildup of base metal would be required to restore the structural integrity and the original blade profile.

The Engen Unit 3 Review found that the Unit 3 turbine which underwent corrective repairs in the 1980s and which failed in 2013 had excessive wear on the turbine runner seals and also presented signs of turbine runout. In 2013, FBC completed the refurbishment of turbine shafts and bearing journals, specifically: welding of bearing journals, sealing of running surfaces, banding of turbines to reclaim seals, welding repairs of turbine runners for cavitation damage and repair of cracks for Unit 3. It is expected that the remainder of the Old Units are in similar condition to that of Unit 3 prior to its repair. Figure 2-7 below illustrates the condition of the Unit 3 turbine cone.

Figure 2-7: UBO Unit 3 Turbine Cracked Cone

Based on the deteriorated condition of Units 1 and 3 turbine runners and seals, the failure of Unit 3 turbine runners in 2013, and that Units 2 and 4 are of similar vintage and design as the two units inspected, FBC has concluded that the turbine runners and seals will require replacement or refurbishment.

2.1.1.3 Governor System

The existing governor systems are of original vintage and are over 100 years old. As with any obsolete equipment, spare parts and technical support from the manufacturer are no longer available, meaning that the governor system cannot be adequately maintained and is unreliable.

The governor system operates using a large volume of oil which is contained in a deteriorated and obsolete storage tank which is at end of life. To date, leaks from this system have been small and contained within the plant itself. However, the age of the equipment increases the likelihood of a larger oil spill, which could be difficult to contain and may flow into the river because of the lack of a central oil containment system at the plant.

The existing governor columns are also of original vintage and are submerged in water during normal operation. The governor columns comprise of a steel pipe riveted to cast flanges, cast guide and thrust bearing supports and a series of clevis yokes and pins. The governor columns are worn and deteriorated and no longer have the ability to perform precise movements required for governor operation and thus are not suitable for continued reliable operation.

Unlike all of FBC's other generating units, the Old Units were not designed with intake gates or an emergency shut down circuit on the governors. Therefore, in the event of an over-speed situation, the supply of water to the turbines cannot be stopped in a controlled manner. Additionally, the governor cannot initiate a unit trip by closing the wicket gates and applying the brake automatically. Consequently, the only way to slow the unit down is to manually close the wicket gates by operating the governor and manually operating the brakes. These procedures require operation in close proximity by the plant operators which poses a safety risk to the operators.

The consequences of a failure of the governor column, which could cause loss of turbine control and could result in an over-speed condition, is excessive turbine vibration leading to turbine destruction and flooding of the power house.

The Engen Unit 3 Review noted heavy corrosion and wear on the Unit 3 governor column bushings, rods, yokes and other components. The Unit 3 governor column has been replaced.

The Engen Unit 1 Turbine Inspection noted in Section 3.6 of the report that the governor column of Unit 1 is heavily corroded (see Figure 2-8 below) and has lost some structural integrity, and recommended replacement of the components of the governor column.

Figure 2-8: UBO Unit 1 Heavy Corrosion on Upper Governor Column and Linkages

Considering the safety, environmental and reliability risks presented above and that the governor system is over 100 years old and is at end of life, FBC has concluded that the governor system requires replacement.

2.1.1.4 Turbine (Distributor) Components

The existing turbine (distributor) components are of original vintage and are over 100 years old and comprise of turbine head cover, wicket gates, and gate linkages. The wicket gates are worn, heavily corroded and deteriorated and can no longer reliably control the flow of water to the turbine runners leading to unreliable operation. The operating rings[4] are manufactured from low quality cast steel and they have a tendency to bind and break.

The deteriorated condition of the operating ring and wicket gate bushings has a direct impact on the ability to regulate the turbine speed. Excessive bushing clearance or failure due to corrosion and wear could cause an imbalance of load between turbines and an increase of wicket gate leakage which results in turbine creep (the turbine cannot be stopped if the brakes are released when at rest). A failure of the gate linkages or wicket gates could cause loss of turbine control and could result in an over speed condition that could create excessive turbine vibration leading to turbine destruction and flooding of the power house.

The Engen Unit 3 Review noted poor condition of the Unit 3 wicket gate bushings, excess bushing clearances on all operating rings. The Unit 3 wicket gates have been replaced in 2013.

[4] Each wicket gate is connected by linkages to a control ring to ensure uniform water flow to the turbines. The control ring is commonly referred to as an operating ring.

The Engen Unit 1 Turbine Inspection noted that the distributor assembly of Unit 1 is heavily corroded with wear on governor linkages, wicket gate bushings, and heavy corrosion on Unit 1 wicket gates as shown in Figure 2-9 and on the head cover and the associated water pipes.

Figure 2-9: UBO Unit 1 Heavy Corrosion on Wicket Gate

2.1.1.5 Trash Racks

The trash racks and operating mechanisms, which prevent water-borne debris from entering the intake of the water turbines, are of original vintage and are over 100 years old.

The Engen Unit 1 Turbine Inspection found that below water level the trash rack lost approximate half of the thickness due to corrosion and the support beams are also heavily corroded (see Figure 2-10 below). The Unit 1 Inspection Report found that the trash rack has lost approximately half its thickness due to corrosion. A failure of the trash rack could result in large debris or broken pieces of the trash rack itself entering into the penstock and from there into the turbine which would most likely cause a catastrophic failure of the turbine and/or its components.

Due to their obsolete design, the trash rack mechanism is difficult to operate and require a make shift arrangement using a truck mounted winch to return the rake to service after each trash pulling cycle. This operation is cumbersome and poses a safety hazard to the operating personnel.

Figure 2-10: UBO Unit 1 Heavy Corrosion on Trash Rack Support Beam

2.1.1.6 Generators

The existing generators are of original vintage and are over 100 years old. The stator windings were replaced in 1926 on Unit 1, in 1924 and 1995 on Unit 2, in 1925 on Unit 3 and in 1928 on Unit 4. The existing generator stator and rotor windings (with the exception of Unit 2) are based on asphalt mica insulation, which is a Class A insulation[5].

The Unit 2 generator stator windings were replaced as part of the repairs completed after the unit failed in 1995. The HDR Generator 1 Inspection Report found, among other issues: poor connections of the field winding circuit; poor rotor winding insulation; at least one shorted field pole winding; cracked fan blades and fan blades with missing weld; plugged stator ventilation openings; reduced air-gap clearances indicating possible core movement; and open clearances on oil seals that allow oil ingress into the generator.

2.1.1.7 Excitation System

The excitation system of a generator provides a source of direct current (DC) energy for the field windings located on the generator rotor. The rotating magnetic field produced by the rotor results in current flow in the high-voltage stator winding. In addition to helping maintain

[5] Asphalt bonded mica insulation was the insulation of choice until synthetic resin and mica paper systems were introduced in the early 1950's. The asphalt bonded mica insulation is thermoplastic and has a very low dielectric strength. The expected service life of windings with this kind of insulation is approximately 40 to 60 years.

synchronous operation[6] of the generator with the power system, the excitation system is also used to control the amount of reactive power that the generator produces or absorbs.

Failure of the generator excitation system could result in the loss the stability of the generator (the ability of the generator to operate synchronously with the power system), overheating of the rotor winding (due to over-excitation), or stator-end iron heating (due to under-excitation). Each of these conditions could cause damage to the respective components and would result in a generator outage.

The excitation for Units 1 to 4 generators, shown in Figure 2-11 below, is supplied from a common DC bus system which is connected to a water turbine driven exciter (E1) made by General Electric, originally installed in 1907. An original spare exciter (E2) is a General Electric motor-generator set which failed some time ago and is irreparable because of its vintage. Should the exciter E1 fail, all four of the Old Units would be unable to generate electricity.

Figure 2-11: UBO Water Turbine Driven Exciters E1 and E2

Components for the excitation system are no longer manufactured and maintenance requires either removing parts of other old equipment or custom manufacture.

The rheostats, which are variable resistors used to control excitation current and thus provide voltage control, are in deteriorated mechanical condition, which includes worn out, broken, or mis-aligned gear trains. Further, the rheostats have inconsistent electrical resistance characteristics due to shortened or broken elements. As a result, manual operation is frequently required, during which the operator is exposed to an arc flash[7] hazard because the rheostats are not enclosed in an arc resistant enclosure.

[6] Synchronous operation means all connected generators operate at a common frequency.
[7] Arc Flash is a type of electrical explosion that is the result of a rapid release of energy arising from an arcing fault when electric current passes through air.

Furthermore, the common DC panel employs an exposed bus design which does not meet industry or utility best practices and poses an employee safety issue due to the risk of exposure to arc flash, necessitating special operating procedures.

2.1.1.8 Generator Step Unit Transformer

The four generator step-up (GSU) transformers installed at UBO are from a variety of manufacturers and vintages, with the oldest, the GSU transformer for Unit 1 (T1), dating from 1932.

The T1 transformer bank is comprised of three 2 megavolt ampere (MVA) capacity single phase transformers. The single phase transformers are 84 years old and water cooled. An analysis of the phase C transformer indicates that the paper insulation is aging, with associated increasing risk of failure.

The transformer water cooling system comprises a heat exchanger located inside each transformer tank which is supplied with cooling water from a circulating pump. The design of the water cooling system with the heat exchanger inside the main transformer tank means that the cooling pipes can easily become clogged, making maintenance and repair of the system expensive and difficult (as oil needs to be removed to inspect/repair the heat exchanger). The inability to quickly determine if the cooling pipes are clogged can lead to transformer overheating which could cause transformer failure, which carries the risk of equipment fire, damage to nearby equipment and poses a safety hazard to personnel working in close proximity.

In May 2016, the T3 transformer bank Phase B failed due to an internal insulation failure and caused an oil spill and smoke venting into the atmosphere. The failure resulted in damage to the T3 phase B explosion vent and oil was spilled due to the internal pressure generated by the internal arcing. Consequently, the T3 transformer bank (which is similar in design with the T1 transformer bank) has now been replaced.

Given the age and condition of the T1 transformer bank, and failure history of the similar T3 transformer bank, FBC considers the T1 transformer bank to be at end of life and requiring replacement.

Furthermore, there is no oil containment installed on any of the generator step up transformers in the Old Units, which increases the likelihood of an uncontained oil spill reaching the water way during maintenance or transformer failure.

2.1.1.9 Protection and Control System

Generator protection and control systems are used, among other things, to ensure safe operations of the plant by protecting the generators from excessive current flows and voltage excursions, by protecting the generators from over/under-voltage or over/under-speed conditions, and by detecting overheating of the rotor or stator windings.

The protection and control systems installed are mainly original vintage electromechanical relays. The obsolescence of the electromechanical protective relays gives rise to a number of operational issues, including the unavailability of spare parts and lack of manufacturer support and in-house expertise, which make repairs to the relays impractical. The existing relays are not sensitive enough to adequately protect the equipment and have no event recording analysis capability to support the engineering personnel investigating faults and trips. The electromechanical relays are also not capable of integration with modern generator and excitation control systems.

Additionally, the existing relay panels use asbestos-containing materials and pose an employee safety risk during testing and routine maintenance.

2.2 RISKS OF CONTINUED OPERATION

The condition of the Old Units which is outlined above gives rise to safety, reliability and environmental risks. Table 2-1 below summarizes the safety and environmental risks associated with running the units in their current condition.

Table 2-1: Risk Assessment of Continued Unit Operation

Risk Category	Major Components	Explanation
Safety	Governor System, Turbine Shaft Bearings and Brake	Start-up/Shutdown/Operation of units is done manually, requiring employees to be in close proximity to moving equipment thus relying on a Governor System and a Brake System which are at end of life.
Safety/Reliability	Governor System, Turbine Distributor Components	Inability to curtail water flow into units during a shutdown because there are no head gates installed thus relying only on the Governor System and the Distributor Components which are at end of life. The only means of isolation (stopping the water flow completely to the Units) is with the manual installation of stop logs. Failure of the Governor System or Turbine Components could result in an over speed condition with potential for turbine failure or flooding of the powerhouse. There is a risk of electrical faults from the over voltage that can arise if the speed rotation of the generator increases above nominal and the risk of mechanical failure of the turbine or the Distributor Components due to the hydraulic inertia.
Safety/Reliability	Excitation System	Unable to automatically set the required generator excitation level and provide voltage control increasing the risk of equipment failure from over voltages. When adjusting the excitation level during normal operation, the operator is in close proximity to exposed equipment that is not enclosed in an arc resistant enclosure exposing the operator to an arc flash hazard, which necessitates special operating procedures.
Safety	Turbine Shaft Bearings and	The Turbine Brake system is located in a confined space,

Risk Category	Major Components	Explanation
	Brake	high up in the water passage. Accessing the brake system requires hoisting heavy equipment exposing employees to multiple safety hazards.
Safety/Reliability	Governor Column, Turbine Distributor Components	Due to their deteriorated condition, a failure of the Governor System and Distributor Components could lead to an over-speed condition and resulting equipment damage thereby increasing risks to workers. With no head gate in place, a failure of the Governor System or Distributor Components during operation means the Units cannot be brought to a standstill and could likely over-speed leading to equipment damage and exposing workers to a safety hazard.
Safety/Reliability	Protection and Control System	The existing protective relaying is unreliable and insensitive to faults and is unable to quickly detect and isolate faulted equipment during a fault which could lead to equipment failure and increased risks to workers.
Safety/Environmental/Reliability	Generator Units	The existing generator windings contain asbestos material. Due to the deteriorated condition of the generator's windings there is an increased risk of generator winding failure which could cause asbestos to contaminate the air.
Environmental	Governor System	The Governor system operates using a large volume of oil contained in a deteriorated and obsolete containment structure which is at end of life. Failure of the containment could lead to contamination of the waterways.
Environmental	Protection and Control System	The existing Protection and Control System is unreliable and insensitive to faults and is unable to quickly detect and isolate faulted equipment. Equipment not isolated timely could fail violently and discharge oil and hazardous substances into the environment.
Environmental	Generator Step Unit Transformer	The generator step up transformers are not fitted with an oil containment system. Failure of a transformer could lead to a discharge of oil and contamination of the waterways.

In summary, the equipment and systems at the UBO Old Plant are at end of life, the majority being in excess of 100 years old. Because of the vintage of the equipment and systems, various independent engineering condition assessments have recommended that replacement and/or refurbishment be done. Moreover, the failures that have occurred since 2013 have demonstrated that the units are at end of life and are incapable of performing reliably. Without these capital works, FBC personnel will continue to be exposed to severe safety hazards and risks, the reliability of the Old Units will continue to be at risk from equipment failure, and the likelihood of contaminants entering the environment will continue to increase.

2.3 *PROJECT OBJECTIVES*

FBC has determined that the age and condition of the Old Units give rise to safety, reliability, and environmental risks, and defines the objectives of the UBO Project to be:

- To ensure the availability of reliable supply to FBC's customers at the lowest reasonable cost;
- To mitigate the safety risks to FBC's employees that result from the obsolete design and poor condition of the generating units; and
- To mitigate the environmental risks posed by the increasing likelihood of failure of the aged equipment.

3. PROJECT ALTERNATIVES

FBC evaluated three options to address the project objectives. This section reviews each of the options and compares their advantages/disadvantages, relative costs and rate impacts. The three options considered are

1. Option 1 – Decommission Old Units (Decommissioning). This would involve the planned shut down and permanent decommissioning of all four Units;
2. Option 2 – Old Units Full Life Extension (Full Life Extension). This would involve completing a "water to wire" replacement or refurbishment of generating unit components, equivalent to the unit upgrades completed on the eleven units under the ULE program, in order to preserve this low-cost source of power in a safe and environmentally responsible manner. This option also modernizes the systems and controls to allow for increased operational flexibility and provides for remote operability of the plant. With the Full Life Extension option the life of the Old Plant is expected to extend another 40 years; and
3. Option 3 – Old Units Refurbishment (Refurbishment). This would involve undertaking only the necessary refurbishment and replacement upgrades to preserve this low-cost source of power in a safe and environmentally responsible manner. The Refurbishment option is expected to extend the life expectancy of the Old Plant by another 20 years. With additional sustainment capital investment in future years on certain components, a 40 year life span can be achieved.

Sections 3.2 and 3.3 summarize the scope of work for Options 2 and 3. The Full Life Extension scope materially differs from the Refurbishment scope by replacing instead of refurbishing the turbine runners, replacement instead of leaving in service the generator main lead cable, and installing a fire detection system and a new medium voltage switchgear. The increased scope included in Option 2 would be required to provide the additional 20 years life expectancy of the Full Life Extension option compared to Option 3 - Refurbishment.

3.1 *OPTION 1 – DECOMMISSIONING*

Under this option, the Old Plant would be shut down in a planned manner and each of the four Units would be permanently decommissioned to address safety and environmental issues associated with the aged condition of the equipment.

The Decommissioning would involve the following activities:

- Plugging the water intake, flood tunnels and tail races for all Units and installing a pump system to remove the accumulation of water that natural dam leakage allows;
- Removing the governor system and associated equipment;

- Repairing and sealing floor openings;
- Removing the generators and associated equipment (such as cables, neutral grounding and resistors);
- Removing the excitation system and all associated control systems;
- Removing all the GSU (Generator Step Up) transformers;
- Removing the GSU circuit breakers and associated bus work;
- Removing all the 600 volt equipment including cables and panels; and
- Securing the turbines, which would be left.

The expected capital cost to decommission the plant is $4.256 million in 2017. No further maintenance, refurbishment or replacement of the existing equipment would be required. In addition, operating savings of approximately $0.160 million annually (2016 dollars) would result from the elimination of annual inspections on the four units, beginning in 2017, and the elimination of O&M Expense for major inspections of $0.300 million (2016 dollars) in year 2022, 2023, 2029, 2031, 2057, and 2063.

The decommissioning of these units would result in a need for 115 GWh of replacement power annually. In its financial analysis of the three alternatives, FBC has valued the replacement power at BC Hydro's Rate Schedule 3808, which is the rate schedule applicable under the terms of the Company's Power Purchase Agreement (PPA) with BC Hydro, and assuming annual escalation of three percent. The forecast cost of replacing the energy entitlement with PPA energy purchases would be $5.574 million in 2017, increasing to $8.707 million in 2032. Additionally, FBC water rental fees would be reduced by approximately $0.831 million per year beginning in 2018 (escalated by inflation annually)[8].

Option 1 has a net present value (NPV) of revenue requirements of $105.018 million and a levelized rate increase of 1.89 percent to the 2016 approved rate over a fifty year period.

Advantages

- Prevents the safety and environmental risks associated with unit failure through the decommissioning of the four Units;
- Low capital cost; and
- Reduces annual operating and maintenance expense.

Disadvantages

- High cost of replacement power.

[8] Water rental fees are based on previous year entitlement; for decommissioning in 2017, water rental fee reduction being in the subsequent year 2018.

3.2 OPTION 2 – FULL LIFE EXTENSION

The Full Life Extension alternative would involve a "water to wire" refurbishment of the Old Units, equivalent to the unit upgrades completed under the ULE program. The Full Life Extension would mainly involve the replacement of many of the vintage systems and components of the Units, with some refurbishment of components where in FBC's view refurbishment is adequate based on condition (excluding certain components that have been recently repaired or replaced, as identified in the scope of work below). This alternative would address all safety concerns, enable reliable operation for a 40-year period and minimize environmental risks. Additionally, this option would modernize the plant with the installation of automation and remote control systems similar to that in place at all other FBC plants. Automation would allow for automatic start and stop, remote dispatch and control, and equipment-based monitoring.

A summarized scope of work for this alternative includes:

- Replacement of the turbine braking system;
- Replacement of the turbine runners and refurbishment of shafts;
- Installation of a high pressure governor system;
- Refurbishment of the governor column (excluding Unit 3);
- Installation of a high pressure oil lift system (excluding Unit 3);
- Refurbishment of the turbine components (excluding Unit 3);
- Replacement of the trash racks;
- Rewinding of the generator stator and rotor (excluding Unit 2) and replacement of the rotor spider (all Units);
- Refurbishment of generator bearings (excluding Unit 3);
- Installation of a new generator bearing lubrication system;
- Installation of a generator cooling system;
- Installation of new excitation equipment;
- Replacement of Unit 1 GSU transformer;
- Installation of new protection and control system, interface to FBC's Supervisory Control and Data Acquisition (SCADA) system and a vibration monitoring system;
- Replacement of main lead cables from the generator to the transformer;
- Installation of a unit fire detection system;
- Replacement of generator neutral grounding equipment; and
- Installation of a new generator switchgear.

