Yukon Utilities Board

Board Order 2017-01
Appendix A: Reasons for Decision
April 27, 2017

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1 Introduction

1. On May 11, 2016, pursuant to the *Public Utilities Act* and Order-in-Council 1995/90, the Yukon Electrical Company Limited (YECL or Applicant),[1] carrying on business as ATCO Electric Yukon (AEY), filed an application with the Yukon Utilities Board (Board) requesting an order approving forecast revenue requirements for the years 2016 and 2017 (test period) (Application). AEY is seeking approval of a revenue requirement of $53,890,000 for 2016 and $56,173,000 for 2017. The applied-for revenue requirement represents cumulative rate increases of 4.4 percent for 2016 and 7.5 percent for 2017, and year-over-year rate increases of 4.4 percent and 3.1 percent respectively.

2. Additionally, AEY sought approval of:
- an interim refundable rate rider of 11.62 percent, effective July 1, 2016;
- the continued use of currently approved deferral accounts, including purchase power flow-through, fuel price flow-through, and defined benefit pension costs during the test period; and
- new deferral accounts related to liquefied natural gas (LNG) fuel price changes, statutory tax rate changes, feasibility studies, and costs arising from Board Orders or legislative provisions not currently contemplated.

3. AEY is a private investor-owned utility serving more than 17,000 customers in 19 communities in the Yukon. AEY purchases power from Yukon Energy Corporation (YEC) for distribution to customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Canyon Creek and a variety of rural areas surrounding Whitehorse. The company maintains backup generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing in the event of a power interruption. AEY also owns and operates the Fish Lake Hydro plant which generates power, and generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Watson Lake and Swift River.

4. On May 27, 2016, the Board issued Board Order 2016-01, in which the Board ordered AEY to publish a Notice of Application and Hearing for the General Rate Application (GRA) no later than June 3, 2016 in appropriate local news publications in AEY's service area to provide adequate notice to the public. AEY was also directed to make the Application and supporting materials available on its website: www.atcoelectricyukon.com, as well as in hardcopy upon request to AEY. Board Order 2016-01 set out a process schedule, pending ministerial approval, for the Application, with a hearing to commence on November 1, 2016.

5. On June 17, 2016, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to section 50 of the *Public Utilities Act*.

[1] Yukon Electrical Company Limited is the legal entity, and ATCO Electric Yukon is the brand name that is now used for the company's utility service operations in Yukon.

6. The Board, through Board Order 2016-02, issued June 24, 2016, granted intervener status for this proceeding to the following:

- City of Whitehorse (CW)
- John Maissan (JM)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Yukon Energy Corporation (YEC)

7. In Board Order 2016-02, the Board also approved a 9.41 percent interim, refundable rate adjustment rider, effective July 1, 2016. Subsequently, in Board Order 2016-02 Errata, the Board changed the interim rate adjustment rider to 11.62 percent, in order to account for a calculation error.

8. In its intervener registration letter, dated June 17, 2016, and subsequently, UCG indicated that it had contacted the Pacific Economics Group (PEG) to help UCG determine if it was possible to benchmark the costs and productivity of AEY. UCG requested that the Board issue a letter to PEG so it can be assured that it would have an opportunity to access recovery of its costs through the cost claims process set by the Board. UCG also indicated that the process schedule would need to be altered to allow for a series of interrogatories to determine if benchmarking was possible.

9. On June 21, 2016, the Board set out a process to address UCG's request. Submissions were received from AEY and UCG. On July 4, 2016, after consideration of the UCG request and parties' submissions, the Board, in Board Order 2016-03, denied the UCG request for a letter of comfort to PEG. No revision to the process schedule was required.

10. On August 12, 2016, UCG submitted a motion requesting that the Board issue an order requiring AEY to provide adequate responses to certain UCG Information Requests (IRs). The Board invited comments from AEY on the UCG motion and reply comments from UCG. In Board Order 2016-04, issued on September 2, 2016, the Board ruled on the UCG motion and directed AEY to provide further and better information responses by September 9, 2016. In that Board Order, the Board amended the process schedule to allow UCG to file its evidence after the receipt of the additional information responses.

11. The Board held an oral public hearing in Whitehorse, Yukon from November 1 to 3, 2016. The Board was comprised of Robert Laking, Chair, and members Andre Fortin, Meagan Hannam, Bonnie King and Phillip Fitzgerald.

12. At the hearing, the Board confirmed that Final Argument was due on November 24, 2016 and Reply Argument on December 15, 2016. The Board considers the record of the proceeding closed on December 15, 2016.

13. In reaching the determinations contained within this Board Order, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each party. Accordingly, references in this Board Order to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be

taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 AEY Sales and Revenue

2.1 Overview

14. AEY stated that its sales and revenue forecast was based on a detailed analysis of historical sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. This data consists of information gathered by AEY staff who work in the communities as well as information resulting from consultation with the City of Whitehorse, Yukon government officials and various local agencies and developers.

15. The following table summarizes AEY's energy sales forecast for 2016 and 2017 by customer class, along with the corresponding actuals for 2013 to 2014, and 2015:

Table 1. **AEY energy sales by customer class – 2013 to 2017 (MWh)**

Customer class	Actuals			Forecasts (Test Period)	
	2013	2014	2015	2016	2017
Residential	148,780	147,253	148,605	147,111	151,617
Commercial	159,322	154,709	155,346	152,187	153,336
Street Lights	3,719	3,765	3,886	3,944	4,008
Private Lights	551	544	519	492	472
Total Retail Primary	313,372	306,272	308,356	303,735	309,433
Secondary Sales	3,959	5,415	7,030	9,429	9,429
Wholesale Sales	356	495	430	427	427
Total	316,687	312,182	315,816	313,592	319,289

Source: Application, Table 1, page 2-1.

16. Due to the changes in the energy sales by customer class, AEY's total primary non-industrial sales are forecast to decrease by 1.5 percent in 2016, and increase by 1.9 percent in 2017.

17. AEY provided an update to its test-period sales forecast to include nine months of actuals to September 30, 2016, as shown in the following table:

Table 2. **AEY updated test period sales forecast by customer class (MWh)**

Customer Class	Forecasts (Test Period)	
	2016	2017
Residential	146,698	153,275
Commercial	153,635	154,639
Street lights	3,922	3,978
Private lights	496	480
Total retail primary	304,751	312,373

Secondary sales	9,429	9,429
Wholesale sales	427	427
Total	314,607*	322,229

Source: Exhibit B-20, AEY undertaking; *Corrected for addition.

2.2 Views of the Applicant

18. In 2015, AEY provided electricity services to approximately 17,600 non-lighting customers in its service area and supplied a total of 308.4 GWh to residential, commercial and lighting customers. This represents an increase in total primary sales of 0.7 percent from 2014 levels. This increase follows decreases of 2.0 and 0.6 percent respectively in 2014 and 2013, from prior year levels.

19. After experiencing strong growth in the Yukon from 2004 to 2012, AEY submitted that the pace of economic activity in the Yukon has slowed down significantly. Slower population growth has also contributed to minimal customer gains in the residential and commercial sectors of AEY. It expected that the overall impact of the economic and population growth slowdown to continue to impact AEY's customer growth and sales over the test period.

20. AEY added that its demand-side management (DSM) program and the Yukon government's energy initiatives, such as those related to the commercial energy incentive program and micro-generation, which were introduced in the Yukon over the last few years, have also contributed to lower electricity sales experienced in the period from 2013 to 2015.

21. AEY reviewed its two-step approach for determining weather-normalized use per customer (UPC), where:

> In the first step, the historical average monthly UPC is regressed on actual monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in the first step is multiplied by the difference between the actual HDD and the "Normal" HDD.[2]

22. In its Application, AEY proposed to update the timeframes used to determine the weather-normalized UPC. The existing methodology uses a longer time period and the proposed methodology uses the last three years of data, as illustrated in the table below:

Table 3. **Comparison of weather-normalized UPC methodologies**

	Regression data for UPC (Step 1)	**"Normal" HDD (Step 2)**
Prior Methodology	15 years	20-year average
Current Methodology	3 years	3-year average

Source: Application, page 2-5.

[2] Exhibit BB-1, Application, page 2-5, lines 3-7.

23. In the proposed methodology, AEY would apply the growth rates experienced over the period from 2013 to 2015 to derive the forecast UPC for the test period.

24. In support of its proposal, AEY stated:

> … over the past few years, in addition to changes in electric heating, there has been an increase in energy efficiency programs in the Yukon such as Demand Side Management and the Commercial Energy Incentive program. These trends, combined with a decline in economic activity and increasing effects of global warming have contributed to an overall downward trend in UPC over the 2013-2015 time period.[3]

25. AEY submitted that using the 2013 to 2015 timeframe for weather-normalizing and forecasting the UPC was more appropriate, as it encompasses trends occurring in the Yukon over the last few years.

2.2.1 Residential sales forecast

26. Respecting its residential sales forecast, AEY stated that the forecast has two key inputs: net customer additions and the UPC. The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast.

27. AEY submitted that the residential average UPC for all communities (except for Keno City, Stewart Crossing and Swift River) is calculated by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC. For Keno City, Stewart Crossing and Swift River, AEY used the actual UPC of the previous year as a base[4] and applied the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC for these communities was "used because there are very few customers in these communities and there is poor correlation between their average UPC and temperature."[5] The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.2.2 Commercial sales forecast

28. Similar to the residential sales forecast, the commercial sales forecast has two key inputs: net customer additions and the forecast UPC. The energy sales forecast is determined by multiplying the forecast number of customers (based on the net customer additions forecast) by the UPC forecast.

29. AEY stated that Whitehorse's commercial UPC for the test period is forecast using the weather-normalized UPC of the previous year and applying the 2013 to 2015 growth in weather-normalized UPC. AEY added that it expects three new large commercial customers to be added during the test period in Whitehorse. AEY added:

[3] Exhibit BB-1, Application, page 2-5, lines 14-19.
[4] Exhibit B-9, YUB-YECL-7 (a): "For the purpose of forecasting the 2016 UPC, 2015 is considered to be the previous year. For the purpose of forecasting the 2017 UPC, 2016 is considered to be the previous year."
[5] Exhibit BB-1, Application, page 2-6, lines 11-12.

> ATCO Electric Yukon has considered these new large customers individually, and has forecast the load each customer will bring to the system each year based on the start-up time and other pertinent information provided by the customer. The commercial energy sales for Whitehorse are then calculated by adding the specific energy sales of the new large commercial additions to each of the test years.[6]

30. With the exception of Whitehorse, AEY submitted that the commercial UPC forecast for all communities is determined by using the actual UPC of the previous year, and applying the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC is used because there are fewer commercial customers in these communities or there is poor correlation between their average UPC and temperature. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

31. In response to UCG, AEY reiterated that three main factors have contributed to the declining trend in residential and commercial UPC, and these factors support the updated forecast methodology. These are:

(a) the economic slowdown in the Yukon;

(b) a continuous warming trend, starting in 2013; and

(c) recent energy conservation initiatives, which have been implemented in the Yukon.

32. AEY added that the proposed change from 15 years to three years to run its regression model for UPC and HDDs results in a more accurate portrayal of the current context in which AEY operates, and is necessary in order to appropriately account for the factors that have led to the change in UPC behaviour since 2012.[7]

33. During the oral hearing, AEY updated its sales forecasts to incorporate nine months of actuals, as of September 2016. The updated sales forecast provided in a table in response to the undertaking showed energy sales to be with 0.3 percent of actuals.[8]

2.2.3 Views of interveners

34. Mr. Maissan noted that residential and commercial sales are expected to decrease slightly in 2016 and then increase modestly in 2017. Mr. Maissan further noted the secondary sales were forecast to increase by 2.4 GWH in the test years. Mr. Maissan recommended that the Board accept AEY's sales forecast as filed.

35. UCG pointed out that AEY has consistently realized sales that were below the approved amounts. UCG submitted that this is in part due to AEY's forecasting methodology, as well as under-estimating the impact of weather, the economy and DSM initiatives. Given the downturn in the Yukon economy and the uncertainty created by a new territorial government, UCG submitted that AEY had erred in simply applying the

[6] Exhibit BB-1, Application, page 2-6 (lines 26 to 27) to page 2-7 (lines 1 to 3)
[7] YECL Final Argument, paragraph 24.
[8] Transcript, Volume 2, November 2, 2016, page 347, lines 1 to 4.

sales growth rates experienced over the 2013-2015 period to derive the weather-normalized UPC for the test period.[9]

36. UCG submitted that AEY should be directed to update its most recent sales forecast provided in its undertaking found at Exhibit B-2 with actuals from 2016 and 2017. This update should be provided when AEY submits its compliance filing and should use the most recent actuals and forecast to determine revenue requirements.

2.2.4 Views of the Board

37. The Board notes that AEY argued that the major reason for the shift in timeframe from 15 years to three years regarding its running of the regression model for UPC and HDDs was due to the shift and the change in direction respecting UPC starting in 2012.[10] AEY has affirmed the contributing factors as being the downturn in the economy and conservation initiatives.[11]

38. The Board finds that recent trends in the Yukon underpin AEY's proposed change in its methodology but the Board has concerns that a recent trend may or may not be reflective of future forecasts required in a test period. The Board considers it important that a methodology be adopted that is representative of energy sales and reflective of UPC and HDD in future years. The Board has concerns that if, for example, there is economic growth prior to the next GRA, a further adjustment to the methodology will be required due to a short time period being used to forecast energy sales.

39. With respect to its updated sales forecast, AEY's original forecast was within 0.3 percent compared to actuals for the 2016 test year. However, the Board notes that there is a one-percent variance in total retail primary sales for 2017 when the updated forecast is compared to the original forecast.

40. The Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016."[12] Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data.[13] Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast,

[9] UCG Final Argument, paragraph 76.
[10] Transcript, Volume 2, November 2, 2016, page 341 (line 24) to page 342 (line 2).
[11] Transcript, Volume 2, November 2, 2016, page 342, lines 4 to 22.
[12] AEY Final Argument, paragraph 26.
[13] Transcript, Volume 2, November 2, 2016, page 343, lines 17 to 20.

incorporating its prior methodology[14] using a 10-year timeframe for UPC regression and normalizing HDD.

3 Purchase power

41. AEY submitted that its primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The following table shows the actual and forecast purchase power over the period from 2013 to 2017:

Table 4. **Actual and forecast purchase power – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	**2014**	**2015**	**2016**	**2017**
Primary Purchase Power	25,552	24,503	24,725	24,451	24,921
Secondary Purchase Power	292	415	454	415	415
Less: Capitalized[15]	(402)	-	(72)	(110)	(86)
Total Purchase Power[16]	25,442	24,918	25,107	24,756	25,250

Source: Exhibit BB-1, Application, page 3-1.

42. The purchase deferral account is related to increases or decreases to the cost of purchased power, which is based on YEC's rates for primary energy sales and secondary sales.

43. AEY submitted that the test period purchase power forecast takes into account the Fish Lake hydro generation output, which is based on the lifetime average output for Fish Lake Unit #2 from 1960-2015 plus the two-year average for the new Fish Lake Unit #1 adjusted for planned decreases in generation due to capital builds.[17] The drivers of the forecasts for 2016 and 2017 were stated as:

> The 2016 and 2017 capital that are causing short term reductions in generation are the replacement of Ditch 1 due to the spillway failure and the Fish Lake Ditch 3 Diversion Replacement in 2016. In 2017, water flows will be reduced for the Fish Lake #2 Head Pond Spillway Replacement and the Fish Lake Unit 1 Spillway Diversion Structure.[18]

44. Furthermore, consistent with the approach approved in Board Order 2014-06, AEY submitted that lines losses are calculated on a five-year average and total 6.2 percent.[19]

[14] The methodology used in its 2013-2015 GRA.
[15] Exhibit BB-1, Application, page 3-1, footnote 1: "Consistent with Board Order 2009-2, AEY will continue to capitalize the incremental purchased power costs for decreased hydro supply resulting from capital builds and rebuilds."
[16] Rider J has not been included, as these are flow-through amounts to YEC.
[17] Exhibit BB-1, Application, page 3-1 (lines 17-18) to 3-2 (lines 1-2).
[18] Exhibit B-9, YUB-YECL-9(a).
[19] AEY Final Argument, paragraph 31.

3.1 Views of interveners

45. UCG submitted that the incremental purchased power costs to be capitalized should only relate to planned capital projects and not maintenance or other projects that were not included in the capital budget reviewed by the Board.[20]

3.2 Applicant responses to interveners

46. In response to UCG's submission, AEY stated that its understanding of Board Order 2009-02 is consistent with UCG's on this matter.

3.3 Views of the Board

47. The Board's determination in Board Order 2009-02 respecting the capitalization of purchase power costs required because of the Fish Lake hydro was based on "YECL's Fish Lake generation forecasts as well as the expensing of purchase power costs associated with Fish Lake hydro rebuilds."[21] The Board directed AEY, at the time of its next GRA, to provide clear documentation of these incremental power purchases due to the Fish Lake hydro rebuilds.

48. In the current Application, AEY has capitalized the forecast purchased power costs related to the Fish Lake hydro rebuilds for 2016 and 2017. In the Board's view, this is consistent with directions provided in Board Order 2009-02:

> The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized. Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time. *(footnotes omitted)*[22]

49. The Board approves the forecast primary and secondary purchase power costs as filed because the methodology used is reasonable and consistent with the previous GRA.

3.4 Deferral Account — Purchase Power Flow-Through

50. AEY requested a Purchase Power Flow-Through Deferral Account (PPFTDA). AEY noted that the cost of purchase power in the Application is based on rates from YEC for primary energy and secondary sales and do not include any adjustments due to YEC's energy reconciliation adjustment (ERA). Any increases or decreases to the YEC rates or any ERA adjustments are to be flowed through to customers.

3.4.1 Views of interveners

51. UCG acknowledged that a deferral account is a reasonable way to track unforeseen changes in costs related to purchased power. However, UCG submitted that

[20] UCG Final Argument, paragraph 89.
[21] Board Order 2009-02, Appendix A, Reasons for Decision, page 9.
[22] Board Order 2009-02, Appendix A , Reasons for Decision, page 10

AEY must ensure that it limits as much as possible the charges from YEC by actively participating in reviews of YEC revenue requirements and implementing DSM initiatives that reduce the need for purchased power.[23]

3.4.2 Applicant responses to interveners

52. AEY responded to the UCG submission that AEY has participated in YEC regulatory applications that impact both AEY's customers and its share-owners and will continue to do so. AEY also submitted that it expects to continue working collaboratively with YEC on initiatives that impact Yukon electricity customers.[24]

3.4.3 Views of the Board

53. The Board notes AEY's responses to IRs on the PPFTDA. More specifically, the Board takes note of the response to YUB-YECL-47(b), in which AEY stated:

> … under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate... AEY submits that a PPFTDA is much more efficient than speculating on potential changes in its Wholesale costs resulting from changes to the Wholesale rate.[25]

54. Further, AEY stated that this account will ensure that there is an additional margin[26] if sales are greater than forecast.[27] Parties were asked to comment on that additional margin in argument[28], but no comments were received.

55. The Board accepts the submissions of AEY that the PPFTDA will provide additional margin on sales that are incremental to forecast levels and that the use of a PPFTDA is more efficient. The Board considers the PPFTDA to be a more efficient mechanism for adjusting potential changes in wholesale costs, especially since there are material timing differences between YEC and AEY GRA filings. Therefore, the Board approves the requested AEY PPFTDA, without changes.

4 Fuel costs

56. Fuel costs included in the AEY Application are reproduced in Table 5 below:

[23] UCG Final Argument, paragraph 88.
[24] AEY Reply Argument, paragraph 27.
[25] Exhibit B-9, YUB-YECL-47(b).
[26] By allowing the PPFTDA, a positive margin is maintained on incremental sales as incremental costs are covered through the deferral account.
[27] Transcript Vol. 3, page 520, lines 19-23.
[28] Transcript Vol 3., page 518, lines13-19.

Table 5. **Actual and forecast fuel costs — 2013 to 2015 ($000s)**

	Actuals			Forecasts (Test Period)	
	2013	**2014**	**2015**	**2016**	**2017**
Fuel Costs	6,708	6,760	6,621	5,225	5,268

Source: Exhibit BB-1, Application, page 4-1.

57. AEY explained that it purchases fuel on an ongoing basis for each of its five isolated plants via a diesel fuel tendering process, where a vendor is selected to be the provider of diesel fuel to AEY. AEY further explained that it has modest generation and fuel requirements associated with standby units that generate power in the event of an interruption of power on the Yukon interconnected system. The standby units are located at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

58. AEY stated that the forecast cost decrease in 2016 is mainly due to lower fuel prices than previously approved, which are currently used as the base fuel prices in Rider F. AEY added that the fuel costs forecast is a function of forecast sales, line losses, plant efficiencies and delivered prices. The fuel-deferral methodology used for this account was described, as follows:

> The previously approved methodology for the fuel deferral uses GRA-approved community-based plant efficiencies (or 'heat rate', kWh / Litre) and the plant's monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and GRA-approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.[29]

59. AEY submitted that the variance between actual and forecast fuel prices is refunded to or recovered from customers by means of Rider F, a fuel-price flow-through rider.

4.1 Views of the Board

60. The Board accepts and approves AEY's fuel cost forecast, as filed. AEY is proposing to continue the deferral for fuel prices for the test period.

4.2 Deferral Account — LNG Fuel

61. Notwithstanding the above, if the Watson Lake bi-fuel project is approved, AEY anticipated that, beginning in the fall of 2017, generation will be based on a variable fuel mix of diesel and LNG. Accordingly, AEY submitted that it required a deferral account to track and subsequently refund or recover changes in costs due to the differential in actual LNG fuel prices and the price included in rates. AEY explained that:

> Similarly to the Diesel Fuel Deferral Account, the LNG Fuel Deferral Account will use the GRA-approved community-based plant efficiencies and the plant's monthly gross generation to determine the volume of litres of diesel equivalent

[29] Exhibit BB-1, Application, page 4-2, lines 20-24.

> for the monthly fuel deferral calculation. Actual diesel volumes used for the diesel fuel deferral account calculation will be subtracted from this volume, with remaining allowable litres of diesel equivalent for use in the calculation of the LNG fuel deferral. [30]

62. AEY went on to explain that the difference between the actual and GRA-approved price per litre of diesel equivalent is then multiplied by the remaining allowable litres of diesel equivalent to arrive at the LNG fuel-deferral amount for the month.

63. AEY proposed to include the LNG price variances in the Rider F deferral account, stating that the principles supporting a diesel price variance deferral are the same as those supporting an LNG price variance deferral or a fuel price variance deferral, namely:

- Commodity prices are subject to material fluctuations outside the utilities' control; and
- It is not in ratepayers', the Board's, or the utilities' interests to speculate on these price fluctuations. [31]

64. AEY argued that it is well within the Board's authority to approve deferral accounts in general. Furthermore, should the Board determine that the wording of the Order in Council does not allow for the inclusion of LNG price variances in the existing Rider F, AEY submitted that a new deferral account and subsequent rider should be approved. Such a rider should operate in the same manner as Rider F.[32]

4.3 Views of interveners

65. UCG noted that Rider F was last approved in Board Order 2012-02, dated February 29, 2012. Noting that the Board, in Board Order 2011-15, confirmed that Rider F applies to all diesel fuel consumed in a period, UCG submitted that it is unclear whether AEY has applied to the Board for the inclusion of LNG price variances in Rider F.

66. Given that AEY is not using LNG at this time and only anticipates using LNG-fuelled generators late in 2017, at the earliest, UCG submitted that the Board should not allow AEY to establish a LNG-related deferral account until a need is established and an application has been made to change Rider F.

67. UCG further submitted that the Board cannot approve the proposed changes to Rider F for fuel used in Watson Lake without changes to section 8 of Order-in-Council 1995/90 to account for LNG use.

4.4 Applicant responses to interveners

68. AEY responded that section 8 of Order-in-Council 1995/90 provides for fuel-price adjustments and sets out that the Board must allow AEY and YEC to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to

[30] Exhibit BB-1, Application, page 4-3, lines 7-12.
[31] Exhibit B-6, UCG-AEY-22
[32] Exhibit B-6, UCG-AEY-22

reflect fluctuations in the price for diesel fuel, without the requirement for specific application to and approval from the Board. However, simply because AEY is entitled to flow-through diesel fuel prices without Board approval, it does not mean that it is somehow prevented, upon Board approval, from flowing through the impact of changes to LNG prices.

4.5 Views of the Board

69. Considering the Board's determination in section 9.7.2 of this decision with respect to the Watson Lake bi-fuel project, the Board does not approve the LNG deferral account.

5 Operations and maintenance (O&M) expense

70. For 2016 and 2017, AEY requested approval of O&M expenses, totalling $11.993 million and $12.181 million respectively. The following table shows forecast and actual amounts for the period 2013-2015, and the forecast for the test years:

Table 6. **Operations and maintenance expense ($000)**

2013		2014		2015		2016	2017
Approved	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Forecast**	**Forecast**
11,604	11,718	11,882	11,698	11,944	11,616	11,993	12,181

Source: Exhibit BB-1, Application, Schedule 5.1

5.1 Labour

71. In the Application, AEY forecasted a complement of 70.38 full-time equivalents (FTEs) for each of the test years. This was an increase of 1.25 FTEs over the actual complement at the end of 2015.

72. AEY discussed labour costs in section 5 of the Application and stated that labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. The labour costs are then distributed to O&M accounts or capital accounts, depending on the nature of work being performed by the staff in the job class. Further, in section 1 of the Application, under the heading "Key Assumptions", AEY provided the following:

Table 7. **Key Assumptions**

	2016	2017
Labour inflation	3.25%	3.00%
Other inflation	2.20%	2.20%
Vacancy rate	4.00%	4.00%
Long-term debt rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 1-5.

5.1.1 Labour complement

73. AEY proposes a labour complement of 70.38 FTEs for each of the test years.

5.1.2 Views of interveners

74. Interveners did not provide any direct comments with regard to AEY's labour complement levels.

5.1.3 Views of the Board

75. Staff complement is one of the elements reviewed by the Board in relation to labour costs and the Board is concerned with the escalation of labour costs and the growth of Administration and General (A&G) costs. In this Application, AEY has requested an increase in its complement by two positions (an Engineering Technologist (1 FTE) and a Supervisor, Business Support Services (0.25 FTE)).

76. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change[33] in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY.[34] This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY.[35] Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement.

77. As of the close of record, the Engineering Technologist position has yet to be filled. AEY did not provide any evidence that the work forecast for the Engineering Technologist position was not already being done by any of the other two existing engineering technologist positions or other members of the two engineering groups.

78. In Board Order 2014-16, AEY was directed to remove the corporate accountant position (1 FTE). It did not do so and did not request a review and variance of that direction.[36] To continue the position or rename the position as an Operational Accountant ignores the direction and concerns of the Board.

79. Therefore, AEY's requested approval for a complement of 70.38 FTEs for both test years is not approved. The Board approves a complement of 68.13 FTEs. The

[33] Referring to the change from reporting to the Manager (Whitehorse-based) to the Business Support Services Supervisor (Yellowknife-based).
[34] Transcript Vol 2, page 365, lines 1-13.
[35] Exhibit B-9, YUB-YECL-34(a).
[36] Transcript Volume 2, page 372, lines 1-17.

complement level of 68.13 FTEs is determined by removing the Engineering Technologist position (1 FTE), the Supervisor, Business Support Services position (0.25 FTE), and the Corporate/Operational Accountant position (1 FTE) as directed in the 2013-2015 GRA. AEY is to reflect this finding in its compliance filing to this decision.

5.2 Vacancy rate

80. As noted above, AEY has forecasted a vacancy rate for each of the test years of 4.0 percent, or approximately three FTEs. AEY said that the vacancy rate is based on a five-year historical average and is consistent with the methodology approved in Board Orders 2009-02 and 2014-06.

5.2.1 Views of interveners

81. Interveners did not comment on AEY's proposed vacancy rates.

5.2.2 Views of the Board

82. The Board has reviewed the submissions of AEY on its vacancy rate in this proceeding. The Board finds the vacancy rate requested is reasonable because it is based on a five-year historical average and is consistent with the methodology approved in Board Order 2009-02 and applied in Board Order 2014-06.[37] For these reasons, the Board approves a vacancy rate for AEY of 4.0 percent for each of the test years.

5.3 Labour inflation

83. AEY stated that the labour escalation for 2016 was based on AEY's existing collective agreement which covers in-scope employees and AEY applied the escalators in that agreement to both in-scope and out-of-scope employees.

84. AEY reiterated its submission from the Application (section 5) that its inflationary increases were consistent with several decisions in Alberta.[38] It added that AEY was appropriately staffed and did not undergo the growth incurred by ATCO Electric prior to the economic downturn in Alberta; therefore, it was not impacted by the economic downturn in Alberta or the ATCO Group reorganization.[39]

5.3.1 Views of interveners

85. In argument, interveners did not make any specific comments on labour inflation. However, in Reply Argument, UCG stated "… it is inconsistent to have labour inflation rates from another jurisdiction dictate what Yukoner ratepayers should pay when Yukon-specific labour and wages information is readily available. UCG submits that AEY's labour inflation should be held to the most recent Yukon statistics available."[40]

[37] Appendix A to Board Order 2014-06, section 5.2.2, page 23.
[38] AEY noted the following decisions in its argument: 3539-D01-2015 (EPCOR Transmission 2015-2017 Tariff), 3577-D01-2016 (ATCO Pipelines 2015-2016 GTA), 20407-D01-2016 (EPCOR 2014 True-Up and 2016-2017 Forecast Capital Tracker) and 20555-D01-2016 (ATCO Electric Distribution 2014 True-Up and 2016-2017 Forecast Capital Tracker), at paragraph 66 of AEY's Final Argument.
[39] AEY Final Argument, paragraph 68.
[40] UCG Reply Argument, paragraph 20.

86. In addition, several of the interveners expressed concerns regarding AEY's costs. CW was concerned with AEY's pattern of over-forecasting.[41] John Maissan observed that AEY is able to control overall O&M costs.[42] UCG supported CW's concerns regarding over-forecasting, additionally mentioning "artificial inflation of rates".[43]

5.3.2 Views of the Board

87. The Board notes that, in the September 9, 2016 updated response to YUB-YECL-27(a), AEY stated that in 2015, 10 employees (15 percent of staff) did not receive wage increases, and in 2016, 11 employees (17 percent of staff) did not receive wage increases.

88. In response to Board questioning, AEY confirmed that the staff who did not receive wage increases in 2015 and 2016 were all out-of-scope employees.[44] Further, AEY stated that for the 2016 and 2017 test years, the labour inflation forecast was based on AEY's existing collective agreement, which expires on December 31, 2016. The labour-escalation rate for the test period is forecast to be 3.25 percent. AEY did not submit any information that a new collective agreement had been reached or would be in place for January 1, 2017. The Board considers that the 2017 forecast labour escalator is not based on a collective agreement that would be in force in 2017.

89. The Board notes that built into the determination of revenue requirement for 2015 was labour inflation of 3.5 percent. However, out-of-scope employees did not receive inflation increments for that year, nor for 2016. In-scope employees received 2015 and 2016 labour-inflation increments of 3.25 percent. For 2015, this was 0.25 percent lower than what was built into the 2015 revenue requirement.

90. As a result, for out-of-scope employees, the Board awards, for 2016, a labour-inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision.

91. For in-scope employees, the Board considered that a collective agreement was in place for the 2016 test period and approves the labour-inflation rate of 3.25 percent as requested for that year.

92. However, for 2017, since the Board has no evidence of the existence of a collective agreement, the Board has to determine the inflationary increase to be awarded for in-scope and out-of-scope employees. In making its determination, the Board considered the May 2016 *Yukon Economic Outlook.*[45] The Board notes that, based on the *Yukon Economic Outlook*, Yukon experienced an economic downturn in 2015 due to reasons such as:

- 2015 GDP was down by 3.8 percent;

[41] Exhibit C3-3, CW Evidence; CW Final Argument, paragraph 27.
[42] JM Final Argument, page 4.
[43] UCG Final Argument, paragraph 98.
[44] Transcript Volume 3, pages 400, line 16, to 401, line 8. .
[45] Exhibit B-9, YUB-YECL-30(a), Attachment 1.

- Average employment was down slightly;
- Unemployment rate was up 2.0 percent;
- Building permits were down 9.7 percent; and
- A modest decrease in the CPI for Whitehorse of 0.2 percent.

93. The preliminary forecast for 2017 discussed in the outlook is for Yukon's real GDP to fall by 5.7 percent, and employment and the labour force to be relatively flat. The Consumers Price Index (CPI) for Whitehorse is expected to be just under 2.0 percent.

94. For these reasons, the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction.

5.4 Pension matters

5.4.1 Defined Benefit Plan Contributions and Defined Benefit Pension Deferral Account

95. AEY provided the following placeholder amounts for pension costs in its Application:[46]

Table 8. **2013 to 2017 placeholder amounts for pension costs ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Defined Benefit	1,041	902	578	578	578
Defined Contribution	209	242	267	276	286
Total Pension Costs	1,250	1,144	845	854	864

Source: Exhibit BB-1, Application, page 5-3.

96. AEY sought Board approval for these amounts to be tied to the outcome of the upcoming ATCO Utilities Pension Application, to be filed before the Alberta Utilities Commission (AUC). In addition, AEY is seeking continuation of its pension deferral account to flow-through any increases or decreases to the defined benefit funding amounts as a result of any updated actuarial evaluations. For the defined contribution pension plan, AEY noted that the company's contributions rate was set at 6.0 percent.[47]

97. In an update[48] to defined benefit pension costs, AEY stated the costs for 2016 are forecasted to be $505,000, assuming a COLA of 100-percent CPI.

98. Further, AEY confirmed that if the deferral account is granted for pension costs, ratepayers would experience "actual cost" rather than placeholder amounts[49] and also

[46] Exhibit BB-1, Application, page 5-3.
[47] Exhibit BB-1, Application, page 5-3.
[48] Exhibit B-9, YUB-YECL-36(f).
[49] Exhibit B-5, JM-AEY-9.

confirmed that AEY would exclude any amounts the AUC does not approve for inclusion in utility rates in the Alberta 2016 pension application.[50]

99. In argument, AEY submitted that the assumption for 2016 of the COLA at 100 percent is based on changed circumstances, as the pension has moved from an unfunded liability to a funding-excess position.[51]

100. In its submission, UCG recommended that if the defined benefit pension deferral account was to be continued, its intended use should be clear, along with how it is to be used.[52] No other interveners made submissions on pension costs or this deferral account.

5.4.2 Views of the Board

101. The Board finds the requested pension amounts are reasonable. As a result, the Board approves the revised defined benefit pension amounts of $505,000 for each of the test years. The Board also approves the defined contribution rate of 6.0 percent, to be applied to the labour rates determined in section 5.3.1 of this decision.

102. Further, the Board approves AEY's request to continue with the Defined Benefit Pension Deferral Account (DBPDA). The Board finds that adjusting for the result of the ATCO Utilities 2016 Pension Application is a reasonable approach because it will reflect actual pension costs.

5.5 Other Inflation

103. As noted in the key assumptions,[53] AEY has requested other inflation of 2.20 percent for each of the test years. AEY stated that this forecast for the 2016 test year was based on the *Yukon Economic Outlook* dated October 2015. AEY added that since no public forecast was available for Yukon for 2017, it applied the 2016 forecast for that test year.

5.5.1 Views of interveners

104. Parties did not provide any specific comments on Other Inflation.

5.5.2 Views of the Board

105. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response.[54] In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent[55] for 2017. AEY is directed to reflect this change in its compliance filing to this decision.

[50] Exhibit B-4, CW-YECL-15(b).
[51] AEY Final Argument, paragraph 71.
[52] UCG Reply Argument, paragraph 21.
[53] Exhibit BB-1, Application, page 1-5.
[54] Exhibit B-9, YUB-YECL-30(a), Attachment 1.
[55] Exhibit B-9, YUB-YECL-30(b).

5.6 Non-labour costs

106. Non-labour costs were discussed in the Application. Schedule 5-1 provided a summary of actual and forecast costs. Schedule 5-2 provided year-over-year variance explanations.

107. AEY stated that non-labour costs are forecasted in two parts: (1) ongoing operational and administrative activities, and (2) new programs or projects. AEY added that it was not forecasting any new programs or projects for this test period.[56]

108. For ongoing operational and administrative activities, the forecast was based on historic spending and adjusted for known changes in work to be completed in the forecast period.

5.6.1 Views of interveners

109. CW submitted evidence challenging the forecast accuracy of AEY, stating:

> When the actual costs are systematically lower than forecast, one must question the reasonableness of the forecasts. When the approved forecast is continually higher than the actual costs for a cost category or item, it means customers are paying for costs the utility will not incur. While the utility is entitled to benefit from efficiency gains in the test period, the regulator must ensure that savings are from efficiency gains, and not the result of over forecasting. When there is a continual pattern of over-forecasting, that usually means that there is an issue with the forecast, and the subsequent forecast should be adjusted. Further, these savings should be captured in the subsequent rate application, to the benefit of customers.[57]

110. CW asserted that a pattern of over-forecasting for the production, distribution and general functions existed.[58] CW recommended that production costs be reduced by 15 percent[59] and that distribution and general costs be reduced by $272,000 in 2016 and $369,000 in 2017.[60]

111. UCG argued that "… there has been a pattern of over-forecasting and artificial inflation of rates in 2013-2015 with respect to O&M costs related to AEY's production facilities ($938,000) and overspending on administration and general ($458,000)."[61] UCG noted the variance between approved and actual affiliate charges for the 2013-2015 period. It recommended that affiliate charges should be reduced by 25 percent.

112. John Maissan submitted that AEY is able to control overall O&M costs according to their actual sales relative to approved forecast sales. He recommended that forecasted O&M costs for the 2016-2017 test years should be reduced by 1.1 percent.[62]

[56] Exhibit BB-1, Application, page 5-3.
[57] Exhibit C3-3, CW evidence, A5, pages 2-3.
[58] Exhibit C3-3, CW evidence, A6, pages 3-4.
[59] CW equated the 15-percent reduction in production costs to be $314,000 in 2016 and $306,000 in 2017.
[60] Exhibit C3-3, CW evidence, A7, pages 4-5.
[61] UCG Final Argument, paragraph 98.
[62] JM Final Argument, page 4, point 6.

113. In Reply Argument, UCG submitted:

> … that AEY has not provided the Board or interveners any alternative but to review O&M cost components. The only way to justify AEY's claim that O&M should only be reviewed in aggregate is if AEY has presented an integrated business strategic plan upon which its O&M is based.[63]

114. With respect to production costs, CW stated:

> … that in assessing the likely accuracy of any forecast in the application, the Board can and should take into account a pattern of over-forecasting in areas where that can be demonstrated.[64] (*underlining omitted*)

5.6.2 Views of the Applicant

115. In argument, AEY stated:

> Furthermore, the Bell Evidence does not take into account the oral testimony provided by Mr. Massie where he described a forecasting process that continuously informs the process with the best available information. Adjustment to the process are made based on historical costs and known costs looking forward. As noted by Mr. Massie, adjustments have been made to accounts going forward and these changes are reflected in the 2016-2017 test year forecasts.[65] (*footnotes omitted*)

116. AEY later added that it is more appropriate to look at total O&M costs and not isolate only those functions that are experiencing increases. In terms of $/MWh and O&M cost per customer, AEY argued that those metrics are influenced by the level of retail sales and those sales were actually decreasing by 1.5 percent. The forecasted average annual O&M cost per customer is flat with historical actuals.[66]

117. In reply to CW, AEY noted that CW did not provide any evidence as to why its method of forecasting is appropriate for the O&M categories in question. AEY went on further to say that CW failed to account for inflationary increases, based on the table provided in its argument that AEY has a history of accurately forecasting its O&M expenses.[67]

118. In reply to John Maissan's recommendation that O&M costs should be reduced by 1.1 percent, AEY said Mr. Maissan's recommendation ignored inflation as well as known increases in excess of inflation.[68]

119. In Reply Argument, AEY challenged UCG's request that affiliate charges be reduced by 25 percent. AEY stated that the difference between 2014-2015 actual amounts for affiliate charges related to the change in service provider and that change was fully reflected in the forecast for each of the test years.

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[63] UCG Reply Argument, paragraph 17.
[64] CW Reply Argument, paragraph 7.
[65] AEY Final Argument, paragraph 54.
[66] AEY Final Argument, paragraphs 58-59.
[67] AEY Reply Argument, paragraph 33.
[68] AEY Reply Argument, paragraph 35.

120. Regarding Administration and General O&M costs per customer, AEY countered the UCG argument by referring to corrected tables filed on November 10, 2016 to replace the original response to CW-YECL-13 Attachments 1 and 2. The update showed Administration and General O&M costs per customer to be less for the 2017 forecast than the 2015 actual.

121. AEY stated that its submissions for Financial Reporting and Regulatory Support affiliate costs should be seen as reasonable in comparison to 2013 amounts, especially given the regulatory events expected in 2017.[69]

5.6.3 Views of the Board

122. The Board is of the view, based on the evidence of CW, that AEY appears to have, at a high level, over-forecasted for each year in the 2013-2015 period. The Board views each year separately and not in aggregate. The forecast for each year is driven by different assumptions and different stages of planned programs. However, the Board agrees with AEY that the high-level approach submitted by CW can be overly simplistic. It is beneficial to have such a high level review, but the trend uncovered by that type of review should be the starting point for further investigation and not taken at face value. From an O&M perspective, deviations can occur due to changes in the capital/O&M mix. Deviations can also be related to deferring planned programs or increased work in other functions. Identifying a trend is insufficient. Identifying root causes and making recommendations for specific accounts or functions are necessary.

123. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual.

124. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period.[70] However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also

[69] The content of the preceding three paragraphs was derived from the AEY Reply Argument, paragraphs 36-41.
[70] Transcript Volume 3, page 444, lines 2-25.

directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs.

125. The Board will now discuss costs at the function level. Changes due to complement levels, vacancy rates, and inflation rates (labour and other) are discussed in earlier sections of this decision and those determinations impact production, distribution, public information and customer accounting function costs.

126. Other[71] costs, as provided in general function costs — in particular, Account 88800 (Maintenance for Company-Owned Houses), Account 88900 (Warehouse and Office Maintenance) — and administration and general function costs — particularly Account 72100 (Administrative) — are discussed in the following paragraphs.

127. **Account 88800 (Maintenance for Company-owned Houses).** "Other" costs were provided in AEY's response to City of Whitehorse's IRs. [72]Variance explanations were provided in Schedule 5.2 of the Application but only for Account 88900 and only for the change from the year 2013 to 2014. The following table shows the actual and forecast "Other" costs for this account:

Table 9. **Account 88800 — Maintenance, Company-Owned Houses — "Other" costs ($000s)**

Account 88800				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
18	27	41	54	51

Source: CW-YECL-14(a), Attachment 1, page 3.

128. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[73] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other" (Account 88800) is $47,000, and the 2017 balance for "Other" (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

[71] Other costs do not include the labour and fringe elements as provided in Attachment 1 of CW-YECL-14(a).
[72] CW-YECL-14(a), Attachment 1.
[73] Exhibit BB-1, Application, page 5-3.

129. **Account 88900 (Maintenance, Warehouse and Office)**. "Other" costs were provided in Attachment 1 to CW-YECL-14(a) and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the forecast and actual "Other" costs for this account:

Table 10. **Account 88900 — Maintenance, Warehouse and Office — "Other" costs ($000s)**

Account 88900				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
137	156	133	150	153

Source: CW-YECL-14(a), Attachment 1, page 3.

130. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[74] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other", (Account 88900) is $143,000, and the approved 2017 balance for "Other" (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

131. **Administrative and General function costs.** Schedule 5.2 provided explanations for the labour portions but did not explain the increase in "Other". Except for an explanation related to $21,000 for employee association agreement negotiations.

132. **Account 72100 (Administrative).** "Other" costs were provided in Attachment 1 to CW-YECL-14(a), and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the actual and forecasted "Other" costs for this account:

Table 11. **Account 72100 Administrative — "Other" costs ($000s)**

Account 72100				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
1,481	1,541	1,256	1,556	1,585

[74] Application, page 5-3.

Source: CW-YECL-14(a), Attachment 1, page 3.

133. In YUB-YECL-45, AEY was asked to explain the increases in each of the "Admin and General" Accounts (Accounts 72100 through 72900). AEY provided explanations; for Account 72100, the explanation chiefly related to labour costs.

134. The three-year average (2013-2015) for "Other" for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in "Other" costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision.

6 Taxes Other Than Income

135. Taxes Other Than Income consist of property taxes paid to communities for AEY's office building, generation facilities, substation properties and power lines.

136. The following table summarizes AEY's recently approved, actual and forecasted amounts for property taxes:

Table 12. **Approved, actual and forecast property taxes 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	257	265	273		
Actual (A) / Forecast (F)	273	251	256	262	267
Actual (under) or over approved	16	(14)	(17)		

Source: Exhibit BB-1A, 2016-2017 GRA Schedule S1.1, line 10.

137. AEY stated that the increase in actual 2013 property taxes over the approved amount was due to payments made to the Town of Watson Lake.[75] Increases in property taxes that had been forecast for the years 2014 and 2015 did not occur because planned capital work, upon which property tax calculations are in part determined, did not materialize. Therefore, any year-over-year increases in property taxes paid during 2014 and 2015 were due primarily to inflation.