The capital cost of Option 2 is estimated to be approximately $47.300 million, inclusive of removal and financing costs.

The cost of replacement power that would be required during the construction phase is estimated between $0.261 million and $0.387 million per unit, for a total of $1.367 million for the four units. O&M Expense would be reduced by approximately $0.040 million in each year during construction (escalated by inflation annually) as a result of the elimination of the annual unit inspection while each unit is undergoing the life extension work. Annual inspection would resume in the year following completion of the unit life extension.

Option 2 has a NPV of revenue requirements of $46.692 million and a levelized rate increase of 0.84 percent to the 2016 approved rate over a fifty year period. The revenue requirements impact is calculated over the depreciable life of the assets (50 years) and assuming the Company's current capital structure and cost of capital.

Advantages:

- Addresses risk to employee safety and to the environment due to unit failure;
- Provides ongoing reliability of the generating units for an additional 40 years;
- Improves operational flexibility through automation;
- Allows for remote start-up/shutdown of units; and
- Lower NPV and rate impact compared to Option 1.

Disadvantages:

- There are no technical disadvantages identified.
- Higher capital cost compared to Option 1.

3.3 *OPTION 3 – REFURBISHMENT*

The Refurbishment alternative would involve mainly the refurbishment, with some replacement, of the Old Units' components to enable the continued operation of the Old Units in a safe and environmentally responsible manner. Consistent with the Company's approach to extending the life of assets, each component would be assessed based on condition, criticality, reliability and maintainability and only replaced when refurbishment is no longer operationally feasible, technically sound or economic. The Refurbishment would address immediate safety hazards and environmental concerns, but would not provide any significant improvements in operability of the Units that comes with introducing automation.

With this approach the Old Units are expected to achieve an additional life expectancy of approximately 20 years but with additional capital investment in future years on certain components, a 40 year life span can be achieved. Over the next 20 years, FBC would continue to assess and monitor the condition of the Old Units to determine the amount of capital investment required to prolong the life of the Units to 40 years. Based on the future condition assessment of the components and the consequence of failure of those components, the additional capital expenditures required would be prioritized to maximize the Old Units' life expectancy while minimizing the safety and environmental risks.

This option includes:

- Replacement of the turbine braking system;
- Refurbishment of the turbine runners and of shaft journals (excluding Unit 3);
- Installation of a high pressure governor system;
- Refurbishment of the governor column (excluding Unit 3);
- Installation of a high pressure oil lift system (excluding Unit 3);
- Refurbishment of the turbine components (excluding Unit 3);
- Replacement of the trash racks;
- Rewinding of the generator stator and rotor (excluding Unit 2)
- Refurbishment of generator bearings (excluding Unit 3);
- Installation of a new generator bearing lubrication system;
- Installation of a generator cooling system;
- Installation of new excitation equipment;
- Replacement of Unit 1 GSU transformer; and
- Installation of new protection and control system

Advantages:

- Addresses risk to employee safety and to the environment due to unit failure;
- Ensures ongoing reliability of the generating units for an additional 20 years;
- Lower capital cost compared to Option 2; and
- Lowest NPV of the alternatives considered.

Disadvantages:

- Does not allow for remote start-up/shutdown or increased operational flexibility; and
- Would require capital investments in future years to ensure continued operability.

The capital cost of Option 3 is estimated to be approximately $31.783 million, inclusive of removal and financing costs.

The cost of replacement power that would be required during the construction phase is estimated to be the same as for Option 2, which ranges between $0.261 million and $0.387 million per unit, at a total project cost of $1.367 million for the four units. O&M Expense would be reduced by $0.040 million in each year during construction (escalated by inflation annually) as a result of the elimination of the annual unit inspection while the unit is undergoing the refurbishment work. Annual inspection would resume in the year following completion of the unit refurbishment.

Option 3 has a NPV of revenue requirements of $34.038 million (including future capital expenditures) and a levelized rate increase of 0.61 percent to the 2016 approved rate over a fifty year period. The revenue requirements impact is calculated over the depreciable life of the assets (50 years) and assuming the Company's current capital structure and cost of capital.

3.4 *OPTION SUMMARY AND RECOMMENDATION*

Table 3-1 below provides a comparison of the alternatives discussed above. The as-spent amount is escalated from the 2016 amount at a rate of two percent annually.

The capital expenditures shown for Option 3 in Table 2 include only the expenditures for which approval is being requested during the period 2017 to 2021, however as explained in section 3.3, FBC estimates that additional capital upgrades (approximately $24.444 million in total from 2037 to 2057) would be required. For comparability between options, the additional capital expenditures have been included in the calculation of the NPV and rate impact.

The comparison shows that Option 3 – Refurbishment is the most cost effective and has the lowest impact on rates. The financial analysis of the three options can be found in Appendix D-4.

Option 3 has been selected as the preferred solution that would satisfy all of the objectives and requirements outlined in Section 2.3 and has the lowest financial impact over the analysis period.

Table 3-1: UBO Project Alternatives Comparison

Evaluation Criteria	Option 1 – Decommissioning	Option 2 – Full Life Extension	Option 3 – Refurbishment
Preliminary Capital Cost Estimate ($2016, incl. Removal)	$4.039 million	$43.512 million	$29.266 million
Preliminary Capital Cost Estimate (As-spent, incl. Removal and AFUDC[9])	$ 4.256 million	$47.300 million	$31.783 million
NPV of Incremental	$105.018 million[10]	$46.692 million	$34.038 million[11]

[9] AFUDC is calculated only on as-spent amounts.

Evaluation Criteria	Option 1 – Decommissioning	Option 2 – Full Life Extension	Option 3 – Refurbishment
Revenue Requirement (50 years)			
Levelized % Increase on Rate to 2016 Approved Rate (50 years)	1.89%	0.84%	0.61%
Added Service Life	None	40 years.	20 years.
Safety	Addresses safety hazards and risks associated with unit failure.	Addresses safety hazards and risks associated with unit failure.	Addresses safety hazards and risks associated with unit failure.
Environmental	Addresses environmental risks associated with unit failure.	Addresses environmental risks associated with unit failure.	Addresses environmental risks associated with unit failure.
Reliability	Addresses reliability risks associated with unit failures.	.Addresses equipment end of life issues and improves reliability Improves operational flexibility.	Addresses equipment end of life issues and improves reliability
Decision	Rejected	Rejected	Accepted

Option 1 – Decommissioning is shown to have the highest financial impact of the three options as a result of the cost of replacement power, and was thus rejected.

Option 2 – Full Life Extension, and Option 3 – Refurbishment would address the safety and environmental impacts and minimize the consequences associated with the potential for Unit failure and thus enable continued safe operation of the Units to preserve this low cost source of power for FBC Customers. The primary difference between the two options is the forecast life expectancy. It is expected that the proposed scope of work for Option 2 – Full Life Extension would extend the life of the Units 1 to 4 by another 40 years. Alternatively, the scope of work proposed for Option 3 - Refurbishment is expected to extend the life on the Units by another 20 years, but with future capital investment a 40 year service life can be achieved.

FBC has determined that Option 3 – Refurbishment provides the appropriate balance between continued safe and reliable management of the asset by refurbishing the Units to provide a

[10] Includes the forecast cost of replacing the energy entitlement with PPA energy purchases of $5.574 million in 2017, increasing to $8.707 million in 2032; and FBC water rental fee reduction of approximately $0.831 million per year starting 2018 (escalated by inflation annually).
[11] Included estimated $24.444 million of future capital investment to prolong the life of the Units to 40 years.

forecast life expectancy of 20 years and the financial impact of the alternative which would minimize the customer rate impacts associated with the Project.

4. PROJECT DESCRIPTION

4.1 PROJECT SCOPE

This section provides an overview of the major scope items for the recommended Option 3 – Refurbishment. In developing the scope of works the existing condition of each component was used to determine whether refurbishment or replacement was required to achieve the Project's objectives. In evaluating the condition of the equipment, based on available information and reports, the guiding principle was to determine if refurbishment instead of replacement mitigated the consequences of failure and minimized the safety and environmental risks. That is, if a component could be refurbished and the safety and environmental risks were eliminated (or minimized) then FBC chose to refurbish the component. One reason for taking this approach is because when the Units are dismantled FBC will have an additional opportunity to examine, perform comprehensive testing and further evaluate the equipment's condition and suitability to remain in service.

4.1.1 Turbine Shaft Bearings (Units 1, 2, 3 and 4)

The scope of the generator bearing work required includes refurbishment of the following components: upper, lower, and head cover guide bearings; and thrust bearings. If the bearings are found to be damaged or unsalvageable, they will be replaced with modern spring bed design. Refurbishment, or re-babbitting[12], the bearings and modifying the oil passages will increase the rate of oil circulation through the bearings for Units 1, 2 and 4. Included in the scope will be the addition of resistance temperature detectors (RTDs)[13] in all bearings and associated gauges and meters for Units 1, 2, 3 and 4.

The Project scope of work will include the replacement of the existing braking system with a modern brake and disk system including all associated actuation and controls. The new brakes will be installed on the Generator shaft above the Generator Bearing and below the Stator core which will take the braking system out of the water passage and as such will eliminate the corrosion and also allow ease of access for maintenance and adjustment.

The scope of work will also include the installation of a new bearing lube oil system including a new motor and pump assembly, installation of oil flow and level switches to provide monitoring of the lube oil system operation, installation of stainless steel piping system, meters and valves, and installation of new drain and return oil piping for Units 1, 2 and 4.

[12] Re-babbitting is the process of repairing/replacing the Babbitt metal on the bearing surface.
[13] RTDs are sensors installed in equipment to measure temperature.

4.1.2 Turbine Runner and Seals (Units 1, 2, and 4)

Each unit incorporates three runners mounted on a common shaft. The required scope of work includes: refurbishment of turbine shaft bearing journals for units, refurbish existing turbines including seal ring and cavitation repair.

4.1.3 Governor System (Units 1, 2 and 4)

The scope of the work will include the installation of a new high pressure oil lift skid, complete with power supply and disconnects along with the associated piping, metering, and controls that will be similar to the system installed on Unit 3.

Also included in the scope is the replacement of the existing governor systems with a new complete high-pressure unit (HPU) system. The new system will reduce the oil stored in the system, will allow finer control of the units, address obsolescence and increase availability of parts.

For the governor column the scope will be: refurbishment of the governor column; replacement of governor column pipe; replacement of the governor bearings, bushings and pins; and replacement of six governor link arms.

4.1.4 Turbine (Distributor) Components (Units 1, 2 and 4)

The scope will include refurbishing the turbine head cover, wicket gates, gate linkages and replacing the operating rings. In addition, the discharge ring components and the turbine bearing trees will be refurbished and the turbine bearing tree caps and inserts will be replaced.

4.1.5 Trash Rack Replacement (Units 1, 2, 3 and 4)

The trash racks and beams will be replaced.

4.1.6 Generator Rotor and Stator (Units 1, 3 and 4)

This scope of work will include the removal of all equipment containing asbestos, and the rewinding of the generator stator[14] and re-insulating of the field windings with Class F insulation. The rotor poles, connections and leads will also be refurbished.

4.1.7 Excitation System (Units 1, 2, 3, and 4)

The scope of work for the excitation system upgrade will include: installation of new digital static excitation system for each unit including all the associated equipment; removal of existing exciters; plugging the intake for the water wheel intakes with concrete; and capping the generation floor where the existing exciters are located.

[14] The Project scope of work includes Units 1, 3, and 4. Unit 2 stator and windings were replaced as part of the repairs completed after the unit failed in 1995.

Due to the plant water system configuration, decommissioning of the existing water driven excitation system will make the existing generator water cooling system inoperable and as such a new generator water cooling system will be required for each generator. The cooling system scope will include the design and installation of a new generator cooling system for Units 1 through 4.

4.1.8 Generator Step-Up Transformer Unit 1 & Oil Containment

A new generator step-up transformer will be installed on Unit 1[15] along with new high and low voltage cables, connections and insulators. The proposed delta wye transformer will improve system protection, will be air cooled and contain less oil reducing the environmental risk of an oil spill.

A new double-walled oil containment tank, complete with a containment membrane and collection pipe, will be installed for the generator step up transformers. The scope of work will include grouting and repairing the floor in the transformer bays.

4.1.9 Unit Protection and Control (Units 1, 2, 3, and 4)

The existing protection and control equipment will be replaced by modern electronic based controls, to provide faster clearing of faults and reduce damage to equipment, address technology obsolescence and increase availability of parts, reduce the time to trouble shoot problems.

4.1.10 Other Balance of Plant and Infrastructure

In order to accommodate the proposed upgrades, the AC/DC station service will be upgraded as needed with the installation of a new centralized 600 V AC station service, metal-clad, arc-resistant switchboards and Motor Control Centres; and the installation of new distributed (unit-based) 125 V DC station service switchboards and cables.

Various generator floor modifications will be required as a result of removing some of the old excitation system and cable conduits. Some civil and structural upgrades will be required to restore and life extend the various civil and structural components

Anchoring will be installed in the intake of units 1, 2, and 4 based on the structural condition of existing concrete structures.

4.2 *CONSTRUCTION AND EXECUTION SCHEDULE*

The proposed construction schedule is based on providing the UBO Project the necessary lead time for engineering and procurement and also to address the Units in order of priority. The Company intends to first complete the work on Unit 3 in 2017, followed by Unit 4 in 2018, then

[15] The transformers for the other three units were replaced.

Unit 2 in 2019 and finally Unit 1 in 2020. The decision to start with Unit 3 allows for increased engineering time on the remaining Units that require a larger scope. In addition, the Company is most familiar with Unit 3 after the 2013 repair; therefore new modifications, such as the installation of the new brake system, are best completed on Unit 3 first, with the other units benefiting from efficiencies gained. Unit 4 is then slated to commence in 2018 as it is considered to be in the worst condition of the remaining Units.

In summary, providing FBC receives project approval by December 31, 2016, the construction schedule will be as follows:

- Unit 3: June 2017 –December 2017 (capital costs enter rate base on January 1, 2018)
- Unit 4: March 2018 – November 2018 (capital costs enter rate base on January 1, 2019)
- Unit 2: March 2019 – November 2019 (capital costs enter rate base on January 1, 2020)
- Unit 1: March 2020 – November 2020 (capital costs enter rate base on January 1, 2021)
- Plant wrap-up: December 2020 – April 2021 (capital costs enter rate base on January 1, 2022)

The project will be resourced by a combination of internal and external resources.

4.3 *RISK ANALYSIS*

Risks to the costs and/or the timely execution of the UBO Project involve the following:

- An unexpected increase in the delivery times or in the cost of major equipment. The risk of such occurrence is considered to be low given the current economic climate and that FBC received budgetary quotes for major materials.
- Unavailability of labour and materials. The risk of occurrence is considered to be low given the current economic climate. From a labour perspective, there is little risk given the majority of the work will be completed in-house. Any external labour requirements will likely be easily met. With respect to materials, FBC believes that the risk of financial and schedule pressures is low because the likelihood of material lead-times and prices changing significantly is low given the current economic climate. This risk has been partially mitigated by developing preliminary equipment specifications and obtaining quotations from vendors. Any residual risk will be managed through the use of project planning and contractual performance guarantees.
- Environmental risk associated with changing the oil system of the existing mechanical governor system. There is a risk associated with removing and transporting this large volume of oil for disposal. The probability of an oil spill is considered low given that FBC has well developed work procedures for transporting oil. Additionally, the impact of a spill while changing the oil is considered low given that any spill would be contained within the existing plant and recovered using FBC's standard oil spill response procedures.

- As-found submerged turbine components may be in worse condition than expected. FBC considers this risk to be moderate because the condition of many components is difficult to assess prior to disassembly and there is a risk that the condition of these components is worse than anticipated. FBC believes that the likelihood of such an event has been reduced because of the recent inspections done on Units 1 and 3 and the fact that the other two units are of a similar vintage and design.
- There is a risk that the as-found condition of some components, especially the stator core, could be in an inoperable condition on some of the Units. To mitigate the risk, FBC will conduct comprehensive testing and condition assessment prior to returning to service.

5. PROJECT COST ESTIMATE

The capital cost of the UBO Project is estimated to be $31.783 million (including $0.867 million of AFUDC and $1.880 million of removal costs). The cost estimate for the Project has been developed to a Class 4 degree of accuracy as defined in the AACE International Recommended Practices No. 10S-90 and 69R-12.

Table 5-1 below summarizes the total estimated project capital costs. The as-spent amount is escalated from the 2016 amount based on 2% annual inflation.

Table 5-1: Summary of Estimated Project Capital Costs ($ millions)

Project Component	2016 $	As-Spent $
Generator	7.462	7.845
Mechanical	6.793	7.207
Transformer	1.325	1.429
Plant & Auxiliary	4.377	4.623
Project Management/Engineering	3,954	4,160
Subtotal - Construction	**23,911**	**25,264**
Cost of Removal	1,786	1,880
Project Contingency	3,568	3,771
Subtotal – Construction & Removal	**29,266**	**30,916**
AFUDC	n/a	867
TOTAL PROJECT COST	**29,266**	**31,783**

Table 5-2 shows the year and the planned construction work to be completed by unit, the estimated capital amounts as well as when they will be transferred to their appropriate plant asset accounts.

Table 5-2: Schedule of Phased Completion Inclusion in Rate Base

Year of Construction Complete	Construction Work to be completed	Estimated amount of capital (As-Spent) transfer to Plant-in-Service[16] ($millions)
2017	Unit 3	$5.412
2018	Unit 4	$8.004
2019	Unit 2	$6.793
2020	Unit 1	$9.579
2021	Plant Wrap-up	$0.116

[16] Excludes cost of removal.

6. CONSULTATION

As the project is entirely contained within the Upper Bonnington powerhouse, there was no public consultation conducted. All of the planned construction activities for the project are within the FBC facility.

6.1 *FIRST NATIONS CONSULTATION*

FBC believes Aboriginal Rights and Title will not be affected by this project and hence First Nation Consultation is not required. All of the planned construction activities for the project are within FBC facilities. Because the size of the turbines will be unchanged and no structural changes will be made the river flows will not be affected nor does FBC expect any impacts to the environment or fish populations.

FBC representatives have discussed the project with some local First Nations and during the course of the project will work to see if any contracting opportunities for Aboriginal owned businesses exist.

Appendix D-1

HDR GENERATOR 1 INSPECTION REPORT

Owner: FortisBC	Rating/Volts: 7500 kVA / 2300 V
Site/Unit: Upper Bonnington / G1	Frame Ref.: 40 – 180 x 36
Machine Type: ATB	OEM/Age: CGE / 1914 with rehab 1928
HDR|DTA Ref #:	Quantity of Poles: 40
Owner Ref.:	S/F Coil Types: Multi-turn / Edge bent

1. Rotor field coil connection inspection

Comment on Item 1: Field coil connections should be inspected for signs of overheating, mechanical damage, and loose components. Bolted interpole connections should be checked for tightness and locking device. Joints of this age were typically soldered with lead based low temperature materials. The solder may have been held in place when molten by a tinned copper clip or the joint was soldered and bolted with the solder acting as the locking device for the hardware.

Observation:

Field leads were found to be heavily taped and outer lead is “V” shaped to allow it to be held against the rim by a metallic strap bolted into the rim. Based on the heavy taping found direct visual inspection of the coil to coil connections is not reasonably possible as stripping of the insulation would be required. The inner field lead is a heavily insulated short piece bridging between coils close to the rim. It is also held into the rim by a metallic strap bolted into the rim.

The bolting hardware appears to be loose on the straps, at least 4 locations have the bolt heads visibly off the washers. When attempts were made to turn the apparent loose hardware with a 9/16th socket and standard ratchet, the hardware was found to be frozen in the current position.

Since direct inspection of the copper surface in the connection area is not within the scope of this inspection (not prepared to strip and re-insulate leads), it was decided to attempt to determine if the connectors are in serviceable condition by passing heavy current through the field coils and the individual leads while scanning with thermal imaging equipment. Current of 100 amps was passed through the rotor circuit on 8 August 09 for sufficient time to raise the field coil and lead temperatures by 4 °C. It was reported that all field leads had very similar temperature rise indications.

See Figure 1 for view looking upward at lower end of field winding. It should be noted that the field leads are mounted on the lower end of the field winding, accessible only from below the unit.

Field Coil and Lead Resistance Testing

Test Instrument: Vanguard WRM-40 Model/Serial #s: VRM-40 / 199014

Calibration Date: 04/27/06 DC Current: 20.8 A

Acceptance Criteria: ______ Field Circuit Resistance: 181.3 mΩ

Coil #	Coil μΩ	Lead μΩ	Coil #	Coil μΩ	Lead μΩ
1			21		
2			22		
3			23		
4			24		
5			25		
6			26		
7			27		
8			28		
9			29		
10			30		
11			31		
12			32		
13			33		
14			34		
15			35		
16			36		
17			37		
18			38		
19			39		
20			40		

Test By:	Date:

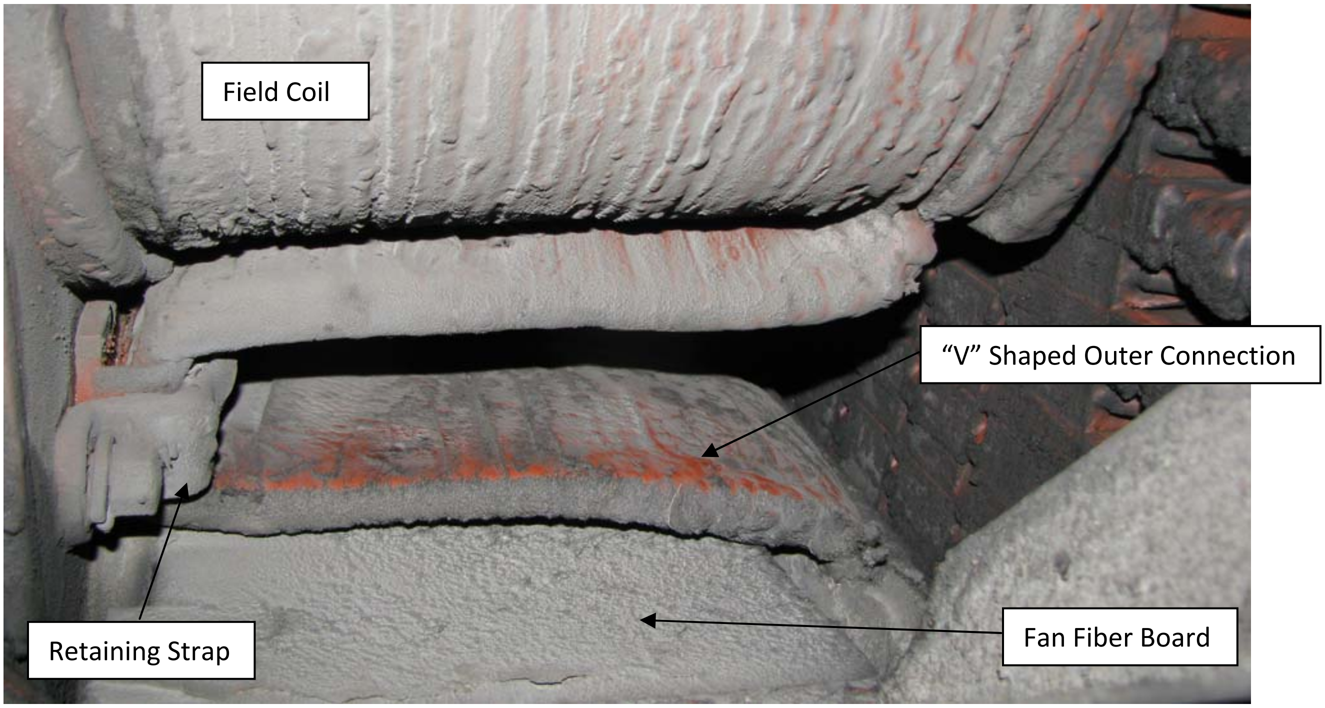


Figure 1 - Field Winding, Lower End

2. Field coil inspection

Comment on Item 2: The copper winding turns should be examined for signs of discolouration (overheating), distortion, and "bowing." Bowing can occur on long poles that have no coil braces between adjacent poles. The turn insulation should be inspected for any sign of movement, missing pieces, or overheating. The filed coil washers should be inspected for mechanical damage, looseness and signs of movement. The amount or build up and type of surface contamination should be assessed.

Observation:

Field coils are heavily coated with dirt on all surfaces. The painted surface appears to be dry, brittle and flaking off the copper surface.

Field coil washers appear to be laminated hardwood, that are all generally tightly fitting on the outer and inner locations. The edge bent copper coil appears to be in good condition. There are some gaps between turns around the full radius ends, (gaps related to thinning from the edge bending process), but nothing that indicates looseness. No unusual heating was visible on the dirt covered coil surface.

A second washer against the pole tip wooden washer is a metallic ring that will be acting as a damper winding.

See Figure 2 for view of field coil from above winding.

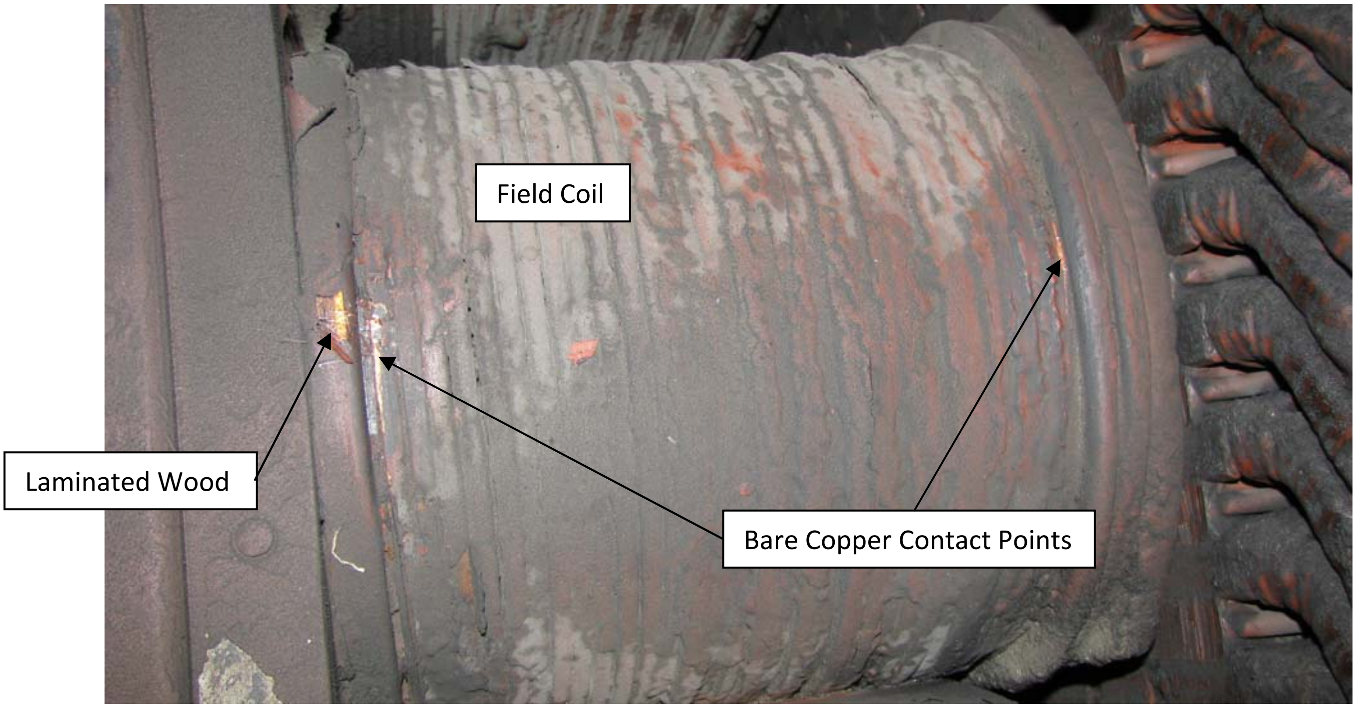


Figure 2 - Field Coil, Upper End

3. Measure the field winding circuit copper resistance.

Comment on Item 3: The field winding is a series DC winding consisting of copper strap sandwiched between insulating sheets or blocks. The total resistance of the winding is normally measured as fractions of an ohm. A significant variation from normal resistance of the winding may only be noticed at the third or fourth decimal place of a resistance measurement. For this reason, a microhmeter or Kelvin bridge with five place accuracy is required. Temperature of the copper must be recorded for later correction of winding resistance to a standard temperature.

Comment:

A Vanguard Model WRM-40 micro-ohm meter was used to accurately measure the copper winding resistance of the field circuit. Current and voltage leads of the micro-ohm meter were connected to the rotating field lead cable lugs at the slip rings. The meter injected a steady 20.8 amps DC and measured 0.1813 ohms with a copper temperature measured at 29.2 °C. This would be 0.1782 ohms corrected to 25 °C.

The calculated field winding resistance based on a copper cross section of 0.25 x 1.625" at 8,310' in length equals 0.171 ohms. If this calculation is reasonable, then it may indicate there are poor connections in the circuit adding to the resistance. Measured data attached.

4. Measure individual interpole connection electrical resistance.

Comment on Item 4: Field windings on salient pole machines are connected together between poles such that they are combined to form a complete series field winding circuit. These connection points can fail due to the thermal, mechanical, and electrical stresses they are exposed to while in service over long periods of time. Testing and inspection of these joints is required to establish condition for life extension estimating. This test is performed using a four terminal, DC low resistance, high current measuring device capable of reading in the microhm range across individual joints.

Observation:

Measurement of the voltage drop across leads with DC current flowing is not practically possible due to the heavily taped leads.

To determine the condition of the field coil leads, an attempt was made to inject around 100 amps DC and view each coil connector with a thermal imaging camera. Initial attempts at 40 amps did not provide enough temperature rise.

Current of 100 amps was passed through the rotor circuit on 8 August 09 for sufficient time to raise the field coil and lead temperatures by 4 °C. It was reported by FortisBC that all field leads had very similar temperature rise indications.

5. Field coil ground insulation resistance test using a 500 volt or 1000 volt megger for one minute.

Comment:

The field winding ground insulation was measured using a Megger model MEG10-01 set at 500 volts DC. On 5 August 09 an initial test to determine the insulation resistance level was attempted. The megger could not manage 500 volts due to a very high leakage current which may indicate poor insulation quality or water contamination.

The slip rings were cleaned of oily debris and the test was attempted again on 6 August 09 with the meter able to test at 500 volts. The insulation resistance was measured as 0.75 mega-ohms at one minute with a Polarization Index (PI) of 1.29.

The second test results are an improvement over the initial testing but they indicate that the winding insulation is likely saturated by moisture from extended un-heated down time. It is reported that after an extended unit shut down periods a re-start can only be successful if the field ground relay is bypassed. Measured data is attached.

6. Field coil ground insulation P.I. test, one minute test resistance divided by the 10 minute resistance value.

Observation:

Initial megger testing of the as found generator rotor winding indicated poor insulation condition with the 500 volt megger unable to achieve 500 volts due to high leakage, resulting in a PI of 1.0 and an insulation resistance of 0.11 mega-ohms. A second megger test was undertaken after cleaning the insulators around the collector leads resulting in the megger holding 500 volts with the insulation resistance improved to 0.96 mega-ohms with a PI of 1.29.

It was reported by FortisBC that the insulation resistance further improved marginally after heating by DC current during the field lead thermal imaging testing.

7. Turn insulation testing to detect shorted turns in rotor field coils by AC voltage drop.

Comment on Item 7: With an AC voltage across the entire winding individual voltage drop should be measured from the start and finish end of each coil. The procedure should be repeated on each pole until all have been measured. Turn-to-turn shorting is indicated when the voltage drop measured across a coil is lower than for a similar coil. A shorted coil may affect the voltage drop of the adjacent coils.

Observation:

G1 configuration has the field coil connection at the lower end of the field coil with the collector rings below the rotor spider. Since working from below the rotor is difficult, it was decided to energized the entire winding from below but measure individual field coil voltage drop from above. See Figure 2 for image of field coil pole drop measurement locations.

Results of field coil voltage drop testing clearly indicated that a single field pole had at least one shorted turn. Pole 34 had a voltage drop that was more than 25% below the average voltage drop per pole. The field poles on either side (33 and 35) had reduced voltage drops likely as a result of the magnetic distortion from pole 34. The measured handwritten data is attached.

8. Visual inspection of rotor components.

Comment on Item 8. The mechanical components of these salient pole rotor are always subjected to the normal running stresses of the machine, but can also be subjected to the much greater forces associated with line faults, improper synchronizations, asynchronous operation or very uneven airgap dimensions. A detailed inspection of all rotor mechanical components could reveal symptoms of these stresses in the following areas:

- Pole tips: The pole tips (caps) should be inspected for any signs of overheating. Overheating can be due to a variety of factors including reactive stator current flow, misalignment in the axial and radial directions, asynchronous operation or mechanical contact damage.

- Pole attachment hardware: The poles are held to the cast rim by concealed keys ~~heavy threaded studs and nuts~~, these should be inspected for movement, fretting or other signs of looseness. Relative radial heights of all of the studs should be compared, and those which are different should be carefully examined.

- Shaft: The shaft should be checked for excessive runout, signs of distress and overheating of guide bearing journals and thrust runners. The coupling interface with the turbine and with the exciter should be checked for correctly tightened bolting and signs of distress.

- Spider: The cast spider fit to the shaft should be checked for signs of movement or fretting. Any keys and key way fits should be inspected for signs of cracking, movement or distortion.

- Rim Iron: The rims in these generators are formed as an integral casting with the spider arms. The rim ring itself and spider arm to rim attachment points should be inspected for any sign of cracking or distortion.

- Blowers: Blowers should be inspected for signs of distress such as cracking, evidence of impact, or discoloration due to heating. Hardware should be checked for tightness.

- Brake Rings: The brake ring are reported to be mounted on the shafting well below the generator. These rings should be inspected for wear, cracks, heating, and hardware looseness.

- Collector and Connections: Most areas of the collector are accessible. The collectors should be carefully inspected for depth and uniformity of surface wear, surface etching and burning, insulation contamination and cracks, arcing or burning of insulation and metallic parts, deformation and mechanical damage. If this collector has machined grooves, the remaining groove depth is a indication of the remaining life of the collector rings.

- Balance Weights: The balance weights should remain tight and well locked against possible movement. Verify the anchoring mechanisms are secure.

Observation:

Field leads from collector rings to number 1 and number 40 field coils appear to be in good condition and are well supported on the spider and rim. Bolt locking for field lead supports appears to be by split washers only, this will need to be changed to a more positive locking method during the next maintenance outage. See Figures 3 and 4.

Upper and lower fan blades have up to 10 fiber board plates that are cracked at the riveted connection to the metal fabricated portion of the fan blade assembly. Also the welding of the metal fabricated blades and attachment have at least one blade assembly with weld segments missing (Figure 11) but otherwise appear to be functioning satisfactorily. The fan to rim hardware appears secure and visibly locked with heavy lock plates.

Field coil lead support straps have hardware that is backing out or was improperly installed initially. The washers under the bolt heads appear to be split type lock washers. An attempt was made to snug the loose hardware but it would not turn under normal torque levels for hardware of that size. Fear of breaking the hardware stopped this repair attempt. See Figure 7.

The field coil leads appeared to be adequately supported with no outward signs of distress on the heavy lead taping. The field coils appeared to be held securely between rim and pole tip. No signs of fretting or looseness were evident. The coil washers holding the coil in place appeared snug, but at least one washer had a crack which may indicate shrinkage or ratcheting. See Figure 8.

The rim has ventilation holes we observed to align with the space between field poles. See Figure 9. A bolted connection between field pole and rim was initially assumed, but no studs or nuts were visible on the inner rim surface. The poles must be attached by a mating dovetail arrangement, but simple inspection on the outer surface of the rim did not reveal the details of the pole to rim attachment method. Continuous rim endplates prevented visual inspection of the rim end areas. Inspection of the spider from below the rotor revealed one large balance weight bolted to the side of an arm close to the rim. The weight appeared to be secure. Near the balance weight there appeared to be a crack in the paint at the mid axial height of the spider arm outer vertical gusset. Closer access was not possible at this time, but more thorough examination of this area should be carried out. See Figure 10.

Figure 3 - Field Lead Attachment Below Rim

Figure 4 - Field Lead Attachment Inside Rim


Figure 5 - Fan Blade To Fiber Board Rivet Connection


Figure 6 - Fan Blade Assembly Rim Mounting Hardware

Figure 7 - Field Lead Support Strap Hardware

Figure 8 - Cracked Inner Field Coil Washer

Figure 9 - Rim Inside Surface, Ventilation Holes

Figure 10 - Balance Weight Bolted To Spider Arm

Figure 11 – Fan Blade with Missing Weld

9. Rotor to stator airgap static measurement.

Comment on Item 9. Various parts of a rotating machine can physically shift in position such that the rotating field poles do not have the same air gap with the stator. The stack of stator core iron can tilt or become non-circular. The field poles can extend more or less into the air gap due to improper attachment with the rim or distortion of the rim itself. When large variations in air gap occur, there may be large variation in magnetic forces acting on rotating components with every rotation. An accurate air gap measurement should be made at the top and the bottom of each pole face. The rotor should then be rotated through 180 degrees and the measurements repeated. A profile of the stator can be obtained by measuring the air gap at the top and bottom of one pole face with the rotor rotated through 360 degrees taking repeated air gap measurements at a minimum of eight positions around the stator. A plumb bob test can be made on these machines to get an approximate indication of how vertical the rotor poles and stator iron are.

Observation:

Rotating air gap measuring was not possible due to the thrust bearing not being equipped with oil lift. It was also very difficult to measure the airgap from below; therefore, not every field pole to core air gap reading was taken. See Figure 12. Results of the air gap measuring indicated the air gap at the upper end of the generator is within required tolerance; however, at the lower end of the generator the airgap is not within recommended tolerance. In the downstream direction over pole 34 a decrease in airgap was measured that was outside recommended tolerance. The raw air gap data and polar plots are attached. A plumb bob indicated the poles appeared vertical but the irregular surface of the core made it difficult to judge the verticality of the stator core bore inside surface.

Figure 12 - Measuring Lower Static Air Gap

10. Bearing visual inspection.

Comment on Item 10. Bearings are subject to deterioration due to mechanical wear, scoring, mechanical overloading (due to improper alignment), impact damage, inadequate oil flow (scoring and overheating), loss of bonding between babbitt and shell, and the presence of rust or other contaminates. Careful examination of the bearings needs to be made to determine the existence of such problems. In addition, the bearing shell seat needs to be examined for wear. Guide bearings should be examined for excessive wear at the points where the alignment mechanism contacts the bearing. Thrust bearings need to be examined for uneven wear of the bearing surfaces. All bearings have the potential for damage if current is allowed to flow through the oil film between the babbitt and the shaft. Such damage is observed as an etching effect on both the bearing and the associated shaft. In some instances, mechanical fretting of the babbitt can have an appearance similar to the etching from arcing. In order to differentiate between the two, replication with magnification will show the melted boundaries of arcing as opposed to the tearing found with fretting.

Observation:

Pete Kabel of FortisBC commented that the guide bearings were original to the best of his knowledge. The only time they are typically inspected is during a total disassembly unit major inspection. No problems on the upper or lower guide bearings have ever been documented. There is a spare guide bearing which has never been used. The guide bearing babbitt is reported to be mechanically attached to its bearing shell. These guide bearings are both very large for the unit rating compared to more modern units and there are what appears to be identical upper and lower guide bearings close to and on either side of the rotor hub. Running clearance, simple, shaft seals are leaking liquid oil and oil vapour into the generator.

There have not been documented problems with the generator thrust bearing. Neither the thrust nor guide bearings were opened for inspection as part of this outage.