138. AEY has forecasted property taxes in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017.

139. AEY stated that property tax increases in the amounts of $0.006 million and $0.005 million for 2016 and 2017 respectively are due to inflationary increases applicable to each test year.

[75] Exhibit B-6, YECL Responses to UCG requests, UCG-AEY-28(b), PDF, page 150 of 260.

6.1 Views of interveners

140. In argument, UCG stated that AEY should not be allowed to increase property taxes for the test years due to a lack of evidence, such as the utility's property tax assessments.

6.2 Applicant responses to interveners

141. AEY replied that the position of UCG constituted new evidence that should be struck from the record or be given no weight by the Board.

6.3 Views of the Board

142. The Board considers that it is reasonable for AEY to forecast its 2016-2017 Taxes Other Than Income based on the application of relevant inflation rates by using, as a starting point, its 2015 actual property taxes paid. With respect to the issue of property tax assessments raised in Final Argument, the Board does not have sufficient information on the record of the current proceeding to determine that consideration of property tax assessments is required. If UCG wishes to explore the issue of whether property tax assessments should be provided in support of AEY's Application, it may bring forward this issue for examination in AEY's next GRA.

143. The Board approves AEY's "Taxes Other Than Income" amounts forecasted in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017, as filed.

7 Depreciation

144. In its Application, AEY forecasted depreciation expense in the amount of $5.792 million for the year 2016 and $6.283 million for the year 2017. This resulted in an increase from 2015 actual expense in the amount of $0.380 million in 2016 and $0.491 million in 2017. AEY explained that the increases were the result of forecasted growth in property, plant and equipment and subject to depreciation expense.

145. AEY stated that the depreciation rates used in the calculations of 2016 and 2017 depreciation expense were developed by way of a technical update, which relied on the depreciation parameters approved by the Board in Board Order 2014-06 for AEY's 2013-2015 GRA. In that application, AEY submitted a full depreciation study in support of the depreciation parameters ultimately approved by the Board. AEY also stated that in 2016 and 2017, it would continue to record the annual amortization of the accumulated depreciation reserve differences credit in the amount of $0.402 million,[76] [77] which was at the same level approved in Board Order 2014-06.

146. The following table summarizes AEY's recently approved, actual and forecast amounts for depreciation expense:

[76] This would have the effect of reducing YECL annual depreciation expense by $0.402 million.
[77] YECL 2016-2017 GRA Schedules, Schedule S7.4, line 50.

Table 13. **Approved, actual and forecast depreciation expense — 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	4.520	5.252	5.778		
Actual (A)/Forecast (F)	4.382	4.895	5.412	5.792	6.283
Actual (under) or over approved	(0.138)	(0.357)	(0.366)		

Source: Exhibit 2016-2017 GRA Schedule S1.1, line 11.

147. During the course of this proceeding, three issues were raised with respect to depreciation, each of which is discussed in the sections that follow.

7.1 Technical update to determine updated depreciation rates

7.1.1 Views of interveners

148. There were concerns raised by UCG that AEY had not indicated nor requested approval in its application of the revised depreciation rates used in its calculation of depreciation expense for the test years stemming from the results of a technical update to its previous depreciation study.

149. UCG argued that since actual depreciation expense incurred for the 2013-15 test period had been lower than the amount approved to be recovered through AEY's tariff, this was evidence of an over-recovery of depreciation expense in the amount of $1.1 million[78] over the 2013-15 period.

150. UCG submitted that AEY's request for increases to its depreciation expense should be denied because of these two issues.

7.1.2 Views of the Board

151. The Board observes that there appears to be some confusion by parties pertaining to certain depreciation-related elements. The Board has provided the following general information with respect to the differences between a full depreciation study and a technical update to a depreciation study.

152. Depreciation expense typically encompasses three components of capital cost recovery: (1) the depreciation related to the original cost of the asset; (2) estimations related to net salvage costs (also referred to in this proceeding as future removal and site restoration); and (3) in some circumstances, the amortization of accumulated reserve differences that arise, in part, from changes in depreciation methodologies or depreciation parameters determined during the course of a depreciation study.

153. Periodically, a new depreciation study is conducted and three depreciation "parameters" — consisting of the average service life, the standard "Iowa curve" and dispersion pattern (collectively referred to as the life-curve parameters) and the net salvage percent parameter — are confirmed or revised. The actual accumulated depreciation recorded to date, based on the prior approved depreciation parameters,

[78] UCG Final Argument, PDF page 21 of 40.

can differ from the theoretical amount of accumulated depreciation that would have been recorded for each account using the updated parameters. The resulting difference — termed the accumulated reserve difference or variance — is measured in dollars and may be recovered or refunded through depreciation expense as a stand-alone true-up amount, or may be combined into a depreciation rate that includes the amortization of the accumulated reserve differences true-up amount.

154. During the preparation of full depreciation studies, technical updates are often conducted. The purpose of a technical update (which is less costly to prepare than a depreciation study) is to apply the currently approved depreciation parameters to the recent actual plant balance information provided by the utility in order to develop the most current and relevant depreciation rates for the test years. The most recent plant balances will reflect both plant additions and retirements occurring since the time of the last depreciation study or technical update.

155. To summarize, it is during the course of examining a depreciation study that the depreciation parameters of life-curve, net salvage percentages and the amortization of accumulated reserve differences are approved. The rates that are proposed by the utility are used as an input in depreciation expense calculations and are a direct result of the depreciation parameters being applied to the most recent actual plant-in-service information. During the course of a technical update, approved depreciation parameters are similarly applied to the most recent plant balances for the purposes of updating depreciation rates, which will then be used in depreciation expense calculations.

156. In its 2016-17 GRA, AEY submitted a technical update to its December 31, 2011 depreciation study, which had been submitted as part of the record in the 2013-15 GRA.

157. The technical update undertaken by AEY relied on currently approved life-curve depreciation parameters to determine updated depreciation rates for the 2016 and 2017 test years based on December 31, 2015 plant-in-service balances. The result was a total decrease in depreciation expense of approximately $0.100 million over the test years.[79]

158. In the case of AEY, and consistent with past Board Orders, there is no estimation made for recovery of any future net salvage costs. As a result, there is no depreciation parameter related to or reflective of a net salvage percent that would otherwise form a part of AEY's depreciation rates and therefore depreciation expense.

159. Furthermore, AEY has historically recovered any amortization of accumulated reserve differences as a dollar amount, which is generally determined and approved during the course of examining a depreciation study.

160. With respect to the 2016-17 amortization of accumulated reserve differences amount, AEY stated that it had "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[80] The

[79] Transcript, Volume 1 page 148.
[80] Transcript, Volume 3, page 424.

result was a credit, or refund, of depreciation expense in the amount of $0.402 million per year.

161. Based on the foregoing, the Board is not convinced by the concerns raised by UCG that there is a need to deny or adjust AEY's depreciation expense calculations due to its December 31, 2015 technical update. Consistent with common depreciation practice, AEY's technical update relied on currently approved life-curve depreciation parameters applied to its most recent plant balances for the purposes of updating its depreciation rates, which were used to inform its 2016-17 depreciation expense calculations. The Board finds there is not an issue with the derivation of AEY's forecast depreciation expense.

162. With respect to UCG's assertion of over-collection of depreciation expense for the years 2013-15, the Board determines the revenue requirement on a prospective basis. Depreciation parameters and the resultant rates are estimates applied to forecasted plant balances to determine forecasted depreciation expense. While the depreciation rates themselves will remain static during the test years, actual plant balances — upon which those rates are applied — may differ from those forecasted by the utility. The end result, as observed by UCG, may be differences between approved and actual depreciation expense.

163. For the purpose of calculating AEY's depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense.

7.2 Use of the mid-year convention for calculation of depreciation expense

164. During the oral hearing, Board counsel questioned AEY as to why, in its depreciation expense calculation for Account 493 — Demand Side Management, the mid-year convention had not been applied. The question posed was directed toward a common regulatory convention related to depreciation expense calculations whereby only a half-year of depreciation expense is taken in the year in which an asset has been capitalized into rate base, followed by full-year depreciation expense calculations in subsequent years. This mid-year convention supports that in the absence of having to consider individual and exact dates of capitalization for any given asset, an assumption can be made for depreciation purposes that, on average, all assets are capitalized at the mid-point of the year.

165. An examination of AEY's schedules indicated that depreciation expense had not been taken for any of the amounts on Account 493 — Demand Side Management 2016 capital addition. The amounts had been deferred to the year 2017 where a full year depreciation expense was recorded.

166. AEY witness, James Grattan, advised that if the Board determined that coincident with the capitalization of the asset in 2016 it should attract a half-year of depreciation expense in that same year, he would not be opposed to this calculation.[81]

7.2.1 Views of the Board

167. The Board considers that consistent with AEY's depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

168. For clarity, the Board confirms AEY's use of a five-year amortization period is acceptable for this depreciation expense calculation, in accordance with the findings in Board Order 2014-06.[82]

7.3 Supporting documentation for the amortization of accumulated depreciation reserve differences

169. During the IR process, AEY confirmed that costs related to net salvage had not been included in the depreciation expense for the years 2013-2017.[83]

170. AEY also confirmed during the oral hearing that despite its Schedule 7.4 — Schedule of Amortization of Differences identified for each account number, negative net salvage in varying percentages, the schedule did not include any costs related to the recovery of net salvage. James Grattan, witness for AEY, stated that Schedule 7.4 "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[84]

7.3.1 Views of the Board

171. The Board is satisfied that the 2016-2017 depreciation expense calculated by AEY, including the calculation related to its amortization of accumulated depreciation reserve differences, does not include any amounts related to the recovery of net salvage.

172. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.

[81] Transcript, Volume 3, page 427.
[82] Board Order 2014-06, Appendix A, page 101..
[83] Exhibit B-6, UCG-AEY-29(a).
[84] Transcript, Volume 3, page 424.

8 Return on rate base

173. AEY included the following information on return on rate base:

Table 14. **Return on rate base — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Return on Rate Base	5,550	5,782	5,838	6,945	7,400

Source: Exhibit BB-1, Application, page 8-1.

AEY explained that the growth in rate base is a result of capital additions and an increase in the return on equity (ROE). This resulted in the increase in return on rate base for the forecast period.

8.1 Cost of capital

174. AEY has requested the Board use the British Columbia Utilities Board (BCUC) Generic Cost of Capital (GCOC) proceeding as the benchmark for determining ROE. In addition, AEY is seeking a 60-basis-point risk premium over the BCUC GCOC benchmark to determine its ROE for each of the test years.

8.1.1 Rate of return on capital

175. In response to YUB-YECL-50, AEY cited the BCUC's most recent GCOC decision (G-75-13) but did not provide that decision as requested. In that decision, the benchmark rate was determined to be 8.75 percent.

176. AEY, YEC[85] and John Maissan[86] accepted the BCUC rate. CW did not comment on the rate established by the BCUC. UCG recommended that the Board use the most recent GCOC decision from the AUC.[87]

177. UCG added that given AEY's direct tie to the Alberta market, AEY should not be allowed to link its ROE for the 2016-2017 test period to the recently approved BCUC GCOC benchmark rate of 8.75 percent plus a risk premium of 0.60 percent.

178. YEC disagreed with the UCG position and stated:

> The Board has previously determined that the BCUC model is the precedent for Yukon; as such, in Yukon Energy's view there is no basis for using a different benchmark ROE for the current review.[88]

8.1.2 Applicant responses to interveners

179. AEY submitted that UCG has ignored past decisions of the Board and the clear statements of the Board as they relate to equity ratio and ROE in Board Order 2014-06.

[85] YEC Final Argument, page 3.
[86] JM Final Argument, page 6.
[87] UCG Final Argument, paragraphs 137-150.
[88] YEC Reply Argument, pages 3-4.

8.1.3 Views of the Board

180. In Board Order 2009-02, the Board ruled that the BCUC generic cost of capital (GCOC) model is the most appropriate and is generally accepted by parties.[89]

181. The Board, in Board Order 2009-08 stated:

> The Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter. The Board strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon.
>
> The Board considers that the BCUC approach has been successfully applied to both utilities under this Board's jurisdiction and has resulted in fair returns to both utilities.
>
> Therefore it is determined that the BCUC approach is a precedent for this jurisdiction and will continue to be the precedent for this jurisdiction until otherwise ordered by this Board.[90]

182. The Board continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon for the reasons set out above. The Board does not agree with the submissions of UCG on this issue as no evidence was filed to persuade the Board to change its approach. Accordingly, the Board finds that AEY is to use the BCUC GCOC benchmark for ROE of 8.75 percent.

8.1.4 Equity premium

183. AEY engaged Concentric Energy Advisors, Inc. (Concentric) to determine whether a risk premium relative to the BCUC GCOC benchmark utility would be appropriate and, if so, what that risk premium should be. The report prepared by Concentric was submitted as Attachment 8.1 to the Application.[91]

184. AEY submitted that it faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore warrants a risk premium. Concentric submitted that the premium should be 60 basis points.[92]

185. Concentric, based on its research, recommended a risk premium of between 40 and 75 basis points in comparison to the BCUC benchmark utility. The range was framed by FortisBC Electric at a 40-basis-point premium and PNG-West (Pacific Northern Gas-West), representing the upper boundary. Concentric chose 60 basis points, as it matched the 9.35-percent ROE awarded to Maritime Electric, a utility Concentric submitted had similar business risk as AEY but had a deemed equity ratio of 40.9 percent.[93]

[89] Board Order 2009-02 Appendix A: Reasons for Decision, page 29.
[90] Board Order 2009-08, paragraphs 280-282.
[91] Exhibit BB-1, Application, page 8-3.
[92] Exhibit BB-1, Application, page 8-4.
[93] Exhibit BB-1, Application, Attachment 8.1, page 6.

186. Concentric added:

> In most respects, the business risk of AEY has not materially changed since 2009 when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable. Weak economic conditions in the province, coupled with the impact of energy efficiency and DSM programs, and increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales;
>
> The business risk profile of AEY is most similar to that of Maritime Electric, which derives a higher percentage of its electricity supply from company owned generation than AEY, but which serves five times more retail customers. Maritime Electric has an authorized ROE of 9.35 percent on 40.9 percent common equity;
>
> The business risk profile of AEY is also similar in many respects to that of Newfoundland Power, except that AEY is substantially smaller in terms of both customers served and rate base. Newfoundland Power has an ROE of 8.80 percent on 45 percent common equity; and
>
> The business risk of AEY is lower than that of PNG-West, which is similar in size but faces more risk than AEY due to the loss of a major customer that caused throughput to decline by 87 percent from 2003-2012. PNG West has an authorized ROE of 9.50 percent (or 75 basis points above the BC benchmark) on 46.5 percent common equity.[94]

187. AEY submitted that the business risks it faces encompass market demand, operational risks, small size and geographic environment and that these risks expose it to a higher degree of business risk compared to the BCUC benchmark utility as well as most utilities located in other areas of Canada.[95]

8.1.4.1 Views of interveners

188. YEC took the position that it is appropriate to use the BCUC benchmark ROE of 8.75 percent as the foundation, and that for Yukon utilities, it is appropriate to "apply a risk premium adder above the benchmark in order to reflect additional risks faced by northern utilities on an isolated grid."[96] However, YEC said that AEY's proposal deviates from the BCUC approach and from past Yukon precedent. AEY's approach maintains a requirement for expert evidence and testimony to determine ROE for Yukon utilities that potentially increases both the cost and complexity of these proceedings.

189. YEC recommended that the Board use the same methodology and justification for determining ROE that was established in the 2005 GRA — that is, a point midway between YEC and FortisBC Electric of 48.5 basis points.[97]

[94] Exhibit BB-1, Application, Attachment 8.1, page 32.
[95] Exhibit BB-1, Application, page 8-3.
[96] YEC Final Argument, page 3.
[97] YEC Final Argument, page 5.

190. In Reply Argument, YEC stated:

> BCUC decisions referenced in the current Board proceedings have confirmed the requirement for a risk premium relative to the approved benchmark for various BC utilities to reflect the relative size of the utility and the characteristics of its service area.[98]

191. YEC later added that in Board Order 2009-02, the Board stated:

> … that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.[99]

192. YEC then stated that the bookends for assessing a risk premium against the BCUC benchmark are FortisBC Electric and PNG-West.[100]

193. John Maissan argued that the position that AEY faces increased sales forecast risk due to customers switching home heating sources is speculative. Based on the conclusion of Concentric, the sales forecast risk does not have a material effect on the risk profile for AEY.[101]

194. Mr. Maissan noted that the concern regarding variation in earnings did not appear to hold. He referred to YUB-YECL-63(b), arguing that in spite of significant economic variations and sales variabilities in 2014 and 2015, AEY, with the exception of 2015, has consistently earned above approved ROE levels.[102]

195. Mr. Maissan recommended:

> … that AEY has flexibility in the way it manages its costs such that it fairly consistently over-earns its approved ROE, and therefor [sic] is not subject to nearly as much risk as it tries to make out it is. In my view a fair ROE is the BCUC Benchmark of 8.75% and any risk premium is more that adequately covered by its equity thickness of 40% as compared to BCUC's 38.5%.[103]

196. CW noted that Concentric concluded that, "In most respects, the business risk of AEY has not materially changed since 2009…"[104] CW submitted that the request for a risk premium was unwarranted.[105]

197. UCG argued that the appropriate benchmark should be based on the latest AUC GCOC proceeding and therefore did not make any recommendation with respect to an equity premium.[106]

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[98] YEC Reply Argument, page 4.
[99] Board Order 2009-02, Appendix A: Reasons for Decision, page 29.
[100] YEC Reply Argument, page 5.
[101] JM Final Argument, page 5.
[102] JM Final Argument, page 6.
[103] JM Final Argument, page 6.
[104] Exhibit BB-1, Application, Attachment 8.1 (Concentric Report), page 31. Concentric did subsequently state that "the most important change has been uncertainty; and unpredictability associated with usage per customer, especially among the residential class".
[105] CW Final Argument, paragraph 26.
[106] UCG Final Argument, paragraphs 137-150.

8.1.4.2 Applicant responses to interveners

198. AEY challenged CW's interpretation that the Board, in Board Order 2014-06, ruled that a risk premium was not necessary or that there was no incremental business risk. Rather, AEY submitted that the Board ruled that the determination of whether a risk premium should be applied was not clear, and the Board directed AEY to provide justification in its next GRA.[107]

199. AEY contended that Mr. Maissan's position that the Board only use the BCUC benchmark ignores the evidence that FortisBC Energy has lower business risk than AEY.[108]

200. In response to YEC argument, AEY said the approach it took was in response to a direction from Board Order 2014-06. Further, AEY disagreed with the submission of YEC that AEY's business risks have not changed, noting that AEY's usage per customer has made it more difficult to accurately forecast sales.[109]

201. For risk due to small size, Concentric stated:

> Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).[110]

8.1.4.3 Views of the Board

202. The Board made its determinations with respect to an ROE risk premium in Board Order 2009-02 and 2009-08 as follows:

> *Should a risk premium be applied?*
>
> In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation.

[107] AEY Reply Argument, paragraphs 57-63.
[108] AEY Reply Argument, paragraphs 64-66.
[109] AEY Reply Argument paragraphs 77 and 80.
[110] Exhibit B-9, YUB-YECL-62(a).

> The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.
>
> *What risk premium should be applied to YECL?*
>
> In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.[111] *(footnotes omitted)*

203. The Board continues to maintain this view. For this Application, as in past GRA decisions, the Board does not have a recent YEC decision to determine one of the bookends for the risk premium range and to use to calculate an ROE premium as it did for Board Order 2009-02.

204. The Board notes that Concentric concluded that AEY's business risks have not materially changed since 2009.[112] Further, Concentric stated that weak economic conditions in Yukon, coupled with the impact of energy efficiency and DSM programs, as well as increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales.

205. However, although forecasting sales volume may be more difficult, the table in the preamble to YUB-YECL-52 shows that AEY's actual sales — with the exception of one major growth year (2012) — are consistently within two percent of the previous year's levels. Further, Concentric concluded that sales forecast risk due to changing heating fuel sources does not have a material effect on the risk profile of AEY.[113]

206. Additionally, AEY testified:

> That we, as a utility, should be able to do come up with a forecast that's somewhat accurate to what our actual sales are going to be. It's changing and there's lot of challenges. You've got weather. You've got all the new demand side management programs, including micro-grid generation. There's lots to it. But I think it should be something that is expected that we should be able to take a guess at. Better than a guess. We should be able to do a thorough analysis and come up with a reliable forecast...[114] I would just add that we did know the existence or lack of existence of a weather-normalization account for ATCO Electric, but we didn't frame it as an adder to the risk premium per se.[115]

[111] Appendix A to Board Order 2009-02: Reasons for Decision, page 29 of 49.
[112] Exhibit BB-1, Application, Attachment 8.1, page 29.
[113] Exhibit BB-1, Application, Attachment 8.1, page 27.
[114] Transcript Volume 1, page 86, lines 2-13.
[115] Transcript Volume 1, page 87, lines 9-12.

207. Based on AEY testimony, sales volume risk is a risk AEY can manage and, in the Board's view, it is a risk that does not attract a risk premium. However, through the submissions of YEC and AEY and the comparisons with FortisBC Energy (the BCUC benchmark utility), the Board is persuaded that AEY can be eligible for a risk premium relative to the BCUC benchmark utility to mitigate risks other than those related to sales volume. The following paragraphs discuss the Board's determination of the appropriate level of the risk premium.

208. The Concentric report made the following comparisons:

> The 2016 Generic Cost of Capital proceeding is currently underway in British Columbia and a decision is expected by July 2016. The benchmark utility, FortisBC Energy, has lower business risk than AEY. FortisBC Energy is substantially larger than AEY, both in terms of retail customers served and regulated rate base. FortisBC Energy serves 56X more retail customers and its rate base is 33X larger than AEY's. FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than AEY. As a gas distributor, FortisBC Energy owns its regulated gas distribution system, whereas AEY owns the electric distribution system and some generation facilities. As discussed in more detail later in the report, investors and credit rating agencies view companies that own generation as higher risk than pure transmission and/or distribution utilities. FortisBC Energy has an allowed ROE of 8.75 percent on 38.5 percent common equity, while AEY currently has the same ROE and a slightly higher equity ratio of 40 percent…[116] FortisBC Electric was awarded an ROE risk premium of 40 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding. Like AEY, FortisBC Electric has 40 percent deemed common equity. FortisBC Electric is almost 10X larger than AEY in terms of retail customers served and has rate base about 15X greater than AEY. FortisBC Electric supplies approximately 45 percent of its load through company-owned generation, while AEY supplies about 9 percent, indicating that FortisBC Electric has relatively more generation risk.[117]

209. "Section IV — Risk Assessment" of the Concentric report listed the following risks:

- small size,
- generation risk,
- fuel and purchased power risk,
- volume/demand risk,
- regulatory environment,
- deferral/variance accounts, and
- competition from alternative fuels.[118]

210. The Board considers the two greatest risks to be size and generation. Discussion of the remaining listed risks follows. Fuel and purchased power are addressed through

[116] Exhibit BB-1, Application, Attachment 8.1, pages 4-5.
[117] Exhibit BB-1, Application, Attachment 8.1, page 5.
[118] Exhibit BB-1, Application, Attachment 8.1, page 1.

deferral accounts. AEY has stated its preference to manage volume/demand risk. Regarding regulatory environment, Concentric has stated that traditional cost of service regulation is generally considered less risky than incentive regulation.[119] AEY is under cost-of-service regulation, while FortisBC Energy and FortisBC Electric are under incentive regulation. Concentric did conclude that AEY was at higher risk than other companies due to not having a variance account for weather-related volume risk. As AEY prefers to manage its sales volume risk, the Board does not accept Concentric's conclusion that AEY faces increased regulatory risk because it does not have a weather-related volume risk deferral account. The Board's view is that AEY faces less regulatory risk than FortisBC Energy and FortisBC Electric because it is under cost-of-service regulation. Additionally, Concentric did not state that AEY deserved a risk premium for variance/deferral accounts.[120] Regarding competition for alternative fuels, Concentric submitted that FortisBC Energy faced competition from electric heat among residential customers and to a lesser extent than did PNG-West. However, Concentric concluded that this type of risk was difficult to quantify and likely does not have a material effect on the risk profile of AEY.[121]

211. Based on the foregoing, the Board concludes that in determining relative risk for AEY, the Board should look at size and generation risk.

212. For the comparators provided by Concentric,[122] the Board does not accept the use of FortisBC Electric for the lower boundary. Although FortisBC Electric is larger than AEY, its generation assets are a quantum level higher than the generation assets of AEY. Concentric referenced the BCUC GCOC Stage 2 proceeding[123] and the awarding of a 40-basis-point risk premium to FortisBC Electric. Part of the determination of the risk premium for FortisBC Electric was:

> The evidence supports the findings that FBC [FortisBC Electric] faces additional price competitiveness risk as compared to the Benchmark and in addition there is some additional risk related to small size. The Panel finds no substantial difference in supply risk as compared to the Benchmark, and, regarding operating risks, we found there was no basis on which to establish the potential impact of any differential in risk.[124]

213. Price competitiveness was a major factor in determining the risk premium for FortisBC Electric. Concentric concluded that competitiveness (from alternate supply) did not have a material impact on the risk profile of AEY. Generation assets for FortisBC Electric are materially higher than for AEY. Similarly, the generation assets for Maritime Electric are materially higher than those of AEY. Maritime Electric procures its power from a different jurisdiction.[125] Due to these factors (competitiveness, relative amount of generation assets), the Board finds that AEY is not directly comparable to FortisBC

[119] Exhibit BB-1, Application, Attachment 8.1, page 25.
[120] Exhibit BB-1, Application, Attachment 8.1, page 26.
[121] Exhibit BB-1, Application, Attachment 8.1, pages 26-27.
[122] FortisBC Electric for the lower boundary, PNG-West for the upper boundary, and settling on an ROE equivalent to Maritime Electric.
[123] Exhibit BB-1, Application, Attachment 8.1, page 5. The reference was to BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014 at page 113.
[124] Exhibit BB-1 BCUC Generic Cost of Capital Proceeding Stage 2 Decision, Order G47-14, March 25, 2014, page 86 (public document available at www.ordersdecisions.bcuc.com)
[125] Exhibit BB-1, Application, Attachment 8.1, page 21. The Board views cross-jurisdictional transactions as facing higher regulatory risk than those transactions occurring within a single jurisdiction.

Electric or Maritime Electric. Accordingly, the Board does not find generation to be a significant risk for AEY in relation to the risk of Fortis BC.

214. Further, in terms of comparisons to Maritime Electric, the Board notes that its ROE was determined through a settlement agreement. There is no evidence on the record of this proceeding indicating the trade-offs that may have occurred during the negotiation process or how the ROE level was determined. As a result, the Board gives little weight to the ROE determined by way of a settlement agreement.

215. Concentric stated that PNG-West was larger than AEY and added that PNG-West was awarded a higher risk from the BCUC due to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012). Concentric referenced the BCUC GCOC Stage 2 decision for this information. These circumstances do not apply for AEY. Therefore, the Board concludes that AEY is not directly comparable to PNG-West.

216. Although earnings variability has been mentioned by Concentric, the Board also notes that AEY has been able to consistently meet or exceed forecast earnings levels.[126]

217. The Board took note of Concentric's view that the extremely small size of AEY is an important risk factor for the purposes of establishing an appropriate risk premium for AEY.[127]

218. Based on the evidence, the Board has determined that small size is the most significant factor to be considered in determining a risk premium for AEY.

219. The evidence on this record shows that BCUC has set a premium for a small size utility at 25 basis points.[128] This Board accepts that a 25-basis-point premium over the BCUC benchmark utility is reasonable for this jurisdiction.

220. Further, as AEY will have an equity thickness[129] greater than that of the BCUC benchmark utility, the Board is of the view that this will compensate AEY for the other differences between it and the benchmark utility.

221. Therefore, the Board approves an ROE of 9.00 percent for AEY for both test years. AEY is to reflect this change in its compliance filing to this decision.

8.1.5 Common equity ratio

222. AEY requests to maintain the previously approved common equity ratio of 40 percent for each of the test years of 2016 and 2017.

223. John Maissan supported AEY's request for an equity thickness of 40 percent.[130]

[126] Exhibit B-9, YUB-YECL-63(b).
[127] Exhibit BB-1, Application, Attachment 8.1, pages 19-20.
[128] Exhibit B-9, YUB-YECL-62(a).
[129] Equity thickness refers to the ratio of debt to equity of a utility.
[130] JM Final Argument, page 6.

224. UCG submitted:

> … that linking AEY's return on equity to cost of capital formulas developed in other jurisdictions will reduce regulatory costs but should also warrant a review of equity thickness of AEY's capital structure. UCG submits that AEY's equity thickness should be reduced to 37% to match the level established by the Alberta Utilities Commission for its benchmark utility.[131]

8.1.5.1 Views of the Board

225. In Board Order 2014-06, the Board states:

> In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application… Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.[132]

226. The Board continues to view that an equity thickness of 40 percent for AEY is reasonable for the reasons set out above. No evidence was presented in this proceeding in support of another approach. The Board does not accept the submissions of UCG on this issue because no evidence was presented in support of these submissions or the use of an Alberta utility as a comparator in the current proceeding. The Board finds that AEY is to maintain an equity thickness of 40 percent.

8.1.6 Cost of debt

227. AEY discussed its forecast for long-term debt rates in the Application.[133] AEY used an average long Canada bond rate and applied a spread to determine the forecast debenture rate. The following was provided by AEY:

Table 15. **Forecast long-term debt rates**

	2016	**2017**
Long Canada Bond Rate	1.90% - 2.70%	2.30% - 3.30%
Credit Spread	1.80% - 2.20%	1.80% - 2.20%
Debenture Rate	3.70% - 4.90%	4.10% - 5.50%

[131] UCG Final Argument, paragraph 136.
[132] Board Order 2014-06, Appendix A: Reasons for Decision, page 54.
[133] Exhibit BB-1, Application, pages 8-4 to 8-5.

Recommended Rate	4.30%	4.80%
Issue Costs	0.05%	0.05%
Recommended All-in Rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 8-5.

228. AEY updated its cost of debt numbers in its October 24, 2016 update. The all-in rates were revised to 3.77 percent for 2016 and 4.07 percent for 2017.

8.1.6.1 Views of interveners

229. CW argued that AEY's cost of new debt has a pattern of over-forecasting, and noted that in 2014, the cost of debt was 0.96 percentage points lower than forecasted and for 2015, new debt was 1.08 percentage points lower than forecasted. CW further stated that AEY was protected in 2013 when actual cost was higher than forecasted, as actual cost was determined and approved by the Board for that year.[134]

230. John Maissan argued that for the years 2008-2015, the actual rates for cost of debt were never above the approved rates for cost of debt, but were usually below the approved rates. Mr. Maissan referenced the response to JM-AEY-14 in support of this argument and recommended a cost of debt rate of 4.35 percent for both test years.[135]

231. UCG, based on Board Order 2013-01, recommended that the Board adopt a historic formulaic approach of 120 basis points for forecasting future debt costs.[136]

8.1.6.2 Applicant responses to interveners

232. AEY argued that CW's evidence in relation to a pattern of over-forecasting debt rates should be ignored because AEY actually under-forecasted the rate for cost of debt in one of the years used by CW. AEY added that its October 24, 2016 update to the rate for cost of debt exceeded the recommended reduction in debt rates recommended by CW.[137]

233. AEY submitted that the UCG recommendation that the historical formulaic approach for determining rates for cost of debt should be used for AEY should be rejected due to lack of evidentiary support.[138]

8.1.6.3 Views of the Board

234. The Board notes that AEY did update its cost of debt in its October 24, 2016 update and that update was in response to YUB-YECL-73. The Board also notes that in Argument and Reply Argument, none of the interveners commented on the update to cost of debt.

235. The Board has reviewed the submissions on cost of debt. Originally, AEY forecasted the long Canada bond rate to be 2.50 percent for 2016 and 3.0 percent for

[134] CW Final Argument, paragraph 33.
[135] JM Final Argument, page 4.
[136] UCG Final Argument, paragraphs 152-154.
[137] AEY Final Argument, paragraphs 98-99.
[138] AEY Reply Argument, paragraph 81.

2017. In its update, AEY revised those long Canada bond rates to 1.92 percent for 2016 and 2.22 percent for 2017. It appears that AEY has maintained a credit spread of 1.8 percent.

236. The Board is persuaded by the submissions of Mr. Maissan that the AEY response to JM-AEY-14 show that actual costs of debt are never above and are consistently below forecast levels. For this reason, the Board rejects AEY's forecast for 2016 cost of debt.

237. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November[139] of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.

238. Further, in YUB-YECL-73(b), AEY was asked to provide the sources for the long Canada bond rate and credit spreads. Although AEY did provide sources, AEY did not explain the manner in which it determined its credit spreads.

239. In response to YUB-YECL-73(a), AEY provided its historical long Canada bond rates and credit spreads for the years 2011-2015. For that period, the average credit spread was approximately 1.6 percent.

240. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision.

8.2 No Cost Capital

241. AEY discussed No Cost Capital (NCC) in its Application. It stated that NCC related to the balances for deferred pensions including Other Post Employment Benefit (OPEB) plans and the Reserve for Injuries and Damages (RID).

242. OPEB plans are administered on a combined basis with Canadian Utilities Limited and AEY is assessed a percentage of its payroll at a rate calculated for the plan as a whole. AEY continues to use the cash basis for its pension plan and the OPEB plan. The OPEB plan covers such items as drug, health and dental costs for retirees.

[139] 2012 is the only year where the issuance was after November 1. The issuance date for that year was November 14.

243. The RID is as an account used for uninsured and uninsurable losses and the deductible portion of insurance claims. Attachments 8.2 (Beaver Creek House Fuel Spill — $109,700) and 8.3 (Fish Lake #1 Spillway Failure — $100,000) to the Application provided details of the two incidents that have been included in the RID account.

244. The following continuity schedule for NCC was provided by AEY:

Table 16. **Continuity for NCC Mid-Year Balance — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Total No Cost Capital	165	(24)	446	660	667

Source: October 24, 2016 Update, Schedule S8.4.

8.2.1 Views of the Board

245. The Board finds AEY's updated NCC costs to be reasonable and approves the updated amounts, subject to any impacts from other sections of this decision.

9 Capital additions

246. AEY submitted that capital additions were primarily driven by the requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their lifecycle, as well as meet system needs due to load growth. AEY's actual and forecasted capital expenditures and additions to rate base for the period from 2013 to 2017 are shown in the following table:

Table 17. **AEY Capital Expenditures and Additions – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Generation	5,574	8,599	3,060	6,630	5,316
Distribution	7,268	6,236	6,232	7,659	8,994
General Property & Equipment	2,516	2,002	1,402	759	1,008
Capital expenditures total	15,358	16,837	10,694	15,048	15,318
Capital additions to rate base	14,321	18,849	10,252	14,234	14,907

Source: Application, Page 9-1; Application, Schedule 9.1.

247. Using the numbers in the above table, the capital expenditures for the test period are forecasted to increase by approximately 40 percent each year when compared to 2015. Capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively, when compared to 2015.

248. Generally, with the exception of projects described in the following sections, AEY's capital additions are categorized as generation, new extensions, distribution improvements, street and sentinel lights, meters and general property and equipment. Generic descriptions of each category are provided in pages 9-1 to 9-5 of the Application, while a listing of the projects that make up the dollars shown Table 17

(above) of this order are provided in Schedules 9.1 and 9.2 of the Application. A listing of the capital expenditure information for 2016 and 2017, as well as project descriptions for those projects greater than $100,000, are found in Attachment 9.1 and Attachment 9.2, respectively. Full business cases for major capital projects, $500,000 or greater, are included in the Application's appendices.

249. AEY provided the following information that shows that its controllable capital was within 3.2 percent the capital expenditure amounts approved in Board Order 2014-06 for its 2013-2015 GRA. The following table shows the variances in AEY's controllable capital expenditures between its actual and approved amounts for 2013-2015:

Table 18. **Controllable Capital Expenditures — 2013 to 2015 ($000s)**

2013-2015 GRA			
	Actual	**Approved**	**Variance (%)**
New Extensions	6,141	15,480	60.3%
Contributions	(4,866)	(13,039)	62.7%
Net New Extensions	1,275	2,441	47.7%
"Controllable" Capital	36,748	37,955	3.2 %
Total Net Capital	38,023	40,396	5.9%

Source: Exhibit B-4, CW-YECL-1.

9.1 Views of interveners

250. Mr. Maissan pointed out that the projects listed in Attachments 11-1 to 11-6 of the Application,[140] relating to project cost overruns, exceeded the forecast budgets by a total of $4.7 million. The 2013 to 2015 forecast controllable project expenditures spent is $32.048 million. Mr. Maissan stated that AEY underspent by $5.947 million or by 15.65 percent of the original forecast. Mr. Maissan went on to state:

> … a significant number of forecasted capital projects did not get done, had they been done the "controllable" capital budget would have been exceeded by $4.7 million or more. Many projects have been dropped or deferred, but AEY provided no information on them.[141]

251. Mr. Maissan recommended that the Board order AEY to provide detailed information on capital projects that have been deferred or dropped, and the level of detail should be commensurate with the detail required for AEY capital forecasts. Mr. Maissan further recommended that the Board reduce the controllable capital budget, after any and all other adjustments, by three percent. The Board should further order AEY to indicate in a compliance filing where these cuts were made.[142]

[140] Exhibit BB-1, Application, Project Completion Summaries Table, page 11-3.
[141] JM Final Argument, page 7.
[142] JM Final Argument, page 7.

9.2 Applicant responses to interveners

252. Responding to Mr. Maissan's submission, AEY referred to its response to YUB-YECL-11(b) Attachment 1, a spreadsheet that includes a list of all projects approved capital projects and deemed capital projects from the 2013-2015 period. AEY pointed out that in this spreadsheet, projects with variances of 10 percent and greater than $50,000 are accompanied by a corresponding explanation. AEY noted that in its Application it had resubmitted updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but have been deferred to the 2016-2017 test period.[143]

253. AEY stated that the arbitrary reduction of the capital forecast, as recommended by Mr. Maissan, ignores the significant amount of evidence on the record supporting the need and prudence of the capital projects within the capital forecast, pointing out that the capital program throughout 2013-2015 was significantly higher than what AEY has experienced in recent years. AEY submitted that it has incorporated the learnings gained from this experience into its capital forecast by making adjustments in its forecasting methodology and assumptions. AEY submits that the evidence on record does not support Mr. Maissan's recommended reduction.

9.3 Views of the Board

254. The Board has reviewed AEY's capital addition forecasts and corresponding information and considers that AEY has provided sufficient support for its capital forecast for 2016-2017. Although the increase in capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively from 2015, the capital additions are reasonable when compared to the prior three years' actual capital additions. Subject to the Board's findings in the subsections that follow, the forecast capital additions and capital expenditures have been supported by business cases and the Board accepts the explanations in the updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but were deferred.

255. For these reasons, Mr. Maissan's recommendation for a general cut for AEY's controllable capital budget is not warranted.

9.4 Distribution Plant additions

256. AEY provided the following information related to distribution plant additions for the period 2013 to 2017:

Table 19. **Distribution Plant Additions — 2013 to 2017 ($000s)**

	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	
	2013	2013	2014	2014	2015	2015	2016	2017
New Extensions	2,350	5,033	1,693	5,147	2,098	5,300	2,160	3,388
Distribution Improvements	4,002	4,021	3,980	4,457	3,326	3,875	4,346	4,178
Street & Sentinel Lights	536	420	322	945	466	813	585	1,132
Meters	308	600	166	204	234	207	200	204

[143] AEY Reply Argument, paragraph 96.

Transformers & Regulators	72	10	75	10	108	10	368	92
Distribution in Total	7,268	10,084	6,236	10,762	6,232	10,205	7,659	8,994

Source: AEY Application, Schedule 9.1.

257. AEY pointed out that, as a result of AEY's forecasting, the 2016 forecasts represent a 41-percent reduction compared to the 2015 approved forecast.[144]

9.4.1 Views of interveners

258. UCG noted that total actual distribution plant additions for the 2013 to 2015 timeframe were $19.736 million, compared to the approved forecast amount of $31.051 million. UCG submitted that ratepayers have paid the costs of $11.315 million in forecasted distribution plant additions that never took place within the test years.

259. Given this recent track record of overestimating plant additions, UCG recommended that the distribution plant forecast for the 2016-2017 test period be reduced by 40 percent.[145]

9.4.2 Views of the Board

260. Regarding the UCG comments that forecasted capital additions were greater than actual capital additions, the Board notes that the approved forecasted plant additions ($31.051 million) for 2013 to 2015 have been subsequently trued up to now reflect the actual plant additions ($19.736 million) for 2013 to 2015. It is the actual plant additions that are now reflected in the 2015 actual closing balances that are used to inform the 2016 test year opening capital balances. Furthermore, this is standard process for forward-looking (or prospective) cost-of-service jurisdictions.

261. The Board has reviewed AEY's forecasted planned additions to distribution and corresponding information and considers that AEY has provided sufficient support for its distribution plant additions for 2016-2017. With respect to AEY's test year distribution forecasts compared to previous year's actual and approved numbers, it appears that the primary reason for the increase is related to distribution improvements. The Board's findings related to distribution improvements are addressed in section 9.4.4. Subject to the findings in that section, the Board considers AEY forecasts to be reasonable for distribution plant additions and does not agree with UCG's recommendation to reduce the 2016-2017 test-period forecasts.

9.4.3 New Extensions

262. With respect to New Extensions, AEY stated that the forecast is based on discussions with the Yukon government, the City of Whitehorse and First Nation governments. AEY holds a seat on the Development Review Committee with the City of Whitehorse. As a result, AEY has contact with developers and engineering firms, which informs the new extension forecast. AEY submitted that it also considers historical customer additions in formulating its forecasts to specifically account for walk-in customers who may require service during the test years.

[144] AEY Reply Argument, paragraph 126.
[145] UCG Final Argument, paragraphs 175 to 176.

263. AEY submitted that the reason for lower new extensions expenditures as compared to previously approved numbers is slower economic growth than previously anticipated. AEY added that new extensions are a capital cost not at the control of AEY and are dependent on development within the communities in which the company operates.[146]

264. AEY submitted that it uses the best information available when preparing its forecasts, which includes any lessons learned from past test periods. AEY reiterated that its new extension forecast is based on "historical actual experience and incorporated information from the Yukon Government, the City of Whitehorse, and First Nation Governments … there is no systemic forecast error and … the forecast has no relation to, or correlation with the 2013-2015 forecast."[147]

9.4.3.1 Views of interveners

265. CW noted that AEY admitted it over-forecasted capital additions related to new extensions over the 2013 to 2015 period. Furthermore, taking customer contributions into account, the forecast for net new extensions over the period is 47.7 percent higher than actuals. CW submitted that the systematic over-forecasting results in customers paying for capital that is not actually put into service. Accordingly, CW recommended the Board reduce the 2016-2017 test period forecast for net new extensions by 47.7 percent to account for the systemic forecast error.[148]

9.4.3.2 Views of the Board

266. With respect to the argument put forth by CW, the Board is not convinced that a three-year period of actuals being lower than approved amounts can be classified as systemic. The Board accepts Mr. Tenney's testimony on behalf of AEY that overall, the three-year forecast period was fairly accurate.[149] However, the Board notes that might not be true on a line-item-by-line-item basis. Mr. Tenney also stated in testimony:

> With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that the need to move forward.[150]

267. Mr. Massie added:

> And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I'd say that we've reflected it in our '16 and '17 forecasts.[151]

268. The Board accepts AEY's testimony that it has adjusted its test period forecasts to account for historical over forecasting. The Board does not accept CW's and UCG's recommendations to reduce AEY's new extension forecast.

[146] Exhibit B-4, CW-YECL-1.
[147] AEY Final Argument, paragraph 130.
[148] Exhibit C3-3, CW Evidence, A8.
[149] Transcript, Volume 3, page 441, lines 13 to 14.
[150] Transcript, Volume 3, page 442, lines 6 to 9.
[151] Transcript, Volume 3, page 442, lines 17 to 22.

269. Furthermore, the Board notes that the 2016 new extension forecast is three percent greater than 2015 actuals, and the 2017 forecast is 2.2 percent greater than the 2016 forecast, after the Whistle Bend Stage 3 project is accounted for in the forecast.