11. Bearing insulation test.

Comment on Item 11. The rotating elements these generators can have voltages induced in them due to magnetic unbalances within the machines. Since these rotating elements have a bearing above and below the rotor, a voltage imposed across the length of the element will cause current to flow through the bearings. As current passes through the bearing journals damage occurs to both the journal surfaces and the bearing surfaces. An etching effect is usually observed on the journal area and the bearing babbitt. In an effort to prevent circulating current flow through the bearings, one or both bearing seats should be insulated. In addition, all other components which may provide a current path between the ends of the shaft through the frame are insulated. It may not be possible to measure the resistance of bearing insulation with the unit assembled.

Observation:

The upper bracket, which positions the upper guide bearing above the rotor, must be electrically isolated from ground to ensure circulating currents do not flow through the guide bearings. Figure 13 shows an image of an upper bracket to frame connection with insulation separating the components. When the upper bracket to frame resistance was measured with a Fluke Ohm meter, it was found to be very low resistance. This is understandable since the upper portion of the generator shaft is contacting the bearing and “grounding” the upper bracket. Therefore with only one insulation layer, testing the electrical isolation of the upper bracket can not be done unless the unit is dismantled.

Inspection of various locations where the upper bracket could be grounded to the stator indicates that the only unconfirmed point of potential grounding could be the speed sensor on the upper bearing cover. The yellow hand rails, pie shaped upper bracket covers and bracket bolting hardware appear to be electrically isolated.

Figure 13 - Upper Bracket to Frame Connection

12. Brush rigging inspection and test.

Comment on Item 12. Brush rigging and brushes should be inspected for contamination of insulated components, burning, poor connections, cracked metallic or insulating components, loose hardware, weak or broken springs, burning of boxes, double facing of brushes and chipping of the brushes. Brush rigging insulation can be measured after the brushes and cables to field coils have been lifted from the collector rings.

Observation:

Collector rings appear to be in serviceable condition, some cracks are visible on the working surface of the collector rings which appear to be small casting voids. The rough surface created by voids and the mating ends of the ring halves, are minimal.

The brushes slide freely in their brush holders and the springs appear to be in serviceable condition. See Figure 11. Checking the spring force on individual brushes was discussed, but the arrangement of the spring when pushing on the brush makes pulling with a force scale difficult. Therefore brush force was not measured. There were no reported problems regarding the performance of the brushes with respect to life, the only concern may be the availability of spare brushes and spring assemblies. It was not known by those present if replacement parts could be purchased.

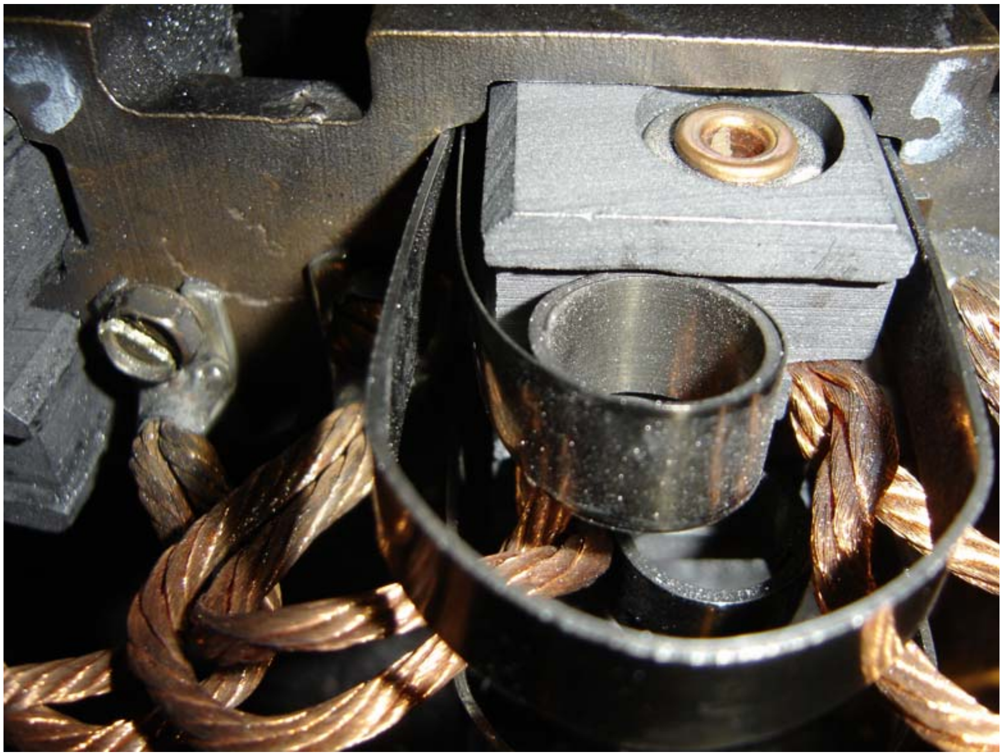


Figure 14 - Brush with Spring in Brush Box

13. Stator core inspection

Comment on Item 13: The core iron of a machine is clamped together such that the thousands of laminated steel plates that make up the core act as a single component. Deformation to the core occurs with every start stop cycle and to a lesser extent from the action of passing poles at synchronous speed. The change in shape of the core is normally low in amplitude but will increase as the core clamping becomes loose. Such looseness can lead to the movement of laminations relative to each other, movement relative to clamping components, loosening of winding clamping components, loosening of wedges, breaking of vent fingers, and breaking of laminations. Evidence of such core looseness is an increase in core noise while in operation and a red oxide type of dusting between core components. Things to look for during a stator core inspection:

- core melting
- broken, proud or loose laminations at tooth tips
- broken ears from laminations at key bars at the outside diameter of the core
- fretting corrosion between building bars and punchings
- evidence of clearance between building bars and punchings
- chevron or circumferential waviness in iron packs; other forms of core distortion or buckling
- mechanical damage due to foreign objects, water incursion, damage during the performance of other corrective work, damage caused by rotor contact with core during removal
- evidence of local or general overheating from mechanical damage, lamination insulation breakdown or coil failures
- broken, misaligned, loose or displaced vent fingers or laminations
- contamination by dirt, oil or other foreign material especially in radial vents

- gaps in endplate to core or endplate to clamping hardware
- amplitude of core wave
- period of core wave relative to end clamping plates

Observation:

This stator core is very dirty from oil from the bearings mixed with air born dust from collector brushes and other sources typical of open ventilated machinery. The build up of material on the core is effectively plugging ventilation openings, which is likely raising the operating temperature of the generator significantly.

Inspection of the core did not reveal any overheating or looseness in the clamped laminations. The core appears to be reasonably straight with respect to core waviness or buckling. The core lamination packs are expanding into the vent ducts between vent fingers but this is not causing looseness or unduly restricting ventilation. The core end clamping fingers appear to be straight and tightly pressing on the core end lamination packs. See Figures 15, 16, 17 and 18.

Knife testing was performed on the bore and back iron and the knife could not penetrate the core in any tested locations. A winders knife was used with a slightly rounded sharp end and was pressed against the laminations at approximately 20 to 30 pounds force. At least 2 locations per frame window were tested except where access was restricted. The bore tightness was checked on the upper portion of the generator in locations around the entire circumference. The knife did not penetrate into any bore side test locations.

The gap between the core and the cast stator frame ribs was gauged for differences that could indicated the core is detaching from the frame. No unusual gaps were measured between frame and core.

Figure 15 - Core Outside Diameter – View #1

Figure 16 - Core Outside Diameter – View #2

Figure 17 - Core Inside Diameter (Bore)

Figure 18 - Core Upper End Clamping Fingers

14. Temperature Instrumentation:

Many types of temperature detectors are used throughout most electric machinery. The two most common types of detectors are resistance temperature detectors (RTDs) and thermocouples (TCs). Common locations of temperature measuring devices in machine and exciter equipment include:

- between coils in a slot to measure coil temperature
- mounted in cooling air passages
- mounted inside bearing metal or in the bearing oil sump or oil drain to measure bearing temperature

The location and condition of existing temperature detectors should be recorded.

Observation:

Core temperature measuring devices are mounted in 4 locations around the outside of the core in the upper 3rd height position. These sensors are inside a well that is placed in a machined recess in the laminations at a core vent duct. The depth of the machined recess could not be determined. Notes on one of the sensors indicate it is connected to a “49S” device which is a machine thermal relay. Three wires enter the connection box which may indicate the device is an RTD. See Figure 19.

There was no indication of any other temperature device on the generator other than very old style mechanical bulb type thermal sensors on the thrust bearing.

Temperature instrumentation on the stator winding was not investigated during this inspection.

Figure 19 - Stator Core Temperature Sensor

15.0 Conclusions

The generator rotor in G1 is in need of a thorough cleaning and re-sealing with a quality electrical insulating paint. The field coils have very old turn and ground insulation in them, and one coil has at least one shorted turn. The coil washers are still holding the field coils in place, but some possible shrinkage type cracking may be starting. The field lead support straps are functioning but their hardware is in need of attention to provide a safer locking mechanism.

Since the demands to be made on this rotor are expected to be base load for 2 to 3 months per year, it may be possible to continue operation of these units with these windings provided they are thoroughly cleaned and resealed. It is recommended that in addition to the resealing etc. the re-insulation of these field coils with new field coil washers and field leads should be included in major maintenance plans. A final decision on finalization of the extent of work required on the field winding could be made after the rotor is removed and cleaned.

The generator stator core is very dirty and in need of a general clean up, but the core and frame appear to be in serviceable condition. The core is straight in the axial direction and appears to be tightly clamped throughout the areas inspected. Static airgap reading in the downstream area showed an air gap reduction outside recommended tolerances. Since the plumb-bob indicated the pole was vertical, it may be that the core in this area is moving. This will need to be investigated further when the unit is dismantled.

Provided the air gap issue can be resolved, it is possible that a replacement core will not be needed, but an ElCid test or loop test will be appropriate to confirm interlamination integrity once the rotor is removed. With the short operating time per year and the small unit capacity, newer more efficient core laminations and or a redesigned core may prove difficult to economically justify.

The open clearance oils seals are leaking liquid and oily vapour into the generator. As part of the upcoming major maintenance, these seals should be modernized to greatly reduce the amount of oil getting into the unit. If the seals can be improved, it may forestall the desire to move the collector rings to a position above the rotor. The collector ring re-positioning can still be done if it is desired for other reasons. The collector rings rough surface and mating ends of the ring halves can be improved by stoning.

There are many minor maintenance issues that must be addressed as part of the upcoming major maintenance, such as, hardware locking, upper bracket isolation, instrumentation updating, fire detection, spare parts, re-designed braking system, NDT to verify rotating parts, etc. need to be addressed.

Inspection of the stator winding confirmed a 3 turn, 8 parallel winding which had been previously assumed. Based on this confirmation, the comments made in HDR|DTA Upgrade Study Report dated 15 July 2009 regarding the potential for rewinding these cores with a connection that will provide 7200 volts line to line at the generator terminals are still valid.

Field Coil Voltage Drop Test

Ambient temp 27.1 °C Humidity 49 (RH)

Test Instrument: Fluke 87 II Model/Serial #s: 95650794

Calibration Date: New Instrument Applied Voltage: 120

Acceptance Criteria: Typically each individual voltage reading within 5% of average.

Coil #	Coil Volts	Amps	Field Volts	Coil #	Coil Volts	Amps	Field Volts
1	2.873	3.58	120.0	21	3.023		
2	2.891			22	2.969		
3	3.053			23	3.046		
4	2.945			24	3.123		
5	3.059			25	2.886		
6	3.150			26	2.867		
7	3.081			27	2.960		
8	2.892			28	2.901		
9	2.840			29	2.910		
10	3.069			30	2.959		
11	2.786			31	2.813		
12	2.740			32	3.080		
13	2.864			33	2.701		
14	3.083			34	2.154		
15	2.888			35	2.635		
16	2.801			36	2.928		
17	2.830			37	2.855		
18	2.830			38	3.011		
19	2.832			39	3.195		
20	3.125			40	2.989	3.59	120.5

Test By: Allen Dermody	Date: 5 Aug 2009 11:30 AM

Copper Temp: 27.7 °C

Ambient Relative Humidity: 49.4 %

HDR | DTA

Owner: Fortis BC	Rating/Volts:
Site/Unit: UBO G1	Frame:
Machine Type:	OEM/Age:
HDR|DTA Ref #:	Quantity of Coils:
Customer Ref.:	Coil Type:

Rotor Field Polarization Index (PI) & Insulation Resistance (IR)

Instrument: Megger

Calibration Date: Unknown Model/Serial #s: MEG10-01

Acceptance Criteria: IEEE 43-2000
Clause 12.2.1 ref. PI, Class A = 1.5, Class B =2.0
Clause 12.2.3 ref. minimum IR = 5 mΩ (corrected to40 °C)

Field Winding PI & IR Test Data:

Time	Test Voltage kV DC	Amperes mA	Insulation Resistance mΩ
15 sec.	.500		67
30 sec.	.504		~~63~~ .70
45 sec.	.504		.73
1.0 min.	.504	682μA	.75
1.5 min.	.504		.76
2.0 min.	.503		.80
3.0 min.	.504		.81
5.0 min.	.504		.86
7.0 min.	.504		.91
9.0 min.	.503		.94
10.0 min.	.504	526μA	.96

P.I. = 1.29

Tested By: MV & AO **Test Date:** AUG 6/09

HDR | DTA

Owner: |	Rating/Volts:
Site/Unit:	Frame:
Machine Type:	OEM/Age:
HDR|DTA Ref #:	Quantity of Coils:
Customer Ref.:	Coil Type:

Rotor Field Polarization Index (PI) & Insulation Resistance (IR)

Instrument: ~~Vanguard WRM 40~~ Megger MEG10-01

Calibration Date: Unknown Model/Serial #s: 6417-03

Acceptance Criteria: IEEE 43-2000
Clause 12.2.1 ref. PI, Class A = 1.5, Class B =2.0
Clause 12.2.3 ref. minimum IR = 5 mΩ (corrected to40 °C)

Field Winding PI & IR Test Data:

Time	Test Voltage kV DC	Amperes mA	Insulation Resistance mΩ
15 sec.	.5?		.10
30 sec.	.318		
45 sec.			
1.0 min.			~~.10~~ .11
1.5 min.			.11
2.0 min.	~~.33~~ .323		.11
3.0 min.	.325		.11
5.0 min.	.326		.11
7.0 min.	.332		.11
9.0 min.	.336		.12
10.0 min.	.33	> .999 µA	.11
P.I. =			
Tested By:		**Test Date:** Aug 5/09	

HDR | DTA

Vanguard Instruments
Company, Inc.

TEST RESULTS

DATE:08/05/09 TIME:14:40:09

COMPANY:	FORTISBC
STATION.	UBO G1
CIRCUIT:	GENERATOR ROTOR
MFR:	GE
MODEL:	180 RPM 2300 VAC
S/N:	15195
KVA RATING:	7500 KVA
OPERATOR:	MV AD

V1 ONLY TEST

R1 = 181.30 MILLI-OHMS

TAP/WINDING: ____________

Appendix D-2

ENGEN UNIT 3 REPAIR OPTION REVIEW

Upper Bonnington Generating Station

Unit 3 Repair Option Review

Revision 0

May 2013

PROFESSIONAL
PROVINCE OF
R. M. STRACHAN
32087
BRITISH COLUMBIA
ENGINEER
03/08/16

Prepared by

ENGEN SERVICES LTD

PO Box 1225 Rossland BC, V0G 1Y0

Table of Contents

i. Disclaimer

ii. Executive Summary

On 1st April 2013, Upper Bonnington Unit 3 was removed from service for a planned routine maintenance inspection. Initial inspection indicated significant in-service damage to, among other components, the lower turbine bearing tree, brake mechanism and turbine stationary seals.

Engen Services Ltd. has been retained to support the review of the equipment condition, development of repair options and presentation of results for FortisBC's review.

Three repair alternatives have been considered:
- Option 1: In-situ repair
- Option 2: Unit Tear Down at Reduced Cost
- Option 3: Unit Tear Down Full Scope, Life Extension

All three options present varying levels of operational and safety risk mitigation with option 1 providing little ongoing confidence and option 3 providing certainty of repaired condition for safe and reliable operability.

Although all decision driving factors have not been included with this analysis, such as lost opportunity costs and corporate risk profiling, option 3 clearly represents the optimal repair approach to both minimize safety concerns and provide operational availably of mechanical turbine and generator components for the next 20 years.

1. Background

Upper Bonnington Unit 3 was removed from service on 1st April 2013 for a routine maintenance inspection which was initially scheduled for five days. Upon entering the unit it was apparent that substantial damage had occurred around the lower runner. Details of the extent of the damage are outlined in Section 2 below.

Following an inspection by FortisBC Engineering, field crews removed the remnants of the lower bearing and prepared the unit for rotational alignment checks. On 19th April 2013, initial shaft alignment readings were taken at the three runner crown seal diameters with the upper turbine bearing and both headcover and runner cover packings installed. A second set of readings were taken on 24th April 2013, with the bearing and shaft seal packings removed and the addition of dial indicators above the generator, above the thrust bearings and at the head cover packing.

2. Equipment Condition Review

Given the age, arrangement/design and service life of this machine, it is not surprising to see extensive wear and corrosion of key components as well as a history of previous repair

Summarizing the observed condition, there is significant damage to the lower turbine bearing and tree, all three turbine seals (crown and band) are badly worn / damaged, and one of the brake support beam pedestals has pulled away from the wall. The leading failure mode for all three of these conditions is excessive loading due to shaft runout or imbalance. Previous in-situ repairs to both the lower turbine guide bearing tree and the brake assembly restored original tolerances which may have led to concentrated stresses in existing worn parts. The governor column and associated wicketgate linkages also appear to be worn and, as seen on this and adjacent units, prone to failure.

Unit alignment readings taken on 19th & 24th April 2013, although not fully conclusive, indicate excessive runout of the machine below the headcover. This runout could be the result of either a bent shaft below the brake coupling or a misalignment of the brake coupling and / or upper to lower turbine shaft coupling. Taking additional alignment readings could be considered but will provide similar uncertainty as the design and excessive wear of this machine is not conducive to accuracy of measurement below the head cover. Similarly, confirmation of a gross imbalance of rotating components is not practical in-situ. The only certain way to confirm the condition of the shafts (lower generator, upper turbine and lower turbine) and couplings (brake and upper / lower shaft) is to remove and check their runout and static balance in a lathe. Similarly, re-alignment of the unit (turbines to their seals and shafts to their bearings) is best completed with the generator, turbines and shafts removed. An in-situ alignment or partial disassembly alignment, although theoretically possible, provides compromises and thus uncertainty to the results.

The following tables break the machine into its primary mechanical sub component assemblies and provides a current and historical overview of their condition. This is not an extensive list of components or scope of repair required.

2.1. Generator

Description	Consists of the Rotor and Stator
Condition	Not reviewed in detail as part of this assessment. The generator is reported to be dirty but in acceptable condition for continued use. Assessment completed in 2003 reports winding to be of 1925 vintage, statistically past end of life and recommends a re-wind for 25 year life extension.
Additional Comments	Generator electrical and mechanical condition should be considered for assessment to confirm generator health

2.2. Generator Bearings

Description	Located above the head cover, there are 4 bearings, one guide bearing above the generator housed in the upper bracket, a second guide bearing located below the generator housed in the lower bracket, and a thrust and guide bearing below the generator mounted to the head cover. All four bearings are oil lubricated.
Condition	Not reviewed in detail as part of this assessment. Operational staff reported it to be in acceptable condition for continued use
Additional Comments	Option 3 requires disassembly of the lower guide/thrust bearing.

2.3. Lower Generator Shaft

Description	This shaft extends from the underside of the generator coupling face, through the guide and thrust bearings, through the head cover and is keyed with a tapered fit to the upper half of the brake coupling.

Condition	Some normal shaft wear has been observed at the headcover seal/packing diameter. This diameter was previously restored to its original size and surface finish in 1971. Currently, this wear is not detrimental but should be considered for repair in the next 5 years. Alignment readings indicate an increase in runout below the headcover. The corroded surface of the wetted shaft (below the headcover) complicates further alignment readings on either the shaft or coupling half. If the shaft is removed, it should be considered for alignment checks in a lathe and the seal diameter considered for repair to return it to original size and surface finish.
Additional Comments	DWG J-390 indicates the extent of shaft repairs completed in late 1971. Note 2 indicates that this shaft was left with ~0.002" run out. Re-alignment of components below the headcover will be complicated and potentially compromised if the shaft is either not removed from the headcover or confirmed straight. Options 1 & 2 do not include the disassembly or assessment of this component.

2.4. Brake Assembly

Description	The unit brake is comprised of a shaft mounted brake drum which forms the coupling between the lower generator shaft and upper turbine shaft, cast iron brake pads, supporting beams, pivots and actuating linkage.
Condition	The brake was refurbished in 2012 with new shoes, support beams and cleanup of the drum face. Currently, one of the support beam pedestals has pulled away from the wall. Site staff have indicated a need to repair the brake application linkage to increase adjustability
Additional Comments	Alignment readings indicate a possible brake drum coupling and resulting shaft misalignment which cannot be confirmed or repaired unless the coupling is removed as in option 3. Damage to the support pedestals indicates possible additional loading due to shaft / coupling misalignment. Options 1& 2 do not fully address the risk of brake /coupling mis-alignment.

2.5. Upper Turbine Shaft and Runner

Description	At 16.5' long, the upper turbine shaft extends from the lower half of the brake drum / coupling, through the upper turbine guide

	bearing and secondary headcover. The upper runner is coupled to the shaft midway along its length and there is a flanged coupling at the bottom end of the shaft to facilitate coupling to the lower shaft. There is record of repairs to this shaft and runner in 1971 and 1987 consisting of the renewal of the bearing, packing and runner seal diameters as well as coupling faces.
Condition	The shaft is suspected to be bent either above or below the runner. Alternatively, the coupling at either end of the shaft could be the source of the misalignment. The bearing diameter is pitted and requires restoration of its surface finish to improve bearing performance and life. The packing diameter is worn and requires restoration of its surface finish for life extension. The runner seals are worn in excess of 0.170” on diameter and require weld build up and machining for renewal. Poor bearing life and runner seal wear is an indication of excessive turbine runout. A detailed runner inspection has not been completed but its condition is considered to be acceptable with only minimal cavitation / crack repair required for life extension.
Additional Comments	DWG J-390 indicates the extent of shaft repairs completed in 1971, and reports show further work was required to refurbish this shaft and runner in 1987. Alignment readings indicate a high likelihood that this shaft is bent and requires a detailed runout check for confirmation.

2.6. Lower Turbine Shaft and Runners

Description	At a length of 12.5’, the lower turbine shaft extends from the flanged coupling face to the intermediate and lower runners. The lower turbine guide bearing is located between the runners. There is record of repairs to this shaft and both runners in 1971 and 1987 consisting of the renewal of the bearing, packing and runner seal diameters as well as coupling faces.
Condition	As the lower turbine bearing failed in operation and broken pieces impacted and became lodged between the lower runner and its crown seals there is substantial damage to this area. This shaft is suspected to be bent. Both intermediate and lower runner seals are worn in excess of 0.700” on diameter. There is impact damage to the lower runner blades, band and coupling bolt cover. The bearing diameter is pitted and requires repair to improve bearing performance and life.

Additional Comments	DWG J-390 indicates the extent of shaft repairs completed in 1971, and reports show further work was required to refurbish this shaft and runner in 1987. Currently, this shaft is likely to be bent and requires a detailed runout check for confirmation.

2.7. Upper and Lower Turbine Bearings

Description	Comprised of two separate water bearings of similar design, the upper bearing is located above the upper runner and the lower bearing is between the intermediate and lower runners. Each bearing is housed in a bearing tree which is fastened to embedments at two diametrically opposite points. Records show that in 2002, the lower bearing tree failed at its anchors requiring in-situ alignment and re-fastening of the tree.
Condition	Although further disassembly is required to confirm, the upper turbine guide bearing appears to be in acceptable condition which, at a minimum requires only renewal of the worn bearing surface. The lower turbine guide bearing and tree has sustained damage due to a failure of the bearing cover resulting in half of the bearing coming out from the tree and the tree dislodging from its embedded supports. New bearing half's covers are required.
Additional Comments	The lower bearing tree has lost all reference to the machine's center of rotation. The embedded anchors used to support the lower bearing tree will require renewal. An in-situ realignment as proposed in option 1 offers a best guess alignment which even if successful, would still require operation with larger than specified bearings clearances.

2.8. Governor Column, Rods, Yokes and Pins

Description	Extending from the governor servo gate shaft to the three turbine operating rings, the governor column is located in the water passage and transmits the linear motion of the governor servo to the angular motion required to open, close and scrunch (squeeze) the wicketgates.
Condition	Originally constructed of wood and later replaced with bronze, the governor column bushings are considered to be in poor condition with excess wear. The rods, yokes and pins that connect the servo to the column and the column to each turbine

	operating ring are also in poor condition with heavy corrosion and wear. Clearance between the yokes and pins have been reported in excess of 0.100" on diameter. In 2012, the upper operating ring pin clearances were temporarily repaired in-situ with the installation of grub screws and epoxy adhesive.
Additional Comments	Condition of the governor column, rods, yokes and pins have a direct relationship to the ability to regulate unit speed. Excessive clearance in the linkage has the potential to provide an imbalance of load between turbines and loss of wicket gate squeeze (ability to seal water from penstock to draft tube during a shutdown). Adjacent unit 4 was subject to the corrosion based operational failure of the threads between one of the operating ring yoke and rod which resulted in the failure of the operating ring and subsequent runaway of the unit.

2.9. Upper, Intermediate and Lower Distributor Assemblies

Description	Each distributor assembly consisting of stay vanes, wicketgates, operating rings and stationary turbine seals.
Condition	Although the condition varies between the three assemblies, all exhibit excess wear and damage. The crown and band seals were replaced in the early 1970's and are damaged on each assembly with clearances in excess of 0.700" on diameter. The intermediate crown seal has come unfastened and is protruding from the distributor. All wicketgate bushings are worn and one lower turbine wicket gate is damaged beyond repair. All three operating rings are reported to have excess bushing clearances and the lower ring has been fish plated to reinforce previous structural damage. Many of the separator rods and fasteners were found to have vibrated loose.
Additional Comments	Condition of the operating ring and wicketgate bushings have a direct relationship to the ability to regulate unit speed. Excessive bushing clearances have the potential to provide an imbalance of load between turbines and loss of wicket gate squeeze required to prevent excessive leakage and penstock water applied rotational torque while the unit is shutdown.

3. Operational Safety

For the purpose of this review, the operational safety of this machine has been categorized into two main concerns to which repair options can be compared. Concerns associated with or as a result of failure of electrical equipment have not been included.

1) **Uncontrolled release of water from the water passage resulting in flooding of the powerhouse:** Although the likelihood of such an event seems low, the consequences are severe. As there are no intake operating gates at this facility, the duration and damage from such an event would continue unchecked until staff have installed the stoplogs. The most likely cause of such an event would be failure of the unit headcover due to mechanical damage from equipment below.

2) **Uncontrolled rotation / runaway:** Units 1-4 have been subject to a number of previous instances of runaway machines. Most events are prolonged as crews are required to mobilize and install the intake stoplogs to stop the flow through the unit. The leading cause of these events can mainly be attributed to the wicketgate's inability to regulate flow through the units as a result of failure or excess wear of key components. Please note that an assessment of this machine's ability to operate above synchronous speed has not been completed by Engen Services Ltd. As such, the actual risk of intermittent or sustained unit operation above synchronous speed is unknown. However an ageing runaway unit is a hazard to itself, adjacent equipment and staff.

4. Expected Life Extension

The expected equipment service life extension associated with each repair option has been discussed in the review of repair options 1, 2 & 3 below. It is important to note that as many of the unit's primary and secondary productive units, such as the generator electrical/mechanical, excitation system and governor hydraulic and control systems, have not been reviewed in this report, it is not possible to apply an expected extension of life to the unit as a whole. The estimates discussed below are limited to the mechanical rotating components scoped for repair in each option. Furthermore, as options 1 & 2 both stop short of a full unit disassembly, inspection and repair, any estimate of the life extension is limited by both the compromises made in the execution of repairs and the unknown condition of components that remain in service.

5. Cost Estimates

Budgetary cost estimates for the three repair options have been completed with the support of Dustin Hale and Peter Kabel of FBC Generation Staff, following the Generation Estimate Template. The Summary tab of each estimate is included in Appendix A, B & C.

Estimates are considered to be at an AACE Class 4 level and therefore not substantiated by defined or detailed engineering, labour, material or machine shop estimates and quotes. A contingency of 40% has been applied to both labour and materials.

6. Repair Option Review

The following three repair options have been prepared to provide insight into the sliding scale of scope required to return the unit to commercial service. A summary discussion and scope overview of each option has been provided followed by a review of cost, operational safety and life expectancy as described in the sections above.

6.1. Option 1: In-Situ Repair

6.1.1. Summary:

This tactical option represents the opportunity to return the unit to service as quickly as possible at the lowest cost by minimizing the scope and extent of disassembly required for repair. It does not provide any guarantee that the machine will remain operational for any predetermined period if required to run. As the runout is currently observed to be excessive and there is extensive damage to both rotating and non-rotating components, if successfully returned to service, there is still cause for concern for the turbine components (namely the lower turbine bearing tree) and their ability to sustain continued operation without a similar in-service failure. Furthermore, once this scope has been completed, the unit should still be considered for additional repair (i.e. option 3) in the immediate future.

6.1.2. Scope Overview:

Sec.	Component	Scope
2.1	Generator	None.
2.2	Generator Bearings	None.
2.3	Lower Generator	Shaft remains in head cover. Replace packing as

	Shaft	required.
2.4	Brake Assembly	Replace pins and bushings in brake linkage. Align & remount all 4 brake arm mounts. Add adjustment turnbuckle in brake actuating shaft. Clean drum braking surface.
2.5	Upper Turbine Shaft and Runner	No repairs to the upper shaft or runner seal diameter. Shaft coupling bolts will be inspected and replaced as required. Shaft runout may be improved with coupling work.
2.6	Lower Turbine Shaft and Runners	In situ repair of runner crown seals with minimal repair completed on either runner.
2.7	Upper and Lower Turbine Bearings	Replace upper and lower bearing covers, replace lower bearing halfs and machine new bearings to suit excess runout conditions. Renew lower tree concrete supports, align lower tree to shaft and fasten.
2.8	Governor Column, rods, yokes and pins	Replace rods, yokes and pins, Governor column bushings remain. Adjust wicketgate alignment.
2.9	Upper, Intermediate and Lower Distributor Assemblies	Replace broken wicketgate, replace intermediate (if possible) and lower turbine seals.

6.1.3. Cost Overview:

TOTAL LABOUR ($)	TOTAL MAT'L & EQUIP ($)	TASK CONTINGENCY @ 40% ($)	OVERALL TOTAL TASK ($)
155,702	55,949	84,660	297,126

6.1.4. Operational Safety:

This option includes scope for the partial upgrade of the wicketgate linkage which supports the reduction in safety concern #2. As the mechanical condition of most rotating components remains unknown, this option provides little reduction to safety concern #1.

6.1.5. Life expectancy:

This option provides no firm extension to life expectancy. If all repairs are successful the unit may remain operational for the immediate future but at a risk to both reliability and safety.

6.2. Option 2: Unit Tear Down at Reduced Cost

6.2.1. Summary:

This option represents the opportunity to partially disassemble the unit, perform a partial repair of stationary turbine components and detailed runout checks of the lower shaft and intermediate and lower runner. Although theoretically achievable, full alignment of the rotating components will be potentially compromised by the partial disassembly and the upper turbine and seals will remain unrepaired.

6.2.2. Scope Overview:

Sec.	Component	Scope.
2.1	Generator	None, condition based repairs as required.
2.2	Generator Bearings	None.
2.3	Lower Generator Shaft	Shaft Remains in head cover. Run out may be better assessed during unit re-alignment but no further repairs can be completed without additional disassembly. Replace packing as required.
2.4	Brake Assembly	Replace pins and bushings in brake linkage. Align & remount all 4 brake arm mounts. Add adjustment turnbuckle in brake actuating shaft. Clean drum braking surface. Replace tapered coupling bolts.
2.5	Upper Turbine Shaft and Runner	Upper shaft and runner removed from machine but not assessed for damage or repair. Minor condition based runner repair may be completed. Shaft coupling bolts will be replaced.
2.6	Lower Turbine Shaft and Runners	Lower shaft and runners removed from machine for assessment. Shaft straightened and statically balanced as required, bearing and runner seal diameters repaired, and coupling face confirmed true. Runner weld repairs completed as required. Shaft coupling bolts will be replaced.
2.7	Upper and Lower Turbine Bearings	Replace upper and lower bearing covers, replace lower bearing halfs and machine new bearings to suit. Renew lower tree concrete supports. With lower shaft removed, bearing tree can be aligned to best center as measured from lower generator shaft.
2.8	Governor Column, rods, yokes and pins	Replace rods, yokes and pins, Governor column bushings remain. Adjust wicketgate alignment.
2.9	Upper, Intermediate	Replace broken wicketgate, attempt to shim operating rings. Replace intermediate and lower

	and Lower Distributor Assemblies	turbine seals to suit renewed runner seal diameters.

6.2.3. Cost Overview:

TOTAL LABOUR ($)	TOTAL MAT'L & EQUIP ($)	TASK CONTINGENCY @ 40% ($)	OVERALL TOTAL TASK ($)
285,919	176,100	184,808	646,827

6.2.4. Operational Safety:

This option includes scope for the partial upgrade of the wicketgate linkage which supports the reduction in safety concern #2 similar to that of option 1. The mechanical condition of the lower shaft and runners will be improved while the detailed condition of upper shaft and runner has the potential to remain unchanged. As a full alignment may not prove productive, the lower shaft and runner runout may remain excessive, and alignment of both the brake and turbine bearings potentially compromised. This option provides an improvement to reduction to safety concern #1over that of option 1 but includes a risk of little to no improvement if alignments are compromised.

6.2.5. Life Expectancy:

As this option provides only a partial repair and complications for unit alignment, the expected life extension is also at risk. Best case scenarios estimate the life extension of up to 5 years while worst case scenarios reduce the expectancy to that of option 1.

6.3. Option 3: Unit Tear Down Full Scope, Life Extension

6.3.1. Summary:

This option represents the opportunity to fully disassembly the rotating turbine components and provide an uncompromised assessment, repair and alignment. Additionally, worn governor column and wicketgate bushings, links and pins will be renewed.

6.3.2. Scope Overview:

Sec.	Component	Scope
2.1	Generator	Inspection, cleaning and condition based repairs as required.
2.2	Generator Bearings	Inspection, cleaning and condition based repairs as required.

2.3	Lower Generator Shaft	Shaft removed from head cover and assessed for straightness. Straighten shaft, repair packing diameter, skim coupling faces as required.
2.4	Brake Assembly	Replace pins and bushings in brake linkage. Align & remount all 4 brake arm mounts. Add adjustment turnbuckle in brake actuating shaft. Replace tapered coupling bolts. Check alignment of brake coupling, machine true as required, skim cut drum braking surface.
2.5	Upper Turbine Shaft and Runner	Upper shaft and runner removed from machine for assessment. Shaft straightened and statically balanced as required, bearing, packing and runner seal diameters repaired, and coupling faces confirmed true. Runner weld repairs completed as required. Shaft coupling bolts will be replaced.
2.6	Lower Turbine Shaft and Runners	Lower shaft and runners removed from machine for assessment. Shaft straightened and statically balanced as required, bearing and runner seal diameters repaired, and coupling face confirmed true. Runner weld repairs completed as required. Shaft coupling bolts will be replaced.
2.7	Upper and Lower Turbine Bearings	Replace upper and lower bearing covers, replace lower bearing halfs and machine new bearings to suit. Renew lower tree concrete supports. With all shafts removed, both upper and lower bearing trees can be aligned with confidence to best center as measured from the generator bearings.
2.8	Governor Column, rods, yokes and pins	Replace rods, yokes and pins, renew governor column bushings. Adjust wicketgate alignment.
2.9	Upper, Intermediate and Lower Distributor Assemblies	Replace broken wicketgate, renew and or replace operating rings and bushings. Replace upper, intermediate and lower turbine seals to suit renewed runner seal diameters.

6.3.3. Cost Overview:

TOTAL LABOUR ($)	TOTAL MAT'L & EQUIP ($)	TASK CONTINGENCY @ 40% ($)	OVERALL TOTAL TASK ($)
439,552	346,150	314,281	1,099,983

6.3.4. Operational Safety:

Once complete, the scope of this option returns all turbine rotating and wicketgate linkage components to a known acceptable condition. In turn, safety concerns #1 and #2 will be minimized.

6.3.5. Life Expectancy:

Based on the scope of repair and operating history of this and adjacent units after similar repairs in both the early1970’s and late 1980’s, the expected life extension is estimated to be 20 years.

7. Summary

This report is based on:

- in depth discussions and interviews with FortisBC field and engineering staff
- office reviews of FortisBC reports, maintenance records, technical information etc
- field inspection and assessment of unit condition

The conclusions reached are based on technical grounds and not entitlement or other non-operational considerations.

8. Recommendations

The only long term safe and reliable solution is option 3.

Option 2 is a curtailed and compromised version of option 3, and as such, it is not recommended.

If the risks to plant and people are acceptable to FortisBC management, option 1 should allow the unit to be available and give additional time to scope and perform a comprehensive unit refurbishment (i.e. option 3).