270. In the Board's view, AEY is taking into account current economic conditions in the Yukon and information available to it at the time of preparing the forecast. Moreover, the Board notes that AEY's submission that indicated that year-to-date costs for new extensions, as of October 31, 2016, are $2.116 million, or 98 percent of the 2016 forecast.[152]

271. For these reasons, the Board approves AEY's forecast as filed.

9.4.4 Distribution improvement projects

272. AEY submitted that distribution improvement projects generally fall into four major categories: (1) system performance projects, (2) life extension projects, (3) system replacement projects, and (4) "forced" projects. AEY clarified that these projects are required to maintain system performance at an acceptable level and that this category of capital projects includes system protection, voltage, current and line clearance projects.[153] AEY added that it tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.[154]

273. AEY submitted that the proposed test period forecast distribution improvement projects are prudent in that they ensure the continued supply of safe and reliable electricity to AEY's customers at a reasonable price. Accordingly, AEY submitted that the Board should approve the 2016-2017 distribution improvements as applied for.[155]

274. AEY pointed out that it files KPI (key performance indicators) reports on an annual basis. AEY submitted that the reports are available on the Board's website and added that that the last such report for year 2015 was filed on May 4, 2016.[156]

9.4.4.1 Views of interveners

275. UCG noted that system improvement expenditures increased an average of $3.75 million per year over the period from 2010 to 2015. UCG further noted that AEY proposed system improvement expenditures of $4.346 and $4.178 million in 2016 and 2017 respectively, but has provided no evidence of expected system performance improvements with respect to line losses and interruption indices. UCG included the following in argument:

> UCG submits that without an established benchmark, the Board and ratepayers cannot determine how well AEY is actually performing with respect to SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) reliability performance indices. UCG submits that the Board

[152] AEY Reply Argument, paragraph 91; Transcript, Volume 3, page 509, line 25, to 510, lines 1-2.
[153] Exhibit BB-1, Application, Page 9-2.
[154] Exhibit BB-1, Application, Page 9-3,
[155] AEY Final Argument, paragraph 138.
[156] AEY Reply Argument, paragraph 46.

> should establish performance and reliability benchmarks and AEY should be directed to report its actual performance against these benchmarks.[157]

276. Considering the above, UCG submitted that AEY should be denied distribution expenditures in 2016 and 2017 since evidence has not been provided that demonstrates a benefit to customers.

9.4.4.2 Views of the Board

277. The Board approves AEY's proposed distribution improvement expenditures as filed. Nonetheless, with respect to system performance projects, the Board notes AEY submission that it:

> … tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. To this end, AEY reviews unplanned outages that may be attributed to system deficiencies, prepares a report for each, and implements corrective action.[158]

278. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings.

9.4.5 Meters

279. AEY submitted that capital additions for meters should include new meter installations that are required to replace end-of-life meters consistent with Measurement Canada requirements. This category of capital additions also includes the installation of new meters required to accommodate load growth associated with customer requests for service. The capital meter additions forecast is based on known areas of development and expected connection repairs.

280. AEY pointed out that it purchases meters from ATCO Electric at cost and, in so doing, is able to take advantage of the economies of scale realized by ATCO Electric in its meter purchases. This is a significant benefit to AEY and its customers. AEY submitted "this is undoubtedly the least cost alternative given that it is able to purchase its meters, but with the buying power of a utility the size of ATCO Electric."[159] Furthermore, other than AEY and its customers benefiting from this relationship, AEY submitted that it is unclear as to what benefit could be derived by the ATCO family of companies, given that the meters are purchased at cost.

[157] UCG Final Argument, paragraph 231.
[158] AEY Final Argument, paragraph 136.
[159] AEY Reply Argument, paragraph 136.

9.4.5.1 Views of interveners

281. With respect to meter replacement and new installations, UCG commented that over the period 2013-2015, AEY had actual expenditures of $708,000 that were well below the approved $1 million total. UCG submitted that this significant over-forecasting trend should be used to reduce the forecasts proposed for 2016 and 2017. UCG also referred to AEY's submission that it purchases meters from ATCO Electric's meter shop in Grande Prairie. UCG submitted that there should be further clarification on how this arrangement was determined to be the least cost alternative supply point and whether the affiliate relationship had been used to provide benefits to the ATCO family of companies.[160]

9.4.5.2 Views of the Board

282. The Board accepts AEY's submission that it is able to purchase its meters at cost from ATCO Electric. Accordingly, the Board finds that no further information is required. The meters are supplied by the affiliate at cost, and the mere existence of the affiliate arrangement for the provision of these meters, in these circumstances, does not merit further clarification by AEY at this time. UCG's request is denied.

9.5 Conversion of existing LED streetlights

283. AEY indicated that it has been in discussions with its customers, some of which are municipalities, regarding recent developments related to the conversion of existing streetlights to light-emitting diode (LED) lamps. Considering there is capital outlay associated with the conversion of existing streetlights to LED, AEY submitted that it is seeking the Board's direction

> … as to the appropriate method of accounting for the capital costs associated with customers requesting conversions of existing streetlights to LED. ATCO Electric Yukon considers there to be two available options:
>
> (1) A full customer contribution required for all associated capital costs; or
>
> (2) All capital costs associated with requested conversions would be a system cost, not subject to a customer contribution.[161]

284. AEY explained that the rationale for this project being a system cost would be that the initial streetlight cost was contributed by the customer when the streetlight was originally installed. At the end of useful life when the asset needs replacement, the customer is not required to contribute again and the cost becomes a system cost.[162]

285. AEY acknowledged the benefit of reducing load on the electrical system and that the longer lifespan of equipment used under this project could lead to reduced costs in operation and maintenance of the lights. AEY submitted that converting all existing high-pressure sodium (HPS) streetlights to LED streetlights in AEY's communities would cost approximately $2 million and the project would need to be completed over several years due to resource constraints.

[160] UCG Final Argument, paragraphs 221 to 222.
[161] Exhibit BB-1, Application, page 9-3.
[162] Exhibit B-9, YUB-YECL-10(c).

286. AEY provided two cost-benefit analyses for converting lights in thermal communities and hydro communities for each of the two options: customer contributions or system costs.[163] The cost-benefit analyses showed that a greater net present value (NPV) would result if the conversions were done in diesel-served (thermal) communities compared to hydro communities. AEY reiterated that it is not applying for approval of a wholesale replacement of all existing HPS streetlights but is seeking Board direction as to the appropriate method of accounting for the costs associated with customer conversions of existing streetlights to LED.[164]

9.5.1 Views of interveners

287. Mr. Maissan indicated his support for the LED-conversion project and recommended that the Board direct AEY to proceed with the conversion of streetlights (i.e. HPS to LED lights) as a system cost and that priority be given to diesel-served communities.

288. CW indicated its support for the conversion of existing streetlights to LED lamps. However, CW submitted that it is inappropriate for AEY to request the Board to issue direction as to the method of accounting for the associated capital costs in the absence of a fully supported proposal by AEY on that issue. Accordingly, CW recommended that the Board direct AEY to submit a proposal, supported by evidence, which can be tested by the Board in order for it to make a determination on this issue.

9.5.2 Applicant responses to interveners

289. AEY submitted that it is not clear as to what additional information CW is proposing that AEY file with the Board. From AEY's perspective, the decision is relatively straightforward in that either the conversion costs are treated as a system cost or the local municipality must pay for the conversion cost as a contribution in aid of construction. AEY pointed out that economic analyses of both treatments as well as the total estimated costs involved are on the record. All parties have had an opportunity to submit IRs and cross-examine AEY with respect to the information. AEY submitted that the record is complete and the Board has ample information to render a decision on the treatment of costs for streetlight conversions.

> Moreover, the treatment of such costs will likely inform the decisions of the relevant communities and/or municipalities with regard to such conversions.[165]

290. AEY asserted that requiring it to come forward with a fully supported proposal is entirely unnecessary and would only serve to add inefficiencies to the regulatory process.

9.5.3 Views of the Board

291. The Board supports AEY's rationale for a streetlight project to be treated as a system cost, as outlined:

[163] Exhibit B-9, YUB-YECL-10(b) Attachment 1.
[164] Exhibit B-4, CW-YECL-27 (h).
[165] AEY Reply Argument, paragraph 95.

> … the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service at the time. At the end of useful life when the asset needs replacement the customer is not required to contribute again and the cost becomes a system cost.[166]

292. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost.

293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction.

9.6 Project cost overruns (related to Direction 13 — Board Order 2014-06)

294. Responding to Direction No. 13 of Board Order 2014-06, in relation to project cost overruns, AEY included project completion summaries for all projects that were forecast in AEY's 2013-2015 GRA for which actual costs were 100 percent and $100,000 greater than the original forecast. AEY's compliance with Direction 13 is discussed in section 11 of this decision.

295. The following table contains the list of projects and the related attachment in section 11 of the Application wherein the project descriptions and summaries are provided. Actual and approved forecast costs are included in the summaries, as well as explanations for the variances:

Table 20. **Project Completion Summaries ($000s)**

Project	Attachment	Approved Forecast	Actuals
Fish Lake Dyke Upgrade	Attachment 11.1	1,720	2,552
Old Crow Plant Expansion	Attachment 11.2	1,950	4,566
Beaver Creek PLC Upgrade	Attachment 11.3	180	377
McIntyre Subdivision Rebuild	Attachment 11.4	725	1,453
Deep Creek Subdivision Connection	Attachment 11.5	60	213
Old Crow Staff Accommodations	Attachment 11.6	100	274

Source: Exhibit BB-1, Page 11-3, Attachments 11.1 to 11.6.

[166] Exhibit B-9, YUB-YECL-10(c)

296. AEY provided business cases for projects where the actual costs were in excess of $100,000 and for which no business case was provided. The following table includes the list of projects and the actual costs:

Table 21. **Business Cases for Completed Projects ($000s)**

Project	Attachment	Actuals
Old Crow #2 Replacement	Attachment 11.7	161
Whistle Bend Subdivision Stages 1 & 2	Attachment 11.8	513
Whistle Bend Underground Residential Service	Attachment 11.9	116
City of Whitehorse Range Road Widening	Attachment 11.10	188
4L314 Chilkoot Way Upgrade	Attachment 11.11	483
Azure Road Extension	Attachment 11.12	151
2nd Ave Rebuild	Attachment 11.13	115

Source: Exhibit BB-1, Page 11-4, Attachments 11.7 to 11.13.

9.6.1 Views of interveners

297. With respect to the Old Crow plant expansion project, which went over-budget by $2.616 million, Mr. Maissan asserted that AEY has been operating in Old Crow for many years and submitted that AEY should have suspended and re-assessed the project when it ran into design cost overruns and local logistical difficulties. Mr. Maissan recommended that the Board retain experts to review and audit the project execution process and cost, or the Board disallow $1 million of the $2,616 million cost overruns and remove it from rate base.[167] With respect to the Old Crow Unit 4 Addition project, Mr. Maissan recommended that the Board direct AEY to provide a business case for this project, as it was completed $112,000 over budget.[168]

298. UCG expressed concerns with the significant expenditures over approved budget amounts for many of the capital projects that had been previously approved. UCG submitted, “If there is no evidence that these extra costs were prudently incurred, they should not be allowed to be added to AEY’s rate base.”[169] UCG stated that additions to AEY’s rate base should be limited to allowed cost estimates unless AEY can provide evidence that the cost overruns were prudently incurred. In particular, UCG submitted that the doubling of the cost for the McIntyre Subdivision Rebuild should be the responsibility of AEY, not ratepayers. It concluded with respect to the McIntyre Subdivision Rebuild:

> AEY’s evidence is that this project went well beyond the Board approved level because the location and installation of the existing underground system would be in constant conflict with the installation of the new system. This along with other issues resulted in a requirement to develop an entirely new project scope. This resulted in AEY incurring an additional $728,000 in costs (for a project originally assumed to cost $725,000) and doubling the cost of the project.[170]

[167] JM Final Argument, page 8.
[168] JM Final Argument, page 9.
[169] UCG Final Argument, paragraph 160.
[170] UCG Final Argument, paragraphs 177.

299. UCG further submitted that AEY should not be able to arbitrarily add capital projects to rate base that have not been previously approved by the Board. [171] Furthermore, expressing concerns respecting the rapid increase in AEY's rate base in the 2013-2015 timeframe, UCG submitted that AEY should be required to submit detailed asset management plans and/or distribution system plans, the elements of which "will drive the development of investment and maintenance for the test year(s) and beyond.[172]

9.6.2 Applicant responses to interveners

300. Notwithstanding the comprehensiveness of the Old Crow business case, as acknowledged by Mr. Maissan, AEY submitted that project timing was restricted given the timing of the construction of the ice road. Furthermore, the magnitude and extent of the many challenges that arose could not have been foreseen. AEY submitted that although the business and community need did not change, AEY proceeded with the project knowing the costs would be fully examined in a future GRA. AEY confirmed that it would be:

> … submitting a Post Completion Summary of the project, that clearly indicates the variances, and gives the Board and Interveners an opportunity to examine the Project during the entirety of a regulatory proceeding is the most appropriate process, without putting the supply of power to the community at risk.[173]

301. Respecting Mr. Maissan's recommendation that AEY submit a business case for the Old Crow Unit 4 addition costs because project costs exceeded the original estimate by more than $100,000, AEY pointed out that the costs did not exceed 100 percent of the approved forecast. As such, AEY submitted "the business case type description of the cost overrun sought by Maissan is not required" and AEY submitted that there is sufficient information on the record to deem the project useful and prudent.[174]

302. Responding to UCG, AEY replied that it does not arbitrarily add capital projects to rate base. AEY's capital expenditure forecasts are based on the best available information at the time of its GRA. AEY submitted that unknown costs that arise and are not included in test period forecasts are subsequently included as actuals in future applications, thus providing the Board and interveners with the opportunity to assess the need and prudency of such costs. AEY submitted that despite UCG's claims, there is ample evidence on the record to demonstrate that all costs related to McIntyre Stage 1 have been prudently incurred. AEY argued that project planning was comprehensive and many assumptions were validated. It could not have predicted what caused the project scope to be adjusted. AEY indicated that, "Project planning and execution was constantly reviewed and updated with the best available information, al while ensuring the customer and Project needs are addressed."[175]

[171] UCG Final Argument, paragraph 162
[172] UCG Final Argument, paragraph 165
[173] AEY Reply Argument, paragraph 104.
[174] AEY Final Argument, paragraph 106.
[175] AEY Reply Argument, paragraph 129.

303. AEY added that there is no evidence on the record indicating that the "capital projects put forward by AEY are not needed or that they have not been completed prudently."[176] With respect to the UCG submission that AEY provide a detailed asset management plan, AEY submitted that such an undertaking is beyond the scope of this proceeding and is being put forward by UCG with limited explanation and no evidence to justify such a request.[177]

9.6.3 Views of the Board

304. The Board notes that in its Application, AEY has provided:

(a) project completion summaries that were forecast in its 2013-2015 GRA, for which actual costs were 100-percent and $100,000 greater than the original forecast; and

(b) business cases for projects where actual costs were greater than $100,000 and for which no business cases were provided.

305. As a result, AEY provided a business case (Appendix 11) for the Destruction Bay Unit 3 replacement where actual costs exceeded the $450,000 forecasted by $184,000. The Board further acknowledges that AEY provided a comparison of forecast and actual costs,[178] accompanied with an explanation for projects with variances of 10 percent and greater than $50,000.

306. When costs are provided in a GRA on a forecast basis, the Board accepts the information available at the time of filing the Application or that becomes available prior to the close of record of the proceeding. Providing the Board with the best available information at the time that it must make its decision assists the Board in determining a revenue requirement for the utility that most closely matches a utility's expected costs given facts known at the time the application was made or before the close of record. It is incumbent on the utility to do so, and for the utility to plan and budget in preparing its forecasts. Unforeseen projects may arise after a Board Order is issued with respect to the forecast test period. In these cases, the Board reviews the project costs and the variances in the subsequent GRA to ensure that the costs were prudently incurred by the utility.

307. Despite the magnitude of some of the variances between forecast and actual capital expenditures for certain capital projects, the Board accepts the variance explanations provided by AEY.

308. Considering the above, the Board accepts the information found in the project completion summaries and business cases for completed projects. No further direction from the Board is required. The projects and their corresponding costs are discussed in the following sections.

[176] AEY Final Argument, paragraph 122.
[177] AEY Reply Argument, paragraph 125.
[178] Exhibit B-9, YUB-YECL-11(b) Attachment 1.

9.7 Major capital projects

309. In the Application, AEY provided 11 business cases found in Appendix 1 to Appendix 11, in support of major capital projects where forecast costs were $500,000 or greater. Major capital projects and the underlying business cases are discussed in the sections below.

9.7.1 Fish Lake System expenditures[179]

310. AEY noted that the Fish Lake hydro system was built around 1950 and the aging infrastructure is coming to the end of its useful life. In order to maintain Inflow Design Flood (IDF) rates and comply with its water licence for Fish Lake, AEY proposed two projects: the Fish Lake Ditch 3 Diversion project and Fish Lake #2 Head Pond Spillway replacement.

9.7.1.1 Fish Lake Ditch 3 Diversion project (Appendix 1)

311. This project was previously approved in AEY's 2013-2015 GRA. On May 31, 2013, AEY was granted a 25-year extension to its water-use licence, HY12-065. AEY submitted that during the water licence application process, it was identified that the Fish Lake Ditch 3 diversion structure and spillway were not adequately built to withstand a 100-year flood event, which is required to meet IDF rates and comply with its water licensing requirements. AEY is planning to replace and upgrade the Ditch 3 diversion structure and spillway to an engineered design that will allow it to meet these requirements. Accordingly, AEY provided an updated cost forecast with respect to this project, which is reproduced below:

Table 22. **Fish Lake Ditch 3 Diversion – 2013 to 2017 — actual and forecast costs ($000s)**

Year	Actuals	Forecasts	Total
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	134	2,915	3,049

Source: Exhibit BB-1, Application, Appendix 1, page 2.

9.7.1.2 Fish Lake #2 Head Pond Spillway Replacement (Appendix 2)

312. Investigative repairs of the Fish Lake #2 head pond spillway structure identified that the overall structure was in need of replacement. AEY explained that it will have to replace the existing spillway structure in order to adequately handle IDF flows while maintaining safe access to AEY generation facilities. AEY submitted that the project was designed in 2016 and construction is expected to be completed in 2017. Design and engineering costs are estimated to be $20,000 and the current construction costs are forecasted to be $593,000.

[179] Exhibit BB-1, Application: Appendix 1, Fish Lake Ditch 3 Diversion Replacement and Appendix 2, Fish Lake 2 Head Pond Spillway Replacement.

9.7.1.3 Views of interveners

313. UCG noted that over the period from 2006 to 2015, AEY has spent $11.429 million in capital and $1.96 million in O&M expenditures, while AEY, over the same period, has recovered $5.87 million in revenue requirement from ratepayers. UCG pointed out that AEY is now looking to spend over $3 million on the Fish Lake Ditch 3 replacement project and an additional $0.593 million on the Fish Lake #2 Head Pond Spillway replacement project. Considering the limited amount of total load that is supplied via the Fish Lake plant, it is questionable whether spending this level of funds on a deteriorating plant is providing ratepayers value for their money.[180]

9.7.1.4 Applicant responses to interveners

314. AEY submitted that the projects were being completed on water management structures that direct and control water and water flows in the Fish Lake system in compliance with AEY's water licence. AEY specified with respect to water licensing requirements that:

> As indicated in the Water License, there are maximum and minimum flows that must be maintained throughout the system. Also, a condition of AEY's Water License is that works associated with the License will be maintained to a sound engineering standard (condition 27 of the Water License).[181]

315. AEY further clarified by stating that the specific recommendations for these projects can be found in its *2014 Dam Safety Report*.[182]

9.7.1.5 Views of the Board

316. The Board accepts the need for both of these projects, as they are a condition of the water licence.

317. In the case of the Fish Lake Ditch 3 diversion project, a higher standard in regard to water licence HY12-065 was directed for this project. The change in standard caused a delay as draft designs and spillway channel brushing were required in 2014, additional surveying was necessary to enable updated design models and adjustments in 2015, and further construction and civil work was scheduled to be completed in 2016.

318. The requirement for the Fish Lake #2 Head Pond Spillway Project was not discovered until repairs in 2013 brought to light a sinkhole near this dam structure. Further, investigative work resulting in the 2014 Dam Safety Report recommended replacement of the structure by the end of 2017. Accordingly, the Board does not accept UCG's recommendation to deny the expenditures for this project.

319. The Board accepts the updated forecast costs for the Fish Lake Ditch 3 diversion project as these costs are necessary to meet the standards of the new water licence. The Fish Lake #2 Head Pond Spillway costs have not been challenged in this proceeding, and for the reasons provided in this decision, the Board finds these costs are reasonable.

[180] UCG Final Argument, paragraphs 218 to 220.
[181] AEY Reply Argument, paragraph 134.
[182] Exhibit B-9, YUB-YECL-14(a), Attachment 1.

9.7.2 Watson Lake Bi-Fuel Project (Appendix 3)

320. AEY is proposing a two-phased, three-year project to convert each of its six diesel generation engines in Watson Lake to bi-fuel. The two phases were described as:

- Phase 1: 2016 – 2017: Source Liquefied Natural Gas (LNG) storage equipment; upgrade Watson Lake plant to meet the safety standard for LNG equipment; install Bi-Fuel technology to one of the six engines; and conduct environmental assessment of engines as directed by Yukon Environmental and Socio-economic Assessment Board (YESAB).

- Phase 2: 2018: Source and install Bi-Fuel technology to the remaining five diesel engines at the Watson Lake plant and increase the volume of LNG storage onsite.[183]

321. If Board approval of the project is received in Q1 of 2017, AEY added that Phase 1 could be completed as early as Q3 of 2017. AEY submitted that Phase 2 of the project is expected to be completed following Yukon Environmental and Societal Assessment Board (YESAB) approval of Phase 1.[184]

322. AEY submitted that this project achieves the federal and Yukon governments' goals of displacing diesel and managing electricity costs by using LNG as an alternative fuel source. Using LNG will reduce diesel consumption of its power generation plant in Watson Lake by approximately 50 percent because it is a cheaper fuel source than diesel. AEY asserted that it "… expects to save hundreds of thousands of dollars annually on fuel costs by the end of this project" and that "These savings would be passed directly on to customers."[185]

323. AEY pointed out that forecasted cost savings are dependent on the differential between the price of delivered diesel and LNG to Watson Lake and the consumption of those fuels. AEY added that the bulk of the delivered LNG price is attributed to the cost of liquefaction and transportation fees. Recognizing the uncertainty as to the future prices for diesel and natural gas, AEY provided 20-year NPV analyses using 12 different scenarios where fuel prices were escalated at differing fixed rates from the 2015 historical price of diesel and natural gas.[186]

324. AEY estimated the total cost of this project to be approximately $5 million, albeit at this time, AEY is seeking approval for $3.3 million to implement Phase 1 of the project. AEY submitted that it will competitively tender each of the major elements of the project,[187] excluding the equipment purchased from ATCO Gas. Further:

> ATCO Electric Yukon proposes to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for

[183] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[184] AEY Final Argument, paragraph 150.
[185] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[186] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, Table 2, page 7, and Table 3, page 8.
[187] The major elements of the project are described in the Application, Appendix 3, page 3.

> Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[188]

325. AEY estimates the annual incremental O&M costs that are not included in the 2016-2017 forecasted costs but will apply in future years to be approximately $50,000 per year. AEY submitted that the O&M contract specific to the LNG equipment will be competitively tendered, will include periodic maintenance, and will involve additional safety training for AEY's operational staff.[189]

326. Asked why it would choose a new unit that requires field modifications to burn both diesel and natural gas rather than purchasing a new unit that is factory capable of burning both fuels, and with nameplate performance ratings, AEY responded:

> Until AEY receives YUB approval for the Watson Lake Bi-Fuel project, AEY wants to minimize the funds committed to this project. At the time AEY tenders the Watson Lake Unit 2 Replacement, requests will be made for both diesel and Bi-Fuel enabled generating units. AEY will determine what unit is most prudent to purchase. Once the Watson Lake Bi-Fuel project is complete, factory enabled dual fuel units will be considered as generating units are due for replacement.[190]

327. AEY submitted that all of the project-related costs presented in the following table are budgetary, except for the actual costs incurred to date:

Table 23. **Watson Lake bi-fuel project — Phase 1 and 2 capital costs**

	Phase 1			Phase 2
	2012-15	**2016**	**2017**	**2018**
Study costs	$222,000			
Engineering, design, and permitting	$272,000	$55,000	$152,000	$105,000
LNG vaporizer and LNG storage tank			$1,194,000	
Installation (civil, mechanical, and electrical) and boarding			$1,090,000	
Conversion of remaining units to bi-fuel				$700,000
Tank expansion, piping, cryopump and installation				$905,000
Phase sub-total			$2,985,000	$1,710,000
Total				$4,695,000

Source: Exhibit B-9, YUB-YECL-13(b).

328. AEY submitted that it believes there are environmental benefits to this project, which it has previously discussed and which have further been the subject of a review pursuant to the *Yukon Environmental and Socio-economic Assessment Act.* A decision document that supported the project was issued in August 2013.[191]

[188] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 3.
[189] Exhibit B-9, YUB-YECL-13(e).
[190] Exhibit B-9, YUB-YECL-24(h).
[191] AEY Final Argument, paragraph 143.

329. With respect to project expenditures, AEY submitted that Phase 1 expenditures are the only costs to be incurred within the test period and AEY is seeking to recover those as part of this GRA. AEY explained that Phase 2 of this project is necessary to provide all of the benefits to ratepayers and reduce costs over the long-term by increasing consumption of LNG over the life of the project. AEY submitted that the objective in this GRA is "to obtain Board approval to complete both phases of this Project and AEY will bring forth Phase 2 costs for a prudency determination as part of a future general rate application."[192]

9.7.2.1 Views of interveners

330. With respect to the results of the analysis provided by AEY in its business case[193] and the fuel price scenarios for diesel and natural gas over the period from 2017 to 2037, Mr. Maissan referred to the following:

> Of the 12 scenarios provided in tables 2 and 3, 2 have a negative 20 year NPVs and 3 are below $2 million in NPV. Four scenarios are at $5 million NPV or higher.[194]

331. Mr. Maissan pointed out that the analysis did not account for renewable generation and assumed that all electrical loads will be served by diesel or LNG for the next 20 years. Noting Mr. Tenney's acknowledgement of this on behalf of AEY, Mr. Maissan pointed out that the Yukon's Independent Power Producers (IPP) policy provides for 2,100 MWh of generation to be available to Watson Lake under the standing offer program portion of the IPP policy. Mr. Maissan submitted that any further generation added under the micro-generation program will displace more diesel generation and weaken the economics of the bi-fuel conversion project.[195]

332. Mr. Maissan noted AEY's submission that the project will break even over 20 years when the price per litre of LNG on a diesel-litre-equivalent basis (DLE) is 75.6 percent of the cost of delivered diesel. Considering the price of LNG over the past 12 months, Mr. Maissan argued that the project is uneconomical if LNG were sourced from FortisBC and is just economical if LNG is sourced from AltaGas in Alberta. Mr. Maissan suggested that in his view, there was a high likelihood that the price differential between natural gas and diesel would approach historic levels (i.e. natural gas prices growing closer to diesel prices). If this were to occur, it would make the project uneconomical regardless of which supplier is liquefying and transporting the natural gas.[196]

333. Considering the above, Mr. Maissan recommended that the Board deny the Watson Lake bi-fuel project. Mr. Maissan further recommended that of AEY's project-related costs to date, approximately $549,000 ($494,000 + $55,000) be amortized over a five-year period. On a related matter, Mr. Maissan suggested that the

[192] AEY Final Argument, paragraph 154.
[193] Exhibit BB-1, Application, Appendix 3, Table 3, page 8.
[194] JM Final Argument, page 12.
[195] JM Final Argument, page 13.
[196] JM Final Argument, page 14.

Board direct AEY to "… channel its off-diesel efforts into the acquisition of local renewable energy sources, including the issuance of an RFP for renewable energy."[197]

334. Should the Board accept AEY's proposed Watson Lake bi-fuel project, UCG submitted that the associated Watson Lake study costs be rolled into capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.[198]

335. YCS recommended that all project-related costs not be allowed into rate base. YCS argued that the project is not economically prudent nor is the project environmentally prudent. YCS submitted that AEY has not made a case for how this project would help governments meet goals to eliminate or reduce the dependence on diesel in indigenous, remote and northern communities with renewable, clean energy as submitted in its GRA filing. YCS also submitted that the project would not help Watson Lake integrate any new renewable energy, but would effectively act as a "barrier to the development of renewables because of the current natural gas prices setting the predicted benchmark cost per kilowatt hour at an unrealistic and unsustainable low."[199]

336. With respect to AEY's claim that the project would result in cost savings for ratepayers, YCS described the claim as dubious and echoed Mr. Maissan's submission, stating the following:

> … the Watson Lake LNG Bi-fuel project is already marginal even with the current fossil fuel prices. Depending on the fuel source, the project is already uneconomic from one supplier. Any shift toward the historical trend (LNG and diesel closer in cost) will make this project uneconomic regardless of which supplier is liquefying and transporting the natural gas.[200]

337. Additionally, YCS submitted that the AEY analysis did not consider the impacts of renewable energy inputs onto the Watson Lake grid within the project lifetime, did not calculate how that would reduce utilization of this project and, by extension, negatively affect the economics and business case. Therefore, considering that the project is not environmentally or economically prudent, the financial risk to the ratepayer from fuel price changes, and the addition of renewable energy to the Watson Lake grid, YCS recommended that the Board deny the Watson Lake bi-fuel project.[201]

9.7.2.2 Applicant responses to interveners

338. Noting that Mr. Maissan and YCS criticized the project business case for not considering the impact of renewables, AEY submitted that it "must make decisions based on the best information it has available to it and there is no evidence of any IPP program developers proposing renewable energy projects in Watson Lake."[202] Given the restriction on nameplate capacity, AEY pointed out that it would take three separate projects to meet the limit of 2,100 MWh/year. Notwithstanding, in order to demonstrate the economic viability of the Watson Lake bi-fuel project, AEY submitted that it re-ran its

[197] JM Final Argument, page 14.
[198] UCG Final Argument, paragraph 172.
[199] YCS Final Argument, page 9.
[200] YCS Final Argument, page 4.
[201] YCS Final Argument, page 5.
[202] AEY Reply Argument, paragraph 141.

model,[203] assuming the availability of 2,100 MWh/year of renewable generation, as of January 1, 2020. AEY submitted that "… there still remains a positive NPV in all six scenarios using AltaGas pricing and three of the six scenarios using the Fortis pricing."[204] Moreover, AEY stated that there is a positive 20-year internal rate of return in all 12 scenarios. AEY added the models were predicated on only two suppliers of LNG, but it is entirely reasonable to expect additional suppliers to come on-line in the near term.

339. AEY pointed out that the current economic evaluation included in the NPVs set out in Table 2 and Table 3 of Appendix 3, and later updated in response to YUB-YECL-13(b), do not include the impact of any Yukon territorial or federal carbon tax.[205] However, should a carbon tax be imposed, AEY submitted that it would likely favour the use of natural gas for electricity generation, the effect of which would be that the NPV of the bi-fuel would increase.[206]

340. AEY submitted that there is no evidence to support any of the statements that YCS made regarding the environmental impacts or lack thereof of the Watson Lake bi-fuel project. AEY further submitted that the Yukon Environmental and Socio-economic Assessment Board heard and considered the environmental evidence in relation to this project and has approved Phase 1.

9.7.2.3 Views of the Board

341. In Board Order 2014-06, the Board stated with respect to this project:

> The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period." The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."[207] (*footnotes omitted*)

342. In Board Order 2014-06, the Board had also denied the project due to concerns regarding fair market value of certain equipment to be leased from ATCO Gas. On page 82 of that decision, the Board found that fair market value of the lease of equipment assets was best determined through a competitive tender process.

343. In this Application AEY proposed:

> … to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[208]

[203] The model is embedded in the table provided in response to UCG-AEY-53(d), Attachment 1 (Exhibit B-9).
[204] AEY Reply Argument, paragraph 144.
[205] Exhibit BB-1, Application, Appendix 3, Page 5.
[206] AEY Reply Argument, paragraph 146.
[207] Board Order 2014-06 – Appendix A: Reasons for Decision, Page 81.
[208] Exhibit BB-1, Application, Appendix 3, page 3.

344. The Board acknowledges that AEY indicated that the Watson Lake Phase 1 and Phase 2 bi-fuel projects were submitted to address the Board's concerns.

345. AEY provided the information related to a comparison of potential suppliers and fuel price forecasts, as well as alternative fuel-escalation scenarios. A compiled table of this information is below:

Table 24. **Comparison of potential suppliers and fuel price forecasts**

	Supplier	Simple Payback (years)	20-year NPV ($M)	Supplier	Simple Payback (years)	20-year NPV ($M)
Sproule price forecast	Fortis	12	0.4	Fortis	11	0.6
	AltaGas	10	2.1	AltaGas	9	2.4
Both Commodities escalate at 5%	Fortis	11	2.7	Fortis	11	3.0
	AltaGas	9	5.6	AltaGas	9	5.9
Scenario 3: both commodities escalated at 2.5%	Fortis	15	(0.9)	Fortis	15	(0.7)
	AltaGas	11	1.7	AltaGas	10	2.0
Scenario 4: diesel escalated at 5%; natural gas at 2.5%	Fortis	11	3.5	Fortis	11	3.7
	AltaGas	9	6.1	AltaGas	9	6.4
Scenario 5: diesel escalated at 2.5%; natural gas at 5%	Fortis	17	(1.7)	Fortis	16	(1.4)
	AltaGas	11	1.2	AltaGas	11	1.5
Scenario 6: both commodities doubled	Fortis	7	7.1	Fortis	6	7.4
	AltaGas	5	10.2	AltaGas	5	10.5

Source: Exhibit BB-1, Appendix 3: Table 2, Page 7; Table 3, Page 8. Source: Exhibit B-9, response to YUB-YECL-13(b), Page 3 of 6.

346. With respect to Table 24, the Board notes that of the 12 original scenarios provided by AEY, two scenarios have negative-20-year NPVs, three scenarios have NPVs below $2 million, and four scenarios have NPVs of $5 million or higher. AEY provided a further 12 scenarios wherein it accounted for the decrease in costs related to the LNG vaporizer and the LNG storage tank. The table shows that the project economics improved only marginally under the additional 12 scenarios examined.

347. Further, when AEY re-ran the model assuming a scenario of 2,100 MWh/year of renewable generation as of January 1, 2020, the generation from the bi-fuel engines was reduced. However, three (instead of two) of the six scenarios using Fortis pricing were negative.[209]

348. That being said, the Board agrees with Mr. Maissan's concern that the economic comparison provided by AEY with respect to diesel and LNG in Watson Lake must sufficiently take into account potential fluctuations in the delivery costs[210] for these fuels.

[209] AEY Reply Argument, paragraph 144.
[210] Delivery costs include the costs of liquefaction and transportation of LNG.

Mr. Maissan pointed out that the liquefaction and transportation of LNG is a higher percentage of the delivered cost than refining and transporting diesel, and he submitted that the economic evaluations must include the delivered costs of these fuels. The Board notes AEY's submission that using "delivered diesel prices based on Sproule forecast, the LNG option breaks even at an average delivered-LNG-price-to-delivered-price ratio of 75.6 percent over the lifetime of the project."[211]

349. The Board further notes that it was established on the record that the price of energy in natural gas has historically been slightly less than the cost of energy in diesel. The ratio of price of energy in natural gas to the price of energy in diesel prior to 2006 ranged from 70 to 100 percent. In 2006, this ratio dropped to about 60 percent and, more recently, it is at approximately 36.2 percent.[212] The Board agrees with Mr. Maissan that it would take only a small increase in the price ratio to make the LNG option uneconomical. In fact, AEY's data in Table 24, as well as AEY's Reply Argument, show that the project would be viable under some scenarios but not under other scenarios. While the Board understands that slightly positive or positive results are expected under some scenarios, the economic benefits of the Watson Lake project are not sufficiently supported given the outcomes of the various scenarios found in Table 24 and given the corresponding assumptions used by AEY that could impact the financial viability and resulting costs for this project.

350. Further, with respect to the Watson Lake bi-fuel project and the use of diesel units, AEY stated in its business case:

> ATCO Electric Yukon and the Independent Power Producers (IPPs) are pursuing the generation of electricity with renewable resources, however, it is almost certain that a fossil-fueled base load generation source will continue to be required in the short to medium term for reliability of the system. ATCO Electric Yukon believes the switch to a Bi-Fuel Project best accomplishes this base load generation need.[213]

351. Mr. Tenney, in testimony, confirmed that while there is development of future technologies, stand-alone bi-fuel units are not currently available other than for marine applications and that is why conversion units are proposed for this project.[214] Conversion units have not been previously utilized by AEY for utility service to Yukon customers. Conversion of the existing diesel units to bi-fuel is the only option proposed other than use of existing diesel, and in fact, conversion to bi-fuel may be the only other option currently available for the use of LNG at the Watson Lake plant. This raises the issue of whether a bi-fuel conversion should be done at this time given emerging plant technologies related to bi-fuel and LNG instead of relying on the existing diesel units at Watson Lake without bi-fuel conversion. Given the state of emerging technologies and the prospect that such technologies may affect the economic benefits associated with

[211] Exhibit B-5, JM-AEY-24(d).
[212] Exhibit B-5, JM-AEY-24(a).
[213] Exhibit BB-1, Application, Appendix 3, Watson Lake Bi-Fuel Project, Page 7.
[214] Transcript, Volume 3, page 473, lines 13 to 23, Mr. Tenney stated, "So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant. So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants."

bi-fuel conversion, the Board finds that the approval of the project as proposed by AEY is not reasonable. Because the impact of the conversion of an individual bi-fuel unit on efficiency, the actual capital costs for conversion as well as the benefits to customers are not sufficiently known and base load generation is currently being supplied to the Watson Lake area by the existing diesel units.

352. The Board is also concerned with AEY's request that the Board approve Phase 1 of the Watson Lake bi-fuel project along with Phase 2 of the project, which will occur entirely in a future test period. Between Phase 1 and Phase 2, the total project costs are $4,695,000 for conversion of diesel units in the power plant that serves Watson Lake and surrounding area, in accordance with AEY's obligation to provide electricity to that area.

353. While the Board acknowledges AEY's position that Phase 2 would be required if Phase 1 is approved and undertaken, the Board does not consider that it is reasonable to approve the need for Phase 2 without the conversion of the unit under Phase 1 given the forecasted costs for the bi-fuel conversion project as proposed.

354. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision.

9.7.3 Old Crow Unit 3 replacement (Appendix 5)

355. AEY submitted that load growth and load duration of the community of Old Crow have steadily diminished the utilization of the 170-kW Old Crow unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, AEY is proposing to purchase and install a new 600-kW unit to replace the existing undersized 170-kW unit. The new unit will be installed in the new building in Old Crow as it will not be able to fit in the existing building.

356. Based on the 2012 load data provided in AEY's 2013-2015 GRA, AEY submitted that the existing 170-kW unit was approved to be replaced with a 250-kW unit. Notwithstanding the Board's approval, in preparation for tender of the new unit in 2015, AEY submitted that a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was recommended to meet load requirements.

9.7.3.1 Views of interveners

357. Mr. Maissan submitted that the desire to have two independent and completely redundant power plants in the community of Old Crow is well beyond any planning criteria approved by the Board. Mr. Maissan went on to state that the need to have a second building is not in question, but "what is in question is the prudency of the decisions about what size generators to put into this plant which operates as an extension of the existing plant."[215] Mr. Maissan pointed out that a 400-kW generator

[215] JM Final Argument, page 9.

would be running below manufacturers' recommendation "that units are operated in the range of 50-80% of rated capacity."[216] AEY's 50-percent loading target appeared tenuous to Mr. Maissan when he noted that additional solar photovoltaic (PV) capacity is planned for Old Crow. Mr. Maissan submitted that plant efficiency will suffer as the larger generators will be very lightly loaded. In addition, Mr. Maissan submitted that a 400-kW unit could be transported into the community easier than a 600-kW unit. Moreover, considering that more solar PV capacity is planned for Old Crow, Mr. Maissan recommended that the Board reject the plan to install a 600-kW generator in Old Crow and authorize the installation of a 400-kW unit at a cost of $612,000, plus $100,000 to allow for cost increases from the previous 2014-2015 timeframe for this project.[217]

9.7.3.2 Applicant responses to interveners

358. AEY replied that, in his argument, Mr. Maissan failed to take into account the Old Crow peak loading table that clearly demonstrates the need for a 600-kW unit. AEY submitted that it would not be prudent for AEY to invest in assets such as lower-capacity units which do not meet long-term generation needs, based on the assumption that a non-dispatchable renewable resource (i.e. solar PV capacity) may potentially be installed. Furthermore, there is no evidence that the possible installation of a solar generation resource, even with a storage battery, will supply any firm capacity to be relied upon to meet the capacity needs of the community. AEY submitted that this project ensures a continued safe, reliable power source for the community.[218]

9.7.3.3 Views of the Board

359. The Board accepts the proposal as submitted by AEY. The peak loading table included in the Application[219] shows continuous growth since 2012 and the need for a higher-capacity generator. Further, as Old Crow is an isolated community, the Board accepts the submissions[220] of AEY that a full contingency backup for that community is required.

9.7.4 Destruction Bay unit replacement

360. The communities of Destruction Bay and Burwash Landing are serviced by three units located at the Destruction Bay generating plant. The Board approved AEY's request to replace two units in Board Order 2014-06 related to AEY's 2013-2015 GRA.

9.7.4.1 Destruction Bay Unit #2 replacement (Appendix 6) and Destruction Bay Unit #3 replacement (Appendix 11)

361. AEY submitted that the replacement of Destruction Bay Unit #2 was one of the units approved in Board Order 2014-06. The original scope of the project in AEY's 2013-2015 GRA was to replace the unit with a similar sized unit (300 kW). At the time of the unit tender and selection, capacity requirements were reviewed, and as a result, AEY submitted that it will tender and procure a 400-kW unit. The total cost of this project

[216] Exhibit B-5, JM-AEY-27 (b).
[217] JM Final Argument, pages 9 and 10.
[218] AEY Reply Argument, paragraphs 107 to 109.
[219] Exhibit BB-1, Application, Appendix 5, pages 1 and 2.
[220] Transcript Volume 3, starting at page 483, line12 and ending page 485, line 23.

is forecasted to be $758,000, compared to the $600,000 capital expenditure previously approved by the Board. AEY indicated that receipt of the unit and installation is scheduled to be completed in 2016.

362. AEY submitted that the replacement of Destruction Bay Unit #3 was one of the units approved in Board Order 2014-06. AEY clarified that the existing 220-kW unit was to be replaced with a larger unit (250 kW) in order to ensure that the unit would continue to operate for a reasonable amount of hours to meet load requirements.

363. AEY stated that the purchase of a new 250-kW unit was put out to tender in 2013; however, none of the bidders in the RFP process submitted bids for a 250-kW unit. Of the bids received, and after a further analysis of best fit for the power plant and community load profile, AEY selected a 312-kW unit. Receipt of the unit and installation was scheduled to be completed in 2014.The total cost of this project was $634,000, compared to the approved cost of $450,000.[221]

364. AEY explained that the actual costs "were higher mainly due to foundation issues discovered, subsequent to the initial forecast, as well as additional control work required due to the delay of the Destruction Bay PLC upgrade."[222] AEY confirmed that receipt of the unit and installation was "completed, prior to the recent installation of the increased amount of solar PV generation."[223]

9.7.4.2 Views of interveners

365. With respect to AEY's proposal to replace the two smaller units in the Destruction Bay diesel plant with larger units, Mr. Maissan pointed out that a fair bit of solar capacity has been added in Destruction Bay in recent years and significant efforts are underway to establish a wind project of 300 kW in the area. Mr. Maissan expressed concerns that AEY is opting for larger diesel generators than necessary for reasons other than efficient plant performance, and the reasons for his position include that AEY is:

> …providing themselves with a stronger negotiating position with respect to a PPA with the Kluane wind project — which AEY has been aware of for many years. The choices seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this diesel served community. The choice of 400 kW and 312 kW generators to replace generators of 300 kW and 220 kW will reduce opportunity for, and add costs to, renewable energy projects in Destruction Bay – Burwash Landing…[224]

366. Mr. Maissan recommended that the Board direct AEY to replace one of the existing smaller units with the installation of one 400-kW unit. Mr. Maissan also recommended that the Board direct the replacement of Destruction Bay Unit #3 (CUL 230 220 kW unit) with a unit no larger than 250 kW. AEY should be directed to provide the 2015 load duration curves for Destruction Bay plant in its compliance filing. Mr. Maissan recommended:

[221] Exhibit BB-1, Application, Appendix 11, page 1.
[222] Exhibit BB-1, Application, Appendix 11, page 1.
[223] Exhibit B-5, JM-AEY-27 (a).
[224] JM Final Argument, page 15.

> … that the Board order AEY, in negotiations for an IPP with the proponents of the Kluane wind project [sic] to allow diesel displacement down to a load level to the lowest normal 2015 dispatch level without penalty or cost to the proponent.[225]

9.7.4.3 Applicant response to interveners

367. AEY pointed out that the two Destruction Bay unit replacement projects were scheduled — and in the case of Unit #3 replacement, completed — prior to the recent installation of solar PV generation in the Destruction Bay and Burwash communities. AEY acknowledged that the Burwash Landing wind project may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid. However, AEY submitted that:

> … it is not prudent or common practice for a utility to reduce the installed capacity of its generation facilities as a result of the possible installation of a non-dispatchable renewable resource, regardless of whether it is owned and operated by a third party or the utility itself.[226]

368. With respect to determining the size of Destruction Bay Unit #2, AEY considered the capacity as well as operational efficiency requirements. AEY submitted that replacement of Unit #2 with a new unit of the same size (300 kW) would not have allowed AEY to meet operational efficiency requirements, as units would have been under or overloaded during automated dispatch. AEY added:

> … at the current dispatch level there are times in which Unit 2 is operated at an overload condition in respect to its prime rating. The only solutions to this overload issue are to de-rate the unit or replace it with a larger unit. If the de-rate option was selected, it would negatively impact the operation of Unit 1, forcing it to run in a low loading mode. Selecting a larger unit allows Unit 2 and Unit 1 to be dispatched in a more efficient manner.[227]

369. AEY submitted that contrary to Mr. Maissan's assertions, the sizing considerations were done to meet firm capacity requirements and to allow for an efficient dispatch of the units, all of which are in line with AEY's obligation to serve customers with safe and reliable electricity.

9.7.4.4 Views of the Board

370. Destruction Bay Unit #3 was approved in AEY's 2013-2015 GRA. The unit was substantially completed and operational in 2014, with final acceptance in 2015. Further, the Board notes that Unit #3 replacement was completed prior to the recent installation of solar PV generation in Destruction Bay and Burwash Landing.

371. AEY determined through the tender process that the best fit for the power plant and community load profile was a 312-kW unit rather than the originally forecast capacity of 250 kW. The final cost of the project was $184,000 over the GRA-approved forecast. AEY indicated that the variance between the actual and forecast costs was

[225] JM Final Argument, page 15.
[226] AEY Reply Argument, paragraph 112.
[227] AEY Reply Argument, paragraph 117.

due to foundation issues discovered subsequent to the initial forecast and additional control work. AEY added that movement to the larger generator capacity would increase operational hours of the unit and concomitantly increase the units' efficiency.[228]

372. The Board finds the reasons provided by AEY — operational efficiency, community and load profile[229] — support the need for the larger capacity unit. In addition, the cost for the larger unit and the need to mitigate the foundation issues identified are acceptable reasons for the cost variance. The Board approves the costs as filed. Although wind capacity may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid, the Board accepts AEY's submission that wind generation will not contribute to firm capacity requirements within the test period.

373. With respect to Unit #2, the Board notes AEY's submission that replacement of this unit with a similar-sized unit would not have allowed AEY to meet the Operational Efficiency Requirements, as units in the generation plant would have been under or overloaded during automated dispatch. Therefore, the Board approves the additional costs associated with the larger 400-kW unit.

374. Considering the above, the Board approves AEY's replacement of Destruction Bay Units #2 and #3, as filed.

9.7.5 McIntyre subdivision rebuild (Appendix 8)

375. The McIntyre subdivision rebuild is a multi-phase project to replace the existing end-of-life underground electrical infrastructure serving the McIntyre subdivision in the City of Whitehorse. The original forecast for Stage 1 was approved as part of AEY's 2013-2015 GRA in Board Order 2014-06.

376. AEY referred to this project as being a complex "brownfield" infrastructure replacement. The original underground electrical system serving the subdivision is operating at 35 kV and was installed circa 1977. The proposed project will convert the subdivision's operating voltage to the standard 25-kV system. AEY indicated that 25-kV equipment is standard in Whitehorse's distribution system and provides improved electrical performance for residential customers.

377. The original scope of the project was to install a new 25-kV underground electrical system in close proximity to the existing 35-kV system. As Stage 1 was underway, AEY discovered that the location of the existing underground system would be in constant conflict with the installation of the new system. This made the field construction more time-consuming. Time constraints imposed on construction permits from the Kwanlin Dun First Nation (KDFN) made it necessary that a new project scope be developed. AEY explained the change in project scope due to installation issues:

> The new project scope involved the installation of a temporary overhead shadow electrical system which would allow construction crews to install the new underground system with the old underground system safely deenergized. This would allow the construction crews to work at a similar pace to a

[228] Exhibit BB-1, Application, Appendix 11, page 2.
[229] Exhibit BB-1, Application, Attachment 11.4, page 1.

> Greenfield project. The work would also include the installation of low voltage pedestals to connect to the overhead system and a new main underground feed to the subdivision.[230]

378. The following table shows approved costs, AEY's actual costs, and its forecast costs for the McIntyre subdivision replacement project:

Table 25. **McIntyre subdivision rebuild — 2013 to 2020 — actual (A) and forecast (F) costs ($000s)**

Year	Actual/Forecast	Streetlights	Total	Scope
2013 (A)	656	-	656	Temporary overhead
2014 (A)	418	-	418	Low voltage pedestals, connected to feeds
2015 (A)	379	-	379	Main underground feed to the subdivision
2016 (F)	565	175	740	Hanna and McCandless
2017 (F)	930	256	1,186	Murphy (partial), O'Brien, and McCrimmon
2018 (F)	500	100	600	McClimon
2019 (F)	600	150	750	Complete Murphy, McIntyre up to McCauly
2020 (F)	300	100	400	McCauly to Hamilton to McIntyre
Total	**4,348**	**781**	**5,129**	

Source: Exhibit BB-1, Application, Appendix 8, Table 1, Page 3.

379. In a letter[231] dated October 24, 2016, AEY submitted that it is seeking Board direction as to the appropriate treatment of the potential cost savings, should the KDFN accept one of the alternatives such as "Alternative 2" in the business case provided in Appendix 8 of the Application. The business case included the following:

> Alternative 2: Explore the benefits of utilizing some of the overhead system in coordination with some of the new underground electrical infrastructure. This would result in a hybrid system as it would be a combination of overhead and underground. This alternative would require the approval of the KDFN.[232]

380. AEY submitted that it is anticipated that "Alternative 2" would alter the work required and result in a potential cost savings in 2018-2020, which is outside of the test years. AEY clarified that it is requesting the Board to provide direction as to whether or not the expected costs savings could be applied as an offset to the contribution required by the KDFN in the future.

9.7.5.1 Views of the Board

381. The Board notes that interveners did not comment on AEY's request.

382. During the hearing, the Board notes AEY's submission that it had extensive meetings with KDFN. AEY submitted, "It's very clear that they want to have an underground power system when we're done in there… that's what they would like to have when we leave that subdivision at the end of the project."[233] Moreover, the Board

[230] Exhibit BB-1, Application, Attachment 11.4, page 1.
[231] Exhibit B-13, YECL letter to YUB re corrections, updates and clarifications, October 24, 2016.
[232] Exhibit BB-1, Application, Appendix 8, McIntyre Subdivision Rebuild, page 3.
[233] Transcript, Volume 1, page 151, lines 1 to 5.

notes AEY submission that "… there was an original customer contribution when the original system went in back in the '70s, so we wouldn't be asking the customer to recontribute."[234]

383. The Board notes that the ultimate scope of the project has not been determined by AEY at this time. AEY submitted two project alternatives: (1) an underground system, or (2) a hybrid system (combination of overhead and underground).

384. The Board accepts AEY's test-period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA.

385. If AEY's proposal for "Alternative 2" (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings.

386. The Board will provide further direction in the next GRA regarding AEY's request as to whether or not the expected cost savings could be applied as an offset to the contribution required by the KDFN.

9.7.6 Significant capital projects

387. In Board Order 2009-2, the Board directed "YECL to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests."[235] In Attachments 9.1 and 9.2 of the Application, AEY provided a listing of capital expenditures for 2016-2017, which included project descriptions for projects greater than $100,000. AEY also provided business cases for all major capital projects ($500,000 or greater) in Appendix 1 to Appendix 11 of the Application.[236]

388. UCG noted the Board's consideration in its January 2007 Report to the Commissioner in Executive Council re YEC's 20-year resource plan[237] that given the smaller rate base in the Yukon and the small number of ratepayers in the Yukon, a $1-million threshold would be appropriate for capital expenditures to be reviewed by the Board pursuant to Part 3 of the *Public Utilities Act.*

389. Considering the above, UCG recommended that the following projects should be reviewed pursuant to Part 3 of the *Public Utilities Act:*

(a) McIntyre subdivision rebuild;[238]

(b) Watson Lake bi-fuel projects;[239]

(c) Watson Lake Unit #2 replacement;[240]

[234] Transcript, Volume 1, page 152, lines 5 to 8.
[235] Board Order 2009-2, Appendix A: Reasons for Decision, page 37.
[236] Exhibit BB-1, Application, page 9-5.
[237] Yukon Utilities Board Recommendations YEC 20-Year Resource Plan: 2006-2025, Page 28, issued January 15, 2007.
[238] UCG Final Argument, paragraph 187.
[239] UCG Final Argument, paragraph 192.
[240] UCG Final Argument, paragraph 197.

(d) Downtown Whitehorse capacity improvement project;[241]

(e) Old Crow Unit #3 replacement;[242]

(f) Whistle Bend Subdivision Stage 3-C project;[243]and

(g) Fish Lake Ditch #3 diversion replacement project.[244]

9.7.6.1 Views of the Board

390. With respect to UCG's submission that the above-mentioned projects be reviewed pursuant to Part 3 of the *Public Utilities Act,* the Board considers that this request is premature because neither application has been made to the minister under section 39 of the *Public Utilities Act*, nor has the minister designated any of the projects as a regulated project under section 37 of the *Public Utilities Act*. Moreover, the Board does not determine that projects are Part 3 projects under the *Public Utilities Act*, but makes recommendations on energy projects only when the minister refers them to the Board. Accordingly, the Board finds that UCG's recommendations on Part 3 projects and associated capital expenditures do not apply.

10 Income tax

391. In its Application, AEY continued to use the flow-through method for calculating income tax expense. This method was approved by the Board in Board Order 2014-06. AEY argued that since the use of the flow-through method was not raised as an issue by any party during the testing of its Application, the Board should continue to approve the use of this method.

10.1 Views of the Board

392. The Board agrees with AEY that there is no reason to change the currently approved flow-through income tax method used by AEY in its Application. AEY's method of determining income tax expense to be recovered through rates is approved as filed.

11 Previous Board directions

393. AEY provided the following responses to prior Board directions from Appendix A: Reasons for Decision from Board Order 2014-06:

Board Direction	AEY Response	Board Comment
Direction 8, Page 51. The Board agrees with the submissions of UCG that no assessment has been provided	*Application, page 11-1,* ATCO Electric Yukon has engaged Concentric Energy Advisors Ltd. to undertake an	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No

[241] UCG Final Argument, paragraph 202.
[242] UCG Final Argument, paragraph 207.
[243] UCG Final Argument, paragraph 212.
[244] UCG Final Argument, paragraph 217.

within this proceeding regarding the comparability of YECL to the BCUC benchmark utility Fortis Energy. The previous risk premium was based on FortisBC, which is an electrical distribution company. BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear. The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.	analysis as to whether a risk premium over the BCUC GCOC benchmark utility is appropriate and if so, the quantum of such premium. Their analysis is contained in Attachment 8.1 included in section 8 of this Application.	further response is required.
Direction 12, page 62. The Board understands that YECL needs to explore alternatives respecting the use of wind to generate power in the area of Burwash and Destruction Bay, which interveners have been promoting. Accordingly, the Board finds the study costs warranted and reasonable. In addition, the Board directs YECL in its next GRA to provide results of the feasibility study.	*Application, page11-2.* ATCO Electric Yukon contributed funds ($20,000) towards this initiative in 2013 and received a report titled “Burwash Landing and Destruction Bay Wind-Diesel Prefeasibility Update.” ATCO Electric Yukon filed this report in response to Undertaking 17 during the 2013-2015 GRA hearing. Since that time ATCO Electric Yukon has received one further update in early 2014 but ATCO Electric Yukon is no longer engaged in this project and no further contributions have been made to this project, as such, ATCO Electric Yukon is not expecting to receive any further reports arising from this initiative.	Upon review of the Application and AEY’s explanation, the Board finds that AEY has complied with the direction. No further response is required.

Direction 13, page 64. YECL needs to provide information in relation to project costs overruns in its Application. Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns. For clarity, for project costs overruns that are (collectively) 100-percent over and $100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the nine expenditures were not foreseen and actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than $100,000, which may arise between GRAs, YECL, in future applications, is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project.	*Application, page 11-3 to 11-4.* ATCO Electric Yukon has included project completion summaries for all projects listed below that were forecast in the 2013-2015 GRA where actual costs were 100 percent and $100,000 greater than the original forecast. In addition, ATCO Electric Yukon has included a project completion summary for the Fish Lake Dyke Upgrade to explain the variance in actual costs to forecast for that project. Business cases have also been provided for completed projects where the actual costs were in excess of $100,000 and for which no business case was provided in the 2013-2015 GRA. ATCO Electric Yukon has included business cases for the completed projects listed below in Attachments 11.7 through Attachment 11.13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 14, page 70. The Board rejects UCG's recommendation because it is the actual amounts spent on projects that are added to rate base. The Board therefore approves other small project costs. That being said, the Board notes YECL's submission that expenditures "forecast as Other Projects are subsequently able to be broken down into greater detail when actual amounts are reported. Looking only at the variance for Other Projects does not provide an accurate picture of variance in the actual amounts spent for capital additions as compared to the forecast." Bearing this in mind, in	*Application, page 11-5.* In section 9, Schedule 9.2 of this Application, ATCO Electric Yukon has provided a detailed listing of all projects completed and actual amounts spent by project from 2013 through 2015. ATCO Electric Yukon has continued to group various projects in the "Other projects less than $20,000" category in Schedule 9.2, and submits this approach is appropriate considering the aggregate totals in this category are under the threshold of $100,000 highlighted in Direction 13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

order to help the Board and interveners examine more efficiently and process an application, the Board directs YECL, in future GRAs, to indicate in their applications how the approved forecast Other Projects amounts are subsequently spent.		
Direction 15, page 71. The Board accepts, based on the evidence, that the expenditures were reasonable and prudent in the circumstances. The Board rejects UCG's recommendations because the business case was not required for each related component and seeing the Board's finding of prudency. However, in future GRAs, the Board directs YECL to provide business cases for completed related projects which may span multiple years and total more than $500,000.	*Application, page 11-6.* On Schedule 9.2 of the Application, ATCO Electric Yukon has included the reference to where the business cases can be found in either the 2013-2015 GRA or in Appendix 1-11 of this Application. Business cases have been provided for all projects that span multiple years where costs were expected to be greater than $500,000.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 20, page 101. As argued by CW and UCG, the Board recognizes that the forecast risks with respect to the DSM program are one-sided. If participation rates are lower than expected, the utilities benefit, but if participation rates are higher than expected, the utilities have the ability to enforce the budget. Therefore, in the Board's view, a deferral account would not only protect ratepayers but it would also normalize the incentive for the utilities to maximize participation in the DSM program. Accordingly, the Board orders YECL to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of those costs in its next GRA. Further, the Board affirms it does not approve the program for the five-year term requested and that the utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015. The Board directs YECL, within its compliance	*Application, page 11-7.* The DSM programming costs approved in Board Order 2014-06 for the 2014 and 2015 test period have been tracked as directed in deferred charges. ATCO Electric Yukon was unable to complete the program as originally designed and spend all of the approved DSM program costs in 2014 and 2015 period; therefore the remaining approved amount will be spent in 2016. ATCO Electric confirms that it has not changed the scope of the approved DSM program. In this Application, ATCO Electric Yukon is applying for recovery of these previously approved costs (incurred from 2014 through 2016) over the next five years in a manner consistent with the previously approved DSM costs.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response required.

filing, to quantitatively provide the load reduction in GW.h related to DSM for each of the years 2014 and 2015, by rate class that has been incorporated in YECL's load forecast and to explain and quantify the changes to the load forecast based on the determinations of the Board regarding DSM.		

12 Deferral accounts

394. In its Application, AEY proposed deferral-account treatment for three new cost categories, while maintaining deferral treatment for those categories previously approved by the Board. AEY's summary of existing and proposed deferral accounts is shown in the following table:

Table 26. **Summary of existing and proposed deferral accounts**

Name of existing or proposed deferral account	Existing	Proposed
Rate case costs	X	
Defined benefit pension plan	X	
Feasibility study or program: DSM program (approved program) Watson Lake LNG — phase I (approved study) Renewables study (proposed study) Joint grid study (proposed study)	X	
Purchase power flow-through	X	
Diesel fuel	X	
LNG fuel		X
Board order or changes in legislative provisions		X
Statutory Federal and Territorial income tax rates		X

Source: Summarized from Application

395. The Board has considered the five existing deferral accounts and finds that their respective intent and scope have not changed. AEY's existing deferral accounts continue to be approved.

396. In the following sections, the Board will discuss the three new deferral account categories proposed in AEY's Application and whether they should receive deferral-account treatment.

12.1 LNG Fuel Deferral

397. Please refer to the section 4.5 of this decision.

12.2 Board Orders or Changes in Legislative Provisions Deferral

398. In its Application, AEY sought the ability to flow through, dollar for dollar, costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that AEY operates under for the 2016-2017 test period.

399. The IPP Policy for Standard Offer Prices was cited as one example in support for this deferral account.

400. In argument, AEY claimed that in future, there is no guarantee of stakeholder input or significant lead time. AEY added that it has no control over these policies or programs and has no way to forecast with certainty the impact related to these types of programs, and therefore seeks deferral account treatment.[245]In reply, AEY challenged the assertions of Mr. Maissan about the micro-generation program, stating that the response to JM-AEY-5(c-d)[246] did not include the full costs incurred by AEY (such as administrative costs), adding that there is no certainty of that program continuing to operate in its current manner.[247]

401. AEY did agree with Mr. Maissan in that it is a stakeholder in relation to the development of the IPP program. However, AEY countered that it does not control the actual implementation of the program and that it would be at risk for any changes until its next GRA.[248]

12.2.1 Views of interveners

402. John Maissan did not support the AEY request for a Board Orders or Changes in Legislative Provisions Deferral Account. Mr. Maissan noted that the micro-generation program provided net benefits to AEY. In regard to the IPP program, AEY has been an active participant along with the Yukon government, Yukon Development Corporation (YDC) and YEC .

403. The effects of the commercial energy incentive program run by the Yukon government were another reason cited by AEY for this deferral account. Mr. Maissan argued that the effects of this program are captured within AEY's load-forecasting process, and thus had minimal impact.[249]

404. UCG stated that a deferral account to track costs related to Board Orders or legislative provisions does not provide AEY with the ability to flow costs through, dollar for dollar, to ratepayers. A deferral account simply tracks costs for review and possible recovery at a later time.[250]

12.2.2 Views of the Board

405. In AEY's 2013-2015 GRA, AEY requested a deferral account to flow through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions

[245] AEY Final Argument, paragraphs 11-12.
[246] Exhibit B-5 — YECL Responses to Maissan Requests
[247] AEY Reply Argument, paragraph 13.
[248] AEY Reply Argument, paragraph 14.
[249] JM Final Argument, page 1.
[250] UCG Reply Argument, paragraph 13.

resulting in changes to the rules or parameters that AEY operates under or that bear on the nature and extent of AEY's obligations as a regulated utility and which impact its 2013 to 2015 revenues or revenue requirement.[251]

406. In Board Order 2014-06, the Board ruled that:

> … on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented… The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any GRA filing. Therefore the Board rejects YECL's request for this deferral account.[252]

407. The Board's views have not changed. The evidence in this proceeding is that AEY has been able to actively participate in potential legislative changes respecting the implementation of new programs, so AEY has not shown the need for such a deferral account. The Board notes Mr. Maissan's comments about little or no impacts of the programs referred to by AEY. The Board denies AEY's request for a Board Orders or Legislative Provisions Deferral Account.

12.3 Statutory Federal and Territorial Income Tax Rates Deferral

408. In its Application, AEY requested deferral-account treatment for income tax beginning in the year 2016. The deferral amounts would be based on any deviance from enacted federal and territorial statutory rates, which were each currently set at 15 percent. AEY submitted that any changes from these rates would be used to determine an updated revenue requirement that, when compared to final approved revenue requirement, would initiate either a refund to or collection from customers for the difference.

409. AEY cited uncertainty with respect to global economics and recent federal government changes as increasing the possibility of significant tax changes between GRAs. During the hearing, AEY witness James Grattan indicated a further potential for changes to the territorial statutory rate depending on the outcome of the territorial election.

410. In argument, AEY summarized:

(a) Changes in statutory tax rates can be material;

(b) Given that the statutory rates are set by the Territorial and Federal Governments and these rates are not published in advance of annual budgets, there is uncertainty regarding forecast accuracy;

(c) The statutory rates are determined by the Territorial and Federal Governments, and tare [sic] therefore beyond AEY's control; and

[251] Board Order 2014-06 – Appendix A: Reasons for Decision, page 1.
[252] Board Order 2014-06 – Appendix A: Reasons for Decision, page 103.

(d) AEY is not typically at risk with respect to items that are beyond its control and that are material.[253]

12.3.1 Views of the Board

411. The Board considers that the need for a deferral account has not been shown given the two-year test period. Further, the criterion for a deferral account is that AEY is typically at risk with respect to items that are beyond its control and that are material. In the Board's view, AEY has not shown that it is at risk or that any risks are material from changes in federal or territorial income tax rates. For these reasons, the Board denies AEY's request for a deferral account for statutory federal and territorial income tax rates.

12.4 Deferred Charges and Credits

412. For those account categories currently approved for deferral-account treatment, AEY monitors charge and credit transactions.[254] Generally, AEY will incur the deferral-account related expenditures over time and will subsequently recover the approved costs through deferral account revenue requirement. This is currently the treatment ascribed to hearing costs and deferred pension costs, each of which were forecasted to be recovered in revenue requirement evenly over the years 2016 and 2017.

413. In its Application, AEY proposed similar treatment for the tracking and recovery of costs related to feasibility or other studies, such as those pertaining to Watson Lake, Renewables and Alternative Energy, and a Joint Smart Grid. In some cases, after the study was completed, AEY proposed to recover the study costs within its deferral accounts over a period of two years. In the alternative, and as is the case with the deferred DSM program costs, AEY proposed to capitalize the costs into rate base and amortize them over a specified period of time.

414. UCG provided a general comment that, "All deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset."[255]

415. UCG submitted that study costs do not meet the "used or required to be used" test for consideration as a utility asset providing utility service to customers, despite that the costs may have been incurred prudently.[256]

416. Interveners raised other concerns with respect to AEY's proposed recovery of these study-related costs, each of which are discussed in the four sections that follow.

12.4.1 Demand Side Management (DSM) Program Study Deferral Account

417. AEY proposed[257] to move costs related to the approved DSM program study out of the deferral account and into rate base. Notwithstanding an issue related to the use of the mid-year convention for depreciation purposes addressed elsewhere in this

[253] AEY Final Argument, paragraph 164.
[254] Exhibit BB-1A AEY GRA Schedules, schedule S8.8.
[255] UCG Final Argument, paragraph 30.
[256] UCG Final Argument, paragraphs 166-174.
[257] AEY Final Argument, paragraphs 115-118.

decision, AEY stated that the use of a five-year amortization period (2014-2018) for cost recovery was consistent with the Board's direction in section 12.1 of Board Order 2014-06.

418. AEY stated that evidence of prudent expenditures related to the DSM program was provided in interim evaluation reports and these reports concluded that the DSM programs were well-received by Yukoners, were cost-effective, and that participation met or exceeded most KPIs.

419. In response to UCG's recommendation that deferred study costs should be removed from rate base, and either amortized outside of rate base or rolled into a related capital asset, AEY stated that the DSM program study costs in this case were for programs previously approved by the Board.

12.4.1.1 Views of interveners

420. UCG[258] questioned why the deferred DSM program costs would subsequently be treated as a capital item and attract carrying costs like other assets placed into rate base. UCG submitted that AEY was entitled only to the return of, and not a return on, prudently incurred DSM costs.

421. YEC[259] disagreed with UCG's suggestion that the DSM study costs should not be treated as capital assets earning a return on the same basis as other rate base elements. YEC submitted that UCG's recommendation should be disregarded by the Board.

12.4.1.2 Views of the Board

422. The Board can find no basis to consider UCG's recommendation that AEY was entitled only to the return of, and not return on, the DSM program study costs. AEY's treatment of these costs — by way of capitalization into rate base, and the attendant calculations of depreciation and return — is consistent with the Board's direction in section 12.1 of Board Order 2014-06. For this reason, the Board does not accept the recommendation made by UCG. The Board approves the transfer of the DSM program study costs out of the deferral account and into rate base to be amortized over a period of five years, as proposed by AEY.

12.4.2 Watson Lake LNG Study Deferral Account

423. In its Application, AEY requested approval for $494,000 in study and development costs related to the Watson Lake bi-fuel project. AEY proposed to recover these forecast costs evenly over the 2016-2017 test period through the study's associated deferral account. AEY submitted that the study costs were incurred prudently and should be recovered from customers whether or not any of the Watson Lake bi-fuel project capital costs are approved.[260]

[258] UCG Final Argument, paragraph 228,.
[259] Yukon Energy Reply Argument, pages 9-10.
[260] AEY Final Argument, paragraphs 105-108.

424. As an alternative, AEY stated that it was not opposed to capitalization of the study costs, should the Watson Lake project be approved, with subsequent cost recovery over the lifetime of the related assets.[261]

12.4.2.1 Views of interveners

425. UCG argued that in Board Order 2013-01, the Board determined that feasibility expenditures associated with projects deemed to be feasible should remain in "Work in Progress" until such time that the project is set aside or the utility comes before the Board for a prudence review. In Board Order 2014-06, the Board determined that Watson Lake bi-fuel project study costs would be held in "Work in Progress" until such time as the project may be completed.

426. UCG submitted that if the Board accepts the proposed Watson Lake bi-fuel project proposed by AEY, then $494,000 in Watson Lake Study costs should be rolled into the capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.

427. Consistent with his views that the Watson Lake bi-fuel project itself be denied by the Board, Mr. Maissan recommended that all actual study costs expended to date should be amortized over a five-year period.[262]

12.4.2.2 Views of the Board

428. The Board does not consider that adding complexity with respect to the recovery of the Watson Lake LNG study costs is necessary. To recover the study costs over the life of the Watson Lake bi-fuel project, as was recommended by UCG, would require an allocation of the study costs to several individual account numbers, each with a unique service life. The Board has determined doing so would not result in an efficient or straightforward process of cost recovery and would be unduly onerous. Further, since in section 9.7.2 of this Order the Board has rejected the Watson Lake bi-fuel project, this issue of rolling the study costs into the capital costs is moot. For these reasons, UCG's recommendation is denied.

429. The Board accepts Mr. Maissan's recommendation that recovery of the Watson Lake study costs and development costs forecast in the amount of $494,000 should be on the basis of an amortization period of five years. This period of time is consistent with that used for the recovery of the DSM program study costs. The Board finds this to be a reasonable approach for the recovery of the Watson Lake bi-fuel study costs.

12.4.3 Renewable and Alternative Energy Feasibility Study Deferral Account

430. AEY proposes to include $300,000 in 2016 and $200,000 in 2017 as charges related to work it has planned regarding the Renewable and Alternative Energy Feasibility study.[263] The $500,000 in costs for the study would be recovered through AEY's deferral account in the amount of $150,000 in 2016 and $350,000 in 2017.

[261] AEY Final Argument, paragraph 108..
[262] JM Final Argument, page 15.
[263] Also referred to in AEY's application as the "Renewables Feasibility Study"; Exhibit BB-1, page 8-8 and Schedule 8.8.

431. AEY proposed to assess individual communities and retain third party expertise to carry out the studies through a combination of competitive processes and "sole-sourcing."[264] The studies are intended to identify the optimal size and configuration of company-built, -owned and -operated renewable and alternative energy generation in each of the five isolated communities served by AEY which currently rely on diesel power generation. The studies will also assess energy storage systems and potential improvement for energy efficiency through waste-heat recovery opportunities in each of the communities.

432. Once the studies are complete, AEY proposed that any technically and economically feasible projects identified therein would be brought forward as business cases in stand-alone proceedings for approval by the Board. This would ensure customers receive more immediate benefit of the studies and resulting projects, without the need to wait for a subsequent GRA.

433. Further, AEY indicated its commitment that, subject to any confidential or proprietary information contained in the renewable energy studies, they would be prepared to share the study publicly in connection with any resulting application or earlier in an appropriate forum, such as the utility's website.

434. During the oral hearing, AEY witnesses confirmed that preparation of the renewables study was behind schedule and that no work had been completed at that time.[265]

435. In response to UCG's recommendation that deferred study costs should be removed from rate base and either amortized outside of rate base or rolled into a related capital asset, AEY stated with respect to feasibility studies, such as the one proposed for renewables, deferral treatment for approved expenditures is appropriate given that such studies may not result in the construction of a project, or a near-term project.[266]

12.4.3.1 Views of interveners

436. Given that AEY had not commenced development of its proposed renewables study, Mr. Maissan argued it was unreasonable to expect that AEY could incur the entirety of its proposed expenditures in a prudent manner subsequent to a Board Order.

437. Mr. Maissan also took issue with AEY development of company-owned renewable and alternative energy sources, stating that such projects would be in direct competition with IPP proponents. Mr. Maissan viewed it to be inappropriate for ratepayers to fund AEY to, in essence, compete with the private sector, which is funded privately.

438. As an alternative to the Board approving a $500,000 renewables study, Mr. Maissan recommended that the Board should approve (1) study costs of up to $150,000 "to prepare for the significant displacement of diesel generation in Destruction

[264] AEY Final Argument, paragraph 110..
[265] Transcript, Volume 2, page 292.
[266] AEY Reply Argument, paragraphs 88-90..

Bay – Burwash Landing, Old Crow, and Watson Lake using renewable energy sources, including wind and solar PV", and (2) study costs of $50,000 "for a study on how to improve the fuel efficiency of AEY's diesel plants, including the utilization of residual heat, that applies to all of AEY's diesel plants."[267]

439. With respect to each of his proposed studies, Mr. Maissan made further recommendation that the Board order AEY to submit detailed terms of reference, submit study reports upon their completion, and also seek Board approval before the implementation of any action arising out of the study findings.

440. YCS expressed similar views to that of Mr. Maissan in that the concept of the renewables study as pursuing a replacement for diesel fuel was flawed and should be denied by the Board. YCS stated that if ratepayers were being asked to pay for the study, then it must be shared as soon as completed and not withheld from viewing until the next GRA.[268]

441. YEC[269] discounted Mr. Maissan's argument that AEY developing renewable and alternative energy sources would be in competition with IPP proponents. YEC stated there was no basis for Board to restrict prudently incurred expenditures related to studies assessing renewable generation options.

442. YEC also addressed comments from Mr. Maissan and YCS requesting the sharing of any renewable study results prior to AEY's next GRA, stating that there is no mandate for the Board to address such proposals. YEC expressed similar views with respect to AEY's proposal to bring forward any business cases stemming from the renewables study in a stand-alone proceeding before the Board without waiting for a subsequent GRA.

12.4.3.2 Views of the Board

443. In this test period, AEY has requested various studies for Board approval to include amounts for studies in rates. The Board considers that such studies are best conducted by industry or funded by government initiatives.

444. In addition, the Board understands that it may be difficult for the utility look to government grants or other sources of funding through customer rates without a fully formulated proposal for a renewable or alternate energy project. This was explained by Mr. Tenney in his testimony:

> Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been — become public since you filed your application and your IRs?
>
> A. MR. TENNEY: Again, in one of the information responses, we did talk about the last — the 2016 federal budget that they earmarked, I believe it was $10.6

[267] JM Final Argument, page 12.
[268] YCS Final Argument, page 9.
[269] YEC Reply Argument, pages 7-9.

> million for renewable energy programs. We have been working with the Federal Government to see if we can access that.
>
> To date, the message — and I think we — in one of that - October 24th, I believe it was, update that we did, we had originally said that we hadn't included the watt — we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.
>
> What we got back — what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project — the economics work to get it under construction.
>
> So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.[270]

445. The Board is of the view that studies proposed in the Application would reasonably involve an assessment of need, feasibility and policy objectives that could involve government, academics, YEC, municipalities, customers or other stakeholders.

446. The legislative scheme is intended to provide for the regulation of utilities and to provide the Board with various responsibilities in the public interest, including the setting of rates of the utility in the provision of electricity to customers in the Yukon.

447. There is not sufficient evidence for the Board to approve the Renewable and Alternative Energy Feasibility Study proposed in the Application and, without further information, the Board is unable to assess whether or not these studies should be conducted given the need or feasibility of a study to support a renewable and alternative energy project or projects, and whether proposed costs for these studies should be recovered in customer rates. The Board considers that information that should be provided in support for these types of studies or initiatives would include, but is not limited to:

- An analysis of how the study or initiative proposed is related to the utility's statutory requirements of provision of utility service pursuant to the *Public Utilities Act* and its regulations;
- The drivers, need and feasibility for the study or initiative;
- The scope of the study or initiative;
- An expected budget for studies, preliminary reports, and any other primary or secondary reports, as well as a budget for any known implementation costs or an estimate of any expected implementation costs;

[270] Transcript, Volume 3, page 453, lines 11 to 25 and 454 lines 1-15.

- The specific utility projects that are expected to be reviewed or impacted by the proposed initiative(s), as well as corresponding benefits to customers expected as a result of the study and initiative(s); and

- Whether cost-recovery studies and alternative-energy initiatives, energy-saving initiatives, or other initiatives have been explored through grants or other sources of funding, including shareholder funding.

448. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility Study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision.[271]

449. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference, or filing any completed Renewable and Alternative Energy Feasibility Study.

450. Further to the request for two alternative studies as proposed by Mr. Maissan in argument, the Board finds the feasibility and the costs for AEY to undertake these studies has not been examined by the utility or the Board through a proceeding. These recommendations have not received the benefit of being tested by parties during the course of this proceeding. For these reasons, the Board does not support Mr. Maissan's request for AEY to undertake two alternative studies.

12.4.4 Joint Smart Grid Study Deferral Account

451. AEY requested approval for costs related to a Joint Smart Grid Study anticipated to be undertaken in 2017 in partnership with YEC at a cost of $100,000. The study is intended to assess the potential fit and viability of a smart grid in the Yukon. AEY advised that it intends to have the completed smart grid study filed with the Board and made public.[272]

12.4.4.1 Views of interveners

452. Mr. Maissan supported the Board's approval of the $100,000 budget for the proposed smart grid study, citing that there could be significant benefits to ratepayers in the long term if the utilities were to embrace a smart grid approach in the Yukon.[273]

12.4.4.2 Views of the Board

453. The Board considers that such studies are best conducted by industry or funded by government initiatives.

454. There is not sufficient evidence for the Board to approve the Joint Smart Grid Study proposed in the Application and, without further information, the Board is unable to assess whether these studies should be conducted given the need or feasibility of a

[271] For example, at Transcript, Volume 2, page 291, lines 6-10, Mr. Tenney confirmed that ATCO Electric Yukon is one of the members of the Northern consortium, together with three Crown corporations, that fund the research chair in Norther Energy Innovation at Yukon College.
[272] AEY Final Argument, paragraphs 119-122.
[273] JM Final Argument, page 6.

study to support a smart grid project or projects, or whether proposed costs for these studies should be recovered in customer rates.

455. Further, there has been no substantive evidence submitted by parties that provided an indication of any benefits accruing to customers as a result of the proposed study.

456. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecasted expenditures and cost recovery related to its proposals in its compliance filing to this decision.

457. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference or filing any completed Joint Smart Grid Study.

Appendix A – Summary of Directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016." Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data. Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast, incorporating its prior methodology using a 10-year timeframe for UPC regression and normalizing HDD. ..... Paragraph 40
2. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY. This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY. Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement. ..... Paragraph 76
3. As a result, for out-of-scope employees, the Board awards for 2016, a labour inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 90
4. For these reasons the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction. ..... Paragraph 94

5. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response. In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent for 2017. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 105

6. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual. ..... Paragraph 123

7. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period. However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs. ..... Paragraph 124

8. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period." However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance

approved by the Board for 2016 “Other” (Account 88800) is $47,000, and the 2017 balance for “Other” (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision..... Paragraph128

9. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.” However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is $143,000, and the approved 2017 balance for “Other” (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 130

10. The three-year average (2013-2015) for “Other” for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 134

11. For the purpose of calculating AEY’s depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense. ..... Paragraph 163

12. The Board considers that consistent with AEY’s depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

..... Paragraph 167

13. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders. ..... Paragraph 172

14. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision. ..... Paragraph 237

15. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 240

16. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. ..... Paragraph 278

17. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost. ..... Paragraph 292

18. With respect to LED streetlight installations that are not conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. ..... Paragraph 293

19. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision. ..... Paragraph 354

20. The Board accepts AEY's test period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA. ..... Paragraph 384

21. If AEY's proposal for alternative 2 (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings. ..... Paragraph 385

22. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 448

23. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 456

Yukon Utilities Board

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Mandate of the Board

The Yukon Utilities Board (Board) receives its mandate from the Public Utilities Act, its regulations, and Orders in Council. These documents can be found in the “Legislation” section of this website.

What We Do

The Board acts as a rate-setting tribunal for two public utilities.

The Board establishes just and reasonable rates for the provision of electricity by Yukon Energy Corporation (YEC) and by the Yukon Electrical Company Ltd., operating as ATCO Electric Yukon (AEY). YEC is a Crown corporation (publicly owned and operated by the Government of Yukon) and its rates are set by the Board independent from the government.

The Board fulfills its mandate through public hearings. The processes involve reviewing information, researching, consulting with experts, carefully deliberating on information received from the utilities and interveners during hearings. The Board considers the record of each proceeding, provides public dissemination of notices of upcoming Board activities, including rate and facilities applications, and issues its decisions on the Board’s website.

When considering a rate application, the Board reviews the financial requirements of the utility, such as fair return and impacts on the customer. The Board must consider both the sustainability of the utility and the recovery of rates from customers through reasonable charges for utility service.

The Board also requires the public utility to establish, construct, maintain, and operate any reasonable expansion of its existing services and it determines the conditions that may be imposed by a public utility to establish, construct, maintain, and operate an expansion of its existing services.

The Board hears and adjudicates complaints from customers regarding the service provided by YEC and AEY.

What We Don’t Do

The Board does not oversee or manage the daily operations of the utilities. It also does not deal with matters that are not within the Board’s jurisdiction – for example, Yukon Water Board matters.

Utility Rates

The Board strives to ensure that Yukoners have safe electricity service at just and reasonable rates. When applying for an increase in rates all utilities under the YUB's jurisdiction must justify all the components of the revenue requirement to support a requested rate increase. Those costs are considered and analyzed in detail by the Board and include but are not limited to:

• The cost to build, operate, and maintain the utility’s facilities;

• The cost to finance debt incurred from building the utility’s facilities;

• The cost for depreciation and amortization expenses;

• The costs for financing general debt incurred by the utility; and

• Any other costs to provide affordable and reliable service to utility customers.

The Board is a quasi-judicial agency in the Yukon. It ensures independent and objective analyses of proposed rates. The Board operates at arm's length from government and weighs the financial needs of the utility with the needs of ratepayers in its rate-setting decisions. This independence from government processes for approval of rates is fair, open, and transparent.

Utility Facility Projects

The Board has limited oversight over the capital expenditures of Yukon public utilities. The Board may be instructed by the territorial government to provide recommendations about capital projects. For example, in 2014 the Board conducted a comprehensive examination of YEC's proposed liquified natural gas facility at the government's request and submitted the resulting report to the government. However, the Board may order the exclusion of certain capital costs in its calculation of appropriate rates to be charged to Yukon consumers.

Capital development plans figure prominently in the Board's decision-making regarding rate adjustments for both Yukon public utilities. New capital expenditures often require a utility to incur more debt, seeking an increase in consumer rates in order to pay it down. As such, the Board examines the utility's business case to ensure that there is acceptable support for such expenditures.

Regulatory Policy

The Board carries out its mandate based on enabling legislation. The legislation grants the Board significant authority to analyze the accounting practices and financial position and statements of public utilities it regulates.

Through directions specified in its orders, the Board instructs utilities on acceptable practices and procedures. In addition to the enabling legislation, these regulatory policies are aided by the Board's staff and expert advisors.

The Board is further aided by its continued connections with other utility regulators and administrative tribunals. These connections are facilitated by the Board's membership in the Canadian Association of Members of Public Utility Tribunals (CAMPUT). Through these connections, the Board strives to offer innovative regulatory policies and solutions that are consistent with national trends in utility regulation.

Hearing Process

There are two typical methods of review of information through a public hearing. An application can be processed in writing or through an oral hearing. It is at the Board's discretion to decide the appropriate method or venue for adjudicating an application.

All Board hearings proceed in accordance with the Board's Rules of Practice available on the website.

As a quasi-judicial administrative tribunal, the Board maintains a publicly open and accessible hearing room to adjudicate applications.

Written proceedings review all documentary evidence, arguments, and reply arguments that are submitted to the Board from the applicant, interveners, or other third parties.

Oral hearings are held in a public forum accessible to all. A more formal approach to the application is taken, which means that witnesses may be called to testify and be cross-examined by all parties. The hearing proceeds in a relatively uniform manner. It begins with an application from the utility and a public notice informing citizens of the date and time of the hearing as well as the matters of interest set to be examined. A pre-hearing conference may be subsequently held to determine which individuals and groups will act as interveners during the official hearing, with potential interveners applying to the Board. The hearing commences, with examination of the utility taking place at variable times depending on the relative complexity and significance of the matter under scrutiny.

The typical hearing process involves the utility, the Board members, Board counsel and staff, interveners, and any witnesses. Then the parties present their arguments and reply arguments, either orally or in writing.

In both written and oral procedures, the Board's decision is a result of a review of the information available at the time of the close of record for a proceeding. The Board issues its regulatory decisions by way of a Board Order. These decisions are subject to a review and variance process and/or an appeal process. While a news release may be issued, it is up to the media to be informed of the Board's decisions through the website.

Public Participation

As an open and transparent quasi-judicial body, the Board welcomes and encourages public participation in its hearings. Public participation ensures that all issues and perspectives come to the Board's attention in a transparent process. Hearings allow the Board to make a fully informed decision with significant public input. As such, there are several ways for the public to become involved in any public hearing before the Board:

A member of the public may become involved as an intervener. Interveners are individuals or groups who want to take a position on an application before the Board by attending the hearing, providing information and/or evidence, questioning the applicant, and potentially providing a closing statement of position at the end of the hearing. Interveners are expected to

participate actively in the hearing process, including by answering questions posed by the Board and its advisors, as well as the applicant or other parties. An individual or group must apply to become an intervener and their costs to participate may be paid by the applicant if the Board directs costs to be awarded. The interveners must show that they can provide information that will be of benefit to the Board when it enters into deliberations.

At some hearings the Board may make it possible for someone to become involved as a presenter. A presenter is someone who wants to make a statement to the Board about the application being reviewed in a public hearing. Presenters may attend the hearing but are not required to participate in the same way as an intervener. Presenters may be required to pre-register with the Board and they should notify the Board before or at the start of the hearing of their intention to present. Presenters are encouraged to also provide a written copy of their presentations.

A member of the public may become involved as an interested citizen. Any member of the public may attend Board hearings.

For other common questions regarding the hearing process, see the FAQs section of the website.

The Application

The hearing process generally begins when a regulated utility applies to the Board for a decision on a matter within the jurisdiction of the board – for example: rates, facilities, or complaint regarding an electric utility in the Yukon. The hearing may be a written hearing process or an oral hearing.

Applications for rate changes must demonstrate to the Board that a change is appropriate and in the public interest.

Applicants must provide information to support their requests, provide supplemental information when required, and respond to pre-hearing questions from the Board and interveners. Information provided before and during the hearing is examined by the Board is made available to the public online and through the Board office, unless that information is confidential or falls within Yukon's Access to Information and Protection of Privacy Act (ATIPP).

Notice of Public Hearing

The Board is mandated to inform the public about issues to be reviewed at a public hearing. Notices of public hearings are typically published in Yukon newspapers and may be posted within a community impacted by the decision. Notices may also be mailed or electronically transmitted to individuals, groups, or associations that have expressed an interest in the issues.

A notice typically provides the following information:

• A brief explanation of the issues;

• An indication of the potential impact on ratepayers;

• The time, date, and place of a pre-hearing conference and/or the oral hearing; and

• The procedures to be followed during the hearing.

Pre-hearing Conference

Prior to convening an oral public hearing on a rate application from a major utility, the Board may hold a pre-hearing conference. During a pre-hearing conference, the Board may address procedural or substantive issues that are relevant to the hearing. A pre-hearing conference process may include, for example:

(1) The Board seeks to outline the issues to be addressed during the hearing;

(2) The Board identifies interveners and presenters who are both interested and relevant to participate in the pre-hearing conference. While presenters are not required follow the same process that goes into determining

(3) The Board sets a schedule for the exchange of information between the applicant, the Board, interveners, and any other interested parties;

(4) The Board addresses any opening motions that may be made by the applicant, interveners, and any other parties;

(5) As a result of the pre-hearing conference, the Board determines any process that may be necessary for the oral hearing.

Hearing

At the outset of a public hearing, the applicant and interveners are asked to summarize their positions. The application is examined by the Board, its advisers, and any interveners. The applicant and interveners are then given an opportunity to make a final statement at the end of the hearing. Other parties may present at the hearing. When the hearing is over, the Board considers the evidence and a decision (Board Order) is issued. Hearings are recorded and transcribed, and transcripts are made available on the Board's website.
During the course of a hearing, interveners, presenters, and the Board may inquire about a broad range of issues impacting the application under review. The Board is bound by its mandate and enabling legislation, which grants it broad powers with respect to the oversight of public utilities under its jurisdiction.

Board Orders

Board Orders state the Board's decision, reasoning, and directions that the utility must follow. Orders are issued in writing and are made available on the Board's website. Board decisions are legally binding subject to appeal by the Yukon Court of Appeal on questions of law and jurisdiction.

In limited circumstances, the Board will reconsider (review and vary) a decision based on a timely request of the applicant or interested parties, or on the Board's own initiative.