Appendix A

SUMMARY

CLASS 4 +50/20% to -30/15%

FORTIS BC
Upper Bonnington - P2
P2U3 Rebuild In-Situ
DRH
07-May-13

Planning Process No:
4.5 & 6.0

PROJ. NO.:

Ave. IBEW Lbr Rate	42.32
Fringe Benefit Loading	33.01
Admin Absorption	0.00
Overhead Rate/hr	0.00
2010 Ave. IBEW Rate	$75.33

BC Capitalized Overhead Loading:	
Labour Contingency:	**40.00%**
Material Contingency:	**40.00%**
Ave. Labour Rate:	**$75.33**
Overtime Rate:	**$84.64**
Contractor:	**$100.00**
Strategic O'time Allowance	**5.00%**
Commissioning Allowance	

Generation, RR#1 S2 C1
South Slocan B.C.
V0G 2G0

LABOUR									MATERIALS								
Total IBEW ELECT (Hrs)	**Total IBEW CRH (Hrs)**	**Total IBEW Flrman (Hrs)**	**Total IBEW MECH Hrs**	**COPE (Hrs)**	**STAFF ELEC (Hrs)**	**STAFF MECH (Hrs)**	**CONSULTANT (Hrs)**	**TOTAL LABOUR $**	**MATERIAL $**	**EQUIP. RENTAL $**	**CONTRACTOR $**	**TOTAL MAT'LS & EQUIP ($)**	**TOTAL TASK ($)**	**TASK CONTINGENCY ($)**	**MATERIAL LOADING ($)**	**OVERHEAD LOADING ($)**	**OVERALL TOTAL TASK ($)**
			857					$64,953	$15,500		$5,000	$20,500	$85,453	$34,181	$1000		$119,634
			321					$24,329	$7,946			$7,946	$32,275	$12,910	$556		$45,741
			295					$22,302	$23,817			$23,817	$46,118	$18,447	$2000		$64,566
			80					$6,082	$3,686			$3,686	$9,769	$3,907	$258		$13,934
				45		210	135	$38,037					$38,037	$15,215			$53,251
			1554	**45**		**210**	**135**	**$155,702**	**$50,949**		**$5,000**	**$55,949**	**$211,651**	**$84,660**	**$814**		**$297,126**

Appendix B

SUMMARY

Level of Estimate: CLASS 4 +50/20% to -30/15%
Planning No.:
Client: FORTIS BC
Location: Upper Bonnington - P2
Title: P2 U3 Option 2
Estimated by: Peter Kabel
Date: 08-May-13

Planning Process No:
4.5 & 6.0

Ave. IBEW Lbr Rate 42.34
Fringe Benefit Loading 33.03
Admin Absorption 0.00
Overhead Rate/hr 0.00
2014 Ave. IBEW Rate $75.37

BC Capitalized Overhead Loading:
Labour Contingency: 40.00%
Material Contingency: 40.00%
Ave. Labour Rate: $75.37
Overtime Rate: $84.68
Contractor: $100.00
Strategic O'time Allowance
Commissioning Allowance

FORTIS BC

Generation, RR#1 S2 C1
South Slocan B.C.
V0G 2G0

PROJECT SUMMARY SHEET

PROJ. NO.:

WBS Task Description	LABOUR									MATERIALS								
	Total IBEW ELECT (Hrs)	Total IBEW CRH (Hrs)	Total IBEW Flrman (Hrs)	Total IBEW MECH Hrs	COPE (Hrs)	STAFF ELEC (Hrs)	STAFF MECH (Hrs)	CONSULTANT (Hrs)	TOTAL LABOUR $	MATERIAL $	EQUIP. RENTAL $	CONTRACTOR $	TOTAL MAT'LS & EQUIP ($)	TOTAL TASK ($)	TASK CONTINGENCY ($)	MATERIAL LOADING ($)	OVERHEAD LOADING ($)	OVERALL TOTAL TASK ($)
Mobilization and Dismantle Unit	173			1073					$93,830	$44,000			$44,000	$137,830	$55,132	$2000		$192,962
Third party refurbishment				53					$3,957			$96,200	$96,200	$100,157	$40,063	-		$140,219
In House Refurbishmment	38			368					$30,523	$10,900			$10,900	$41,423	$16,569	$1000		$57,992
Reassembly and alignment	98			1245					$101,178	$25,000			$25,000	$126,178	$50,471	$2000		$176,649
P2 U3 Option 2 EPCM				120	4		324	71	$56,432					$56,432	$22,573			$79,005
P2 U3 Option 2 Asset Removal																		
PROJECT TASKS TOTALS	**308**			**2858**	**4**		**324**	**71**	**$285,919**	**$79,900**		**$96,200**	**$176,100**	**$462,019**	**$184,808**			**$646,827**

Appendix C

SUMMARY

Level of Estimate: CLASS 4 +50/20% to -30/15%
Planning No.:
Client: FORTIS BC
Location: Upper Bonnington - P2
Title: P2 U3 Option 3
Estimated by: Peter Kabel
Date: 08-May-13

Planning Process No:
4.5 & 6.0

Ave. IBEW Lbr Rate	42.34
Fringe Benefit Loading	33.03
Admin Absorption	0.00
Overhead Rate/hr	0.00
2014 Ave. IBEW Rate	$75.37

BC Capitalized Overhead Loading:	
Labour Contingency:	40.00%
Material Contingency:	40.00%
Ave. Labour Rate:	$75.37
Overtime Rate:	$84.68
Contractor:	$100.00
Strategic O'time Allowance	
Commissioning Allowance	

FORTIS BC
Generation, RR#1 S2 C1
South Slocan B.C.
V0G 2G0

PROJECT SUMMARY SHEET

PROJ. NO.:

WBS Task Description	LABOUR: Total IBEW ELECT (Hrs)	LABOUR: Total IBEW CRH (Hrs)	LABOUR: Total IBEW Flrman (Hrs)	LABOUR: Total IBEW MECH Hrs	LABOUR: COPE (Hrs)	LABOUR: STAFF ELEC (Hrs)	LABOUR: STAFF MECH (Hrs)	LABOUR: CONSULTANT (Hrs)	LABOUR: TOTAL LABOUR $	MATERIALS: MATERIAL $	MATERIALS: EQUIP. RENTAL $	MATERIALS: CONTRACTOR $	MATERIALS: TOTAL MAT'LS & EQUIP ($)	TOTAL TASK ($)	TASK CONTINGENCY ($)	MATERIAL LOADING ($)	OVERHEAD LOADING ($)	OVERALL TOTAL TASK ($)
Mobilization and Dismantle Unit	173			1733					$143,571	$62,350			$62,350	$205,921	$82,368	$3000		$288,289
Third party refurbishment				53					$3,957			$149,900	$149,900	$153,857	$61,543	-		$215,399
In House Refurbishmnent	38			1140					$88,743	$80,900		$10,500	$91,400	$180,143	$72,057	$3000		$252,200
Reassembly and alignment	98			1755					$139,614	$42,500			$42,500	$182,114	$72,846	$2000		$254,960
P2 U3 Option 3 EPCM	16			141	4		366	77	$63,668					$63,668	$25,467			$89,135
P2 U3 Option 3 Asset Removal																		
PROJECT TASKS TOTALS	**323**			**4821**	**4**		**366**	**77**	**$439,552**	**$185,750**		**$160,400**	**$346,150**	**$785,702**	**$314,281**			**$1,099,983**

Appendix D-3

ENGEN UNIT 1 TURBINE INSPECTION

Upper Bonnington Generating Station

Unit 1 Turbine Component Mechanical Inspection

Revision: 1

Report Date:
July 2015

PROFESSIONAL
PROVINCE OF BRITISH COLUMBIA
R. M. STRACHAN
32097
ENGINEER

07.07.15

Prepared by
R.M. Strachan, P.Eng

ENGEN SERVICES LTD

PO Box 1225 Rossland BC, V0G 1Y0

Table of Contents

1.0 Summary

In support of Fortis BC's Certificates of Public Convenience and Necessity (CPCN) application to the BCUC, Robin Strachan of Engen Services Ltd. attended the Upper Bonnington Generating Station (UBO) on 20 May 2015 to complete a mechanical inspection of the water passage turbine components of Generating Unit 1. Additionally, an inspection of the intake trashrack was completed and is included in this report.

Although operational, the overall condition of the water passage components indicates the unit is due for a major refurbishment in which key components are disassembled, corrosion removed, inspected, non-destructively tested and restored or replaced as required to maintain the unit's safe, efficient and reliable operation.

This report details the inspection of the key components, provides an appendix of key figures and makes recommendations for future inspection and repair to support the CPCN application.

2.0 Background

Construction on the UBO facility started in 1905. Initially, unit 2 & 3 were installed in 1907 followed by units 1 & 4 in 1914. Although of similar design and arrangement, unit 2 & 3 generators were supplied by Canadian general electric, while the turbines were supplied by I.P, Morris Co. and rated at 8,000 HP. Units 1 & 4 generators were also supplied by Canadian General Electric Co. but the turbines were supplied by Allis Chalmers co. and rated at 9,000 HP. In 1938, construction of an extension to the old plant started with units 5 & 6 commencing operation by 1940.

Although periodic maintenance and refurbishment has been completed throughout the operating history of the facility, the units remain largely original and of a significantly antiquated design. The last major refurbishment of Unit 1 was completed in the mid 1980's.

As shown in Figure 1 below, each vertical turbine assembly consists of two right hand runners and one left hand runner on a common shaft. All the turbines are fed from a single penstock, the top and intermediate turbines discharge into an upper draft tube which converges with the discharge draft tube of the bottom turbine before exiting through the draft tube gate slots to the tailrace.

The distributor assembly associated with each runner consists of wicket gates and an operating ring which is positioned by a hydraulically actuated gate shaft governor column and associated linkages.

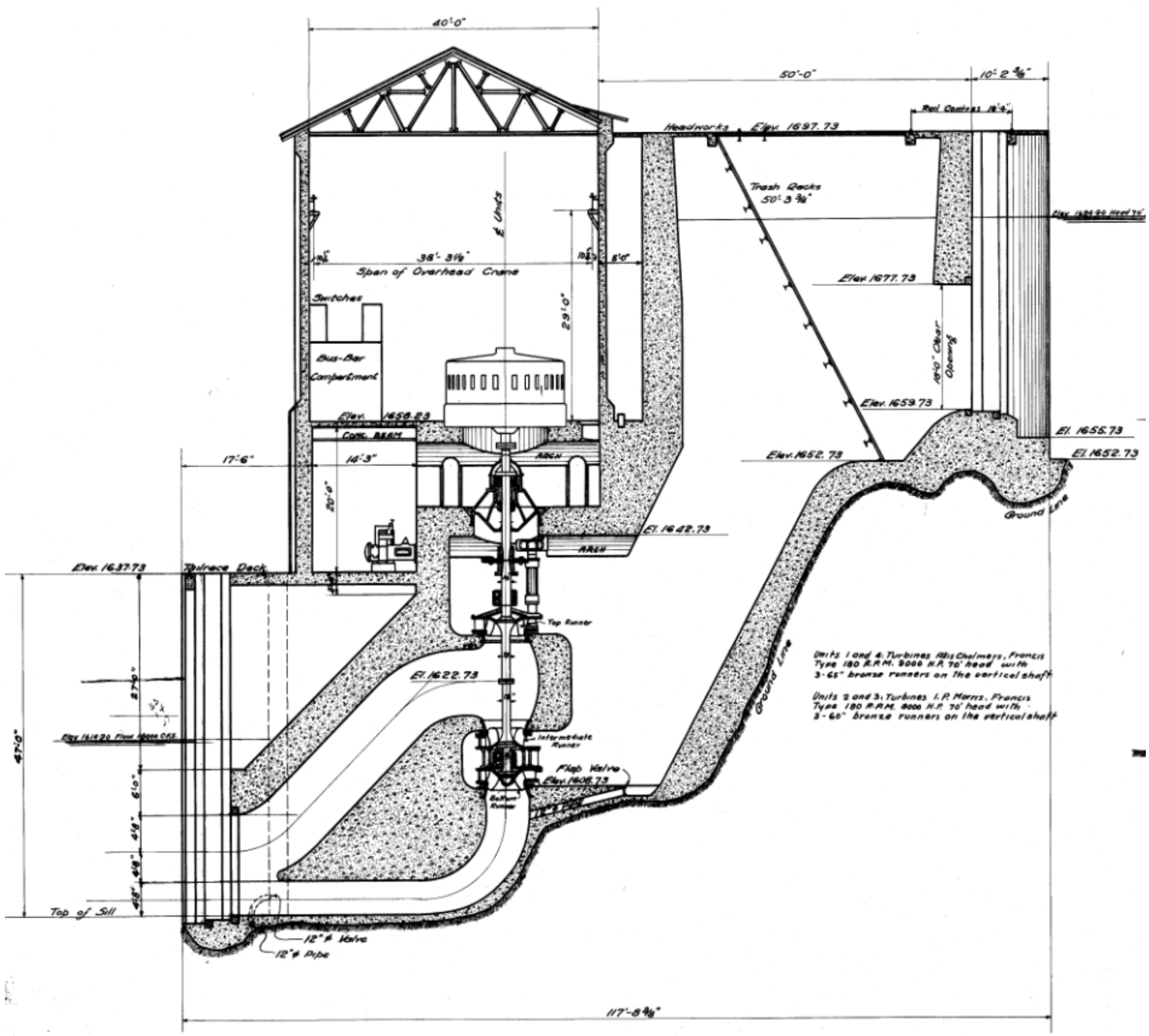


Figure 1: UBO Unit Cross-section

3.0 Equipment Condition Assessment

The following section provides details of the UBO Unit 1 water passage equipment condition assessments which are based on the inspections completed in May 2015. General and specific pictures of key components are provided in Appendix A.

3.1 Top, Intermediate and Bottom Turbine Runners: Units 1 & 4 are operating with the original turbines supplied in 1914 by Allis-Chalmers – Ref drawing: 813-62. The turbines are constructed of bronze (Specified as: 90 parts copper, 10 parts tin with a trace of phosphorous). When removed in the mid 1980's during a major unit overhaul, the three turbines were subject to cavitation damage repairs by brazing and restoration of the crown and band seal diameters with a stainless steel overlay or strip. Inspection of the turbine was limited to what can been seen through the relatively small openings (~18 in. tall X 4.5 in. wide) between the wicketgates. The discharge/draftube side of the turbines was not accessible at the time of inspection. The turbine blade inlets, by design, are very thin and through the process of cavitation, flow and particle induced erosion, showing signs of washout and horizontal cracking on the majority of the pressure side of the inlets. The cracking and erosion is most prominent on the lower 6 in. of the blades extending 2 in. to 3 in. from the inlet edge but also present on some blades near the crown. The bottom turbine was observed to have the most erosion of the three as it is expected to pass the majority of the larger entrained river sediment and gravel. On the blade inlet's suction sides, the remnants of previous repairs are present along with strips of cavitation damage ~ 2 in. wide extending from the band upward ~ 9 in.. Cavitation up to an estimated 1/8 in. deep was observed extending from the blade inlet suction side down the band to blade fillet and on the trailing edge pressure side at the band fillet. Light cavitation was also observed between the blades on the crown and on the crown adjacent to the coupling bolt holes. The crown and band seal diameters, which are overlaid with stainless steel, do not exhibit signs of heavy wear or galling but their clearance to the stationary seals looks to be in excess of ½ in.. The bronze surrounding the band seal is heavily washed out with loss of material up to 1/8 in.

3.2 Turbine Shafts: Overview of the three turbine shafts did not indicate any unusual deterioration. The forged steel shafts exhibit wide spread surface corrosion and while the bearings and packing seals were not removed to gain access to the respective shaft diameters, these areas are expected to be worn and pitted. The couplings between each shaft are intact but showing light corrosion and washout of the bolts and keys.

3.3 Unit Brake: The brake shoe support beams, linkage and pivot supports all exhibit signs of heavy corrosion. The pivot support wall brackets look to be well fastened but observed wear markings indicate excess clearance in the pins and bushings. Both brake shoes were found to be sitting ~ ¾ in. below the center of the brake drum and one of the brake support I-beams is slightly bent/twisted. The brake drum is worn according to the shoe misalignment with a ridge on its upper edge.

3.4 Upper and Lower Turbine Bearings: The upper and lower turbine bearings are supported to the embedments on bearing support trees. No significant movement or deterioration was observed at the embedments. The tree brackets, which are constructed of cast iron, display heavy corrosion with many large rust tubercles. On removal/scraping of the tubercles, minimal loss of base metal was observed. The bearings were not disabled at the time of the inspection and therefore the bearing strips and shaft diameters were not observed. The original bearing design made use of pump supplied and filtered cooling/lubricating water. This system was decommissioned many years ago and the current supply is from the unfiltered water passage.

3.5 Top, Intermediate and Bottom Distributor Assemblies: The distributor assemblies are mainly constructed of cast iron components which on the surface, are heavily corroded with wide spread growth of rust tubercles. Similar to many of the other cast iron components on this machine, once the tubercles are removed, minimal loss of base material can be observed. The wicket gates were isolated in their open (10/10) position at the time of inspection preventing any operational checks. It is however expected that the wicket gate intergate clearances are loose which may be caused by worn operating ring bushings, governor linkages and wicket gate linkages and bushings. The operating rings were inspected and found to be intact but still present some operational concern based on a history of failure on the adjacent units.

3.6 Governor Column: The gate shaft governor column is constructed of steel pipe riveted to cast flanges, cast guide and thrust bearing supports and a series of clevis, yolks and pins. Overall, the governor column is heavily corroded and it is expected that the pipes will have lost some structural integrity. The support bearings, linkage bushings and pins can be expected to be worn due to their age and service environment. Based on the history of failure on the adjacent units, the threaded rods and associated rod ends between the governor column and operating rings and yokes require further review to confirm the integrity of their threaded connections.

3.7 Head Cover: The cast head cover and its embedments form a critical assembly that both supports the weight and thrust of the machine and also contains the water within the water passage. When viewed from the water passage (under side), the head cover and embedments exhibit wide spread corrosion on their wetted surfaces. Similarly, the cooling water pipes associated with head cover are heavily corroded.

3.8 Trashrack: The unit intake trashrack was inspected from the upstream side only. The rack consists of eight horizontal support I-beams which are embedded on either side and ten 1.5 ft. wide racks consisting of horizontal fastening rods and ¼ in. wide flat bars on edge spaced 1.25 in. apart. A number of areas of repair can be seen on the rack sections and one of the middle racks is slightly bent at about the middle of its span. Above the normal operating water level, the racks are in generally acceptable condition with only minor surface corrosion. At and below the water line the vertical bars were observed to have lost approximately half their thickness to corrosion. Although difficult to investigate from the upstream side, the support beams contain an accumulation of organic debris on the webs with heavy corrosion beneath.

4.0 Recommended Remedial Steps

The following recommendations and suggested interventions have been provided in consideration of a base line of scope required to fully assess and restore the turbine water passage components to safe, efficient and reliable operation.

Top, Intermediate and Bottom Turbine Runners:

4.1 Extensive buildup of the base metal will be required to restore both the structural integrity and original blade profile. A repair procedure suitable to the bronze runners will be required.

4.2 A NDT inspection of the turbines high stress areas is recommended prior to any future repairs.

4.3 The restoration of the seal diameters will be required in conjunction with the restoration of the stationary seals. A repair procedure will be required for the overlay of the seal diameters, either building off of the existing unknown stainless overlay or off of the base bronze.

4.4 As an alternative to the repair, procurement of replacement turbines may prove to provide less risk to project cost and schedule, due to both the currently unknown full extent of repair required and long term suitability of repairs.

Turbine Shafts:

4.5 The shafts packing and bearing diameters will require restoration through sleeving or overlaying.

4.6 All coupling bolts and coupling keys will require detailed inspection to confirm their integrity for continued use.

4.7 Shaft runout and NDT inspection of the coupling bolt holes and flange radiuses are advisable.

Unit Brake:

4.8 Restoration of the brake will require a complete disassembly, removal of heavy corrosion to assess loss of base metal, refurbishment of the brake drum and shoes as well as the pivots and linkage.

4.9 As an alternative to repair, consideration should be given to removing the existing brake and replacing it with a disk brake located out of the water passage above the thrust bearing.

Upper and Lower Turbine Bearings:

4.10 Alignment of the bearing support trees may support improved/extended bearing life by ensuring the bearing is placed at the best center of rotation of the shaft.

4.11 Replacement of the previously discarded filtered bearing cooling water supply may help to further improve bearing and shaft life by reducing the abrasive quantity of sediment in the water within the bearing.

Top, Intermediate and Bottom Distributor Assemblies:

4.12 Restoration of the wicket gate intergate clearances is recommended and will require refurbishment of the associated bushings, links and pins.

4.13 A detailed inspection, refurbishment or replacement of the operating ring and associated bushings will be required.

Governor Column:

4.14 Assessment of the structural integrity of the pipes that form the governor column will be required during its disassembly.

4.15 The support bearings, linkage bushings and pins can be expected to be worn due to their age and service environment. Refurbishment and replacements will be required.

4.16 The threaded rods and associated rod ends and yokes between the governor column and operating rings should be disassembled to confirm the integrity of their threaded connections.

Head Cover:

4.17 Further inspection to assess the depth of pitting and structural integrity of the head cover is recommended.

4.18 As they are a critical component to sealing the water passage, the head cover fasteners and embedments should be inspected to confirm their structural integrity.

4.19 The cooling water piping is expected to require replacement due to corrosion.

Trashrack:

4.20 Consider limiting the operating differential pressure applied to the racks until they are replaced or assessed for a de-rated load capacity.

5.0 Conclusion

UBO generating Unit 1 water passage turbine components are due for a major overhaul. As detailed in this report, the observed heavy corrosion of key components will necessitate their short term investigation, repair or replacement. Remaining key components, such as the turbines, wicket gate links and bushings, governor links and bushings and the turbine shafts will require restoration and replacement to restore them to a suitably reliable condition.

Appendix A:

UBO Unit 1 Inspection Figures

Figure 1: Upper turbine bearing and distributor assembly

Figure 2: Intermediate and bottom turbine gearing and distributor assemblies

Figure 3: Typical cracking and erosion of the blade inlet pressure side near the band

Figure 4: Typical blade suction side inlet at the band showing previous repairs and new cavitation damage.