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2023 GENERAL RATE APPLICATION

SUMMARY OF APPLICATION

The Yukon Electrical Company Limited, carrying on business as ATCO Electric Yukon (AEY), has filed an application with the Yukon Utilities Board (Board) requesting an order approving its forecast revenue requirements for the two-year test period 2023 and 2024 (Application). AEY provides electrical services to customers in 19 communities.

AEY is seeking approval of forecast revenue requirements of $60.992 million for 2023 and $68.096 million for 2024. This represents a decrease of $1.211 million for 2023 over revenues from existing rates and riders of $62.203 million (1.9% decrease). For 2024, this represents an increase of $7.914 million over the proposed 2023 revenue requirement (13% increase).

In addition, in its Application, AEY is also seeking approval of an interim refundable rate rider (Rider R) for 2023 of 6.68% (down 1.62% from the existing approved 8.3% for Rider R) for retail and industrial firm rates, effective August 1, 2023. AEY is also requesting a Rider R increase of 5.2% above the current 8.3% for retail and industrial firm rates, effective January 1, 2024.

MESSAGE TO CUSTOMERS

We understand that changes to your utility bill can be concerning and recognize that keeping electricity affordable is vital for both households and businesses alike. We want to take this opportunity to communicate openly and transparently about the reasons behind our proposed rate increase. We acknowledge the financial pressures many of you face and assure you we've carefully considered this decision.

We also recognize that there are questions about our revenue during recent years, even though our rates have not increased. It's important to note that our revenue requirement was set during our General Rate Application in 2017 based on our forecasted business operations. Although our rates have remained unchanged since that time, factors beyond our control have led to higher-than-forecasted revenue. Population growth, increased electricity demand, and expansion in the resource sector have all played a role in the Yukon's revenue growth.

For the past seven years, AEY has successfully maintained stable rates despite the challenges posed by a growing Yukon, a pandemic and hyperinflation. During this time, more than $50 million was invested into Yukon's power grid to ensure safe and reliable power delivery to your homes and businesses. We have carefully managed expenditures and leveraged shared services with ATCO to help keep costs down, and we are proud of our small but mighty team of 55 local Yukoners who keep the lights on and provide customer service across the Yukon. However, with changes in our environment and demand, we find it necessary to file a General Rate Application to ensure continued quality service.

As we move forward, we want to highlight that the proposed rate increase of 5.2% for 2024 comes after a rate decrease of -1.6% in 2023. The proposed rate increase will enable us to:

- **Accommodate Growing Demand**: *With an increasing population and greater energy consumption, we must continue to build and maintain our infrastructure to ensure a reliable and uninterrupted power supply.*
- **Upgrade Aging Infrastructure**: *To ensure the continued reliability and safety of our services, we need to modernize and replace aging components of our system.*

While these are difficult decisions, the investments we are making are vital to maintaining a modern and reliable electric system that meets the needs of Yukoners today and into the future. As we navigate these challenges together, our customers remain top of mind, and our commitment to providing you with safe, reliable, and affordable power is unwavering.

- **Jay Massie, Vice President, Northern Development & Indigenous Relations, ATCO Electric Yukon**

SCHEDULE OF PROCEEDINGS

Pending Ministerial approval, the Board has established the following schedule for this proceeding:

- AEY Procedural Conference - July 27
- Interveners register with the Board - August 4
- Interveners file submissions regarding AEY interim rate request - August 4
- AEY reply to interveners' interim rate submissions - August 10
- IRs to AEY - August 24
- IR Responses from AEY - September 14
- AEY files depreciation parameter information - August 31
- Interveners file any motions regarding IR Responses from AEY - September 21
- IRs to AEY on depreciation parameters - September 26
- IR Responses from AEY on depreciation parameters - October 10
- Intervener evidence - October 19
- IRs on intervener evidence - October 26
- IR Responses on intervener evidence - November 2
- Rebuttal evidence - November 9
- Oral public hearing - November 27-30
- Final argument - December 5
- Reply argument - December 12

An oral public hearing regarding the Application will take place in Whitehorse, Yukon. The venue for the hearing will be determined by the Board at a later date.

INTERVENTIONS

Interveners actively participate in a proceeding, including the filing of evidence (if needed), argument, and reply argument.

Interveners intending to participate in the workshop, hearing, and other process steps are to register in writing with the Board's Executive Secretary by no later than August 4, 2023, indicating the nature of their interest and the issues of interest in relation to the Application. Interveners are also to submit any comments regarding AEY's interim rate request at that time.

To register for AEY's procedural conference as an intervener, member of the public, or organization, please email Beth Rogers at elizabeth.rogers@atco.com.

APPLICATION AVAILABLE

ATCO Electric Yukon 2023 General Rate Application

Business Cases 01-03

Business Cases 04-21

Business Cases 22-38

Business Cases 39-41

The Application and supporting documents are also available on the Board's website at the following URL: https://yukonutilitiesboard.yk.ca/proceedings/atco-electric-yukons-2023-2024-general-rate-application/

CLARIFICATION AND BOARD CONTACT

Persons who wish to intervene or present, and who are uncertain as to the manner in which to proceed, may contact Deana Lemke, Executive Secretary, Yukon Utilities Board, by telephone at (867) 667-5058, in writing at Box 31728, Whitehorse, Yukon Y1A 6L3, by email to yub@utilitiesboard.yk.ca or by fax at (867) 667-5059.

FREQUENTLY ASKED QUESTIONS

- Who regulates ATCO Electric Yukon's rates?
- What is a rate rider?
- What is rider R?
- Why is rider R an interim rider?
- How much is the actual proposed rate increase? What is the fuel adjustment factor?
- Is the proposed rate decrease beginning on August 1 to pay back extra revenue received?
- Has the application for interim rates been approved?
- What is the process for rate changes?
- Why does AEY expect to need higher rates beginning in 2024?
- What infrastructure improvements will a rate increase support?
- Is the rate increase linked to the Yukon government's Our Clean Future plan?
- Is the rate increase linked to the cost of electricity from Yukon Energy?

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Yukon Economic Outlook

May 2016

Yukon
Economic Development

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ECONOMIC FORECASTING AND RISK

This forecast examines near-term expectations for Yukon's economy, focusing on the anticipated performance of key economic indicators and sectors.

As with all forecasts, the results are dependent on the information available at the time of forecast completion and key assumptions incorporated into the forecast. Assumptions such as the level and timing of mining development activity, estimates of annual mineral production and estimates of construction spending, can all impact the forecast results, particularly for an economy as small as Yukon's. While best efforts are made to develop assumptions that reasonably capture Yukon's potential economic performance in the near-term, there is always a degree of risk and uncertainty associated with these assumptions, and ultimately the forecast results. Key examples of potential risks to the forecast are noted below:

- Global Economic Performance – The performance of Yukon's economy is tied to the performance of other key economies, such as the U.S. and China, and to the global economy as a whole. Demand for Yukon goods and services, including minerals and local tourism activities, can depend very much on what is happening outside of the territory.

- Metal Prices – Metal prices are a key determinant of mining activity (exploration, development and production) and are determined on the global market. Projections from a variety of forecasters were considered in preparing this forecast.

- Energy Prices – Energy prices are also determined on the world market. For Yukon, the price of oil can influence economic activity particularly in how it can impact mining sector activity (fuel for project operations and equipment) as well as impact tourism activities (fuel for travelers' vehicles). The price of fuel also influences the cost of Yukon construction activities and the cost of goods in Yukon as the majority of goods purchased locally are transported from outside the territory.

- Exchange Rates – The value of the Canadian dollar versus other currencies can impact spending decisions by tourists and also investment decisions by resource-based companies. A strengthening or weakening dollar may affect this forecast.

- Interest Rates – Lower interest rates can contribute to increased investment as the cost of borrowing is reduced. Alternatively, increasing interest rates increase the cost of borrowing and can dampen investment spending. The cost of borrowing in Canada has been low for a prolonged period, with the Bank of Canada's daily overnight target for the bank rate not exceeding 1.0 per cent since January 19, 2009. This forecast assumes that interest rates will remain relatively low for the foreseeable future.

Finally, circumstances that impact forecast assumptions can change rapidly, resulting in the forecast becoming dated. Yukon is an example of a small economy that can be rapidly influenced by outside events. Information in this forecast is current to May 12, 2016 which allows for the inclusion of Statistics Canada's preliminary GDP estimates for 2015.

HIGHLIGHTS FOR 2015

- Statistics Canada preliminary estimates for Yukon real Gross Domestic Product (GDP) for 2015, released May 12, 2016, have Yukon's real GDP by Industry at $2.177 billion in 2015, down 3.8 per cent from $2.264 billion in 2014, representing the third consecutive annual contraction.
    - The primary contributor to the contraction was lower mineral production, the result of weak mineral prices and an ongoing slowdown in the global mining industry.
- Yukon's June 2015 population of 37,343 up slightly from the June 2014 figure of 37,251, marking the 12th consecutive year of growth.
- Yukon's labour market was impacted by the weaker economic activity:
    - Total employment averaged 19,400, down 400 from 2014.
    - The labour force averaged 20,700, unchanged from 2014.
    - Average unemployment rate of 6.3 per cent, up from 4.3 per cent in 2014.
- Statistics Canada data for retail sales reports Yukon sales of over $692 million, up 4.7 per cent from 2014.
- Border crossings are reported as falling by 4.1 per cent, to 327,778.
    - Concerns have been raised about the accuracy of the 2015 data as anecdotal information indicates that 2015 was a good year for local tourism operators.
- At $117.7 million, the value of building permits in 2015 was down 9.7 per cent from $130.5 million in 2014.
    - Permit value was down in all areas, with the exception of government/institutional permits. Biggest losses were noted in residential permits.
- A modest decrease in the Consumer Price Index (CPI) was experienced in Whitehorse, down 0.2 per cent in 2015.

FORECAST FOR 2016

- The forecast for real GDP in 2016 is for growth of 2.8 per cent.
    - Growth in 2016 is primarily related to an expected increase in mineral production at the Minto mine with the beginning of stripping of the Minto North pit.
- Modest population growth is expected, with gains of 0.7 per cent in 2016.
- The number of employed and the size of the labour force are both expected to increase slightly to 19,500 and 20,900, respectively. The unemployment rate in 2016 is expected to rise to 6.6 per cent.
- Following reported strong gains in 2015, retail sales are expected to post modest growth in 2016.
- Early indications are that 2016 will be a positive year for Yukon tourism.
- Building permit value is expected to be up slightly from the 2016 level.
- Following deflation in 2015, the Whitehorse CPI is expected to grow by 2.0 per cent in 2016.

PRELIMINARY FORECAST FOR 2017

- Early expectations for 2017 are for Yukon's real GDP to fall by 5.7 per cent.
  - Lower year-over-year mineral production, associated with the expected shutdown of the Minto mine, is the primary contributor to the contraction.
- Population growth of 0.3 per cent.
- Employment and the labour force are expected to post modest gains, with employment increasing to over 19,600 and the labour force increasing to almost 21,000. The unemployment rate in 2017 is expected to fall slightly to 6.3 per cent.
- Retail sales are expected to grow to over $700 million.
- A modest increase in building permit value is expected, growing to about $125 million.
- Growth in the Whitehorse CPI is expected to be just under 2.0 per cent.

GLOBAL, U.S. AND CANADIAN OUTLOOK

The April 2016 *World Economic Outlook* prepared by the International Monetary Fund (IMF) notes that global growth prospects have worsened since their previous forecast release (January 2016).

The current IMF forecast is for global growth of 3.2 per cent for 2016, slightly higher than the 2015 estimate of 3.1 per cent, but below the IMF's January 2016 forecast of 3.4 per cent. Looking to 2017, the IMF is projecting stronger global growth of 3.5 per cent, down from the January 2016 forecast of 3.6 per cent.

The strengthening recovery in 2017 is noted as being driven primarily by emerging market and developing economies, as conditions in stressed economies start to gradually normalize. While growth is expected to pick-up, the IMF notes that uncertainty has increased, and risks of possible weaker growth were becoming more tangible. [1]

Even with the growth rate declining for the fifth consecutive year in 2015, growth in emerging market and developing economies continues to outpace that of growth in advanced economies. The IMF is forecasting that growth in emerging and market and developing economies will continue to account for the lion's share of projected world growth in 2016 and 2017. Following growth of 4.0 per cent in 2015, the IMF is forecasting growth of 4.1 per cent in 2016, to be followed by stronger growth of 4.6 per cent in 2017.

While continuing to grow, prospects across emerging market and developing countries remain uneven and generally weaker than over the past two decades.[2] The IMF's April Outlook noted in particular that a number of large emerging markets, including Brazil and Russia, are still in the midst of recessions. Others, including several oil-exporting countries, were also noted as dealing with weaker terms of trade and tighter external financial conditions.[3] Declining investment growth in emerging market economies was also noted as a contributing factor to recent weaker performance.

China's economy remains in a period of transition, moving to development of services and retail in support of its domestic demand from an economy supported substantially through

manufacturing activities and large scale industrial development. Even with the recent slowdown, China, along with India, will continue to lead the way for emerging market countries. Following estimated growth of 6.9 per cent in 2015, China's economy is expected to grow 6.5 per cent and 6.2 per cent over the next two years. Following growth of 7.3 per cent in 2015, India is forecast to post gains of 7.5 per cent in both 2016 and 2017.[4]

Following estimated growth of 1.9 per cent in 2015, advanced economies are forecast to grow by 1.9 and 2.0 per cent annually over the next two years. U.S. growth is expected to remain the primary driver of growth in advanced economies with U.S. growth rates in both 2016 and 2017 exceeding the overall growth rates of advanced economies.

Stronger housing and labour markets and favourable financial conditions continue to support the U.S. economy. Significant employment gains were noted in 2015, with an average of 221,000 jobs added on a monthly basis.[5] Improving labour income and lower gasoline prices have supported private domestic demand, as reflected in near-record-high vehicle sales, robust residential construction and strong business investment outside the commodity-related sectors.[6] The current IMF forecast has U.S. growth in the near-term approximating recent growth rates. Following estimated growth of 2.4 per cent in 2015, the forecast calls for growth of 2.4 and 2.5 per cent in both 2016 and 2017.

Recently, Canada's economy has underperformed the U.S. economy and expectations are that this will continue in the near-term. Much of the recent weakness is attributed to weaker commodity prices, particularly oil prices, which due to oversupply in the global market has declined significantly in the last 18-20 months, falling below $30 per barrel for a time in early 2016. Prices for many key mineral exports are also down substantially from recent levels which has contributed to mine closures, layoffs, reduction in mineral exports and lower levels of investment in Canada's mining sector. Evidence of the recent poor performance of oil and mineral prices can be seen in estimates of economic performance and expectations for performance in the near-term. The IMF is estimated that Canada's economy only grew by 1.2 per cent in 2015. Expectations for slightly stronger growth is noted by the IMF for 2016 and 2017, with gains of 1.5 per cent and 1.9 per cent, respectively. The April 2016 forecast represents a downgrade from the January 2016 forecast of 1.7 per cent and 2.1 per cent for 2016 and 2017 respectively.

The Bank of Canada is also forecasting relatively weak economic growth for Canada in 2016, to be followed by improved performance in 2017. The April 2016 *Monetary Policy Report* includes real GDP growth forecasts of 1.7 per cent in 2016 and 2.3 per cent in 2017. While the Bank noted that global and domestic developments, including the economy's adjustment to the ongoing weakness in oil prices, would have resulted in a modest downgrade of its outlook for 2016 and 2017, fiscal measures announced in the March Federal budget will have a notable positive impact.[7]

Resource extraction activities continue to be a significant contributor to Canada's economy, and growth prospects for the country are inherently linked to the performance of commodity prices. The weakness in mineral prices that began in 2014 became more prominent in 2015 and has continued into 2016. Prices for key commodities such as gold, silver and copper recently touched lows not seen in five to six years. Concerns about global demand, especially declining demand from China, as well as increases in supply that followed the most recent mining investment boom, continue to contribute to uncertainty about a recovery in mineral prices.

Even more of a downward drag on Canada's economy has been the rapid decline in oil prices. A glut of supply, weaker demand from China and Iranian oil hitting the global market with the lifting of Nuclear related sanctions have all contributed to weakness in oil prices. High crude oil inventories held by the U.S. are also working to keep oil prices low, near record levels at the time of writing. The outlook for oil prices remains poor, with many forecasters expecting prices to remain relatively low throughout 2016, before a minor recovery in 2017. At the time of writing, BMO Capital Markets is calling for oil prices to average US$37 per barrel in 2016, down from US$48.69 in 2015, and US$93.26 just two years ago (2014).[8] At US$37 per barrel, the price of oil would be the lowest since 2003 when it averaged just over US$31 per barrel.

After averaging US$4.39 per MMBTU[9] (Henry Hub) in 2014, the highest annual average since 2010, natural gas prices declined significantly in 2015, averaging about US$2.63 per MMBTU. Natural gas prices are expected to perform better than oil prices in the near-term, but remain well below recent highs. BMO Capital Markets is forecasting Henry Hub Natural Gas prices to fall to US$2.25 per MMBTU in 2016 before increasing to US$3.20 per MMBTU in 2017.

Future growth prospects for Canada are also tied to interest rates. After being pegged at 1.0 per cent since September 2010, the Bank of Canada surprised most analysts in January 2015 when it lowered the overnight rate to 0.75 per cent, and then lowered it further to 0.5 per cent in July 2015. Given the weaker outlook for Canada's economy Canadian interest rates are expected to remain low throughout 2016 and likely into 2017. At its most recent rate announcement on April 13, 2016, the Bank of Canada maintained the overnight rate at 0.5 per cent, opting to continue to keep the cost of borrowing relatively low. The next interest rate announcement for the Bank of Canada is scheduled for May 25, 2016.

Outlook for Global, U.S. and Canadian Economies

The IMF's April 2016 update to the World Economic Outlook includes the following forecasts:

- Global Growth: 3.2 per cent (2016) and 3.5 per cent (2017);
- U.S. Growth: 2.4 per cent (2016) and 2.5 per cent (2017); and
- Canadian Growth: 1.5 per cent (2016) and 1.9 per cent (2017).

RECENT PERFORMANCE AND SHORT-TERM OUTLOOK

PART A: ECONOMIC INDICATORS

GROSS DOMESTIC PRODUCT (GDP)

Preliminary data released by Statistics Canada in May 2016 estimates that Yukon's real GDP by industry in 2015 contracted by 3.8 per cent to $2.177 billion. The decline in 2015 represented a third consecutive year of contraction for the territory.

Among the provinces and territories, Yukon 2015 performance ranked only ahead of Alberta which saw a contraction of 4.0 per cent. Prior to 2013, Yukon's real GDP had posted nine straight years of growth.

Weakness in the mining sector continued to weigh on Yukon's economy in 2015, resulting in a substantial decline in mineral production in 2015. Suspension of production from the Wolverine mine in January 2015 saw mineral production come in well below the 2014 level. A 43 per cent decline in the mining quarrying and oil and gas extraction component of GDP was the primary contributor to the 2015 decline.

While the percentage contribution of mining in 2015 falls well below the high of abour 22 per cent noted in 2012, figure 3[10] shows the current contribution of mining related activities still remains well above estimates of a decade ago. At over 11 per cent of total real GDP the 2015 contribution of mining, quarrying and oil & gas extraction is more than double the contribution noted in 2005.

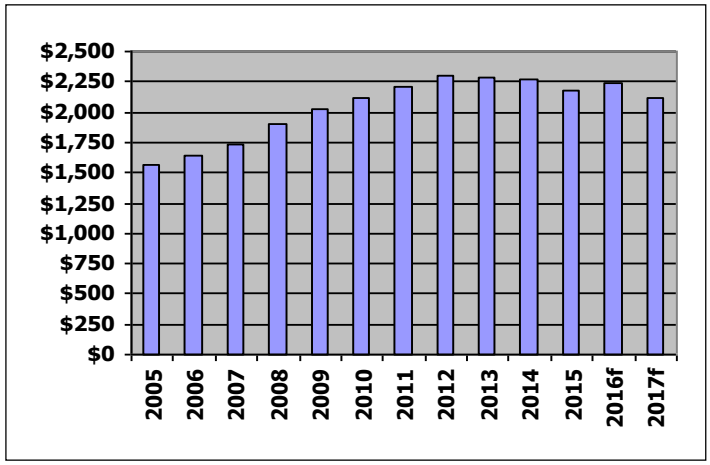


Figure 1 – Real GDP by Industry (2007$ millions)
Source: Department of Economic Development; Statistics Canada

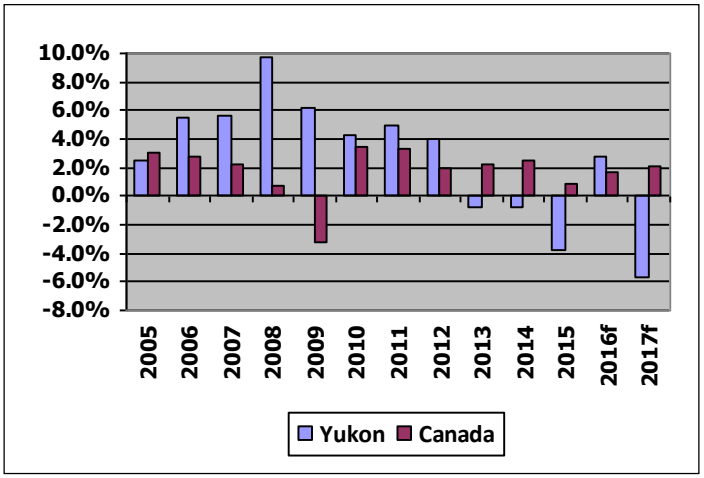


Figure 2 – Real GDP by Industry – Annual Growth Rate
Source: Department of Economic Development; Statistics Canada; International Monetary Fund

Yukon's real GDP is expected to post gains in 2016, with growth primarily related to expectations of increased mineral production as the inclusion of production from its Minto North pit contributes to gains in Minto production. Overall, Yukon's real GDP is forecast to grow 2.8 per cent in 2016.

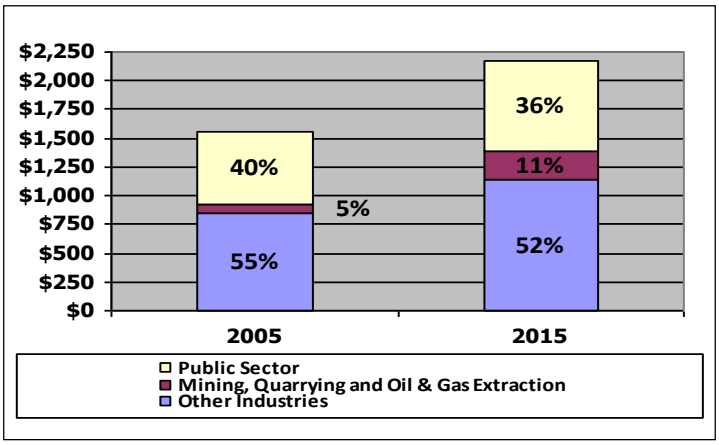


Figure 3 – Real GDP by Industry (2007$ millions)
Source: Department of Economic Development; Statistics Canada

Yukon's economic performance is linked to the performance of the global mineral industry. Expectations are for mineral prices to remain depressed for the medium-term, which will weigh on Yukon growth prospects beyond 2016. With Capstone Mining Corporation already noting that they plan to temporarily shut the Minto mine in the second quarter of 2017, the preliminary forecast for 2017 is for a contraction of 5.7 per cent.

Outlook for GDP

- Preliminary estimates from Statistics Canada note a third straight decline in Yukon's real GDP by industry, with the 2015 estimate of $2.177 representing a 3.8 per cent decline from $2.264 in 2014.
- Anticipated growth in mineral production in 2016 is expected to contribute to real GDP gains, with growth of 2.8 per cent forecasted for 2016.
- The preliminary forecast for 2017 is for a real GDP decline of 5.7 per cent, with the contraction related primarily to lower mineral production.

POPULATION

Population is estimated to have grown for the 12th consecutive year in 2015. Annual population in 2015, as represented by the June 2015 figure, was 37,343, up slightly from 37,251 in June 2014.

Whitehorse[11] – at 28,872 – accounted for over 77 per cent of Yukon's total population in June 2015. Serving as Yukon's primary goods and services hub, population gains in Whitehorse have accounted for the majority of Yukon's recent population growth.

Of the remaining Yukon communities, only two had populations above 1,000 in 2015, Dawson City at 2,067 and Watson Lake at 1,469.

Expectations for the near-term are for modest population gains in the next two years. The current forecast is for population to grow by 0.7 per cent in 2016, followed by growth of 0.3 per cent in 2017. The population forecast represents in part the generally weaker outlook for Yukon's economy. Ongoing weakness in the mining sector and the local economy also presents downside risk to the near-term outlook for population.

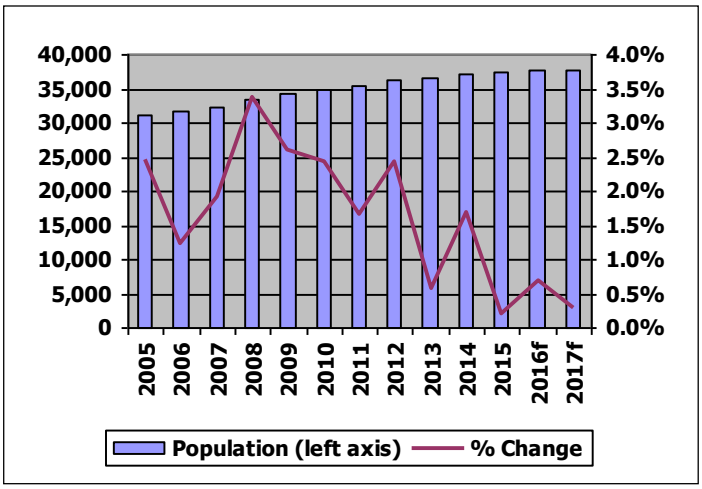


Figure 4 – Yukon Population (June)

Source: Department of Economic Development; Yukon Bureau of Statistics

Outlook for Population

- Following growth of 0.2 per cent in 2015, gains in population in the near-term are expected to remain modest with growth of 0.7 per cent in 2016 and 0.3 per cent in 2017.

LABOUR MARKET

Yukon's labour market has generally performed well in recent years, with Yukon's unemployment rate tracking below the national average for over a decade (see Figure 6). During this time, record levels of employment and labour force have been recorded, with Yukon's unemployment rate amongst the lowest in the country.

Even in light of the struggles for the local economy in 2013 and 2014, Yukon's labour market proved resilient, with notable growth in the labour market and employment, and an unemployment rate that fell to 4.3 per cent.

Signs of weakness in the local labour market were noted in 2015. While Yukon's labour force remained unchanged at 20,700 in 2015, employment fell to 19,400, down 400 from the record level of 19,800 noted in 2014. While down, the number of people employed in Yukon in 2015 was the second highest on record. With no change in the labour force and falling employment, Yukon's unemployment rate increased to 6.3 per cent, up markedly from 4.3 per cent in 2014.

The outlook for Yukon's labour market in 2016 is for marginal growth in both the labour force and employment, with an increase in the unemployment rate for a second consecutive year. With expected GDP growth in 2016 stemming primarily from an increase in mineral production from a mine that is already in production, there is no expectation that this will have a positive impact on local employment. In fact, with Capstone Mining Corporation announcing that it will be ceasing underground mining operations in 2016, local employment losses at the mine are anticipated.

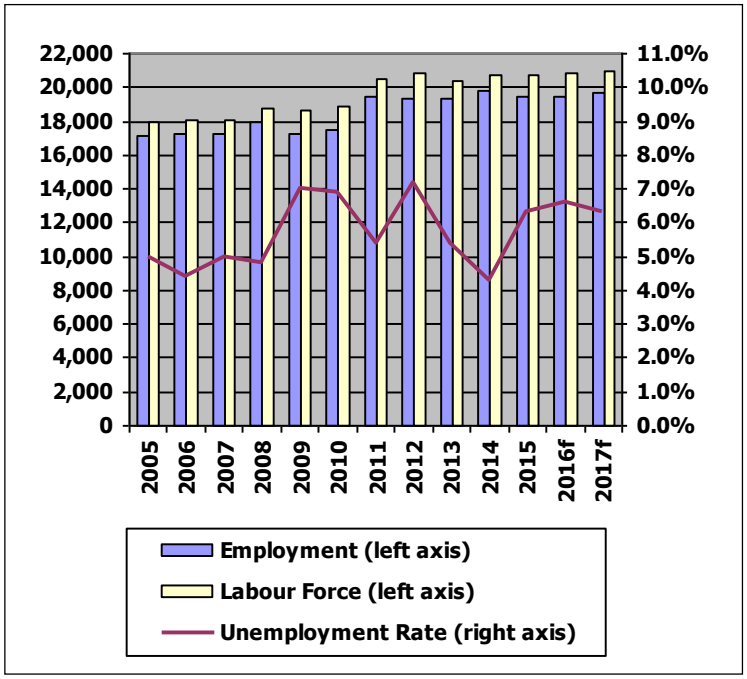


Figure 5 – Key Labour Market Statistics
Source: Department of Economic Development; Statistics Canada

Employment in 2016 is expected to see a modest increase averaging near 19,500. The labour force is also expected to grow, increasing to almost 20,900. A further increase in the unemployment rate is forecasted, increasing to 6.6 per cent in 2016.

Preliminary expectations are for little change in Yukon's labour market in 2017. The number of people employed and the size of the labour force are expected to see minor increases. With the gains in employment to exceed those of the labour force Yukon's unemployment rate is expected to decline slightly to 6.3 per cent.

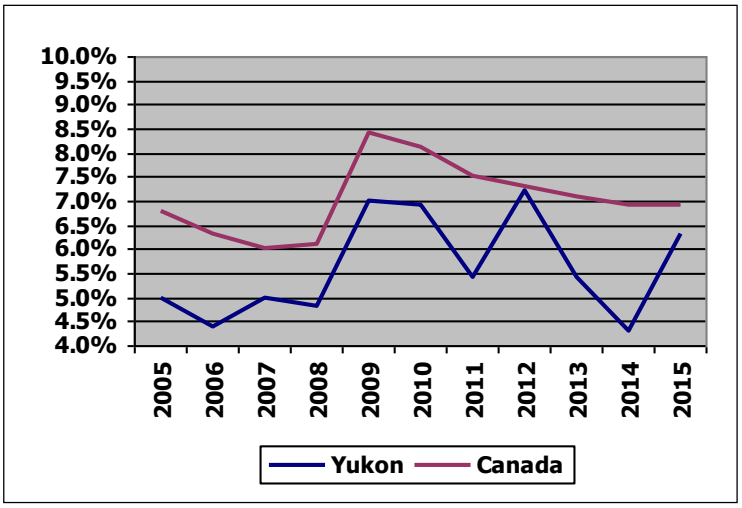


Figure 6 – Unemployment Rate – Yukon vs. Canada
Source: Department of Economic Development; Statistics Canada

Outlook for the Labour Market

- Weaker economic outlook reflected in near-term expectations for the labour market.
  - Average employment is expected to grow slightly in 2016 and 2017.
  - Average labour force expected to increase modestly in 2016 and 2017.
  - Yukon's unemployment rate in 2016 is expected to increase, before a slight decrease in 2017.

CONSUMER PRICE INDEX

Inflation in Whitehorse, as measured by the change in the Whitehorse Consumer Price Index (CPI)[12], has been low in recent years falling below 2.0 per cent over the 2013-2015 period.

The Whitehorse CPI actually declined in 2015, falling 0.2 per cent below the 2014 level. Nationally, CPI posted an increase of 1.1 per cent.

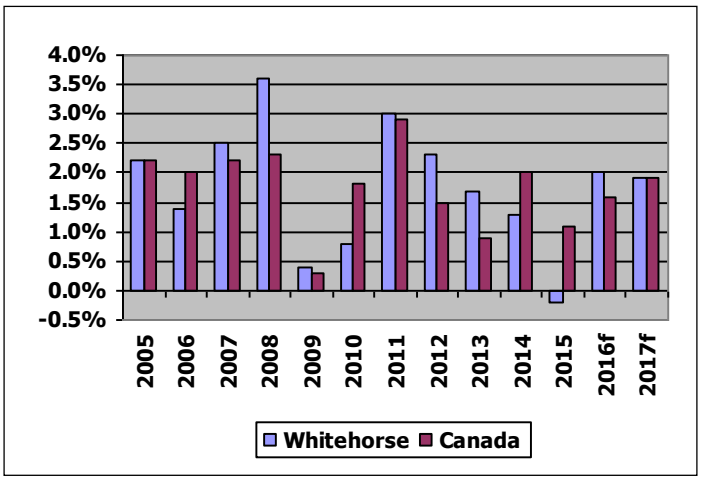


Figure 7 – Change in CPI: Whitehorse vs. Canada
Source: Department of Economic Development; Statistics Canada; BMO Capital Markets

Lower oil prices weighed on gasoline prices in 2015, with average gasoline prices in Whitehorse down about 16 per cent from 2014. Lower gasoline prices were reflected in the Gasoline component of CPI, down 15.7 per cent and the Transportation component, down 3.2 per cent.

The Shelter component of CPI was also down in 2015, 2.4 per cent lower than the average 2014 figure. Lower prices for home heating fuel in Whitehorse, down almost 20 per cent from 2014, helped to contribute to lower shelter costs in 2015.

CPI Components that posted notable price increases in 2015 included Clothing and Footwear (3.0 per cent), Alcoholic Beverages and Tobacco Products (2.4 per cent), Food (2.2 per cent) and Recreation, Education and Reading (2.2 per cent).

Current expectations are for prices to pick up steam in 2016, growing 2.0 per cent. Contributing to this increase is the expectation of higher food prices, partly due to the expectation of the weakness in the Canadian dollar to persist throughout 2016, as well as the expectation that fuel prices might begin to increase later in the year.

Beyond 2016 prices are expected to continue to increase, with a further increase of 1.9 per cent in the Whitehorse CPI growth in 2017.

Outlook for CPI

- Following price deflation of 0.2 per cent in 2015, the Whitehorse CPI is expected to increase by 2.0 per cent in 2016 and 1.9 per cent in 2017.

PART B: ECONOMIC SECTORS

MINING

Weak mineral prices continue to weigh on the global mining sector, contributing to mine closures, layoffs, project delays, and generally lower levels of spending.

Not surprisingly, Yukon's mining sector has also been negatively impacted with two mine closures since the beginning of 2013 and far lower levels of exploration and development spending than what has been experienced in recent history.

While Yukon's world-class geology does position the territory favorably for future growth in the mining sector, the relatively poor outlook for mineral prices has created substantial uncertainty for exploration, development and production activities going forward.

MINERAL EXPLORATION

A weaker environment for mineral prices prevailed throughout 2015 contributing to an inability of many mining companies, particularly junior mining companies, to raise capital to finance exploration activities. A number of operators also took steps to lower costs in response to lower prices.

Yukon, like many jurisdictions, saw less activity related to exploration and lower levels of spending. With much of the exploration work undertaken in the territory completed by junior mining companies, the difficulty of juniors to raise money has seen exploration expenditures fall off substantially. Natural Resources Canada's (NRCAN) latest *Survey of Mineral Exploration, Deposit Appraisal and Mine Complex Development Expenditures*, released in February 2016, estimates exploration spending[13] fell to $73.3 million in 2015, down from $107.1 million, spending in 2015 and well below spending of $331.7 million in 2011 and $233.2 million in 2012.

Following a period where a much greater proportion of exploration-related spending was associated with "exploration"[14] activities, recent years have seen more spending in the areas of deposit appraisal[15]. NRCAN's spending estimate for 2015 includes an estimated $45.3 million related to expenditures on deposit appraisal and the remaining $28.0 million associated with exploration. At $45.3 million, spending on deposit appraisal accounted for almost 62 per cent of the total spending figure, far higher than during the last exploration boom which saw deposit

appraisal spending of $40.7 million (26 per cent), $76.0 million (23 per cent) and $52.9 million (23 per cent) in 2010, 2011 and 2012, respectively.

Estimates from the Department of Energy, Mines & Resources (EMR) have exploration expenditures of about $65 million in 2015, down from EMR's estimate of $80 million in 2014. EMR exploration spending estimates are generally lower than NRCAN estimates as the NRCAN spending numbers include such expenditures as related road development and environmental baseline work. The EMR number is more representative of spending on pure exploration work such as drilling and geochemical. Differences between EMR and NRCAN exploration spending numbers can also occur because the NRCAN numbers are based on a survey completed early in the year while EMR numbers are based on announced company budgets.

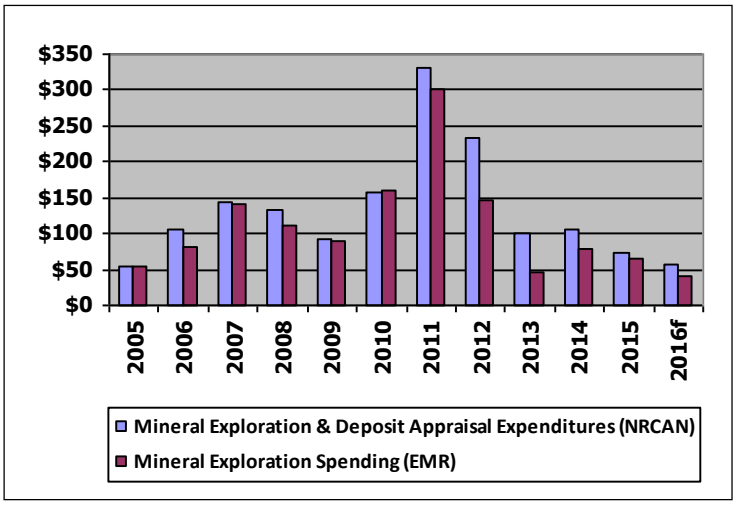


Figure 8 – Mineral Exploration Expenditures ($ millions)
Source: Department of Economic Development; Natural Resources Canada

The near-term outlook for the global mining sector remains poor, as global mining prices are expected to remain well below recent highs. Mining companies are anticipated to continue to take steps to keep costs low with spending on exploration and development activities remaining relatively low. Current estimates from EMR have exploration spending in 2016 falling to approximately $40 million, with spending by BMC Minerals Ltd. at its Kudz Ze Kayah property expected to account for about half of the total spending. Results of NRCAN's latest spending intentions survey have exploration related expenditures in 2016 at $56.4 million, also down from its 2015 spending estimate.

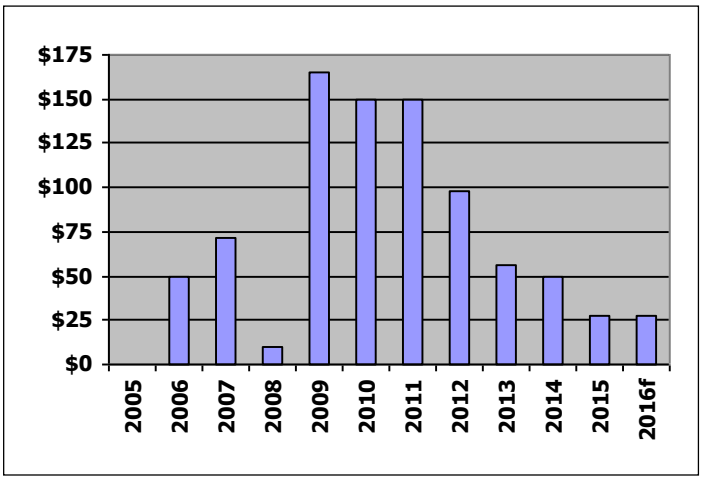


Figure 9 – Mineral Development Expenditures ($ millions)
Source: Department of Economic Development; Department of Energy, Mines & Resources

MINING DEVELOPMENT

With no mines in development, spending over the past three years has fallen well under recent highs.

Development spending in 2015 was estimated at just under $30 million, down from about $50 million in 2014. Almost two-thirds of the 2015 spending estimate is associated with expenditures at the Minto mine related to the continued expansion of underground mining.

EMR's development expenditure forecast for 2016 has spending at slightly below the 2015 estimate.

MINERAL PRODUCTION

After approaching $500 million in 2012, the value of mineral production has fallen in every year since. Closures of the Bellekeno mine in September 2013 and the Wolverine mine in January 2015 account for the majority of the recent declines.

The notable decline in the value of mineral production in 2015 was the result of both lower production and substantially lower year-over-year prices. The closure of the Wolverine mine in January 2015 accounted for the majority of the decline in mineral production. As illustrated in Figure 10, after approaching $500 million in 2012, the value of mineral production in 2015 fell below $250 million.

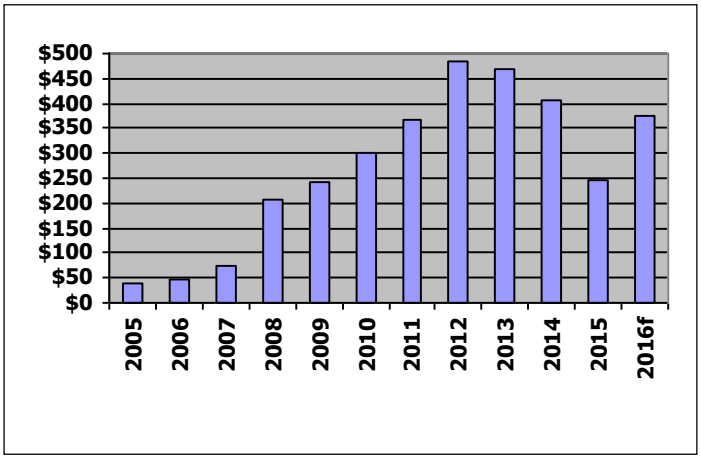


Figure 10 – Value of Mineral Production ($ millions)
Source: Department of Economic Development; Natural Resources Canada

Looking to 2016, expectations are for prices to remain weak and to fall below 2015 levels. Production on the other hand is expected to increase markedly with Capstone Mining Corporation's production guidance[16] for 2016 indicating production well above the 2015 level. The current outlook for the value of mineral production is for growth of over 50 per cent to about $375 million.

Placer mining continues to be a positive story for Yukon's mining sector. Over the past four years, the value of placer production has averaged almost $70 million, making it a significant contributor to Yukon's total value of mining. For the period 2013 to 2015, placer gold production has averaged almost 59,000 crude ounces. Placer gold production in 2016 is expected to be similar to the over 62,000 crude ounces produced in 2015.

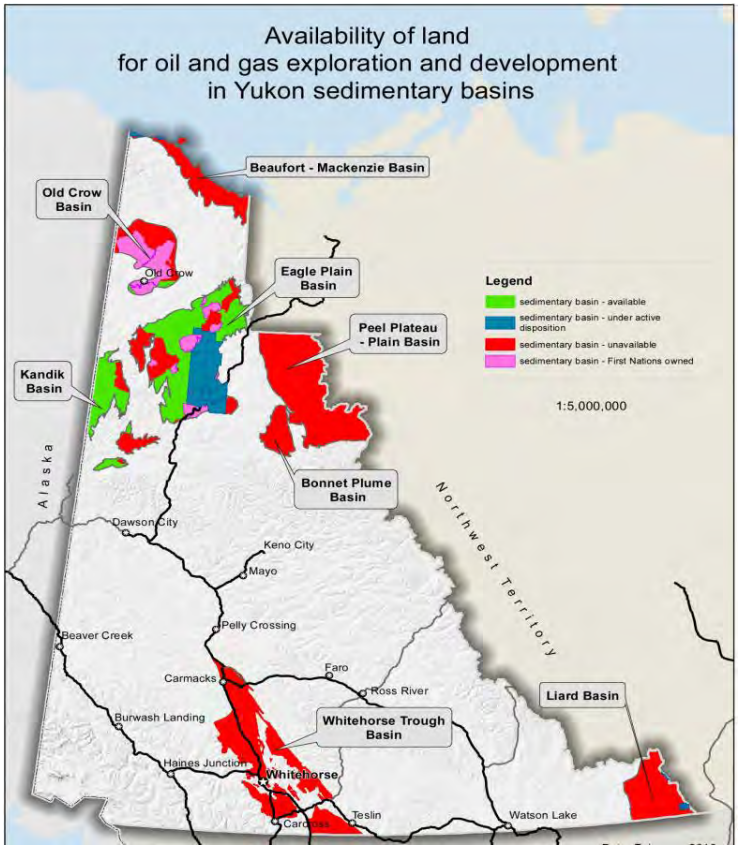
Beyond 2016, further headwinds for Yukon's mining sector are anticipated. The outlook for mineral prices remains poor which is expected to continue to dampen mining-related spending. With the January 2015 announcement by Capstone Mining Corporation that they plan to temporarily cease operations of the Minto mine in early 2017, the value of mineral production will likely fall to the lowest level since 2008 which was the first full year of Minto production.

Outlook for Mining

- Exploration and development spending in 2016 expected to fall below 2015 levels.
- Increased Minto production is expected to contribute to gains in the value of mineral production in 2016, but the planned temporary shutdown of the Minto mine in early 2017 will significantly impact next year's mineral production.

OIL & GAS

Yukon is home to significant hydrocarbon resources, both onshore and offshore. Yukon's onshore sedimentary basins contain an estimated 14.77 trillion cubic feet (Tcf) of conventional natural gas and 663 million barrels (MMbbls) of conventional oil. Offshore conventional resources in the Beaufort Sea include an additional estimated 40 Tcf of natural gas and 4,500 MMbbls of oil. Yukon also has the potential to host significant unconventional oil and gas resources although further assessment work is required.



Since production ceased at the Kotaneelee field in September 2012, there has been no commercial hydrocarbon production in Yukon. EFL Overseas Inc. (EFLO) has a 54 per cent working interest in the Kotaneelee field, and had been interested in workovers of existing wells. At this time EFLO has no plans to start this work in the foreseeable future.

Interest has also been shown in the hydrocarbon potential of the Eagle Plain Basin in Northern Yukon. Supported by investment from China National Offshore Oil Corporation (CNOOC), Northern Cross (Yukon) Limited has spent more than $100 million since their current exploration program began in late 2011.[17] Northern Cross' multi-well exploration program that was submitted to YESAB in 2014, proposes to drill and conduct extended flow tests on up to 20 exploratory oil and gas wells in the area that it completed a 3D seismic program in early 2014. Wells are planned to be drilled and tested from December to mid-April and from May to October, over a period of eight years.[18] These wells would be in addition to the four wells drilled in 2012 and 2013. Citing concerns about the uncertainty of the drilling program's impacts on the Porcupine Caribou Herd, YESAB released an evaluation report that referred the exploration program to the Executive Council for screening.

Future oil and gas development in Yukon is inherently tied to the performance of oil and gas prices. Looking at the performance of the past 10 years, natural gas prices are shown to be quite variable, going as high as US$8.86 MMBTU in 2008 and falling as low as US$2.63 MMBTU in 2015.[19] At US$2.63 MMBTU, the price was down over 40 per cent from US$4.39 MMBTU in 2014. Many forecasters are calling for prices to decline in 2016, before posting growth in 2017.

Like natural gas, oil has seen its price decline substantially in recent history. After averaging over US$90 per barrel in every year from 2011 to 2014, oil prices declined dramatically in 2015,

averaging US$48.69 per barrel, down 48 per cent from 2014 and the lowest annual average since US$41.44 per barrel in 2004.[20] Increased supply and weaker demand have contributed to lower oil prices, and these factors are expected to continue to weigh on oil prices in the near term as oil is expected to average about US$40 per barrel in 2016. Prices are expected to recover somewhat in 2017, averaging almost US$50 per barrel, well below levels seen in the last ten years.

Any development of Yukon's hydrocarbon resources will be shaped in part by decisions related to the production process of hydraulic fracturing. In an effort to engage with Yukoners and generate discussion on what has become a high profile, public topic, the Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing was formed.

The final report of the Select Committee was released on January 19, 2015 and included 21 recommendations. The recommendations focus on the need for continued public dialogue, continued First Nation engagement, detailed assessment of the economic, human health and social impacts, more baseline data and scientific research around water, greenhouse gases, air emissions, wildlife and induced seismicity and assurance that regulatory processes will protect the safety of people and the environment.

The Government of Yukon has stated that it agrees with all 21 recommendations, and has developed an Action Plan on Oil and Gas Development to address many of these areas. Included in this Action Plan is a plan for dialogue on how to responsibly develop oil and gas resources with the public and First Nations; the need to conduct a study of the economics associated with unconventional oil and gas development; requirement for baseline water monitoring work; the need for expanded seismic baseline data; and a discussion of exploring partnerships with affected First Nations and other potential partners.[21]

Outlook for Oil & Gas

- Future development will depend on a number of factors including the performance of oil and natural gas prices and decisions made related to the use of hydraulic fracturing in the territory.
- There is interest in using LNG for power generation in proposed mines in Yukon.
- Production of local resources could offset future hydrocarbon imports.

TOURISM

Tourism activities have long been an important contributor to Yukon's economy, often serving as a stabilizing force for Yukon's economy during times when the mining sector has struggled. Tourism related activities add to the diversity of the local economy, help promote the territory, and support employment across a wide variety of local goods and services providers. Retailers, grocery stores, accommodations providers, restaurants, as well as providers of sports and recreational activities and providers of arts and culture all benefit annually from visitors to the territory.

Tourism activities over-lap a number of industries, therefore determining the economic contribution of tourism is not straight-forward. Accommodations & Food Services, Retail Trade and Transportation & Warehousing are three industry classifications where tourism related

activities are reflected strongly. One of the more recent attempts to capture the economic contribution of tourism is noted in the 2015 *Yukon Business Survey* where Yukon businesses are cited as attributing $226.9 million of their gross revenue in 2014 to tourism and based on these revenues the total GDP attributable to tourism was estimated at about $95.9 million, representing almost four per cent of Yukon's total GDP in 2014.[22]

Based on reporting from the Canada Border Services Agency (CBSA), the Department of Tourism & Culture notes a decline in total border crossings for 2015, with 327,778 people crossing international borders in Yukon, a decrease of 13,929 or 4.1 per cent from 2014. Excluding Yukon residents, who are not traditionally considered tourists, total border crossings were down 7,151 people, or 2.4 per cent, over 2014. Since posting a 20-year low in 2009, crossings have been well over 300,000 annually, averaging over 330,000 for the period 2010 to 2014. While an imperfect indicator of tourism performance, international border crossings are often used as a performance measure.

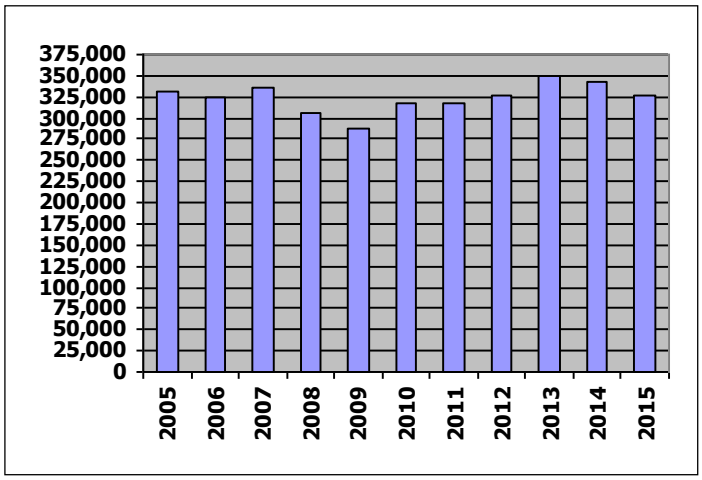


Figure 11 – Border Crossings
(Includes International Air Travel)
Source: Canada Border Services Agency

Anecdotally, Yukon's tourism industry has indicated that 2015 was a good year for tourism and a number of tourism indicators support their perspective. Air arrivals at Erik Neilson Whitehorse International Airport were up 1.7 per cent compared to 2014 with over 156,000 passengers arriving at the airport.[23] Visitation to Yukon Visitor Information Centres was also up 2.4 per cent recording 252,349 visits. Attendance at the Beringia Interpretive Centre was up 6.0 per cent and visitation to Parks Canada's Kluane National Park and Reserve and National Historic Sites were up 8.2 and 5.9 per cent, respectively, compared to the same period last year.[24] The number of non-residents camping at Yukon Government campgrounds was up 13.6 per cent, and the number of non-resident person nights spent at government campgrounds were up 16.6 per cent over 2014.[25]

Further, border crossings provided by U.S. Customs and Border Protection indicate that the number of people entering Alaska from Yukon were up 1.1 per cent to 404,751 people compared to the same period in 2014.[26]

Looking ahead, a weakened Canadian dollar, lower fuel prices, improving consumer confidence, and gains in domestic airline seat capacity are prominent among the factors that will likely impact tourism activities in the near-term.

After a prolonged period where the Canadian dollar performed well against the US dollar, often trading above par, the dollar saw a significant devaluation in 2015 and this has continued into 2016. The Canadian dollar traded at over US$0.90 for the majority of 2014 but began trending downward in the fall of the year. By the end of 2015, the dollar was trading in the low 70s, and in January 2016 dipped below US$0.70 for the first time since 2003. The persistence of a

weaker Canadian dollar may bode well for local tourism operators as visitation becomes more affordable for U.S. and some overseas visitors and may also result in Canadians becoming more inclined to vacation in their own country.

Lower oil prices have translated into lower gasoline prices. Lower fuel prices decrease the cost of travel via personal motor vehicle, and also possibly the costs of travel via motorcoach and airplane, if a portion of the fuel savings are passed along to the customer. Oil prices have fallen dramatically, down over 70 per cent in the last year and a half. Lower oil prices have contributed to lower fuel prices, with the price of regular unleaded gasoline in Whitehorse near $1.00 per litre at the time of writing.

As noted, anecdotal information for 2015 indicates that it was a positive year for the local tourism community. Expectations are that 2016 and 2017 will continue to grow upon the recent positive performance.

Outlook for Tourism

- Expectations are that the near-term will build on what many local operators noted as a good year in 2015.

CONSTRUCTION

Following a 65 per cent increase to $130.5 million in 2014, the value of building permits in 2015 are reported as falling to $117.7 million.

The value of non-residential permits declined in 2015, falling 2.6 per cent to $81.6 million. While down, non-residential permits continued to account for the majority of building permit value in 2015, representing 69 per cent of the annual total. Since the start of 2010, non-residential building permit value accounted for 59 per cent of the total building permit value of over $730 million.

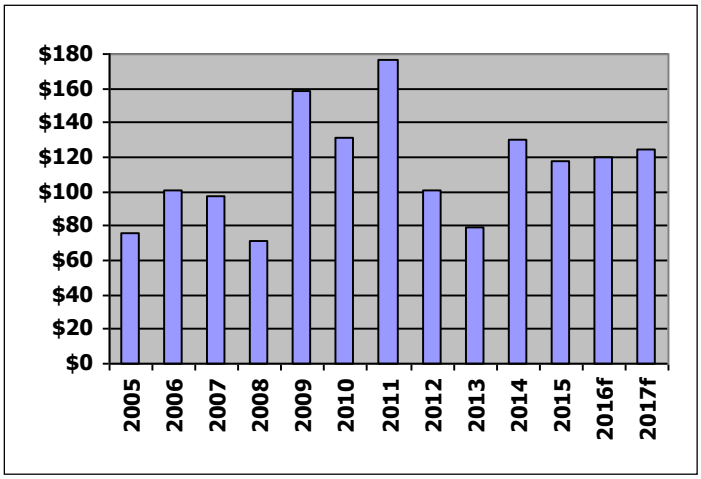


Figure 12 – Value of Yukon Building Permits ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Contributing to the decline in non-residential permits in 2015 was a significant decline in the value of industrial permits which fell from $5.8 million to $769,000. Commercial permit value also fell in 2015, totalling $27.0 million, down about 15 per cent from $31.6 million in 2014. Countering a portion of the decline in non-residential permit value was an increase in government/institutional permit value, up 16 per cent to $53.9 million.

The value of residential permits showed a more significant decline in 2015, falling 22.5 per cent to $36.1 million. After totalling over $71 million in 2011 and almost $66 million in 2012, residential permit value has averaged about $39 million over the last three years. For the period 2010 to 2015, residential building permits accounted for 41 per cent of total building permit value, totalling just over $300 million.

Weaker residential activity in 2015 is also supported by the most recent Northern Housing Report[27] from the Canada Mortgage & Housing Corporation (CMHC), which forecasts a near 13 per cent decline in the number of housing starts, falling from 212 in 2014 to 185 in 2015. The annual decline in 2015 is noted as being similar for both single-detached starts, down 12.8 per cent to 95, and multi-family starts, down 12.6 per cent to 90. At 185, total starts in 2015 are well below the high of 332 in 2011, and the average of the previous five years of over 240 starts.

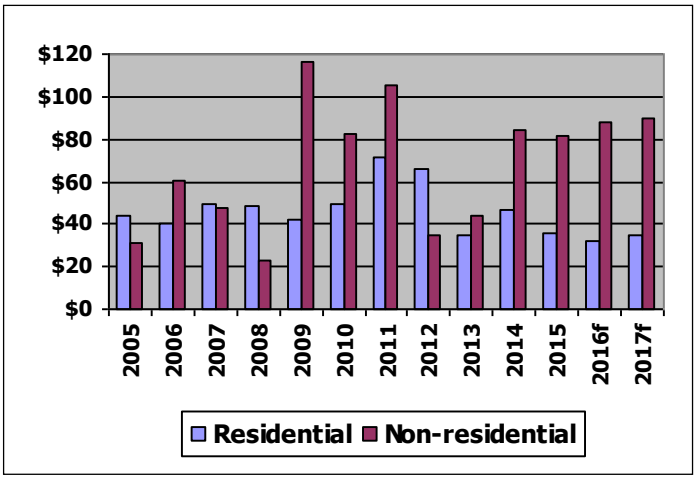


Figure 13 – Value of Yukon Building Permits – Residential vs. Non-residential ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Estimates noted in 2016-17 budget documents have capital spending in 2015-16 at nearly $313 million, representing a record level of spending. Key areas of spending in 2015-16 include:

- There were a number of notable capital projects associated with health and social services, including the contruction of a 150-bed continuing care facility in Whitehorse ($26.0 million)[28], work related to the new Magnetic Resonance Imaging (MRI) scanner and expansion of the emergency department at the Whitehorse General Hospital ($22.3 million), construction of a new drug and alcohol detox centre to replace the Sarah Steele building ($16.4 million), the replacement of the Whitehorse Salvation Army building ($9.1 million), replacement of the McDonald Lodge continuing care facility in Dawson City ($7.8 million) and purchase and conversion of the Oblate Centre on 6th Avenue in Whitehorse to a small continuing care facility ($1.9 million).
- Notable projects related to community operations and infrastructure, included work related to planning of phase 3-5 of the Whistle Bend sub-division ($7.7 million), renovation of the Government of Yukon's main administration building ($5.4 million), replacement of the Carcross fire hall ($3.7 million), replacement of the Faro RCMP detachment ($3.5 million), construction of a recreation centre in Dawson City ($1.4 million) and water and sewer upgrades in various communities including Mayo ($6.6 million), Watson Lake ($4.8 million), Teslin ($2.1 million) and Watson Lake ($2.0 million), Mendenhall Subdivision ($1.8 million), Dawson City ($1.7 million), and Carmacks ($1.1 million).
- Spending on several projects related to transportation were noted for 2015/16, including $8.1 million for Campbell Highway reconstruction, $9.8 million for Shakwak permafrost remediation and crushing, $4.6 million for Atlin road improvements, $2.9 million for

work on the Dempster Highway, $2.1 million allocated to the Watson Lake Aerodrome, $1.5 million for work on the Partridge Creek Bridge and $1.3 million for the Whitehorse Corridor redevelopment.

- Education related construction activities are associated primarily with replacement of the F.H. Collins School in Whitehorse including $9.4 million for construction work and to upgrade the Technical Education Wing. Spending in 2015/16 also included $2.4 million for the Yukon College's Centre for Northern Innovation in Mining and $2.5 million for renovations of the Del Van Gorder School in Faro.
- Other notable projects identified in 2015-16 Government of Yukon spending include construction of a seniors housing project in Whitehorse ($9.5 million), the Keno-Stewart transmission line ($4.3 million), $2.0 million related to development of hydro infrastructure, and $1.8 million for development of rural residential land in Mount Lorne.

While falling below the record capital spending noted for 2015-16, the 2016-17 territorial budget delivered on April 7, 2016 includes a total capital spending figure of $306.6 million. Key areas of spending identified for 2016-17 include:

- Notable projects associated with health and social services, included continued work on a 150-bed continuing care facility in Whitehorse ($66.9 million), $21.9 million for the ongoing Whitehorse emergency department expansion and MRI at the Whitehorse General Hospital, a further $8.3 million for the new Salavation Army building being constructed in Whitehorse, an additional $7.3 million for replacement of the Sarah Steele alcohol and drug detox centre, and $1.7 million for the 6th Avenue continuing care facility in Whitehorse.
- Notable capital projects associated with supporting and improving community services include $21.7 million under the New Building Canada Fund including spending on a new wastewater treatment plant in Burwash Landing and upgrades to the Mayo water reservoir, $15.0 million associated with planning of phases 3-7 of the Whistle Bend sub-division, $4.4 million for upgrades to the Government of Yukon's main administration building, $3.0 million for a new firehall in Carcross, $2.2 million for a wastewater treatment facility in Ross River and $2.0 million for the sewage system in Carmacks.
- Among the notable projects related to transportation are the $12.0 million identified for spending on rehabiliating sections of the road covered under the Alaska Highway-Shakwak Agreement, $11.4 million for reconstruction and rehabilitation of the Robert Campbell Highway, $3.1 million for Dempster Highway erosion and rehabilitation, $3.9 million for work on the Erik Nielsen Whitehorse International Airport, $2.8 million for Community Airport improvements, and $2.5 million for Whitehorse Corridor passing and turning lanes on the Alaska Highway.
- The majority of education specific spending remains associated with the replacement of the F.H. Collins school in Whitehorse. The 2016-17 budget notes $3.0 million for construction of the F.H. Collins Technical Education Wing and $2.9 million for site development of the old F.H. Collins School.
- Other notable projects identified in the 2016-17 budget include $7.2 million from the CMHC for Investments in Affordable Housing, $5.6 million for the expansion of the Department of Tourism & Culture's Archives Vault Expansion, $4.0 million under the the Rural Land Development Program and $3.0 million for the construction of a 6-unit residential staff housing building in Ross River.

The City of Whitehorse's building consolidation project is another major initiative that will impact the local economy in the near-term. The City of Whitehorse's Capital Budget 2016-2019 notes a total capital cost of over $56 million for this project with almost $50 million of that slated to be spent in 2017.

Because of questions regarding timing of permits, and what future construction activities may require permits, forecasting the value of building permits can be difficult. As well, the performance of mineral prices and the subsequent impact on the local mining sector continue to be key determinants of the nature and level of construction activity in Yukon. Given the current uncertainty in the global mining sector and what it could mean for local mining activities, the risk to the building permit outlook is elevated. In terms of the value of building permits, modest gains in the value of residential and non-residential building permits are anticipated for 2016 and 2017 with growth focused primarily in non-residential permits.

Outlook for Construction

- The value of building permits is expected to grow modestly in the next two years.
  - Construction activities in the realm of health and social services are expected to be a key driver of the value of institutional building permits and overall building permits in the near-term.

RETAIL TRADE

Data from Statistics Canada indicates that Yukon reported a record level of retail sales in 2015, with the value of $692.2 million[29] representing annual growth of 4.7 per cent from $660.9 million. While growth in 2015 was anticipated, the impressive annual growth was unexpected given recent weaker economic performance.

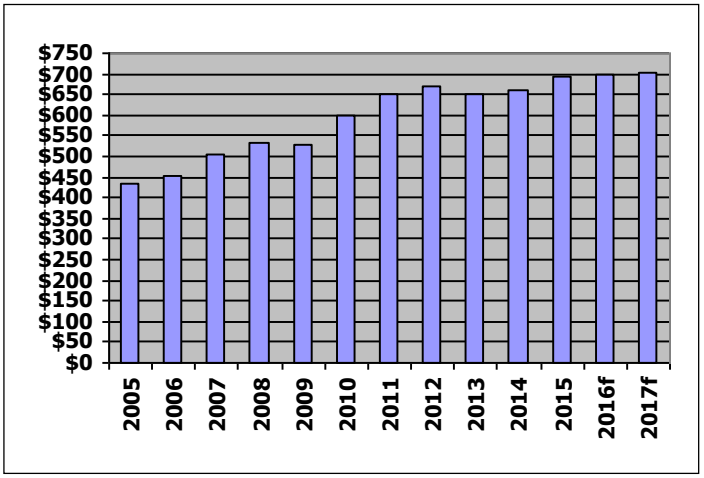


Figure 14 – Value of Retail Sales ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Among categories of retail sales that are not suppressed for Yukon, sales from Food and Beverage Stores represented the largest component in 2015 accounting for over 29 per cent of total sales, increased by 2.7 per cent to $203.4 million. The value of sales related to Gasoline stations, the second largest component of retail sales, were reported as increasing slightly (up 0.3 per cent) to $107.8 million in 2015 as lower gasoline prices dampened sales. Sales from Health and Personal Care Stores were also reported as being up in 2015, with the estimated value of $37.5 million up 17.1 per cent from $32.0 million in 2014.

Sales from Furniture and Home Furnishings Stores were noted as being down in 2015, declining 4.6 per cent to $12.9 million.

Due to issues around confidentiality, retail sales data for other retail classifications are suppressed.[30] Total sales from these suppressed classifications in 2015 totalled $330.7 million, well above the $310 million recorded in 2014.

Growth in the short-term is expected to be modest with the current forecast calling for growth of 0.8 per cent in 2016 and 1.1 per cent in 2017.

Outlook for Retail Trade

- Statistics Canada reports the value of retail sales in 2015 at over $692 million, up 4.7 per cent from $660.9 million in 2014.
- Retail sales are forecast to grow 0.8 per cent in 2016 and a further 1.1 per cent in 2017.
- A weaker economy and continued weakness in the mining sector increases the uncertainty for the near-term performance of retail sales.

KEY ECONOMIC INDICATORS

Indicator	*2014*	*2015*	*2016f*	*2017f*
Population, Prices, Rates				
Population (June)	37,251	37,343	37,600	37,750
Population Growth Rate	1.7%	0.2%	0.7%	0.3%
CPI Growth Rate^	1.3%	-0.2%	2.0%	2.0%
Overnight Rate	1.00%	0.63%	0.50%	0.69%
Canada/U.S. Exchange Rate	$0.906	$0.783	$0.757	$0.777
Employment ƒ				
Labour Force	20,700	20,700	20,900	21,000
Employment	19,800	19,400	19,500	19,650
Unemployed	900	1,300	1,400	1,350
Unemployment Rate	4.3%	6.3%	6.6%	6.3%
Economic Output				
Real GDP By Industry (billions of chained 2007 $)	$2.264 (r)	$2.177 (p)	$2.238	$2.111
Real GDP Growth Rate	-0.8%	-3.8%	2.8%	-5.7%
Commodity Prices~				
Gold ($US/oz)	$1,266	$1,160	$1,170	$1,150
Silver ($US/oz)	$19.08	$15.70	$14.75	$15.00
Zinc ($US/lb)	$0.98	$0.88	$0.80	$0.95
Copper ($US/lb)	$3.11	$2.50	$2.10	$2.20
Oil - WTI ($US/bbl)	$93.26	$48.69	$37.00	$47.00
Natural Gas – Henry Hub ($US/MMBTU)	$4.39	$2.63	$2.25	$3.20
Mining				
Value of Mineral Production	$408.0 million (r)	$246.9 million (p)	$375 million	--
Exploration Expenditures	$107.1 million	$73.3 million	$56.4 million	--
Development Expenditures	$50 million	$28 million	$27 million	--
Construction				
Permitted Building Construction	$130.5 million	$117.7 million	$120 million	$125 million
Trade				
Value of Retail Sales	$660.9 million	$692.2 million	$698 million	$705 million
Tourism				
Non-resident Border Crossings+	341,707	327,778	--	--

f = forecast, e = estimate, p = preliminary, r = revised, -- = not available
^ CPI increase for Whitehorse only
ƒ annual averages – Labour force and employment rounded to nearest 100. Totals may not add due to rounding.
~ annual averages
+ as reported by the Department of Tourism & Culture

DATA SOURCES FOR KEY ECONOMIC INDICATORS TABLE

Indicator	*Source*
Population	Yukon Bureau of Statistics, Yukon Population Estimates, Yukon Department of Economic Development
Inflation (Consumer Price Index)	Statistics Canada, Consumer Price Index, Yukon Department of Economic Development
Overnight Rate	BMO Capital Markets
Canada/U.S. Exchange Rate	BMO Capital Markets
Labour Force Indicators	Statistics Canada, Yukon Labour Force Survey, Yukon Department of Economic Development
Economic Output (Real GDP)	Statistics Canada, Provincial Economic Accounts, Yukon Department of Economic Development
Commodity Prices	BMO Capital Markets
Value of Mineral Production	Natural Resources Canada Minerals and Mining Statistics Division, Yukon Department of Economic Development
Mineral Exploration Expenditures	Natural Resources Canada; Minerals and Mining Statistics Division
Mine Development Expenditures	Yukon Department of Energy, Mines & Resources, Yukon Department of Economic Development
Tourism Visitation	Yukon Department of Tourism & Culture, Yukon Department of Economic Development
Permitted Building Construction	Yukon Bureau of Statistics, Yukon Department of Economic Development
Retail Trade	Statistics Canada, Yukon Department of Economic Development

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[9] MMBTU refers to a million British thermal unit (Btu)
[10] The "Public Sector" is an aggregation of the industry classifications of Public Administration, Educational Services Health Care & Social Assistance and.
[11] Includes City of Whitehorse and surrounding area as well as the community of Marsh Lake.
[12] Consumer Price Index data is only available in Yukon for Whitehorse.
[13] Exploration and deposit appraisal expenditures include on-mine-site and off-mine-site activities; field work, overhead costs, engineering, economic and pre- or production feasibility studies, environment, and land access costs. Expenditures also include only the search for and appraisal of deposits and do not include work for extensions for known reserves.
[14] The exploration work phase is defined as the search for, discovery, and first delimitation of a previously unknown mineral deposit or the re-evaluation of a sub-marginal or neglected mineral deposit in order to enhance its potential economic interest based on delimited tonnage, grade, and other characteristics. The phase is completed when a deposit has sufficient indicated mineral resources accompanied by a positive scoping study (preliminary economic assessment that justifies additional, more detailed, and costly deposit appraisal work.
[15] The deposit appraisal work phase is defined as the steps undertaken to bring a delimited deposit, by definition drilling, comprehensive tests, and planning, to the stage of detailed knowledge required for a complete feasibility study that will fully justify and support a production decision and the large investment required.
[16] Capstone Mining 2016 Operating and Capital Guidance. http://capstonemining.com/news/news-details/2016/Capstone-Mining-2016-Operating-and-Capital-Guidance/default.aspx
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[18] Eagle Plains Multi-well Exploration Program. Project Proposal Summary YESAB Registry. http://www.yesabregistry.ca/wfm/lamps/yesab/lowspeed/projectsummary.jsp;time=1434126836032
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[28] Values represent estimated spending for the fiscal year in question and do not necessarily reflect the entirety of capital spending for each project. Spending estimates are rounded down to the nearest one decimal.
[29] Retail sales data is unadjusted for inflation.
[30] Data suppressed but included in the total: Motor Vehicle and Parts Dealers; Electronics & Appliance Stores; Building Material & Garden Equipment; Clothing & Clothing Accessories Stores Sporting Goods, Hobby, Book & Music Stores; General Merchandise Stores; and Miscellaneous Store Retailers, and Supplies Dealers.

FBC 2023 ANNUAL REVIEW OF RATES
EXHIBIT B-2

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August 5, 2022

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

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2023 Rates

In accordance with the MRP Plan and BCUC Order G-193-22 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2023 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners to the FBC Annual Review for 2022 Rates

FORTIS BC™

FORTISBC INC.

Annual Review for 2023 Rates

August 5, 2022

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10 of the Application, FBC proposes to distribute $0.911 million pre-tax ($0.665 million after-tax) in earnings sharing to customers in 2023.

The proposed rates for 2023 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2021 earnings sharing to customers, result in a 3.99 percent rate increase from 2022 rates. The increase is primarily due to an increase in power purchase expense (PPE) as well as rate base growth.

In the subsections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FBC's 2021 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2023 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

With this Application, FBC requests BCUC approval for the following pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.
2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1.

3. The following deferral account approvals, as described in Section 7.6:

   - Creation of a rate base deferral account for the 2023 Joint Pole Use Audit, with the balance in the deferral account to be amortized over five years commencing January 1, 2023; and
   - Approval of a three-year amortization period for the existing COVID-19 Customer Recovery Fund Deferral Account, commencing January 1, 2023.

4. Approval to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account, as described in Section 7.6.2.1.

FBC also seeks approval pursuant to section 99 of the UCA to vary the following Orders:

1. Directive 6 of Order G-42-21 in order to facilitate the return of the net incremental COVID-19 related cost reductions to customers through inclusion of the cost reductions in the Flow-through deferral account, as described in Section 12.2.1.

2. Directive 2 of Order G-83-14 to ensure that FBC continues to have approval from the BCUC to use US GAAP for regulatory accounting purposes, as described in Section 12.3.1.

A draft order is included in Appendix D.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10

Item	Description	Response or Reference
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 *FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES*

1.4.1 Overview of 2021 Formula O&M Savings

For 2021, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.4 million.

Approximately $0.9 million in formula O&M savings were realized due to the net incremental impact of the COVID-19 pandemic, which will be returned to customers via the Flow-through deferral account. Please refer to Section 12.2.1 for further details. Lower spending in the Finance and Information Systems departments of approximately $0.6 million from vacancies, reduced consulting, and lower computer consulting services and expenses contributed to the savings. Additionally, approximately $2.2 million of O&M savings were due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. These savings were partially offset by approximately $0.3 million of higher spending compared to the formula amount for incremental expenditures related to System Operations, Integrity and Security. Please refer to Section 6.2.1 for further details. While some of the savings are one-time in nature (e.g., delay in filling vacancies), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As mentioned in FBC's Annual Review for 2022 Rates (2022 Annual Review), in 2021, FortisBC Energy Inc. (FEI) and FBC (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying areas for productivity initiatives. An area of focus for potential productivity opportunities is initiatives that offer financial and customer service benefits and leverage technology and innovation to achieve these benefits.

Following is a summary of productivity initiatives from different parts of the organization FortisBC reviewed this past year and/or is investigating.

1. **Field Operations Improvements:** This initiative was investigated through collecting feedback and analyzing efficiency gains within FBC's Outage Management System (OMS) and Mobile Workforce Management System (MWFM). Changes have been made to the software and processes that allow for improved information sharing and functionality when dispatching and performing jobs. This allows for less manual intervention and a more streamlined workflow. On a separate, but related initiative, enhancements are also underway to provide FBC's storm response restoration teams with an improved interface to access triage information. This will allow for a better prioritization of repairs, and a more efficient allocation of the available resources, resulting in faster restorations.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC is investigating using UAVs to perform transmission line condition assessments. In 2021, FBC requested its contractor performing condition assessments to incorporate the use of drones for collecting data for certain suspected deficiencies. This use of drones was expected to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from the ground, and allow FBC to prepare work-packages for deficiencies identified during condition assessments in a more timely manner. Additionally, some of the drone-collected data has been used to help assess potential system upgrades and reconfigurations without requiring additional field verification of existing assets. For 2022, FBC is developing a request for pricing to assess the potential efficiencies associated with a condition assessment program relying exclusively on drone-collected data and the use of artificial intelligence and machine learning to help identify and categorize deficiencies related to FBC's transmission assets. Should a proponent be identified through this process, it is expected that this work will help validate the use of these techniques for performing condition assessment work and also help quantify the potential cost-savings associated with a drone-based approach for condition assessments.

3. **Technology Investments to Support Enhanced Communications:** FBC introduced enhancements during the COVID-19 pandemic to enable employees to productively work remotely. The implementation of the Microsoft Teams platform was expedited in 2021, allowing for use of video meetings for employee communications. In 2021, FBC also introduced the Microsoft Teams mobile app that provided seamless integration and access to Teams meetings, Teams sites, calendar, chat functionality and a seamless transition

from phone to computer or vice versa during meetings. It was and continues to be a platform to reduce travel requirements for staff, providing options to meet in person less often, which enables continued savings on fuel costs, hotels, meals, and wear and tear on vehicles. Hybrid meetings support large audience attendance using Teams meetings, with the added benefit of not requiring time away from the home office and the resulting lost productivity. Additional functionality will continue to be added to the Teams platform (i.e., whiteboard, enhancements to breakout rooms, Presenter modes and group control of presentation, etc.) as Microsoft continues to develop and release upgrades. The mobile application will also see improvements.

The Company's rapid implementation of communications software during the pandemic has contributed to creating a productive work environment for employees to complete their work with the benefit of not requiring time away from the home office and lost productivity. In total, FBC invested approximately $0.2 million over the two years 2020 and 2021. This investment has contributed to achieving employee-related expense savings (i.e., travel) during the pandemic and will also help to permanently sustain some of the related savings post pandemic.

4. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. Data analytics is the process of extracting and analyzing data sets to identify or uncover patterns, correlations, trends, customer preferences and other information for the purpose of allowing an organization to make more informed business decisions. Better decisions will lead to improved business operations and customer service and increased productivity. The ability to easily access and analyze data can be inhibited by internal processes, decentralization of information and a lack of understanding of the data. With Data Analytics, departments will be provided a common cleansed data source and the tools to create advanced analytics quickly and easily. Resources will be provided to business areas to help identify reporting and analytic needs that will lead to efficiencies. Through a centralized approach, this will provide the skills along with the data and the tools to drive business capability to support analytic needs and also provide better visibility to costs or benefits of data analytics initiatives.

   The requirements and business case for the necessary information systems infrastructure were completed in 2021. FBC plans to implement systems that will allow centralized data access in 2022 and add new data sources in priority sequence over time. Data usage cases for this initiative are being prioritized first for those that enable cost savings.

5. **Streamlining and Automating Reporting Process:** This initiative is one of the earlier usage cases that FBC is considering for the Data Analytics initiative. The focus is on streamlining the reporting processes for financial and management reporting information (i.e., internal cost reporting, key performance indicators, etc.). Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Source system (i.e., SAP) reports are not formatted for users and SAP reports are data extracts and are not set-up for data integration and manipulation. Instead, Excel is

used to integrate, transform and format reports. FBC is presently assessing the feasibility of implementing an automated solution that will reduce the effort required to generate reports, with expected productivity gains. This automation is expected to be achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service.

FBC will be in a better position at next year's Annual Review to provide details of this initiative should it be undertaken, and to provide details of other specific data analytics initiatives undertaken and the benefits achieved.

6. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FBC are challenged. Both the Finance and Engineering departments have experienced an increase in manual activities over several years. Between steps performed multiple times daily, to weekly, monthly or annually, the common theme is a manual and repetitive task with limited decision points.

   In the first phase of RPA implementation, the Company is evaluating opportunities within the Finance and Engineering areas to apply RPA. There are a number of processes being evaluated for RPA with the focus on processes requiring supporting manual activities. The processes vary from creating journal entries, generating third party billing, populating reports, filing documents, and collecting information for budgeting purposes.

   FBC will be in a better position at next year's Annual Review to provide details of this initiative, including the results and benefits achieved.

7. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2021, FBC had approximately 69,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 8,000 customers choosing this option in 2021. This increase equates to approximately $0.07 million in printing and postage cost savings in 2021 as compared to 2020.[1]

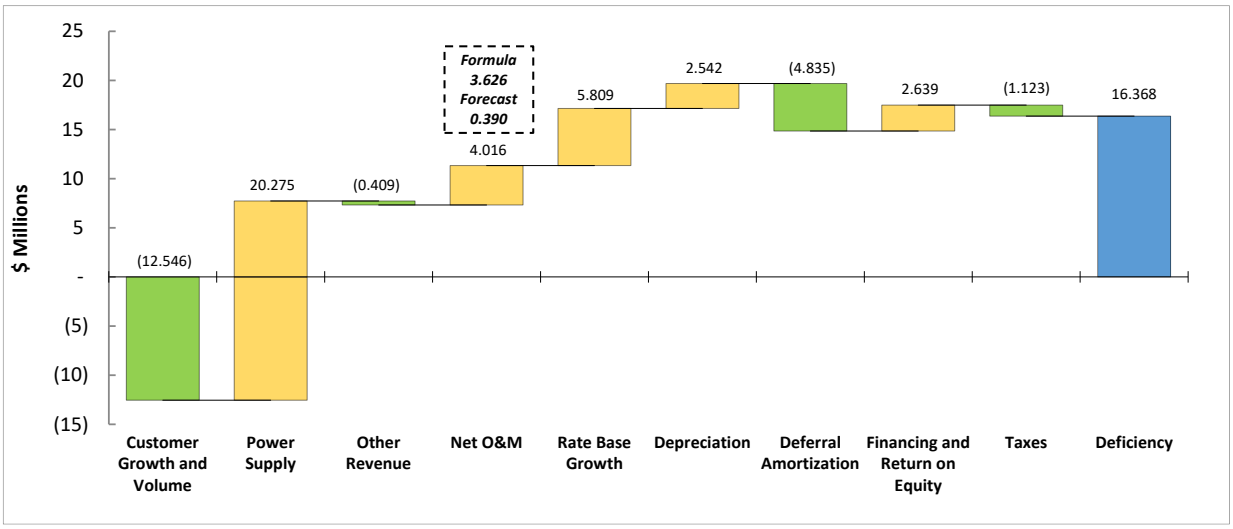
[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.24 per bill.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2023

The revenue requirement components set out in the Application result in an effective rate increase of 3.99 percent for 2023 compared to 2022. The effective rate increase results from a revenue deficiency of $16.368 million.

The following chart summarizes the items that contribute to the 2023 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2023 deficiency of $16.368 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2023 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2023, FBC forecasts a net load increase of 170 GWh compared to 2022 Approved, resulting in a decrease in FBC's 2023 revenue deficiency of $12.546 million. The increase in net load is primarily due to increased loads in the industrial classes, followed by smaller increases in the residential, commercial, wholesale, and irrigation classes. FBC's 2023 Forecast revenue at 2022 approved rates is $409.840 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $20.275 million in 2023 compared to 2022 Approved. This increase is primarily due to the increase in load, and an increase in PPE under the BC Hydro Power Purchase Agreement (PPA) by approximately $27.240 million. This is offset by reduced market and contracted purchases by approximately $8.776 million.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase by $0.409 million in 2023 compared to 2022 Approved. The main drivers of this increase are higher Late Payment Charges and the expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

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

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 4.017 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers[2]. The 2023 Formula O&M net of capitalized overhead has increased by $3.626 million[3] when compared to the 2022 Formula O&M. Net O&M forecast outside of the formula is increasing by $0.390 million[4] over 2022 Approved, primarily due to an increase in pension and OPEB expense. Overall, the 2023 increase in total O&M expense net of capitalized overhead is $4.016 million (6.9 percent).

1.5.5 Rate Base Growth and Depreciation (Section 7)

The 2023 rate base is forecast to increase by approximately $92.524 million when compared to the 2022 Approved rate base, resulting in an increase to the 2023 revenue deficiency of $5.809 million. The increase in rate base is primarily the result of the mid-year impact of FBC's 2023 regular capital additions to plant, as well as the full-year impact of FBC's major capital project additions, including the Kelowna Bulk Transformer Additions (KBTA) project, the Corra Linn Dam Spillway Gates Replacement project, and the Playmor Substation Upgrade project, as described in Section 7.1.

The increase in rate base also results in an increase in 2023 depreciation expense by approximately $2.752 million compared to 2022 Approved, which is offset by approximately $0.210 million of CIAC from net additions, resulting in a net increase of $2.542 million in depreciation expense.

1.5.6 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2023 decreased by $4.835 million, primarily due to the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account, partially offset by increases in the amortization expense of the DSM deferral account, the BCUC Initiated Inquiry Costs deferral account, and the COVID-19 Customer Recovery Fund deferral account. The credit amortization in the Flow-through deferral account in 2023 is $9.625 million, which is $5.698 million higher than the credit amortization in this account compared to 2022 Approved. As discussed in Section 12.4.2.1, the credit amortization in the Flow-through deferral account is

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $3.810 million (5.8 percent) compared to 2022 Approved.
[4] Increase in gross forecast O&M of $0.491 million (26.8 percent) compared to 2022 Approved.

primarily due to favourable revenue variances resulting from increased loads from industrial, commercial, wholesale, and residential classes.

1.5.7 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2023 deficiency by $2.639 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2023, FBC is forecasting a short-term debt rate of 4.24 percent, which is an increase from the 1.51 percent short-term debt rate embedded in the 2022 Approved revenue requirement. Overall, FBC's deficiency is increased by $3.688 million from financing rate changes which is offset by $1.049 million from the ratio change between long-term and short-term debt.

In calculating its 2023 revenue deficiency, FBC has utilized its currently approved capital structure and ROE of 40 percent and 9.15 percent, respectively. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FEI is currently participating in the BCUC-initiated GCOC proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

1.5.8 Taxes (Section 9)

FBC's 2023 property taxes are forecast to increase by 2.1 percent or $0.371 million from 2022 Approved. The increase is primarily due to changes in tax rates and increases in assessed values, as well as an increase in grants in-lieu of taxes which are calculated based on a fixed percentage of FBC's revenue.

There has been no change in the income tax rate of 27 percent from 2022. Taxes are forecast to decrease in 2023 by $1.494 million due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC reports on its 2021 and June 2022 year-to-date SQI results in Section 13. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2023 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and determined that a growth factor multiplier of 75 percent for formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2023, FBC has used July 2020 through June 2022 inflation data for the 2023 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2022 for AWE-BC has been used as a placeholder, as results to June 2022 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2021 labour weighting of 60 percent, the calculation of the 2023 I-Factor is (4.940 percent x 40 percent) + (4.235 percent x 60 percent) = 4.517 percent.

[5] FBC's most recent year of completed actuals is 2021 so that ratio has been used for the 2023 I-Factor calculation.
[6] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2020	132.6	1,093.72								
2	Aug-2020	132.4	1,089.35								
3	Sep-2020	132.5	1,093.75								
4	Oct-2020	132.9	1,095.32								
5	Nov-2020	133.3	1,102.95								
6	Dec-2020	132.8	1,110.36								
7	Jan-2021	133.6	1,113.22								
8	Feb-2021	134.1	1,114.21								
9	Mar-2021	134.9	1,107.66								
10	Apr-2021	135.2	1,112.04								
11	May-2021	135.1	1,118.59								
12	Jun-2021	135.8	1,115.40	133.8	1,105.55						
13	Jul-2021	136.7	1,140.52								
14	Aug-2021	137.0	1,142.40								
15	Sep-2021	137.2	1,139.64								
16	Oct-2021	137.9	1,136.85								
17	Nov-2021	138.1	1,132.25								
18	Dec-2021	138.0	1,134.84								
19	Jan-2022	139.4	1,157.19								
20	Feb-2022	140.4	1,153.88								
21	Mar-2022	143.0	1,161.22								
22	Apr-2022	144.2	1,176.54								
23	May-2022	146.1	1,176.54								
24	Jun-2022	146.5	1,176.54	140.4	1,152.37	4.940%	4.235%	40%	60%	4.517%	2023

2.3 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M.

The calculation of average customers used to determine 2023 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2023 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2023 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Projected 2022	Forecast 2023	Total for 2023 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,861		Appendix A2 - Section 3.1 Customers
2							
3	Additions:						
4	January	292	257	226	256		
5	February	174	89	194	266		
6	March	8	123	122	264		
7	April	110	113	178	264		
8	May	173	319	537	255		
9	June	172	116	250	261		
10	July	522	308	255	265		
11	August	129	187	252	262		
12	September	83	136	254	264		
13	October	545	132	255	265		
14	November	234	217	252	262		
15	December	245	119	256	266		
16	Total Additions	2,687	2,116	3,031	3,150		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,587	1,701		
18							
19	Current Year Ending Customer Count	143,714	145,830	148,861	152,011		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20							
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,417		2020: G-42-21; Sch 3, Line 13; 2021 and 2022: Prior Year Ending, Line 22
22	Average Customers for the Year	142,321	144,877	147,417	150,562		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,540	3,145	**10,646**	Sum of Annual Change in Average Customers on Line 23
24							
25	Growth Factor Multiplier					**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes					**7,985**	Line 25 x Line 23
27							
28	Average Customers Used to Determine the Starting UCOM					**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**					**147,901**	Line 28 + Line 26
30							
31	2021 Approved Average Customers for Rate Setting		142,473				2021: G-42-21; Sch 3, Line 22
32	2021 Actual Average Customers for Rate Setting		143,637				Line 21(2020) + Sum of Line 23 (2020 & 2021) x 0.75
33	**2021 True Up**		**1,164**				Line 32 - Line 31

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine formula O&M for 2023 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.		2023	Reference
1	CPI	4.940%	Table 2-1, Line 24
2	AWE	4.235%	Table 2-1, Line 24
3			
4	Non Labour	40%	Table 2-1, Line 24
5	Labour	60%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.517%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	4.017%	Line 7 + Line 9
12			
13	Average Customers for Formula O&M purposes	147,901	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2023 is 4.017 percent and formula O&M for 2023 is determined using average customers of 147,901.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting an increase in consumption in the 2023 Forecast (2023F) compared to the 2022 Approved. The 2023F gross load is forecast to be approximately 3,775 GWh, which is a 184 GWh increase compared to the 2022 Approved gross load. The increase in 2023F is due to increased loads in the industrial, commercial, wholesale, residential and irrigation classes. Based on the 2022 Approved rates for each customer class, FBC's 2023 revenue forecast is $409.840 million.

FBC has provided further information supporting its load forecast in Appendix A of the Application.

3.2 *OVERVIEW OF FORECAST METHODS*

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the UPC forecast is multiplied by the corresponding forecast of the number of annual average customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

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

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- 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 filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- Forecast Year: 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, the forecast year is 2023 (2023F).
- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2022 Rates.

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

3.3 *DEMAND SIDE MANAGEMENT SAVINGS*

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2021.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast incremental DSM savings for 2023 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[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 Incremental 2023 DSM Savings (GWh)

Line No.	Description	DSM 2023
1	Residential	(8.9)
2	Commercial	(22.6)
3	Wholesale	(7.7)
4	Industrial	(16.2)
5	Lighting	(0.3)
6	Irrigation	(0.2)
7	Net	(55.9)
8	Losses	(4.6)
9	Gross Load	(60.5)

3.4 *LOAD FORECAST*

FBC's total load consists of the weather normalized residential, commercial and wholesale load and the actual industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2021 was 0.2 percent. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,476 GWh in 2023F, which is 3 GWh more than 2022S and an increase of 170 GWh from 2022 Approved.