Figure 5: Light cavitation occurring on the crown between blades

Figure 6: View of typical band seal showing overlay with stainless and erosion of bronze

Figure 7: Upper turbine shaft showing the brake drum, shoes and beams

Figure 8: Brake drum and shoe misalignment and wear

Figure 9: Brake beam pivot point showing heavy corrosion and pivot wear

Figure 10: Lower bearing tree

Figure 11: Typical bearing tree leg, dowels and embedments

Figure 12: View of intermediate turbine distributor operating ring, linkages and wicket gates

Figure 13: View of typical wicket gate condition

Figure 14: Upper governor column and linkages

Figure 15: lower governor column and linkages

Figure 16: Water passage side of the head cover showing corrosion of it and the cooling water pipes

Figure 17: Overview of dewatered trashrack

Figure 18: Trashrack bars at the waterline

Figure 19: Trashrack support beam corrosion on the web

Appendix D-4

REVENUE REQUIREMENTS ANALYSIS

FortisBC Inc.
Upper Bonnington - Alternative 1 - Decommissioning of Units 1-4
August 2016
($000s), unless otherwise statec

Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2037	2041	2045	2049	2053	2057	2061	2065	2067
1	**Cost of Service**																										
2	Power Purchase Expense		5,574	5,746	5,915	6,092	6,276	6,466	6,661	6,862	7,070	7,283	7,503	7,730	7,963	8,204	8,451	8,707	9,904	10,720	11,604	12,561	13,596	14,717	15,930	17,243	17,940
3	Water Fee Adjustment		-	(831)	(846)	(861)	(876)	(891)	(907)	(924)	(940)	(957)	(974)	(992)	(1,010)	(1,028)	(1,046)	(1,065)	(1,166)	(1,254)	(1,350)	(1,453)	(1,564)	(1,685)	(1,816)	(1,958)	(2,033)
4	Operation & Maintenance	Line 23	(160)	(163)	(166)	(170)	(173)	(477)	(786)	(802)	(818)	(834)	(851)	(868)	(1,185)	(1,209)	(1,533)	(1,564)	(1,727)	(1,869)	(2,023)	(2,190)	(2,370)	(2,866)	(3,102)	(3,670)	(3,818)
5	Property Taxes	Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Depreciation Expense	Line 46	-	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)
7	Income Taxes	Line 80	(58)	(106)	(69)	(60)	(52)	(44)	(37)	(30)	(24)	(18)	(13)	(8)	(3)	1	5	9	25	35	43	50	55	61	65	69	71
8	Earned Return	Line 66	-	146	295	300	304	309	313	317	322	326	331	335	339	344	348	353	375	392	410	428	445	463	480	498	507
9	**Incremental Annual Revenue Requirement**	Sum of Line 2 to Line 8	**5,356**	**4,727**	**5,064**	**5,236**	**5,414**	**5,297**	**5,179**	**5,359**	**5,544**	**5,735**	**5,931**	**6,132**	**6,040**	**6,247**	**6,160**	**6,374**	**7,346**	**7,960**	**8,620**	**9,330**	**10,097**	**10,624**	**11,492**	**12,118**	**12,602**
10	PV of Revenue Requirement (After-tax WACC of 5.97%)	Line 9 / (1 + Line 68)^Yr	5,054	4,209	4,255	4,152	4,051	3,740	3,450	3,369	3,289	3,210	3,132	3,056	2,840	2,772	2,580	2,519	2,172	1,866	1,602	1,375	1,179	984	844	705	653
11	Total PV of Annual Revenue Requirement	Sum of Line 10	***105,018***																								
12																											
13	2016 Approved Revenue Requirement (G-202-15 Compliance Filing)		350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593
14	% Increase on 2016 Rate	Line 9 / Line 13	1.53%	1.35%	1.44%	1.49%	1.54%	1.51%	1.48%	1.53%	1.58%	1.64%	1.69%	1.75%	1.72%	1.78%	1.76%	1.82%	2.10%	2.27%	2.46%	2.66%	2.88%	3.03%	3.28%	3.46%	3.59%
15																											
16	PV of Annual 2016 Approved Revenue Requirement	Line 13 / (1 + Line 68)^Yr	330,826	312,174	294,574	277,965	262,293	247,505	233,551	220,383	207,958	196,233	185,169	174,729	164,878	155,582	146,810	138,533	103,642	82,172	65,150	51,653	40,953	32,469	25,743	20,410	18,174
17	Total PV of 2016 Approved Revenue Requirement	Sum of Line 16	5,563,561																								
18	**Levelized % Increase (51 yrs) on 2016 Rate**	**Line 11 / Line 17**	**1.89%**																								
19																											
20	**Operation & Maintenance**																										
21	Labour Costs		(160)	(163)	(166)	(170)	(173)	(477)	(786)	(802)	(818)	(834)	(851)	(868)	(1,185)	(1,209)	(1,533)	(1,564)	(1,727)	(1,869)	(2,023)	(2,190)	(2,370)	(2,866)	(3,102)	(3,670)	(3,818)
22	Non-Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Net O&M Expenses**	Line 21 + Line 22	(160)	(163)	(166)	(170)	(173)	(477)	(786)	(802)	(818)	(834)	(851)	(868)	(1,185)	(1,209)	(1,533)	(1,564)	(1,727)	(1,869)	(2,023)	(2,190)	(2,370)	(2,866)	(3,102)	(3,670)	(3,818)
24																											
25	**Capital Spending**																										
26	Project Capital Spending[1]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	AFUDC		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Annual Capital Spending & AFUDC	Sum of Line 26 to 29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Cost of Removal		4,256	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total Annual Project Cost - Capital	Line 28 + Line 29	4,256	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																											
32	**Total Project Costs (incl. AFUDC)**	**Sum of Line 28**	**-**																								
33	**Net Project Costs (incl. AFUDC and Removal)**	**Sum of Line 30**	**4,256**																								
34	1 - First year of analysis includes all prior year spending																										
35																											
36	**Gross Plant in Service (GPIS)**																										
37	GPIS - Beginning[2]	Preceding Year, Line 41	-	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)
38	Additions to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Net Addition to Plant	Sum of Line 38 to 39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	GPIS - Ending	Line 37 + Line 40	-	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)
42	2 - Addition and Retirement in 2017 are shown in the opening balance of 2018 (CPCN addition and retirement to plant on Jan 1 of following year)																										
43																											
44	**Accumulated Depreciation**																										
45	Accumulated Depreciation - Beginning[3]	Preceding Year, Line 49	-	3,372	7,693	7,758	7,823	7,887	7,952	8,017	8,082	8,147	8,212	8,277	8,342	8,407	8,472	8,537	8,862	9,121	9,381	9,641	9,901	10,160	10,420	10,680	10,810
46	Depreciation Expense[4]	Line 37 @ 1.93%	-	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
47	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Cost of Removal		-	4,256	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Accumulated Depreciation - Ending	Sum of Line 45 to 48	-	7,693	7,758	7,823	7,887	7,952	8,017	8,082	8,147	8,212	8,277	8,342	8,407	8,472	8,537	8,602	8,927	9,186	9,446	9,706	9,966	10,225	10,485	10,745	10,875
50	3 - Retirement in 2017 is shown in the opening balance of 2018 (see note 2 above)																										
51	4 - Depreciation & Amortization Expense calculation is based on opening balance x composite depreciation rate; The composite rate of all assets addition to plant is 1.93%																										
52																											

FortisBC Inc.

Upper Bonnington - Alternative 1 - Decommissioning of Units 1-4

August 2016

($000s), unless otherwise statec

Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2037	2041	2045	2049	2053	2057	2061	2065	2067
53	**Rate Base and Earned Return**																										
54	Gross Plant in Service - Beginning	Line 37	-	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)
55	Gross Plant in Service - Ending	Line 41	-	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)	(3,372)
56																											
57	Accumulated Depreciation - Beginning	Line 45	-	3,372	7,693	7,758	7,823	7,887	7,952	8,017	8,082	8,147	8,212	8,277	8,342	8,407	8,472	8,537	8,862	9,121	9,381	9,641	9,901	10,160	10,420	10,680	10,810
58	Accumulated Depreciation - Ending	Line 49	-	7,693	7,758	7,823	7,887	7,952	8,017	8,082	8,147	8,212	8,277	8,342	8,407	8,472	8,537	8,602	8,927	9,186	9,446	9,706	9,966	10,225	10,485	10,745	10,875
59																											
60	Net Plant in Service, Mid-Year	Sum (Lines 54 through 58)/2	-	2,160	4,353	4,418	4,483	4,548	4,613	4,678	4,743	4,808	4,873	4,938	5,003	5,068	5,133	5,198	5,522	5,782	6,042	6,302	6,561	6,821	7,081	7,341	7,471
61	Cash Working Capital	Line 41 x FBC CWC/Closing GPIS %	-	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
62	**Total Rate Base**	**Sum of Line 60 to 61**	**-**	**2,157**	**4,350**	**4,415**	**4,480**	**4,545**	**4,610**	**4,675**	**4,739**	**4,804**	**4,869**	**4,934**	**4,999**	**5,064**	**5,129**	**5,194**	**5,519**	**5,779**	**6,038**	**6,298**	**6,558**	**6,818**	**7,077**	**7,337**	**7,467**
63																											
64	Equity Return	Line 62 x ROE x Equity %	-	79	159	162	164	166	169	171	173	176	178	181	183	185	188	190	202	211	221	231	240	250	259	269	273
65	Debt Component	[5]	-	67	136	138	140	142	144	146	148	150	152	154	156	158	160	162	173	181	189	197	205	213	221	230	234
66	**Total Earned Return**	**Line 64 + Line 65**	**-**	**146**	**295**	**300**	**304**	**309**	**313**	**317**	**322**	**326**	**331**	**335**	**339**	**344**	**348**	**353**	**375**	**392**	**410**	**428**	**445**	**463**	**480**	**498**	**507**
67	Return on Rate Base %	Line 66 / Line 62	0.00%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
68	After- Tax Weighted Average Cost of Capital (WACC)	[6]	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%
69	5 - Line 62 x (LTD Rate x LTD% + STD Rate x STD %)																										
70	6 - ROE Rate x Equity Component + [(STD Rate x STD Portion) + (LTD Rate x LTD Portion)] x (1- Income Tax Rate)]																										
71																											
72	**Income Tax Expense**																										
73	Earned Return	Line 66	-	146	295	300	304	309	313	317	322	326	331	335	339	344	348	353	375	392	410	428	445	463	480	498	507
74	Deduct: Interest on debt	Line 65	-	(67)	(136)	(138)	(140)	(142)	(144)	(146)	(148)	(150)	(152)	(154)	(156)	(158)	(160)	(162)	(173)	(181)	(189)	(197)	(205)	(213)	(221)	(230)	(234)
75	Add: Depreciation Expense		-	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)	(65)
76	Deduct: Capital Cost Allowance	Line 88	(165)	(317)	(292)	(268)	(247)	(227)	(209)	(192)	(177)	(163)	(150)	(138)	(127)	(117)	(107)	(99)	(65)	(47)	(33)	(24)	(17)	(12)	(9)	(6)	(5)
77	Taxable Income After Tax	Sum of Line 73 through 76	(165)	(303)	(197)	(172)	(148)	(126)	(105)	(86)	(68)	(52)	(36)	(22)	(9)	4	16	26	72	100	123	142	158	172	185	197	203
78	Income Tax Rate		26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
79																											
80	**Total Income Tax Expense**	Line 77 / (1 - Line 78) x Line 78	**(58)**	**(106)**	**(69)**	**(60)**	**(52)**	**(44)**	**(37)**	**(30)**	**(24)**	**(18)**	**(13)**	**(8)**	**(3)**	**1**	**5**	**9**	**25**	**35**	**43**	**50**	**55**	**61**	**65**	**69**	**71**
81																											
82	**Capital Cost Allowance**																										
83	Opening Balance	Prceding Year, Line 89	-	3,963	3,646	3,354	3,086	2,839	2,612	2,403	2,211	2,034	1,871	1,721	1,584	1,457	1,340	1,233	813	582	417	299	214	153	110	79	67
84	Additions to Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85	Add: Cost of Removal		4,256	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	Less: AFUDC		(128)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	Net Addition for CCA	Sum of Line 84 through 86	4,128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
88	**CCA (Composite CCA Rate @ 8%)**	**Line 83 + (Line 87 x 1/2)] x CCA Rate**	**(165)**	**(317)**	**(292)**	**(268)**	**(247)**	**(227)**	**(209)**	**(192)**	**(177)**	**(163)**	**(150)**	**(138)**	**(127)**	**(117)**	**(107)**	**(99)**	**(65)**	**(47)**	**(33)**	**(24)**	**(17)**	**(12)**	**(9)**	**(6)**	**(5)**
89	Closing Balance	Line 83 + Line 87 + Line 88	3,963	3,646	3,354	3,086	2,839	2,612	2,403	2,211	2,034	1,871	1,721	1,584	1,457	1,340	1,233	1,135	748	536	384	275	197	141	101	72	61
90																											

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Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2037	2041	2045	2049	2053	2057	2061	2065	2067
1	**Cost of Service**																										
2	Power Purchase Expense		261	351	369	387	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Water Fee Adjustment		-	(28)	(50)	(50)	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Operation & Maintenance	Line 23	(40)	(41)	(42)	(42)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Property Taxes	Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Depreciation Expense	Line 48	-	122	350	544	803	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805
7	Income Taxes	Line 82	(107)	(176)	(244)	(315)	(260)	(177)	(105)	(40)	20	73	122	166	205	241	273	302	402	444	463	464	454	434	409	379	362
8	Earned Return	Line 68	-	880	1,703	2,562	3,038	3,006	2,951	2,897	2,842	2,787	2,733	2,678	2,623	2,569	2,514	2,459	2,186	1,968	1,749	1,531	1,312	1,093	875	656	547
9	**Incremental Annual Revenue Requirement**	Sum of Line 2 to Line 8	**114**	**1,109**	**2,087**	**3,085**	**3,531**	**3,634**	**3,651**	**3,662**	**3,666**	**3,666**	**3,660**	**3,649**	**3,634**	**3,615**	**3,592**	**3,566**	**3,393**	**3,217**	**3,017**	**2,800**	**2,571**	**2,333**	**2,089**	**1,840**	**1,714**
10	PV of Revenue Requirement (After-tax WACC of 5.97%)	Line 9 / (1 + Line 70)^Yr	108	988	1,753	2,446	2,641	2,565	2,432	2,302	2,175	2,052	1,933	1,819	1,709	1,604	1,504	1,409	1,003	754	561	413	300	216	153	107	89
11	Total PV of Annual Revenue Requirement	Sum of Line 10	***46,692***																								
12																											
13	2016 Approved Revenue Requirement (G-202-15 Compliance Filing)		350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593
14	% Increase on 2016 Rate	Line 9 / Line 13	0.03%	0.32%	0.60%	0.88%	1.01%	1.04%	1.04%	1.04%	1.05%	1.05%	1.04%	1.04%	1.04%	1.03%	1.02%	1.02%	0.97%	0.92%	0.86%	0.80%	0.73%	0.67%	0.60%	0.52%	0.49%
15																											
16	PV of Annual 2016 Approved Revenue Requirement	Line 13 / (1 + Line 70)^Yr	330,826	312,174	294,574	277,965	262,293	247,505	233,551	220,383	207,958	196,233	185,169	174,729	164,878	155,582	146,810	138,533	103,642	82,172	65,150	51,653	40,953	32,469	25,743	20,410	18,174
17	Total PV of 2016 Approved Revenue Requirement	Sum of Line 16	5,563,561																								
18	**Levelized % Increase (51 yrs) on 2016 Rate**	**Line 11 / Line 17**	**0.84%**																								
19																											
20	**Operation & Maintenance**																										
21	Labour Costs		(40)	(41)	(42)	(42)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Non-Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Net O&M Expenses**	Line 21 + Line 22	(40)	(41)	(42)	(42)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																											
25	**Capital Spending**																										
26	Project Capital Spending[1]		7,095	12,342	10,628	13,928	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	AFUDC		144	389	332	441	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Annual Capital Spending & AFUDC	Sum of Line 26 to 29	7,238	12,731	10,960	14,368	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Cost of Removal		495	505	335	552	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total Annual Project Cost - Capital	Line 28 + Line 29	7,733	13,236	11,295	14,920	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																											
32	**Total Project Costs (incl. AFUDC)**	**Sum of Line 28**	**45,414**																								
33	**Net Project Costs (incl. AFUDC and Removal)**	**Sum of Line 30**	**47,300**																								
34	1 - First year of analysis includes all prior year spending																										
35																											
36	**Gross Plant in Service (GPIS)**																										
37	GPIS - Beginning[2]	Preceding Year, Line 41	-	6,396	18,284	28,401	41,926	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042
38	Additions to Plant[3]		-	12,731	10,960	14,368	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Retirements[4]		-	(843)	(843)	(843)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Net Addition to Plant	Sum of Line 38 to 39	-	11,888	10,117	13,526	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	GPIS - Ending	Line 37 + Line 40	-	18,284	28,401	41,926	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042
42	2 - Addition and Retirement in 2017 (when first phase of project complete and in-service) is shown in the opening balance of 2018 (CPCN addition to plant on Jan 1 of following year)																										
43	3 - Project is to complete and placed in-service in phases on a unit-by-unit basis																										
44	4 - Retirement is to occur in phases on a unit-by-unit basis																										
45																											
46	**Accumulated Depreciation**																										
47	Accumulated Depreciation - Beginning	Preceding Year, Line 51	-	-	1,215	2,213	2,848	2,597	1,792	987	182	(623)	(1,428)	(2,233)	(3,038)	(3,843)	(4,648)	(5,452)	(9,477)	(12,697)	(15,916)	(19,136)	(22,356)	(25,575)	(28,795)	(32,015)	(33,625)
48	Depreciation Expense[5]	Line 37 @ 1.91%	-	(122)	(350)	(544)	(803)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)	(805)
49	Retirements[6]		-	843	843	843	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Cost of Removal		-	495	505	335	552	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Accumulated Depreciation - Ending	Sum of Line 47 to 50	-	1,215	2,213	2,848	2,597	1,792	987	182	(623)	(1,428)	(2,233)	(3,038)	(3,843)	(4,648)	(5,452)	(6,257)	(10,282)	(13,502)	(16,721)	(19,941)	(23,161)	(26,380)	(29,600)	(32,820)	(34,429)
52	5 - Depreciation & Amortization Expense calculation is based on opening balance x composite depreciation rate; The composite rate of all assets addition to plant is 1.91%																										
53	6 - Retirement is to occur in phases on a unit-by-unit basis																										
54																											