Figure 3-1: Total Net Load (GWh)

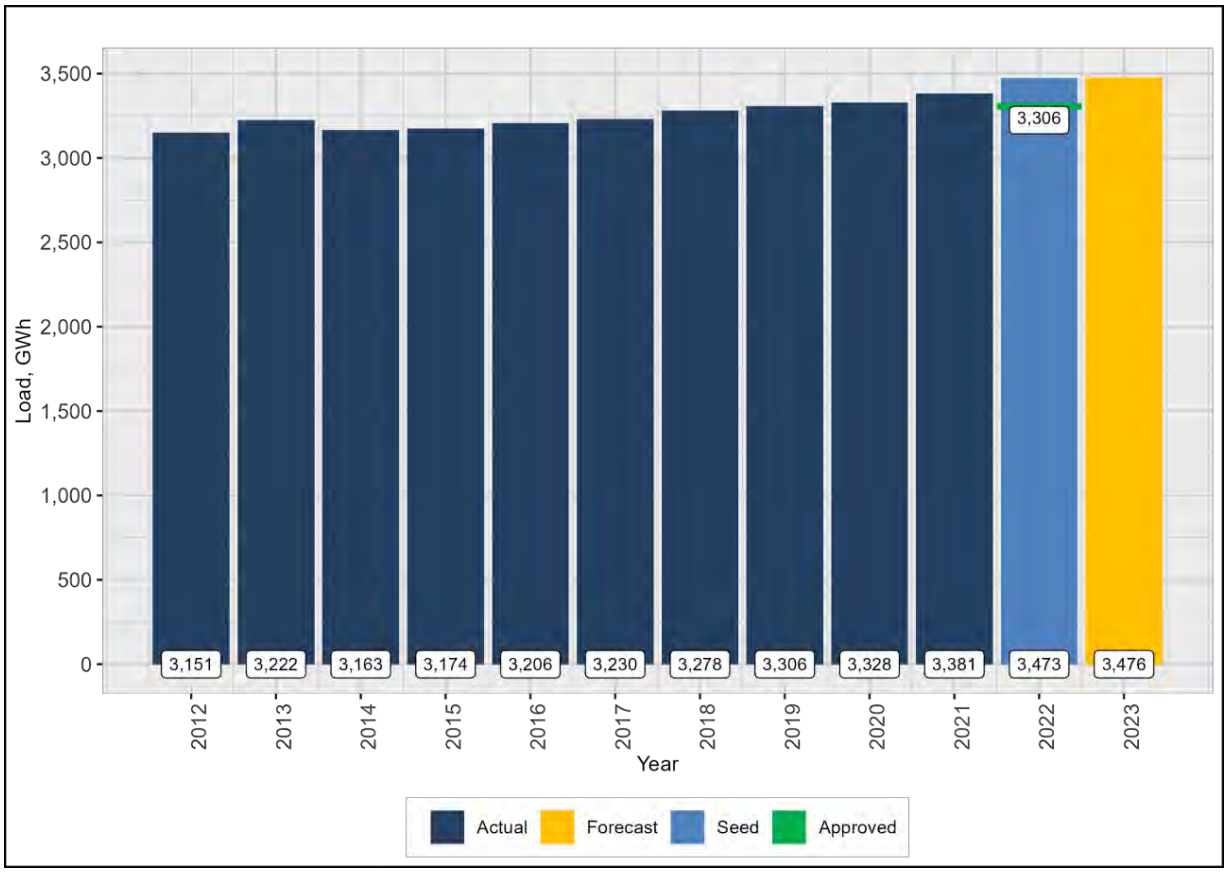


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2023F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: Normalized After-Savings Gross Load and System Peak

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
	Energy (GWh)												
1	Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
2	Commercial	681	788	863	853	905	915	926	932	922	960	962	973
3	Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
4	Industrial	291	352	381	380	373	363	403	495	441	472	579	575
5	Lighting	13.5	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.5	9.4
6	Irrigation	38.0	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	39.5	39.4
7	Net Load	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
8	Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
9	Gross Load	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
10													
11	System Peak (MW)												
12	Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
13	Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

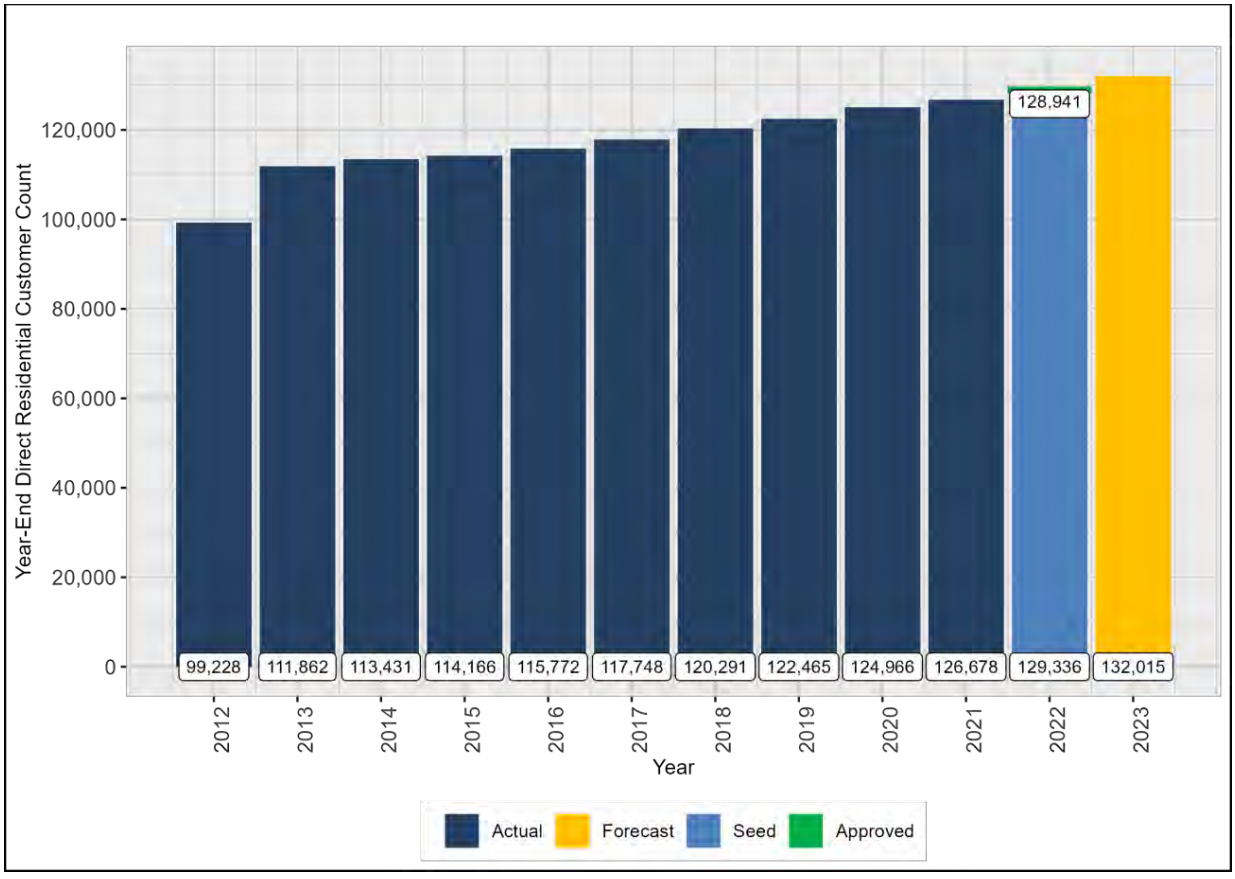
3.4.1 Residential

3.4.1.1 Residential Customers

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

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

Figure 3-2: Year-End Direct Residential Customer Count

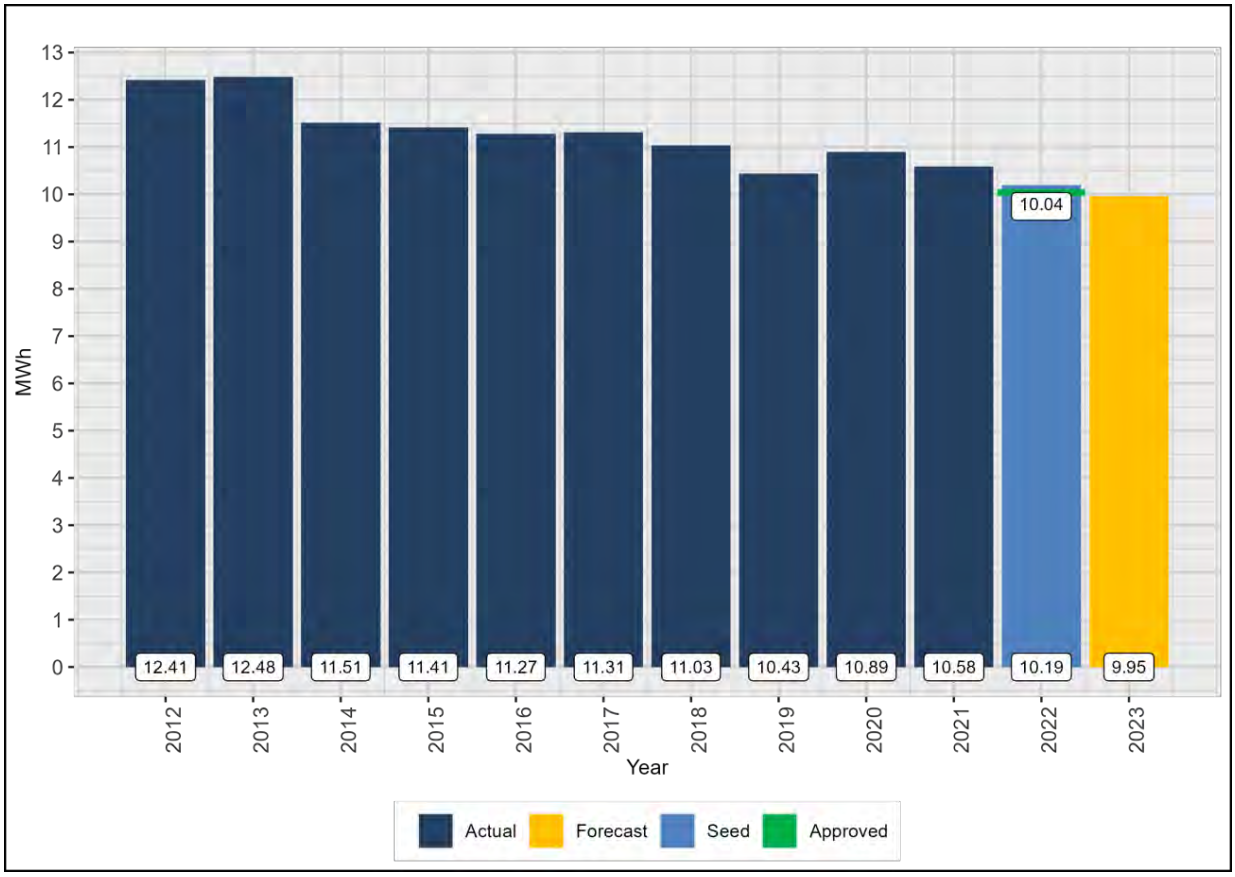


3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a 10-year trend to the normalized historical UPCs. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2021, are then deducted from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average

customer count. As shown in Figure 3-3 below, the residential after-savings UPC is forecast to decrease by 0.24 MWh in 2023F from 2022S and decrease by 0.09 MWh from 2022 Approved.

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

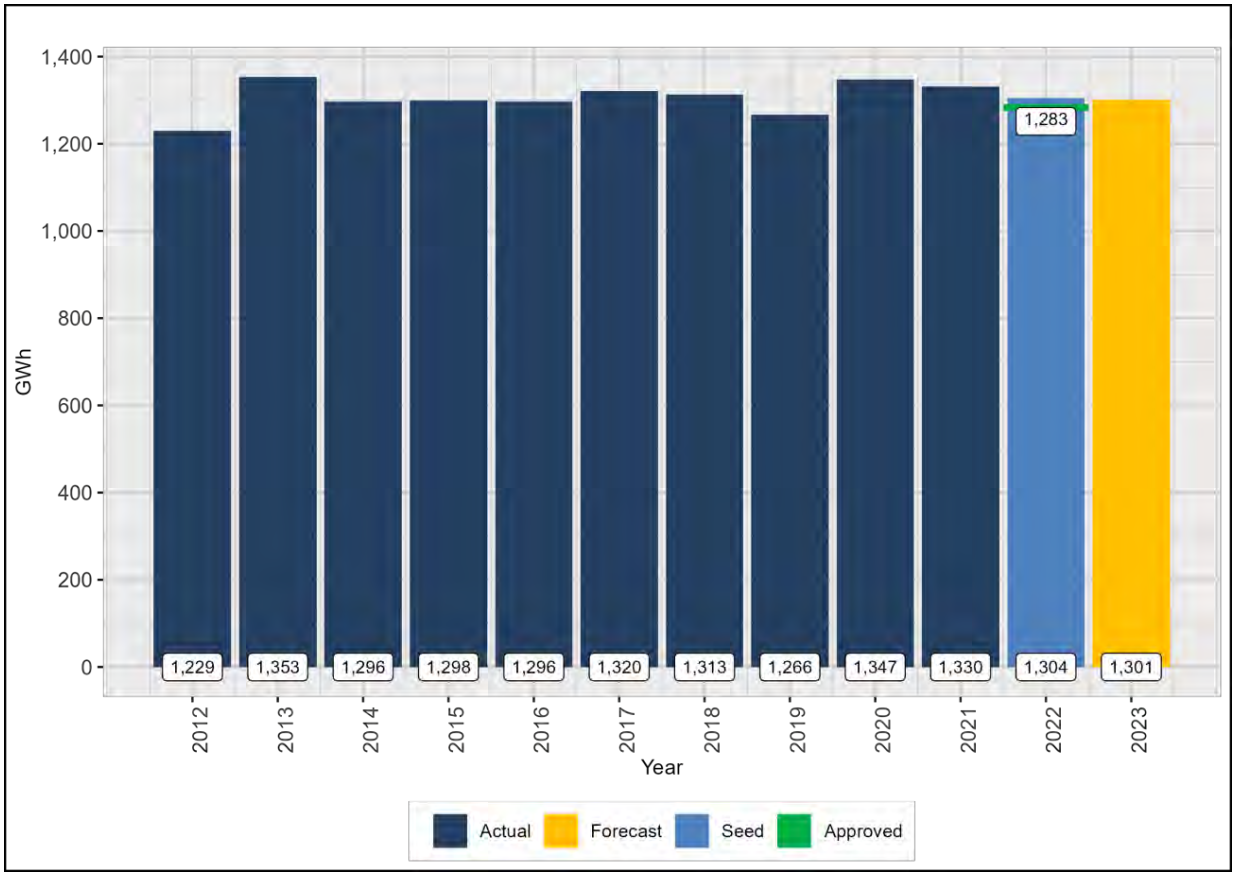


3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings.

As shown in Figure 3-4 below, residential after-DSM savings load is forecast to decrease by 3 GWh in 2023F from 2022S and increase by 18 GWh from 2022 Approved levels.

Figure 3-4: Normalized After-Savings Residential Load (GWh)

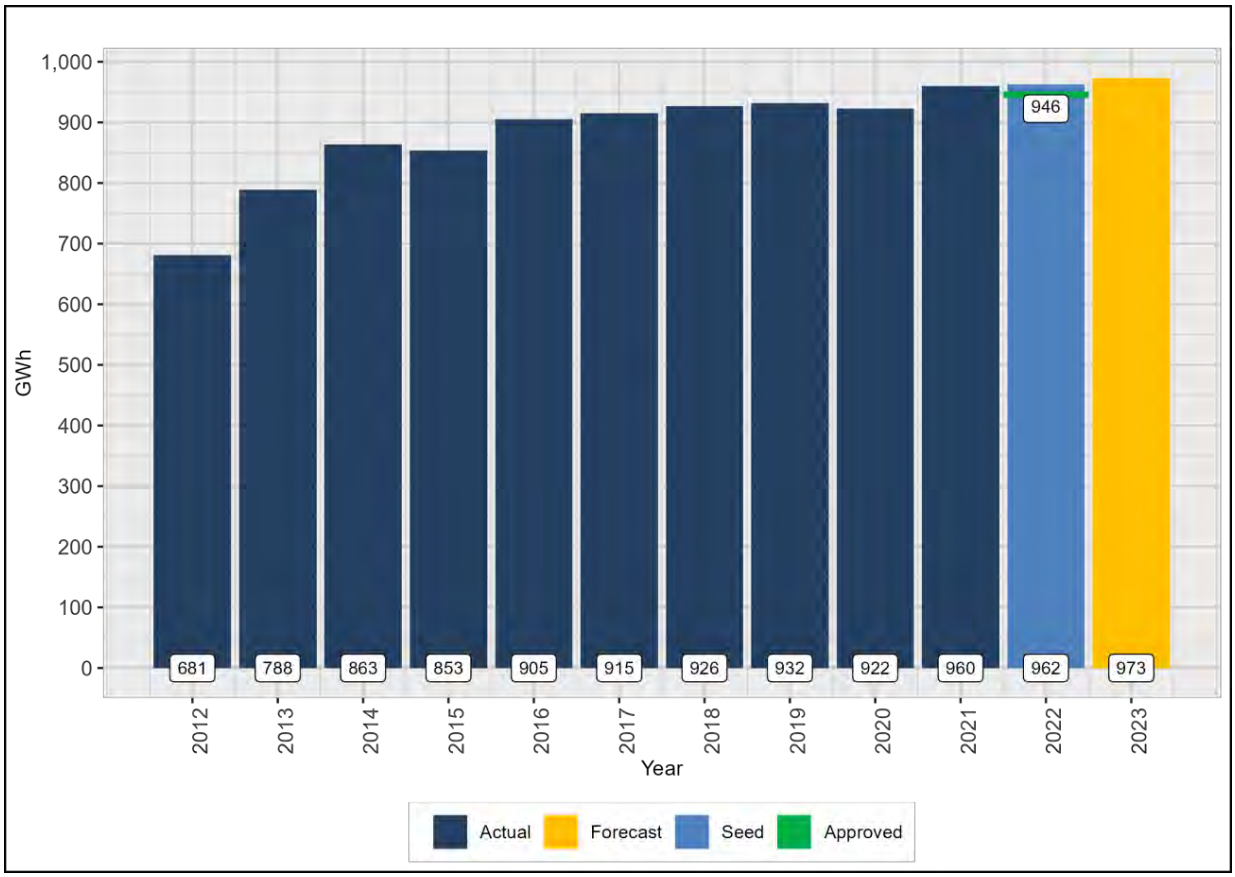


3.4.2 Commercial

3.4.2.1 Commercial Load

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2022S and 2023F and account for less than a 1 GWh increase in both 2022S and 2023F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 11 GWh in 2023F from 2022S and increase by 27 GWh in 2023F from 2022 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

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

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2023, all but one of the wholesale customers responded with their load forecast projections.

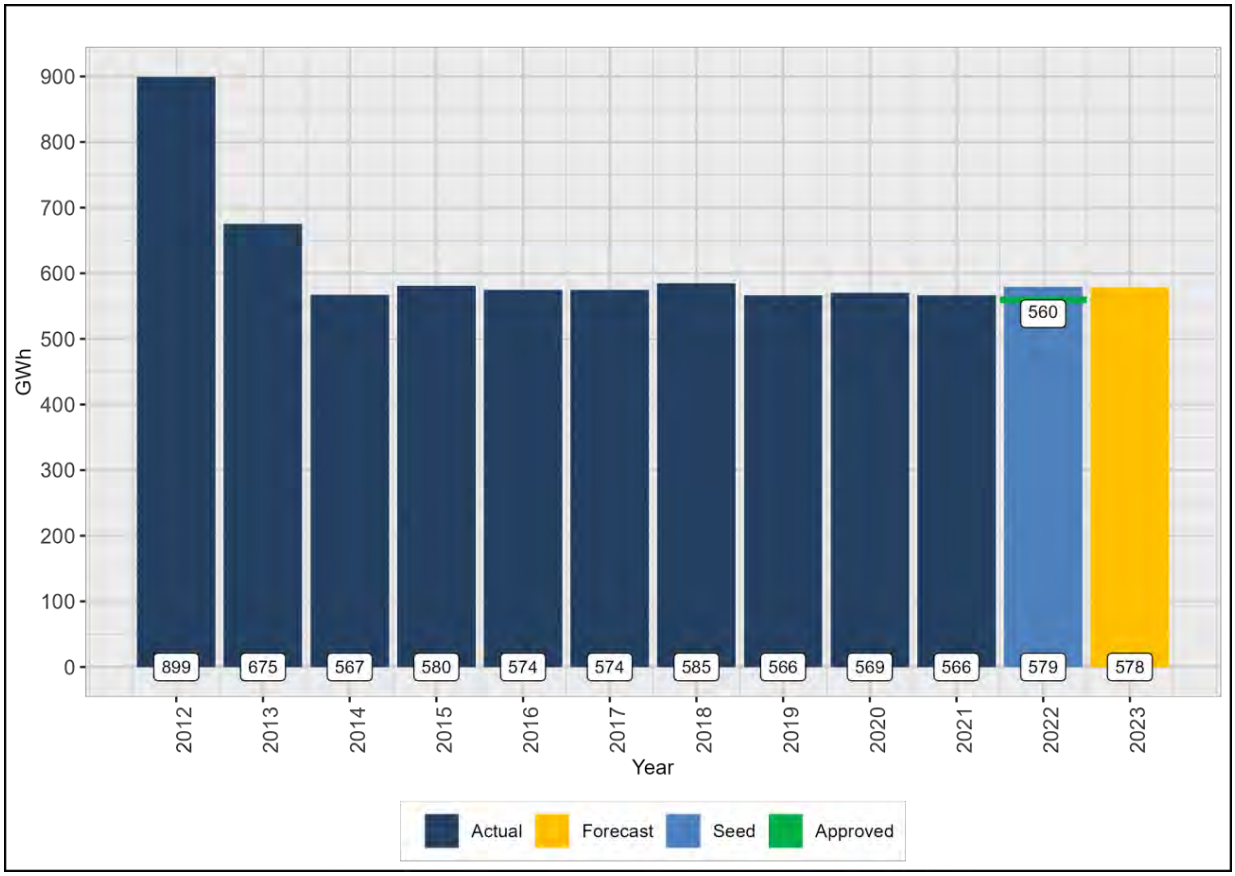
In the Annual Review for 2022 Rates Decision, the BCUC Panel directed FBC "to provide any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts."[8] The BCUC Panel further requested that FBC work more closely with wholesale customers to develop more accurate forecasts. As such, in April of this year, FBC met with the City of Penticton, the District of

[8] FBC Annual Review for 2022 Rates Decision and Order G-374-21, p. 32.

Summerland and the City of Nelson to discuss load forecast methods, techniques and tools, as well as each City's/District's individual load forecasts. Both FBC and the Cities/District found the workshops to be informative and productive, and FBC intends to continue to conduct these workshops on an annual basis in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 1 GWh in 2023F from 2022S and increase by 18 GWh in 2023F from 2022 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



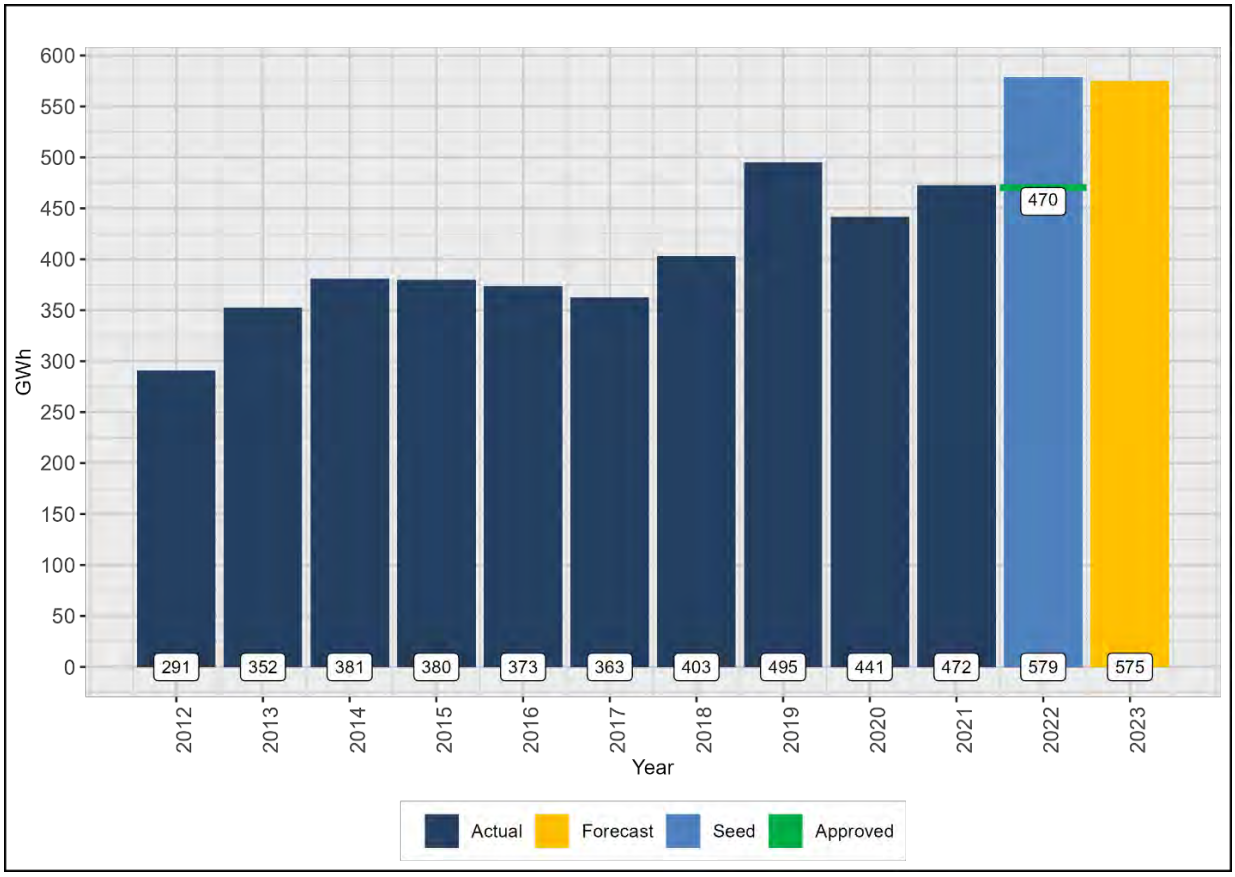
3.4.4 Industrial

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 existing industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 81 percent (34 of 42) of the surveys sent out. The responding customers represent approximately 90 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to decrease by 4 GWh in 2023F when compared to 2022S and increase by 105 GWh in 2023F compared to 2022 Approved. The increased forecast in 2022S and 2023F compared to 2022 Approved is primarily due to projected increases in data centre loads.

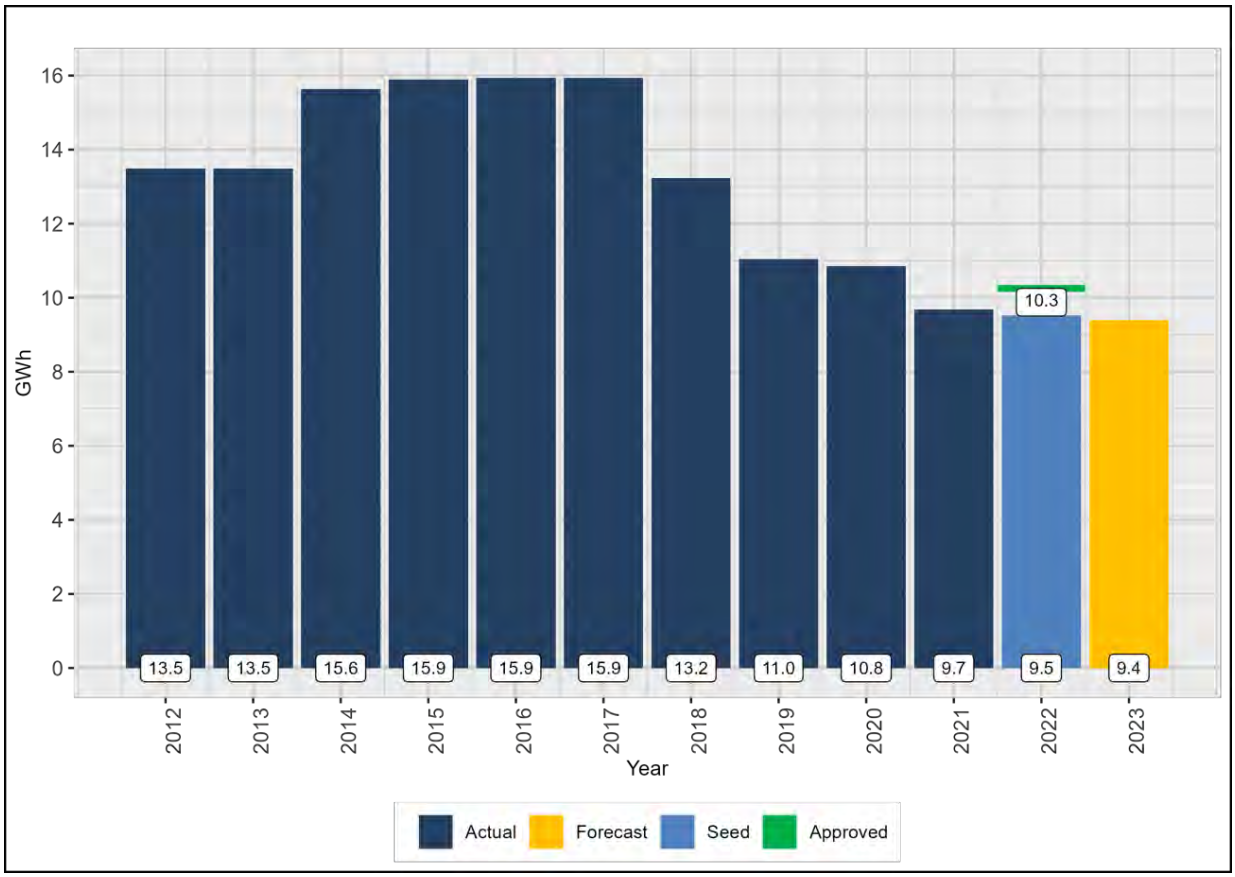
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has seen declines for the past four years. FBC used the 2021 Actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2023F from 2022S and decrease by 0.9 GWh when compared to 2022 Approved.

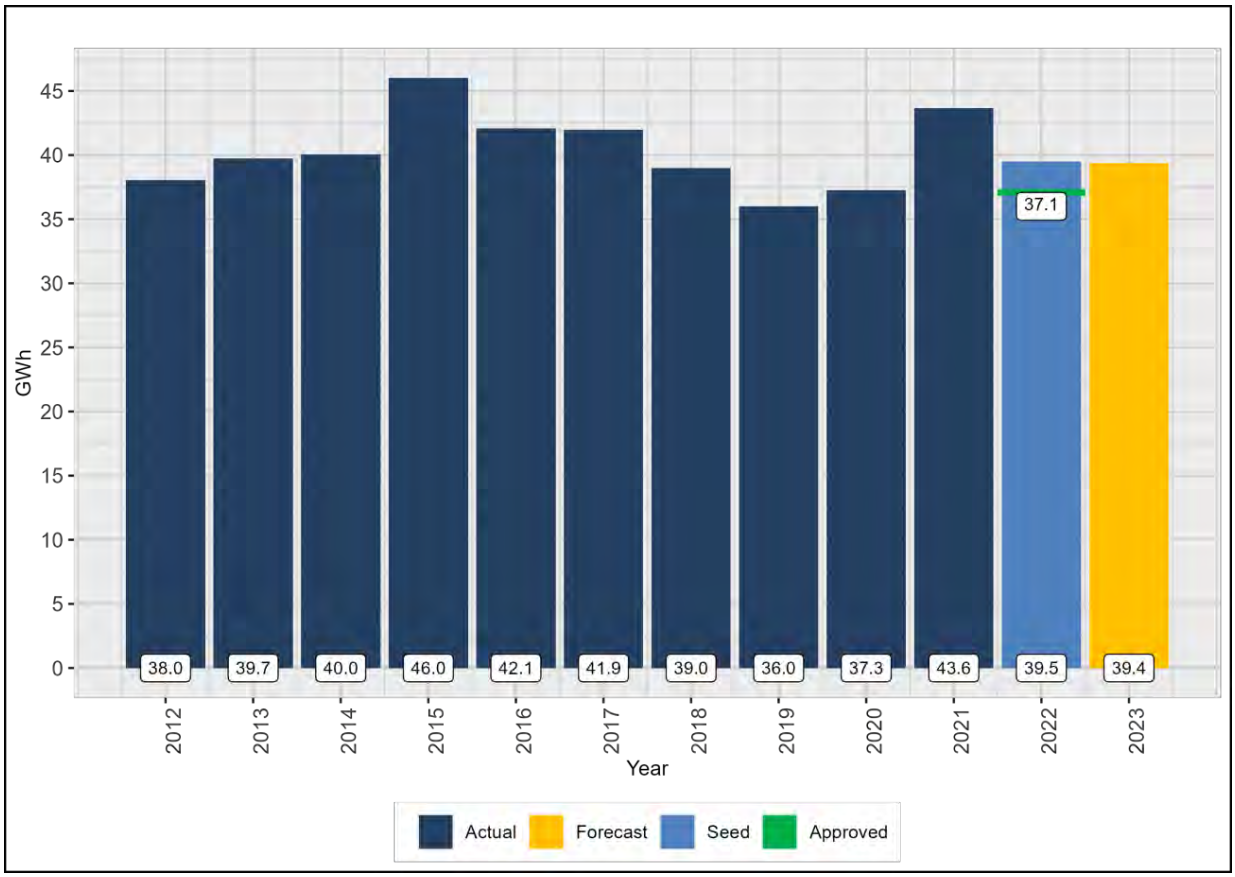
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease 0.1 GWh from 2022S to 2023F and increase by 2.3 GWh in 2023F when compared to 2022 Approved.

Figure 3-9: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

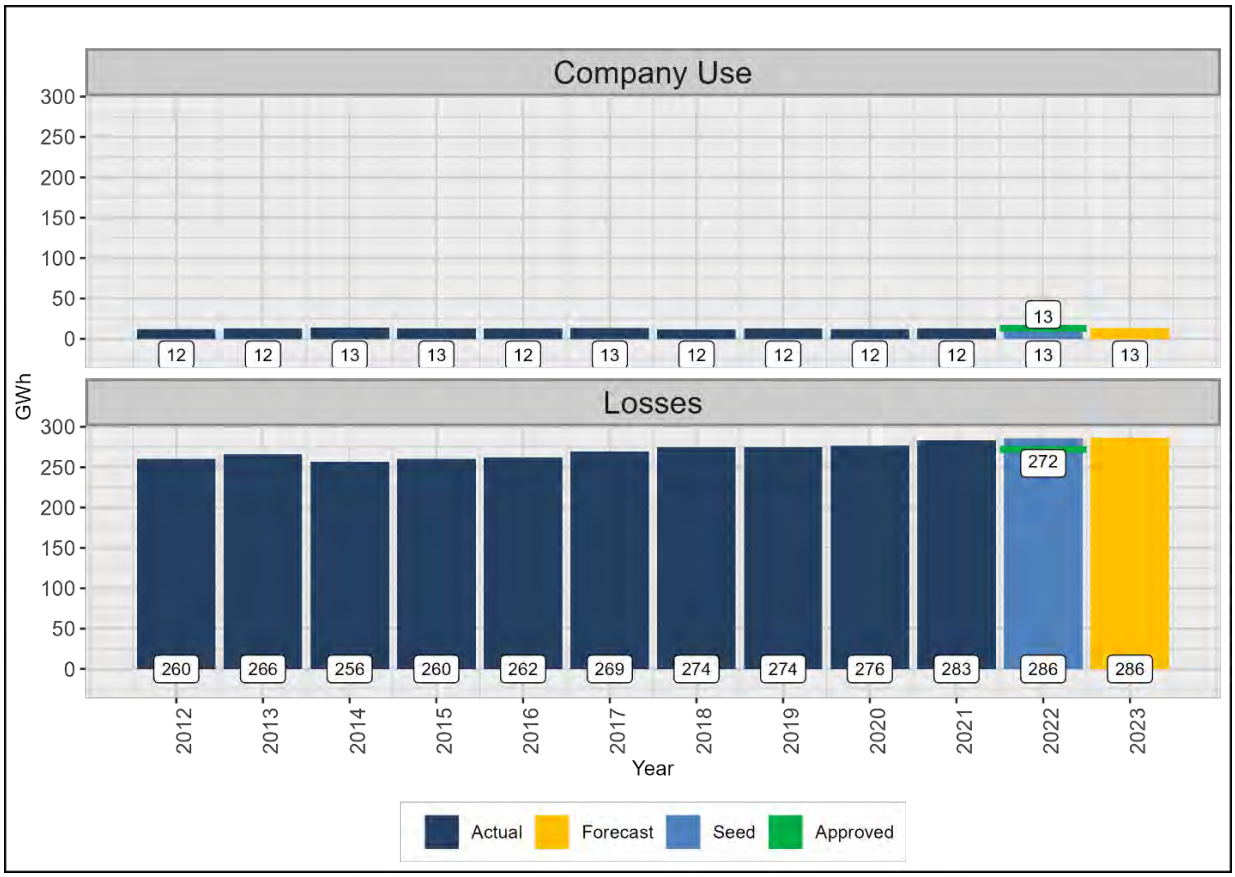
FBC conducted a Losses Study in 2019[9] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-10 below, after-savings load losses are forecast to remain constant in 2023F because the gross load is forecast to be relatively stable when compared to 2022S. When compared to 2022 Approved, the 2023F after-savings load losses are forecast to increase by 14 GWh due to increased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2023F, consistent with 2022S.

[9] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 “heat dome” event. 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 historical winter and summer peaks are shown below along with 2022S and 2023F. The peaks shown below are seasonal, where the winter peak can fall in either November or December of the current year or January and February of the following year, while the summer peak falls in June, July or August of the current year.

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

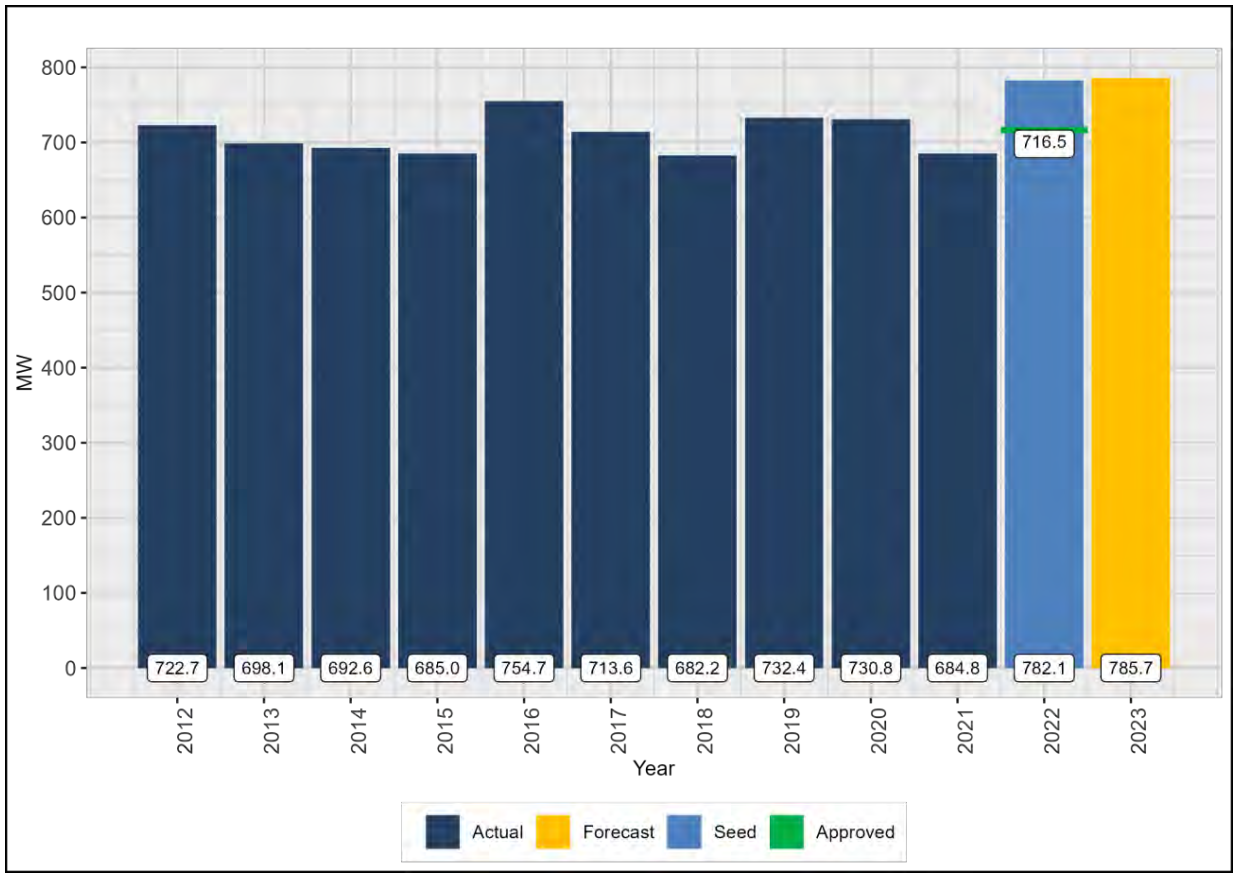
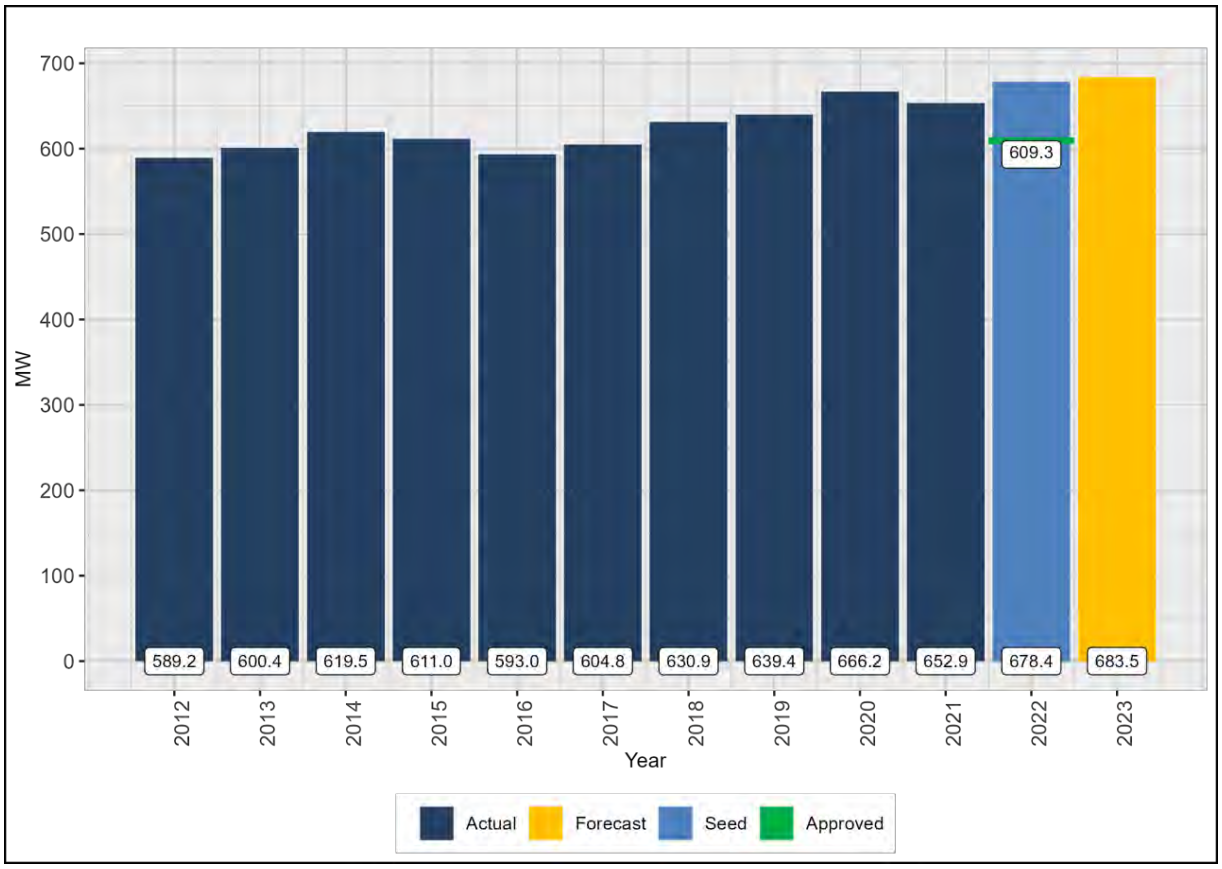


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 *CUSTOMER FORECAST*

Table 3-3 shows the actual and forecast year-end customer count by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2, respectively. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a three-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2021 levels.