FortisBC Inc.
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Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2037	2041	2045	2049	2053	2057	2061	2065	2067
55	Rate Base and Earned Return																										
56	Gross Plant in Service - Beginning	Line 37	-	6,396	18,284	28,401	41,926	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042
57	Gross Plant in Service - Ending	Line 41	-	18,284	28,401	41,926	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042	42,042
58																											
59	Accumulated Depreciation - Beginning	Line 47	-	-	1,215	2,213	2,848	2,597	1,792	987	182	(623)	(1,428)	(2,233)	(3,038)	(3,843)	(4,648)	(5,452)	(9,477)	(12,697)	(15,916)	(19,136)	(22,356)	(25,575)	(28,795)	(32,015)	(33,625)
60	Accumulated Depreciation - Ending	Line 51	-	1,215	2,213	2,848	2,597	1,792	987	182	(623)	(1,428)	(2,233)	(3,038)	(3,843)	(4,648)	(5,452)	(6,257)	(10,282)	(13,502)	(16,721)	(19,941)	(23,161)	(26,380)	(29,600)	(32,820)	(34,429)
61																											
62	Net Plant in Service, Mid-Year	Sum (Lines 56 through 60)/2	-	12,947	25,056	37,694	44,706	44,236	43,431	42,626	41,821	41,016	40,211	39,407	38,602	37,797	36,992	36,187	32,162	28,943	25,723	22,503	19,284	16,064	12,844	9,625	8,015
63	Cash Working Capital	Line 41 x FBC CWC/Closing GPIS %	-	19	30	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
64	**Total Rate Base**	**Sum of Line 62 to 63**	**-**	**12,966**	**25,086**	**37,738**	**44,750**	**44,280**	**43,475**	**42,670**	**41,865**	**41,060**	**40,255**	**39,451**	**38,646**	**37,841**	**37,036**	**36,231**	**32,206**	**28,987**	**25,767**	**22,547**	**19,328**	**16,108**	**12,888**	**9,669**	**8,059**
65																											
66	Equity Return	Line 64 x ROE x Equity %	-	475	918	1,381	1,638	1,621	1,591	1,562	1,532	1,503	1,473	1,444	1,414	1,385	1,356	1,326	1,179	1,061	943	825	707	590	472	354	295
67	Debt Component	[7]	-	406	785	1,181	1,400	1,385	1,360	1,335	1,310	1,284	1,259	1,234	1,209	1,184	1,159	1,133	1,008	907	806	705	605	504	403	302	252
68	**Total Earned Return**	**Line 66 + Line 67**	**-**	**880**	**1,703**	**2,562**	**3,038**	**3,006**	**2,951**	**2,897**	**2,842**	**2,787**	**2,733**	**2,678**	**2,623**	**2,569**	**2,514**	**2,459**	**2,186**	**1,968**	**1,749**	**1,531**	**1,312**	**1,093**	**875**	**656**	**547**
69	Return on Rate Base %	Line 68 / Line 64	0.00%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
70	After- Tax Weighted Average Cost of Capital (WACC)	[8]	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%
71	7 - Line 64 x (LTD Rate x LTD% + STD Rate x STD %)																										
72	8 - ROE Rate x Equity Component + [(STD Rate x STD Portion) + (LTD Rate x LTD Portion)] x (1- Income Tax Rate)]																										
73																											
74	Income Tax Expense																										
75	Earned Return	Line 68	-	880	1,703	2,562	3,038	3,006	2,951	2,897	2,842	2,787	2,733	2,678	2,623	2,569	2,514	2,459	2,186	1,968	1,749	1,531	1,312	1,093	875	656	547
76	Deduct: Interest on debt	Line 67	-	(406)	(785)	(1,181)	(1,400)	(1,385)	(1,360)	(1,335)	(1,310)	(1,284)	(1,259)	(1,234)	(1,209)	(1,184)	(1,159)	(1,133)	(1,008)	(907)	(806)	(705)	(605)	(504)	(403)	(302)	(252)
77	Add: Depreciation Expense		-	122	350	544	803	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805	805
78	Deduct: Capital Cost Allowance	Line 90	(304)	(1,097)	(1,961)	(2,822)	(3,180)	(2,930)	(2,696)	(2,480)	(2,282)	(2,099)	(1,931)	(1,777)	(1,635)	(1,504)	(1,383)	(1,273)	(839)	(601)	(431)	(308)	(221)	(158)	(113)	(81)	(69)
79	Taxable Income After Tax	Sum of Line 75 through 78	(304)	(500)	(693)	(897)	(740)	(505)	(300)	(113)	56	209	347	472	585	686	777	858	1,145	1,265	1,317	1,322	1,291	1,236	1,163	1,078	1,031
80	Income Tax Rate		26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
81																											
82	**Total Income Tax Expense**	Line 79 / (1 - Line 80) x Line 80	**(107)**	**(176)**	**(244)**	**(315)**	**(260)**	**(177)**	**(105)**	**(40)**	**20**	**73**	**122**	**166**	**205**	**241**	**273**	**302**	**402**	**444**	**463**	**464**	**454**	**434**	**409**	**379**	**362**
83																											
84	Capital Cost Allowance																										
85	Opening Balance	Prceding Year, Line 91	-	7,286	19,037	28,038	39,696	36,626	33,696	31,000	28,520	26,239	24,140	22,208	20,432	18,797	17,293	15,910	10,486	7,512	5,382	3,855	2,762	1,979	1,417	1,015	859
86	Additions to Plant		7,238	12,731	10,960	14,368	116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	Add: Cost of Removal		495	505	335	552	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
88	Less: AFUDC		(144)	(389)	(332)	(441)	(5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
89	Net Addition for CCA	Sum of Line 86 through 88	7,589	12,848	10,963	14,479	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	**CCA (Composite CCA Rate @ 8%)**	**Line 85 + (Line 89 x 1/2)] x CCA Rate**	**(304)**	**(1,097)**	**(1,961)**	**(2,822)**	**(3,180)**	**(2,930)**	**(2,696)**	**(2,480)**	**(2,282)**	**(2,099)**	**(1,931)**	**(1,777)**	**(1,635)**	**(1,504)**	**(1,383)**	**(1,273)**	**(839)**	**(601)**	**(431)**	**(308)**	**(221)**	**(158)**	**(113)**	**(81)**	**(69)**
91	Closing Balance	Line 85 + Line 89 + Line 90	7,286	19,037	28,038	39,696	36,626	33,696	31,000	28,520	26,239	24,140	22,208	20,432	18,797	17,293	15,910	14,637	9,647	6,911	4,951	3,547	2,541	1,820	1,304	934	791
92																											

FortisBC Inc.
Upper Bonnington - Alternative 3 (Preferred) - Refurbishment
August 2016
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Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2037	2041	2045	2049	2053	2057	2061	2065	2067
1	**Cost of Service**																										
2	Power Purchase Expense		261	351	369	387	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Water Fee Adjustment		-	(28)	(50)	(50)	(50)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Operation & Maintenance	Line 23	(40)	(41)	(42)	(42)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Property Taxes	Line 23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Depreciation Expense	Line 49	-	88	226	341	509	511	511	511	511	511	511	511	511	511	511	511	511	555	603	654	710	770	836	906	983
7	Income Taxes	Line 83	(81)	(129)	(172)	(223)	(188)	(131)	(82)	(38)	2	39	72	101	128	153	174	194	246	269	287	302	314	324	334	343	363
8	Earned Return	Line 69	-	596	1,122	1,687	2,018	2,006	1,971	1,936	1,902	1,867	1,832	1,798	1,763	1,728	1,693	1,659	1,563	1,574	1,587	1,600	1,613	1,627	1,642	1,658	1,662
9	**Incremental Annual Revenue Requirement**	**Sum of Line 2 to Line 8**	**139**	**838**	**1,453**	**2,100**	**2,289**	**2,386**	**2,400**	**2,410**	**2,415**	**2,417**	**2,415**	**2,410**	**2,403**	**2,392**	**2,379**	**2,364**	**2,320**	**2,399**	**2,477**	**2,556**	**2,637**	**2,722**	**2,812**	**2,907**	**3,008**
10	PV of Revenue Requirement (After-tax WACC of 5.97%)	Line 9 / (1 + Line 71)^Yr	131	746	1,221	1,665	1,712	1,685	1,599	1,515	1,433	1,353	1,276	1,201	1,130	1,062	996	934	686	562	460	377	308	252	206	169	156
11	**Total PV of Annual Revenue Requirement**	**Sum of Line 10**	***34,038***																								
12																											
13	2016 Approved Revenue Requirement (G-202-15 Compliance Filing)		350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593	350,593
14	% Increase on 2016 Rate	Line 9 / Line 13	0.04%	0.24%	0.41%	0.60%	0.65%	0.68%	0.68%	0.69%	0.69%	0.69%	0.69%	0.69%	0.69%	0.68%	0.68%	0.67%	0.66%	0.68%	0.71%	0.73%	0.75%	0.78%	0.80%	0.83%	0.86%
15																											
16	PV of Annual 2016 Approved Revenue Requirement	Line 13 / (1 + Line 71)^Yr	330,826	312,174	294,574	277,965	262,293	247,505	233,551	220,383	207,958	196,233	185,169	174,729	164,878	155,582	146,810	138,533	103,642	82,172	65,150	51,653	40,953	32,469	25,743	20,410	18,174
17	Total PV of 2016 Approved Revenue Requirement	Sum of Line 16	5,563,561																								
18	**Levelized % Increase (51 yrs) on 2016 Rate**	**Line 11 / Line 17**	**0.61%**																								
19																											
20	**Operation & Maintenance**																										
21	Labour Costs		(40)	(41)	(42)	(42)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Non-Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Net O&M Expenses**	Line 21 + Line 22	(40)	(41)	(42)	(42)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24																											
25	**Capital Spending**																										
26	Project Capital Spending[1]		5,309	7,754	6,584	9,279	111	-	-	-	-	-	-	-	-	-	-	-	2,278	2,466	2,669	2,889	3,127	3,385	3,664	3,966	-
27	AFUDC		103	250	209	300	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Annual Capital Spending & AFUDC	Sum of Line 26 to 29	5,412	8,004	6,793	9,579	116	-	-	-	-	-	-	-	-	-	-	-	2,278	2,466	2,669	2,889	3,127	3,385	3,664	3,966	-
29	Cost of Removal		487	503	334	556	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total Annual Project Cost - Capital	Line 28 + Line 29	5,898	8,507	7,127	10,135	116	-	-	-	-	-	-	-	-	-	-	-	2,278	2,466	2,669	2,889	3,127	3,385	3,664	3,966	-
31																											
32	**Total Project Costs (incl. AFUDC)[2]**	**Sum of Line 28**	**54,346**																								
33	**Net Project Costs (incl. AFUDC and Removal)**	**Sum of Line 30**	**56,227**																								
34	1 - First year of analysis includes all prior year spending																										
35	2 - Includes a total of $24.444 million of as-spent future capital investment																										
36																											
37	**Gross Plant in Service (GPIS)**																										
38	GPIS - Beginning[3]	Preceding Year, Line 42	-	4,569	11,730	17,680	26,415	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	28,809	31,275	33,944	36,833	39,960	43,345	47,009	50,975
39	Additions to Plant[4]		-	8,004	6,793	9,579	116	-	-	-	-	-	-	-	-	-	-	-	2,278	2,466	2,669	2,889	3,127	3,385	3,664	3,966	-
40	Retirements[5]		-	(843)	(843)	(843)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Net Addition to Plant	Sum of Line 39 to 40	-	7,161	5,950	8,736	116	-	-	-	-	-	-	-	-	-	-	-	2,278	2,466	2,669	2,889	3,127	3,385	3,664	3,966	-
42	GPIS - Ending	Line 38 + Line 41	-	11,730	17,680	26,415	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	28,809	31,275	33,944	36,833	39,960	43,345	47,009	50,975	50,975
43	3 - Addition and Retirement in 2017 (when first phase of project complete and in-service) is shown in the opening balance of 2018 (CPCN addition to plant on Jan 1 of following year)																										
44	4 - Project is to complete and placed in-service in phases on a unit-by-unit basis																										
45	5 - Retirement is to occur in phases on a unit-by-unit basis																										
46																											
47	**Accumulated Depreciation**																										
48	Accumulated Depreciation - Beginning	Preceding Year, Line 52	-	-	1,242	2,362	3,198	3,245	2,734	2,222	1,711	1,199	688	177	(335)	(846)	(1,358)	(1,869)	(4,426)	(6,603)	(8,967)	(11,533)	(14,317)	(17,338)	(20,615)	(24,169)	(26,057)
49	Depreciation Expense[6]	Line 38 @ 1.93%	-	(88)	(226)	(341)	(509)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(511)	(555)	(603)	(654)	(710)	(770)	(836)	(906)	(983)
50	Retirements[7]		-	843	843	843	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Cost of Removal		-	487	503	334	556	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Accumulated Depreciation - Ending	Sum of Line 48 to 51	-	1,242	2,362	3,198	3,245	2,734	2,222	1,711	1,199	688	177	(335)	(846)	(1,358)	(1,869)	(2,381)	(4,938)	(7,159)	(9,570)	(12,187)	(15,027)	(18,108)	(21,450)	(25,075)	(27,040)
53	6 - Depreciation & Amortization Expense calculation is based on opening balance x composite depreciation rate; The composite rate of all assets addition to plant is 1.93%																										
54	7 - Retirement is to occur in phases on a unit-by-unit basis																										
55																											

FortisBC Inc.
Upper Bonnington - Alternative 3 (Preferred) - Refurbishment
August 2016
($000s), unless otherwise stated

Line	Particulars	Reference	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2037	2041	2045	2049	2053	2057	2061	2065	2067
56	**Rate Base and Earned Return**																										
57	Gross Plant in Service - Beginning	Line 38	-	4,569	11,730	17,680	26,415	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	28,809	31,275	33,944	36,833	39,960	43,345	47,009	50,975
58	Gross Plant in Service - Ending	Line 42	-	11,730	17,680	26,415	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	26,531	28,809	31,275	33,944	36,833	39,960	43,345	47,009	50,975	50,975
59																											
60	Accumulated Depreciation - Beginning	Line 48	-	-	1,242	2,362	3,198	3,245	2,734	2,222	1,711	1,199	688	177	(335)	(846)	(1,358)	(1,869)	(4,426)	(6,603)	(8,967)	(11,533)	(14,317)	(17,338)	(20,615)	(24,169)	(26,057)
61	Accumulated Depreciation - Ending	Line 52	-	1,242	2,362	3,198	3,245	2,734	2,222	1,711	1,199	688	177	(335)	(846)	(1,358)	(1,869)	(2,381)	(4,938)	(7,159)	(9,570)	(12,187)	(15,027)	(18,108)	(21,450)	(25,075)	(27,040)
62																											
63	Net Plant in Service, Mid-Year	Sum (Lines 57 through 61)/2	-	8,770	16,506	24,827	29,694	29,520	29,009	28,497	27,986	27,475	26,963	26,452	25,940	25,429	24,918	24,406	22,988	23,161	23,340	23,528	23,724	23,929	24,144	24,370	24,426
64	Cash Working Capital	Line 42 x FBC CWC/Closing GPIS %	-	12	19	28	28	28	28	28	28	28	28	28	28	28	28	28	30	33	36	39	42	45	49	53	53
65	**Total Rate Base**	**Sum of Line 63 to 64**	**-**	**8,782**	**16,525**	**24,855**	**29,722**	**29,548**	**29,037**	**28,525**	**28,014**	**27,502**	**26,991**	**26,480**	**25,968**	**25,457**	**24,945**	**24,434**	**23,018**	**23,193**	**23,376**	**23,567**	**23,766**	**23,975**	**24,193**	**24,423**	**24,479**
66																											
67	Equity Return	Line 65 x ROE x Equity %	-	321	605	910	1,088	1,081	1,063	1,044	1,025	1,007	988	969	950	932	913	894	842	849	856	863	870	877	885	894	896
68	Debt Component	[8]	-	275	517	778	930	924	908	892	876	860	844	828	812	796	780	764	720	726	731	737	743	750	757	764	766
69	**Total Earned Return**	**Line 67 + Line 68**	**-**	**596**	**1,122**	**1,687**	**2,018**	**2,006**	**1,971**	**1,936**	**1,902**	**1,867**	**1,832**	**1,798**	**1,763**	**1,728**	**1,693**	**1,659**	**1,563**	**1,574**	**1,587**	**1,600**	**1,613**	**1,627**	**1,642**	**1,658**	**1,662**
70	Return on Rate Base %	Line 69 / Line 65	0.00%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%	6.79%
71	After- Tax Weighted Average Cost of Capital (WACC)	[9]	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%	5.97%
72	8 - Line 65 x (LTD Rate x LTD% + STD Rate x STD %)																										
73	9 - ROE Rate x Equity Component + [(STD Rate x STD Portion) + (LTD Rate x LTD Portion)] x (1- Income Tax Rate)]																										
74																											
75	**Income Tax Expense**																										
76	Earned Return	Line 69	-	596	1,122	1,687	2,018	2,006	1,971	1,936	1,902	1,867	1,832	1,798	1,763	1,728	1,693	1,659	1,563	1,574	1,587	1,600	1,613	1,627	1,642	1,658	1,662
77	Deduct: Interest on debt	Line 68	-	(275)	(517)	(778)	(930)	(924)	(908)	(892)	(876)	(860)	(844)	(828)	(812)	(796)	(780)	(764)	(720)	(726)	(731)	(737)	(743)	(750)	(757)	(764)	(766)
78	Add: Depreciation Expense		-	88	226	341	509	511	511	511	511	511	511	511	511	511	511	511	511	555	603	654	710	770	836	906	983
79	Deduct: Capital Cost Allowance	Line 91	(232)	(775)	(1,320)	(1,885)	(2,132)	(1,966)	(1,808)	(1,664)	(1,531)	(1,408)	(1,296)	(1,192)	(1,097)	(1,009)	(928)	(854)	(654)	(638)	(641)	(658)	(686)	(724)	(771)	(825)	(844)
80	Taxable Income After Tax	Sum of Line 76 through 79	(232)	(366)	(489)	(634)	(535)	(373)	(234)	(108)	6	110	204	289	365	434	496	552	700	766	818	859	894	923	950	975	1,034
81	Income Tax Rate		26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%	26.00%
82																											
83	**Total Income Tax Expense**	Line 80 / (1 - Line 81) x Line 81	**(81)**	**(129)**	**(172)**	**(223)**	**(188)**	**(131)**	**(82)**	**(38)**	**2**	**39**	**72**	**101**	**128**	**153**	**174**	**194**	**246**	**269**	**287**	**302**	**314**	**324**	**334**	**343**	**363**
84																											
85	**Capital Cost Allowance**																										
86	Opening Balance	Prceding Year, Line 92	-	5,564	13,045	18,642	26,593	24,571	22,606	20,797	19,133	17,603	16,195	14,899	13,707	12,611	11,602	10,674	7,035	6,742	6,674	6,776	7,014	7,362	7,805	8,330	10,553
87	Additions to Plant		5,412	8,004	6,793	9,579	116	-	-	-	-	-	-	-	-	-	-	-	2,278	2,466	2,669	2,889	3,127	3,385	3,664	3,966	-
88	Add: Cost of Removal		487	503	334	556	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
89	Less: AFUDC		(103)	(250)	(209)	(300)	(5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Net Addition for CCA	Sum of Line 87 through 89	5,795	8,257	6,917	9,835	111	-	-	-	-	-	-	-	-	-	-	-	2,278	2,466	2,669	2,889	3,127	3,385	3,664	3,966	-
91	**CCA (Composite CCA Rate @ 8%)**	**Line 86 + (Line 90 x 1/2)] x CCA Rate**	**(232)**	**(775)**	**(1,320)**	**(1,885)**	**(2,132)**	**(1,966)**	**(1,808)**	**(1,664)**	**(1,531)**	**(1,408)**	**(1,296)**	**(1,192)**	**(1,097)**	**(1,009)**	**(928)**	**(854)**	**(654)**	**(638)**	**(641)**	**(658)**	**(686)**	**(724)**	**(771)**	**(825)**	**(844)**
92	Closing Balance	Line 86 + Line 90 + Line 91	5,564	13,045	18,642	26,593	24,571	22,606	20,797	19,133	17,603	16,195	14,899	13,707	12,611	11,602	10,674	9,820	8,659	8,570	8,702	9,007	9,455	10,023	10,698	11,471	9,709
93																											

Appendix E

DRAFT ORDER

British Columbia Utilities Commission

Sixth floor, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
TEL: (604) 660-4700
BC Toll Free: 1-800-663-1385
FAX: (604) 660-1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review of 2017 Rates

BEFORE:
N.E. MacMurchy, Panel Chair/Commissioner
W.M. Everett, Commissioner
M. Kresivo, 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. On July 15, 2016, FBC filed a proposed regulatory timetable for the filing and review of the annual review materials in advance of filing its Annual Review of 2017 Rates materials;

C. On July 28, 2016, the regulatory timetable for the FBC Annual Review of 2017 Rates proceeding was established by Order G-123-16 and included, among other things, an anticipated date of August 10, 2016 by which FBC would file its 2017 Annual Review materials;

D. On August 8, 2016, FBC submitted its Annual Review for 2017 Rates materials (Application);

E. On October 12, 2016, a workshop was held in Vancouver, BC and on October 26, 2016, FBC filed its responses to undertakings from the workshop;

F. The Commission has reviewed the Application and evidence filed in the proceeding and makes the following determinations.

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

1. Pursuant to sections 59-61 of the *Utilities Commission Act*, the Commission approves the following:

   a. Effective January 1, 2017, a permanent rate increase of 3.60 per cent for all FBC customers, as compared to FBC's 2016 rates, with the increase being applied to all components of rates for all customer classes.

…/2

b. The establishment of five non-rate base deferral accounts financed at FBC's short term interest rate for the following regulatory proceedings, as described in Section 12.4.1 of the Application:

  i. The Self-Generation Policy Stage II Application;

  ii. The Net Metering Program Tariff Update Application;

  iii. The BCUC Residential Inclining Block Report;

  iv. The 2017 Demand Side Management Expenditure Schedule; and

  v. The Transmission Tariff Review.

c. The amortization of the Celgar Interim Period Billing Adjustment deferral account in 2017 as described in Section 12.4.2 of the Application;

d. Z-factor treatment of $1.350 million for the incremental O&M and capital expenditures related to the Mandatory Reliability Standards (MRS) Assessment Report No. 8, as described in Section 12.2.2 of the Application.

2. Pursuant to section 44.2 of the *Utilities Commission Act,* the Commission accepts the capital expenditure schedule consisting of the capital expenditures for:

   a. The Ruckles Substation Rebuild project, as described in Appendix C; and

   b. The Upper Bonnington Old Units Refurbishment project, as described in Appendix D.

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