Overall, for 2023F, FBC is forecasting customer growth of 2.1 percent compared to 2022S and growth of 2.4 percent compared to 2022 Approved.

Table 3-3: Year-End Direct Customer Count

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
1	Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
2	Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
3	Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	39	47	49	50	50	50	52	51	43	42	42	42
5	Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
6	Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
7	**Total**	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.6 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2022 rates to the forecast billing determinants for each customer class.

Table 3-4 below summarizes the 2022 Approved, 2022 Projected and 2023 Forecast sales revenue.

Table 3-4: Forecast Sales Revenue at Approved Rates ($ millions)[10]

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Residential	$ 195.058	$ 200.837	$ 197.962
2	Commercial	104.380	107.153	106.230
3	Wholesale	51.255	53.722	52.031
4	Industrial	40.804	46.764	47.856
5	Lighting	2.411	2.266	2.207
6	Irrigation	3.386	3.550	3.554
7	Total	$ 397.294	$ 414.292	$ 409.840

When comparing the 2022 Approved to 2022 Projected there is an increase in revenue of $16.998 million, the majority of which is due to increased residential and industrial loads.

The 2023 Forecast revenue is $12.546 million higher than 2022 Approved, primarily due to an increase in the industrial load, followed by small increases in the residential, commercial, and wholesale loads. These increases are slightly offset by a decrease in the lighting load resulting from the continued conversion to LED streetlights in the FBC service territory.

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

3.7 SUMMARY

The normalized after-savings gross load forecast for 2023F is 3,775 GWh. Based on net load of 3,476 GWh at the approved 2022 rates, FBC's 2023 revenue forecast is $409.840 million. When comparing 2023F to 2022 Approved, there is an increase in net load of 170 GWh. The net load increase in 2023F is due to increased loads in the industrial, commercial, wholesale residential and irrigation classes.

[10] The commercial sales revenue includes the revenues under RS 96 EV DCFC Stations. Please refer to Section 5.8 for further detail on EV DCFC station costs and revenues.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2022 Projected and 2023 Forecast power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the power supply cost.

As shown in Table 4-1 below, the 2023 Forecast power supply cost of $182.105 million represents an increase of 12.5 percent or $20.275 million compared to the 2022 Approved cost of $161.830 million. The increase in 2023 Forecast power supply cost is mainly due to increases in PPE, however, wheeling expense has increased as well. The 2023 Forecast PPE has increased as a result of increased gross load and a reduction in wholesale market purchases, which has resulted in a correspondingly greater reliance on energy supplied under BC Hydro Rate Schedule (RS) 3808. 2023 Forecast wheeling expense has increased as a result of both rates and usage. The 2023 Forecast water fee expense has decreased compared to 2022 Approved as a result of decreased usage.

Any variances between forecast and actual power supply costs 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 2022	Projected 2022	Forecast 2023
1	Power Purchase Expense	$ 143.779	$ 153.164	$ 163.575
2	Wheeling Expense	6.093	6.330	6.987
3	Water Fees	11.958	11.916	11.543
4	Total Power Supply Cost	$ 161.830	$ 171.409	$ 182.105
5				
6	Gross Load (GWh)	3,591	3,786	3,775

4.2 SUMMARY OF POWER SUPPLY RESOURCES

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

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year-to-year timing differences in the entitlement energy storage under the CPA;
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade

power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

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

4.3 *PORTFOLIO OPTIMIZATION*

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

The Company currently has long-term, firm resources from which it can supply all of its 2023 forecast annual energy requirements, and most of its forecast capacity requirements with the exception of a small number of hours during June and July. These forecast capacity gaps result from the Company's updated, increased load forecast. As mentioned in previous Annual Reviews, the nature of FBC's contracted resources, in particular the BC Hydro PPA, provides the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. However, in contrast to recent years, the regional electricity market has experienced a step change over the past year due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace PPA purchases on a forward basis. Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's 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 Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 *FBC 2022/23 ANNUAL ELECTRIC CONTRACTING PLAN*

On May 2, 2022, FBC filed its 2022/23 Annual Electric Contracting Plan (AECP) with the BCUC. 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, 2022 and ending September 30, 2023, 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 manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy, but could be more or less, depending on system conditions.[11] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2022 and for 2023 are based on the plan detailed in the 2022/23 AECP, which was accepted by the BCUC on May 26, 2022, by Letter L-19-22.[12]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2022/23 contract year equal to 767 GWh, less any firm market contracts that FBC could enter into, as described in Section 5 of the 2022/23 AECP. Prior to the June 30, 2022 nomination deadline, FBC updated its forecast load and resource balance for the 2022/23 contract year and submitted a nomination of 774 GWh.

4.5 *2022 PROJECTED POWER PURCHASE EXPENSE*

As shown in Table 4-2 below, FBC's 2022 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 195 GWh above the 2022 Approved value, and PPE is projected to be above the 2022 Approved value by $9.385 million. The increase in 2022 Projected PPE is primarily due to the increase in gross load above the 2022 Approved value. This increase in gross load drives increases in both the BC Hydro PPA and wholesale market expense to meet the additional load. In addition, increases in both the purchase price under the BC Hydro PPA and the average cost of purchases from the market further contributed to the increase in PPE.

[11] 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.

[12] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-19-22.

Table 4-2: 2022 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Difference
1	Brilliant	$ 41.841	$ 42.367	$ 0.526
2	BC Hydro PPA	44.062	49.539	5.477
3	Waneta Expansion	42.701	41.434	(1.267)
4	Market and Contracted Purchases	15.102	21.672	6.570
5	Independent Power Producers	0.073	0.058	(0.015)
6	Self-Generators	-	-	-
7	CPA Balancing Pool	-	(1.252)	(1.252)
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	-	(0.654)	(0.654)
10	Total	$ 143.779	$ 153.164	$ 9.385
11				
12	Gross Load (GWh)	3,591	3,786	195

4.6 *2023 FORECAST POWER PURCHASE EXPENSE*

As shown in Table 4-3 below, the 2023 Forecast PPE is $10.412 million greater than the 2022 Projected. The forecast increase from $153.164 million in 2022 to $163.575 million in 2023 is mainly a result of a reduction in market and contracted purchases as they increase in price and correspondingly, a greater reliance on energy supplied by BC Hydro as it becomes more cost effective compared to market. Furthermore, as a result of load growth and uneconomic wholesale market prices, FBC expects to take Tranche 1 PPA energy over the nominated amount during 2023. Tranche 1 PPA energy taken over the nominated amount costs 150 percent of the Tranche 1 embedded cost rate,[13] and this exposure to more expensive PPA energy is also contributing to increased costs. Also contributing to the increase are escalations to the Waneta Expansion and Brilliant contract rates.

Table 4-3 below shows a comparison of the 2022 Projected and 2023 Forecast PPE. Reasons for significant variances from the 2022 Projected PPE are discussed below.

[13] $50.94 per MWh x 150 percent = $76.41 per MWh.

Table 4-3: 2023 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2022	Forecast 2023	Difference
		-		
1	Brilliant	$ 42.367	$ 44.050	$ 1.683
2	BC Hydro PPA	49.539	71.302	21.763
3	Waneta Expansion	41.434	41.834	0.400
4	Market and Contracted Purchases	21.672	6.326	(15.346)
5	Independent Power Producers	0.058	0.062	0.004
6	Self-Generators	-	-	-
7	CPA Balancing Pool	(1.252)	-	1.252
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	(0.654)	-	0.654
10	Total	$ 153.164	$ 163.575	$ 10.412
11				
12	Gross Load (GWh)	3,786	3,775	(11)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2023 by $1.683 million compared to 2022 Projected due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2023 by $21.763 million compared to the 2022 Projected expense. The drivers of the increase are a higher purchased volume (371 GWh), which increases the expense by $21.775 million, and an increase in BC Hydro rates, which accounts for an increase of $3.987 million, for a total of $25.763 million. FBC has decreased its 2023 Forecast of PPA expense by $7.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2022 Projected BC Hydro expense was reduced by $3.000 million to account for potential real-time opportunities during the remainder of 2022. This results in a variance between 2022 Projected and 2023 Forecast of $21.763 million[14], as shown in Table 4-3. Actual market savings for the remainder of 2022 and 2023 may be higher or lower and will depend on system and market conditions at the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

4.6.3 Waneta Expansion

The $0.400 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, offset by a $0.291 million increase in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of

[14] $21.763 million is calculated as follows: Total increase of $25.763 million less the $4.000 million variance between the 2022 Projected and 2023 Forecast real-time opportunities, or, $25.763 million – ($7.000 million - $3.000 million).

capacity FBC releases to Powerex and 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. The method used to forecast market prices and surplus sales is the same as in the Annual Review for 2022 Rates. The forecast of surplus capacity sales revenue in 2023, which is included in line 3 of Table 4-3, is approximately $10.700 million.

4.6.4 Market and Contracted Purchases

The $15.346 million decrease in Market and Contracted Purchases forecast for 2023 is due to a lesser volume purchased at higher rates when compared to 2022 Projected. Market and Contracted Purchases for 2022 Projected include both 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 2023 Forecast are based on fixed price contracts executed by the Company, with the exception of forecast real-time market purchases for Rate Schedule 37[15] load. As discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.6.5 CPA Balancing Pool

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 2022 Projected PPE, FBC has stored a net total of 25 GWh of entitlement energy, valued at $1.252 million. For the 2023 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 *TRANSMISSION SERVICE LOSS RECOVERIES*

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load forecast (included in Tables 4-2 and 4-3, line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2022 and 2023 loss recoveries.

[15] RS 37 is large commercial stand-by service, which is on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2023 is 15 GWh or 0.4 percent of total gross load.

Table 4-4: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Loss Recoveries	12	12	12

4.8 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 RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2022 Rates. Table 4-5 below shows FBC's Wheeling Expense for 2022 and 2023.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,475	2,475	2,670
3	Creston	420	420	420
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.903	$ 4.976	$ 5.555
7	Creston	0.542	0.550	0.570
8	Other	0.648	0.804	0.863
9	Total Wheeling Expense	$ 6.093	$ 6.330	$ 6.987

Total 2022 Projected wheeling expense is $0.237 million greater than 2022 Approved. The 2022 Projected ARWA costs are $5.526 million (lines 6 and 7 in the table above), a $0.081 million increase when compared to 2022 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2022 Projected Teck and OATT wheeling costs are $0.804 million (line 8 above), which is $0.156 greater than 2022 Approved. This is mainly due to increased use of OATT wheeling.

2023 Forecast wheeling expense is $0.657 million higher than 2022 Projected. This is a result of both increased use and rates. FBC increased the Okanagan wheeling nomination to 2,670 MW months in 2023 from 2,475 MW months in 2022. ARWA rates are forecast to increase on October 1 of both 2022 and 2023, based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

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

As shown in Table 4-6 below, the 2023 Forecast water fees are decreasing by $0.373 million from the 2022 Projected due to decreased entitlement use. 2023 water fees are forecast using the same method as in the Annual Review for 2022 Rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Plant Entitlement in Previous Year (GWh)	1,679	1,663	1,571
2				
3	Water Fees	$ 11.958	$ 11.916	$ 11.543

4.10 SUMMARY

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.

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing and is consistent with the 2022/23 AECP. Any variances in the power supply cost, including any decreases in PPE due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.[16]

FBC is forecasting Other Revenue for 2023 to be $0.409 million higher than 2022 Approved, primarily due to higher Late Payment Charges and expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

2022 Projected Other Revenue is $1.335 million higher than 2022 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue and Late Payment Charges.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Apparatus and Facilities Rental	$ 6.018	$ 6.018	$ 6.108
2	Contract Revenue	2.277	2.750	2.367
3	Transmission Access Revenue	1.771	1.788	1.834
4	Interest Income	0.020	0.020	0.030
5	Late Payment Charges	0.875	1.095	0.994
6	Connection Charges	0.505	0.505	0.553
7	EV Stations Carbon Credits	-	0.625	-
8	Other Recoveries	0.366	0.366	0.355
9	Total Other Revenue	$ 11.832	$ 13.167	$ 12.241

In the following sections, FBC summarizes its projections and 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. There are no variances projected in 2022 compared to 2022 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2023 Forecast is higher than 2022 Approved due to expected escalations in unit rental rates for continuing contracts.

[16] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

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

The 2022 Projected revenue is higher than 2022 Approved due to an increase in costs related to the close-out of a multi-year asset refurbishment project for a third party that began in 2020, as well as certain costs that shifted from 2021 into 2022 for the same project. The 2023 Forecast is higher than 2022 Approved due to expected increases in the average cost of work and materials recovered from third-party customers.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2022 Projected revenue is slightly higher than 2022 Approved due to a higher nomination than originally forecast for one customer. The 2023 Forecast is higher than 2022 Approved due to the phased increase in rates over three years beginning January 1, 2020, as approved by Order G-40-19.

5.5 INTEREST INCOME

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans outstanding; as a result, no significant changes in interest income are expected in 2022 Projected or the 2023 Forecast.

5.6 LATE PAYMENT CHARGES

Late Payment Charges have historically been forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to the impact of the COVID-19 pandemic and FBC's implementation of customer relief measures, which included the suspension of Late Payment Charges until March 2021, the actual amounts collected have fluctuated from year to year.

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

FBC continues to see fluctuations in Late Payment Charges. The 2022 Projected Late Payment Charges are higher than 2022 Approved by $0.220 million based on amounts charged so far in 2022 as well as growth in customers since the 2017 to 2019 period used to develop the 2022 Approved.

In consideration of the continued fluctuations being experienced, the 2023 Forecast has been calculated based on the average of 2021 Actual and 2022 Projected Late Payment Charges of $0.892 million and $1.095 million, respectively. This results in an increase in Late Payment Charges of $0.119 million compared to 2022 Approved.

5.7 CONNECTION CHARGES

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2022 Projected is expected to be consistent with 2022 Approved based on amounts charged so far in 2022. The 2023 Forecast is expected to be higher than 2022 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[18] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. The EV charging rates, the depreciation rate for EV charging stations, and the inclusion of related revenues and expenses associated with FBC's EV DCFC stations in FBC's regulated accounts were approved by the BCUC on November 24, 2021[19]. The revenues to be included in FBC's regulated accounts include the Other Revenue from the sale of carbon credits related to EV stations[20] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR), which is embedded in the rate design of the EV DCFC stations.

At the time of the 2022 Annual Review, FBC did not have any carbon credits validated by the British Columbia Low Carbon Fuel Standard (BC-LCFS); as such, and as reflected in Table 5-1 above, FBC did not forecast any revenue from the sales of the credits for 2022 Approved. However, as of the end of the first quarter of 2022, the BC-LCFS has validated approximately 1,337 carbon credits for FBC that have accumulated since 2019, with an approximate market value of $0.625 million[21]. FBC anticipates monetizing these credits prior to the end of 2022 and has therefore reflected them in the 2022 Projected column in Table 5-1 above, and also included the $0.625 million credit in the Flow-through deferral account, to be returned to customers in 2023.

[18] Order G-215-21 dated July 14, 2021.
[19] FBC EV DCFC Service Application Decision and Order G-341-21.
[20] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's 2022 Annual Review, BCSEA IR1 4.3. Beginning in 2022, FBC will only be permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.
[21] 1,337 credits x $467.32 average Q1-2022 sales price (source: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf).

Consistent with the practice from the 2022 Annual Review, FBC does not forecast revenue from the sale of credits that are pending validation; FBC is therefore not forecasting any of these revenues in 2023.

As part of the 2022 Annual Review Decision, FBC was directed to include the following in future Annual Review filings:[22]

> …an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.

FBC currently has a total of 40 EV DCFC stations in service across 23 sites and is planning to install two additional DCFC stations at two of the existing sites in 2022, resulting in a total of 42 EV DCFC stations across 23 sites. Consistent with the format of the information provided during the 2022 Annual Review[23], Table 5-2 below provides the costs and revenues for 2021 Actual (previous fiscal year), 2022 Projected, and 2023 Forecast. As highlighted in Table 3-4 of Section 3.6, the RS 96 EV DCFC revenue (i.e., Line 10 of Table 5-2 below) is included as part of the Commercial Sales Revenue. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses for the EV DCFC stations and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations, as well as information on how the two new stations are prescribed undertakings. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 5-2 below.

Table 5-2: EV DCFC Stations Costs and Revenues for 2021 Actual, 2022 Projected, and 2023 Forecast ($ millions)[24]

Line	Particulars	2021 Actual	2022 Projected	2023 Forecast	Cumulative
1	Cost of Energy	0.013	0.282	0.300	
2	Less: Power Purchase Expense	(0.013)	-	-	
3	O&M	0.101	0.187	0.193	
4	Depreciation	0.307	0.456	0.612	
5	Amortization of CIAC	(0.150)	(0.191)	(0.249)	
6	Other Revenue - Carbon Credits	-	(0.625)	-	
7	Income Tax	(0.299)	(0.199)	0.158	
8	Earned Return	0.124	0.172	0.183	
9	Total Cost of Service	0.083	0.082	1.196	
10	RS 96 Revenue	(0.058)	(0.155)	(0.178)	
11	(Surplus) / Deficiency	0.025	(0.072)	1.018	0.971
12	Prior Year 2018-2020 (Surplus)/Deficiency				(0.142)
13	Cumulative (Surplus) / Deficiency				0.828

[22] FBC 2022 Annual Review Decision and Order G-374-21, p. 32.
[23] Exhibit B-3, BCUC IR1 16.1.
[24] As explained in Exhibit B-3, BCUC IR1 16.1 of the FBC 2022 Annual Review, RS 96 was approved on an interim basis in 2021 by Order G-9-18 in which the cost of energy embedded was based on BC Hydro's RS 3808; therefore,

As directed by Order G-341-21, FBC is to file a detailed assessment of the EV DCFC service by no later than December 31, 2022 or within six months of Measurement Canada's approval of DCFC energy-based metering for FBC, whichever is earlier. FBC is not expecting to receive approval from Measurement Canada prior to December 31, 2022; thus, FBC will file the detailed assessment report by December 31, 2022. As directed by the BCUC, the detailed assessment will include:

- An update of the financial models with actual and forecast information and updated assumptions;
- A detailed assessment of RS 96 and alternative rate design options;
- An overview of the current EV fast charging service market and rates across Canada and the United States;
- A proposal for a depreciation rate for its EV DCFC stations and information to support its proposal; and
- An assessment as to whether idling fees are warranted.

5.9 *OTHER RECOVERIES*

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and AMI radio-off meter read fees. There are no variances expected in 2022 Projected compared to 2022 Approved based on amounts recognized to date. The 2023 Forecast is expected to be slightly lower than 2022 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 *SUMMARY*

FBC has forecast the Other Revenue components for 2023 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, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

the cost of energy for 2021 Actual shown in Table 5-2 is equal to the power purchase expense. As approved in Order G-341-21, the permanent rate for RS 96 is based on FBC's commercial service RS 21. As such, starting in 2022, the cost of energy shown in Table 5-2 above is based on FBC's commercial service RS 21.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, 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 2023, the formula O&M is $69.957 million, representing a 5.8 percent increase from the 2022 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2023 are $2.323 million, representing a 26.8 percent increase from the amount approved for 2022. Overall, the 2023 Forecast gross O&M expense is $72.789 million, which is an increase of approximately 7.0 percent from the 2022 Approved level.

The components of 2023 O&M expense are shown in Table 6-1 below.

Table 6-1: 2023 O&M Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Formula O&M	$ 66.147	$ 66.147	$ 69.957	Section 11, Schedule 20, Line 8
2	Forecast O&M	1.832	1.635	2.323	Section 11, Schedule 20, Line 20
3	Prior year O&M True-up	0.053	0.053	0.509	Table 6-2, line 16
4	Total Gross O&M	68.032	67.835	72.789	Line 1 through 3
5	Capitalized Overhead	(10.177)	(10.177)	(10.918)	Section 11, Schedule 20, Line 23
6	Net O&M	$ 57.855	$ 57.658	$ 61.871	Line 4 + Line 5

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2023. Additionally, in compliance with the BCUC's directive in the MRP Decision,[25] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2023 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 4.017 percent.

For 2023, the annual operating and maintenance expense under the formula is calculated as:

[25] MRP Decision, p. 118.

2022 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2021 Formula O&M True-up

Table 6-2 below shows the calculation of the 2023 Formula O&M, including the calculation of the 2021 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2021.

Table 6-2: Calculation of 2023 Formula O&M ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	455	G-374-21 FBC 2022 Annual Review
2	I-Factor		4.017%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	473	
4	Average Customer Forecast		147,901	Section 2, Table 2-3, Line 13
5	2023 Inflation-Indexed O&M before 2020 True-up	$	69.957	Line 3 x Line 4 / 1,000,000
6	2021 True-up O&M		0.509	Line 16
7	Inflation-Indexed O&M	$	70.466	Line 5 + Line 6
8				
9	2021 O&M True-up			
10	2021 Actual 12 month Average Customers		144,877	FBC 2021 Annual Report
11	2021 Forecast 12 month Average Customers		143,325	G-42-21 FBC 2020-2021 Annual Review
12	Difference		1,552	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		1,164	Line 12 x Line 13
15	2021 Unit Costs	$	437	G-42-21 FBC 2020-2021 Annual Review
16	O&M True-up for 2023	$	0.509	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2021 Formula O&M, 2021 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first two years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2021 Formula O&M[1]	Actual 2021 O&M	2021 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.080	$ 0.278	$ 0.199	$ 0.436
2	Generation Dam Safety	$ 0.246	$ 0.415	$ 0.169	$ 0.137
3	Network Operations Apprentice Program	$ 0.209	$ 0.243	$ 0.034	$ (0.167)
4	Cyber Security	$ 0.085	$ 0.085	$ -	$ 0.250
5	Data Analytics	$ 0.105	$ -	$ (0.105)	$ (0.206)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.724	$ 1.021	$ 0.297	$ 0.449

Notes to Table:

[1] 2021 Formula O&M is the approved 2020 formula for incremental funding with Net Inflation factor applied (3.668%).
[2] Cumulative Forecast/Actual variance is the 2020 Actual variance plus the 2021 Actual variance.

Overall, total actual spending in 2021 was $1.021 million, which is $0.297 million higher than the 2021 Formula O&M amount. Areas with notable variances include tree management, generation dam safety and data analytics.

For tree management, FBC spent $0.199 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.169 million more than the formula amount due to the continuation of dam safety review activities from 2020, as FBC required more time to complete the analysis for the determination of the dam classifications for the Upper Bonnington, Lower Bonnington and South Slocan plants.

Offsetting the higher costs in these two categories was lower spending in data analytics. FBC spent $0.105 million less than the formula amount in 2021 primarily due to labour savings from a delay in hiring. In 2021, FBC focused on finalizing the requirements for the necessary information infrastructure, with the implementation of the systems that will allow centralized data access occurring in 2022 and the addition of new data sources in priority sequence over the remaining term of the MRP.

For the first two years of the MRP, FBC spent $0.449 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

In addition to FBC's formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost

of service associated with Clean Growth initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. For 2023, FBC has included incremental O&M for the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the 2022 Annual Review.

The 2023 amounts are shown in Table 6-4 below along with a comparison to 2022.

Table 6-4: 2023 Forecast O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Pension/OPEB (O&M Portion)	$ (1.716)	$ (1.716)	$ (1.297)
2	Insurance Premiums	2.223	2.291	2.457
3	BCUC Levies	0.373	0.373	0.385
4	Clean Growth Initiative - EV DCFC Stations	0.187	0.187	0.193
5	Exogenous Factor - MRS	0.765	0.500	0.585
6	Total Forecast O&M	$ 1.832	$ 1.635	$ 2.323

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2023 is based upon actuarial estimates using a range of assumptions as of December 31, 2021 with an update of discount rate estimates as of April 30, 2022 provided by the Company's external third party actuary, Willis Towers Watson. The discount rate determined reflects the market yields of high quality Canadian corporate bonds which have increased since 2021. In addition to O&M, pension and OPEB expense is embedded in Capital Expenditures, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	O&M	$ (1.716)	$ (1.716)	$ (1.297)
2	Capital (Approved)	3.807	3.807	1.888
3	Capital (to Pension & OPEB Variance Deferral)[1]	(0.400)	(0.400)	-
4	Total	$ 1.691	$ 1.691	$ 0.591

Notes to Table:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Regular Capital Expenditure forecasts on Line 2 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019 as part of the 2020 to 2024 MRP Application, and the actuarial estimates

updated for 2023 rate-setting purposes. There is no difference for 2023 since FBC was directed to file an updated forecast of the 2023 and 2024 Regular Capital Expenditures in the 2023 Annual Review, as directed in the MRP Decision and Order G-166-20.

The variance between the 2022 Approved and actual pension and OPEB expense, including the known capital variance on Line 3 of Table 6-5 above, and any variance between the 2023 Forecast and actual amounts, is flowed through to the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2023 Forecast pension and OPEB expense has decreased by $1.100 million compared to the 2022 Approved expense primarily due to the following factors, which are all components of pension and OPEB expense:

- An approximate $3 million decrease in current service costs due to an increase in the discount rate. The discount rate, which is determined with reference to the market rate of interest on high quality debt instruments at a point in time, increased from 3.5 percent, which was used to determine the 2022 Approved expense, to 4.5 percent, which is used to determine the 2023 Forecast expense;

offset in part by:

- An approximate $2 million increase in interest costs due to an increase in the discount rate.

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Insurance Premiums	$ 2.223	$ 2.291	$ 2.457	Section 11, Schedule 20, Line 16
2	Total	$ 2.223	$ 2.291	$ 2.457	

The 2022 Projected insurance premium expense of $2.291 million is $0.068 million higher than 2022 Approved, as it incorporates FBC's actual July 2022 to June 2023 insurance renewals of $2.253 million. The higher premiums experienced in 2022 are expected to continue into 2023, though at a lower rate of increase. The 2023 Forecast is $2.457 million, which is an increase of $0.166 million from 2022 Projected. The 2023 Forecast is calculated as the amount of the first six months of actual annual insurance premiums for January to June 2023 of $1.126 million and

applying a 5 percent increase for the remaining six months, plus the cost of fire fighting services FBC pays to the Province of $0.148 million.[26]

6.3.3 BCUC Levies

FBC's 2023 Forecast for BCUC levies is $0.385 million. The 2023 Forecast is based on Order G-188-22 for the BCUC's Fiscal 2022/23 year, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2023/24 will not be available until early or mid 2023.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[27] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 5-2 in Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

As shown in Table 6-7 below, the 2022 Projected EV DCFC station O&M expense is expected to be consistent with 2022 Approved[28], and consists of network management, repairs and maintenance, inspection fees and FBC labour costs. The 2023 Forecast EV DCFC station O&M expense is anticipated to be similar to the 2022 Projected level, with an approximate increase of $6 thousand primarily due to inflation.

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ 0.187	$ 0.187	$ 0.193	Section 11, Schedule 20, Line 19
2	Total	$ 0.187	$ 0.187	$ 0.193	

6.3.5 MRS Incremental Operating Expenses

In the 2022 Annual Review Decision,[29] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the 2022

[26] $2.253 million/2 = $1.126 million. $1.126 million x 1.05 = $1.183 million. $1.126 million + $1.183 million + $0.148 million annual firefighting service fee = $2.457 million.
[27] Order G-215-21 dated July 14, 2021.
[28] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 6-7 is the amount included in the Compliance Filing.
[29] Decision and Order G-374-21, p. 21.

Annual Review, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[30].

BC Hydro issued AR13 on May 1, 2020 recommending adoption of seven standards, retirement of one standard, and holding one standard in abeyance pending resolution of the Planning Coordinator (PC) function along with the NERC Glossary dated August 12, 2019. The BCUC issued Order R-19-20 on September 8, 2020 accepting BC Hydro's recommendation and determined the effective dates of those standards. Of the standards and respective NERC Glossary terms assessed by FBC, five standards have associated costs, of which one was held in abeyance. The effective date for the four adopted standards is April 1, 2023, including the existing CIP-005-6 (Electronic Security Perimeter(s)), CIP-008-6 (Incident Reporting and Response Planning) and CIP-010-3 (Configuration Change Management and Vulnerability Assessments) standards and the new CIP-013-1 (Supply Chain Risk Management) standard. In order to address these changes, FBC is required to monitor and disconnect vendor remote access, evaluate and report attempts to compromise, ensure software downloads and installations are unaltered and secure, and assess risk for any product or service procured for Bulk Electrical System assets under the Critical Infrastructure and Protection (CIP) standards. These requirements are reflected in the 2022 Approved, 2022 Projected, and 2023 Forecast expenses in Table 6-8 below.

The following table provides the 2022 Approved and Projected and the 2023 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.335	$ 0.200	$ 0.490	
2	Non-Labour	0.280	0.250	0.095	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.765	$ 0.500	$ 0.585	Section 11, Schedule 20, Line 18

The 2022 Projected O&M expense is lower than 2022 Approved by $0.265 million. The reduction of $0.265 million is a result of less overall effort required to modify existing programs and processes as mentioned above than originally expected.

The 2023 Forecast O&M expense of $0.585 million is related to the expected ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. The 2023 Forecast is based on the expected costs in 2022 Projected and is therefore less than the 2022 Approved level. These costs are annual and will continue in future years.

[30] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.4 NET O&M EXPENSE

Net O&M expense is gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2022. After capitalized overhead, the net O&M expense is $61.871 million in 2023.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2022 Approved to 2023 Forecast is 7.0 percent. Formula-driven O&M is increasing at a rate of 5.8 percent, and O&M forecast outside the formula is 26.8 percent higher than 2022 Approved.

The capitalized overhead rate for 2023 remains unchanged from 2022.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.675 billion for 2023. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[31]

FBC's 2023 Rate Base includes the full-year impacts of the 2022 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $94.209 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $64.407 million; and
- Capital additions of CPCNs and other Major Projects totalling $45.439 million[32], as discussed in Section 7.3 below, which include:
    - Full-year impact of $21.250 million for the capital expenditures and related AFUDC for the Kelowna Bulk Transformer Additions (KBTA) Project, which is expected to complete in late 2022 or early 2023;
    - Full-year impact of $16.151 million for the final capital expenditures and related AFUDC for the Corra Linn Dam Spillway Gates Replacement Project, which is expected to complete in 2022; and
    - Full-year impact of $8.036 million for the final capital expenditures and related AFUDC for the Playmor Substation Upgrade Project, which is expected to complete in 2022.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $24.303 million in 2023.

Details of the 2023 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures for the years 2020 through 2022; and

[31] 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.

[32] The 2023 capital additions of $45.439 million also include $0.002 million for the close out costs and related AFUDC in 2022 for the UBO Old Units Refurbishment Project.

- Approval of a number of items to be forecast on an annual basis.

Further, in the MRP Decision the BCUC directed FBC to file an updated forecast of the 2023 and 2024 regular capital expenditures in the 2023 Annual Review.[33]

The components of FBC's 2023 regular capital expenditures are shown in Table 7-1 below.

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

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Forecast Capital	$ 81.925	$ 87.735	$ 94.428	Table 7-2 and Table 7-3, Line 4
2	Flow-Through Capital	0.935	2.430	0.248	Table 7-11, Line 3
3	Total Gross Regular Capital	$ 82.860	$ 90.165	$ 94.676	Sum of Lines 1 & 2
4	Less CIAC	(11.712)	(8.287)	(11.628)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 71.148	$ 81.878	$ 83.048	Sum of Lines 3 & 4

In Section 7.2.1, FBC provides its updated 2023 and 2024 regular capital forecasts. In Section 7.2.2, FBC provides details on its forecast flow-through expenditures for 2023, consistent with the format provided in previous annual reviews during this MRP term.

7.2.1 Updated 2023 and 2024 Forecast Regular Capital Expenditures

As stated above, in the MRP Decision and Order G-166-20[34], the BCUC directed FBC to file updated 2023 and 2024 regular capital forecasts as part of the 2023 Annual Review. The BCUC in its decision highlighted FBC's evolving operating environment and inherent uncertainties in the capital forecasts, and thus considered it appropriate for FBC to have the opportunity to true-up its capital spending and re-forecast its capital for the final two years of the MRP term. Specifically, the BCUC stated the following:

> …FEI and FBC face evolving operating environments and there are inherent uncertainties in the five-year forecast. Reviewing the capital forecast in 2022 allows for a review of any significant variances between forecast and actual to date and provides an opportunity to true-up the rate-base for actual spending and to re-forecast the remaining years in the MRP term.[35]

As further explained below, FBC has begun to experience pressures due to a variety of factors which are outside of the Company's control and could not have been anticipated at the time of the MRP proceeding, including supply chain issues and rising commodity prices and other inflationary pressures brought on by the COVID-19 pandemic and the war in Ukraine. These factors, as well as the increased cost and complexity in permitting and land acquisition as well as increased growth, are impacting FBC's ability to execute on all of its planned capital projects and programs. While FBC has pursued various mitigation measures to manage through the spending

[33] MRP Decision and Order G-166-20, p. 131.
[34] Directive 1.c. of Order G-166-20.
[35] MRP Decision and Order G-165-20, p. 131.

pressures, FBC requires an increase in its capital spending for 2023 and 2024 compared to its original forecasts to execute on its planned activities.

The following tables summarize the growth, sustainment and other capital expenditures[36]. The first table presents the 2020 through 2022 Approved forecasts (i.e., the forecasts approved in the MRP Decision) and the 2023 and 2024 forecasts which were reviewed during the MRP proceeding (Original Forecasts). The second table provides the Actual/Projected results for 2020 through 2022 and FBC's updated forecasts for 2023 and 2024 (Updated Forecasts).

Table 7-2: Regular Capital Expenditures, 2020-2022 Approved and 2023-2024 Original Forecasts ($ millions)

Line No.	Description	Approved 2020	Approved 2021	Approved 2022	Original Forecast 2023	Original Forecast 2024
1	Growth Capital	27.029	23.042	24.339	26.283	23.170
2	Sustainment Capital	50.463	49.818	42.830	44.377	53.470
3	Other Capital	15.752	14.712	14.756	15.281	15.134
4	Total	93.244	87.573	81.925	85.941	91.774

Table 7-3: Regular Capital Expenditures, 2020-2021 Actual, 2022 Projected and 2023-2024 Updated Forecasts ($ millions)

Line No.	Description	Actual 2020	Actual 2021	Projected 2022	Updated Forecast 2023	Updated Forecast 2024
1	Growth Capital	28.799	21.865	29.868	30.973	24.568
2	Sustainment Capital	47.325	49.601	41.486	45.797	58.673
3	Other Capital	16.036	15.349	16.381	17.658	17.213
4	Total	92.160	86.815	87.735	94.428	100.454

In Section 7.2.1.1, FBC describes its updated forecasts for growth and sustainment capital. In Section 7.2.1.2, FBC describes its updated forecasts for other capital.

7.2.1.1 Growth and Sustainment Capital

7.2.1.1.1 GROWTH CAPITAL

Growth capital expenditures involve transmission and distribution system improvements required to meet incremental customer and load growth, in addition to the cost of connecting new customers to the system.

The three main growth capital portfolios are: (i) Transmission Growth; (ii) Distribution Growth; and (iii) New Connects. In the MRP Application, FBC provided forecasts of these three categories of

[36] Excluding sustainment CIAC.

growth capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-4: Growth Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Transmission Growth	5.172	7.109	2.063	0.744	2.740	5.524
2	Distribution Growth	3.716	1.926	1.876	1.965	1.807	3.450
3	New Connects	18.141	19.764	19.104	19.156	19.792	20.894
4	Total Growth Capital	27.029	28.799	23.042	21.865	24.339	29.868

Table 7-5: Growth Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Transmission Growth	5.195	6.223	1.086	1.088
2	Distribution Growth	1.899	2.800	1.921	1.716
3	New Connects	19.188	21.951	20.163	21.764
4	Total Growth Capital	26.283	30.973	23.170	24.568

As shown in Table 7-5 above, FBC's Updated Forecasts for growth capital have increased by $4.690 million in 2023 and $1.398 million in 2024 compared to the Original Forecasts. FBC is forecasting increases in all three growth capital portfolios in 2023. For 2024, the increase is primarily in the New Connects portfolio, with FBC reducing the expenditures for the Distribution Growth portfolio to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.2 SUSTAINMENT CAPITAL

The expenditures within sustainment capital include system improvements to the transmission and distribution system in order to maintain existing equipment to meet forecast load and for the safety, reliability and quality of the system. FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects. FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The five main sustainment capital portfolios are: (i) Generation; (ii) Transmission Sustainment; (iii) Stations Sustainment; (iv) Distribution Sustainment; and (v) Telecommunications. In the MRP

Application, FBC provided forecasts of these five categories of sustainment capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-6: Sustainment Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Generation	6.697	5.884	6.766	6.949	6.309	6.731
2	Transmission Sustainment	8.353	12.506	6.387	10.667	5.698	7.841
3	Stations Sustainment	13.538	4.821	13.624	12.083	5.279	6.889
4	Distribution Sustainment	20.057	21.530	20.058	17.479	19.262	17.439
5	Telecommunications	1.818	2.584	2.983	2.423	6.280	2.587
6	Total Sustainment Capital	50.463	47.325	49.818	49.601	42.830	41.486

Table 7-7: Sustainment Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Generation	7.008	7.623	6.514	7.225
2	Transmission Sustainment	7.951	9.159	7.591	12.800
3	Stations Sustainment	3.793	7.928	15.971	15.229
4	Distribution Sustainment	19.710	17.480	19.922	18.219
5	Telecommunications	5.915	3.606	3.472	5.199
6	Total Sustainment Capital	44.377	45.797	53.470	58.673

As shown in Table 7-7 above, FBC's Updated Forecasts for sustainment capital have increased by $1.420 million in 2023 and $5.203 million in 2024 compared to the Original Forecasts. For 2023, the increases are primarily in the Transmission Sustainment and the Stations Sustainment portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Telecommunications portfolios to offset some of the required increases. For 2024, the increases are primarily in the Transmission Sustainment and Telecommunications portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Stations Sustainment portfolios to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.3 DRIVERS OF UPDATED GROWTH AND SUSTAINMENT CAPITAL FORECASTS

The drivers of the increases in growth and sustainment capital are summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;
- Increases in growth capital as a result of more customer applications; and
- Additional reliability, refurbishment or end of life projects being required that were not anticipated at the time of the MRP proceeding.

These cost drivers, as well as the mitigation efforts FBC has undertaken during the first three years of the MRP term, are described in the following subsections.

FBC is Experiencing Significant Inflationary Pressures

FBC's Original Forecasts were developed using an assumption of two percent for annual inflation. While FBC has generally managed its overall capital spending within the approved levels over the first two years of the MRP term, FBC has begun to experience pressures throughout its growth and sustainment portfolios. These pressures coincide with the significant global market events experienced during this time period, including the COVID-19 pandemic, supply chain disruptions, and the war in Ukraine. These unforeseen events have had a significant impact on market conditions for many commodities and services that make up FBC's supply chain, and the impacts are still being felt and continue to contribute to volatility in the supply chain and the overall commodity and services market in 2022.

In order to better understand the extent of the inflationary impacts that have affected North American utilities since 2020 and to compare the impacts on the industry with FBC's experience, FBC engaged Wood Mackenzie Supply Chain Consulting (Wood Mackenzie) to provide a market report on electric and gas utility transmission and distribution (T&D) markets from 2020 to 2022 and the anticipated impact until the end of 2024 (Wood Mackenzie Report). Wood Mackenzie identified an average escalation of 17.5 percent in capital costs for electric utilities between the period of the first quarter of 2020 and the first quarter of 2022. The Wood Mackenzie Report is based on the aggregated spend from utilities across North America, and incorporated over 150 indices which roll up to form the model for each category. Indices specific to BC have also been incorporated where appropriate, particularly around trades and other labour in the Province. This report has been included as Appendix C1.

FBC has experienced significant inflationary pressures during the first three years of the MRP term and expects these pressures will continue into 2023 and 2024. In particular, FBC has experienced the most significant inflationary cost pressures for poles, transformers and wires/cables. The projects in Transmission, Distribution and Station growth and sustainment portfolios have been impacted by incremental increases in the cost of these materials since 2020. Cost escalation is also impacting FBC due to steel commodity prices in North America, which have increased approximately 117 percent from the first quarter of 2020.

As shown in the Wood Mackenzie Report, it is expected that the average capital costs for electric utilities will continue to rise until the fourth quarter of 2024, although at a slower pace than what was experienced between the first quarter of 2020 and the first quarter of 2022, and will not come back down to the 2020 level. This expectation also aligns with the Bank of Canada's July 2022 Monetary Policy Report[37] which projects that CPI is expected to hover around 8 percent in the third quarter of 2022 before decreasing to approximately 3 percent by the fourth quarter of 2023 and 2 percent in 2024.

[37] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

Updated Forecasts Reflect Increased Growth

The New Connects category includes the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in its service area. This category also funds any costs associated with upgrading FBC facilities to provide service for an extension or drop service. Consistent with past practice, the forecast expenditures for New Connects are based on a historical rolling average of expenditures adjusted by inflation. The overall increase is due to more customer applications for connections.

Updated Forecasts Reflect New Growth and Sustainment Projects

As noted by the BCUC in the MRP Decision, there are inherent uncertainties in capital forecasting, particularly when forecasting projects over a five-year period. In the MRP Application, FBC identified projects over $1 million that it anticipated undertaking over the five-year MRP term. Due to a variety of reasons, such as land and permitting issues, re-prioritization of capital spending, and changes in capacity requirements, some projects have been delayed or cancelled while other new projects have been identified and prioritized.

For example, in order to address aging infrastructure and to support load growth while maintaining current levels of reliability, substation rebuild projects or transformer addition projects are required. In some cases, these projects require increasing the station footprint and acquiring more adjacent land or larger parcels of land in new locations. The selection of an appropriate land parcel can be a lengthy process that can include activities such as open houses as part of stakeholder consultation. Given the uncertainties related to consultation and purchase negotiation, it introduces risk to project timelines if these activities are not completed in advance of the project execution window. The need to acquire land has arisen in a number of FBC's planned projects and has resulted in increased costs and, at times, delays to the project schedule. Projects that have been impacted by land acquisition requirements are described in Appendix C2 and include, as an example, the Fruitvale Station Upgrade project.

As detailed in the MRP Application[38], FBC actively manages its capital plan to ensure projects are planned and executed efficiently. Accordingly, the timing, scope, and cost of the individual projects and programs within the overall regular capital forecasts are subject to change, and FBC may identify new projects and programs that need to be added over the term of the MRP. The capital plan contains a mix of projects across the portfolio categories, some of which are time sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that are expected to occur throughout the year within the resource and budget constraints of the capital plan. While this flexibility means that individual projects may move around, at a portfolio level, FBC has consistently executed a similar portfolio of work to the Original Forecasts.

[38] Section 3.4.1.5, page C-106.

In Appendix C2, FBC provides a list of the projects over $1 million which are included in the Updated Forecasts for 2023 and 2024.

FBC Employed Mitigation Strategies to Limit Cost Pressures

FBC has implemented the following strategies to mitigate the impact of the aforementioned cost pressures:

- Re-scheduling projects that can be safely re-scheduled to 2023 to accommodate other project costs increase that could not be deferred. As detailed in Section 3.2 (Capital Planning Process – page C-52) of the MRP Application, FBC manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change, and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that is expected to occur throughout the year within the resource and budget constraints of the capital plan. While FBC has delayed some work with flexible timing to accommodate the increased demands in 2022, this has only mitigated part of the capital pressures due to the magnitude of market pressures;
- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants, construction contractors, etc.);
- Competitively tendering large contracts for materials and services to ensure competitive pricing;
- Communicating with critical suppliers and contractors to discuss issues and mitigation strategies;
- Negotiating collective agreement with unionized FBC employees that provide longer-term stability for internal labour rates (IBEW and MoveUP agreement expires in 2023); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, FBC has not been able to fully mitigate cost increases due to the cost drivers described above.

7.2.1.2 Other Capital

In this section, FBC provides its Updated Forecasts for other capital. Other capital includes Equipment, Facilities and Information System (IS) expenditures.

Table 7-8 below shows the Approved and Actual/Projected other capital from 2020 to 2022 while Table 7-9 below shows the Original and Updated Forecasts of other capital for 2023 and 2024. FBC notes that the majority of the increase shown in the Updated Forecasts is related to Facilities, primarily as a result of the Kelowna Space Project.

Table 7-8: Approved and Actual/Projected Other Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Equipment	3.407	3.444	3.338	2.711	3.274	3.560
2	Facilities	3.264	3.434	2.346	3.685	2.346	2.846
3	Information Systems	9.081	9.158	9.028	8.953	9.136	9.975
4	Total Other Capital	15.752	16.036	14.712	15.349	14.756	16.381

Table 7-9: Original and Updated Forecasts of Other Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Equipment	3.681	4.099	3.388	3.717
2	Facilities	2.346	4.305	2.346	4.096
3	Information Systems	9.254	9.254	9.400	9.400
4	Total Other Capital	15.281	17.658	15.134	17.213

The following sections provide further details on the Updated Forecasts for other capital.

7.2.1.2.1 EQUIPMENT CAPITAL

Equipment capital expenditures include the acquisition of vehicles, specialized tools and equipment. Expenditures for the equipment listed above are driven by obsolescence, excessive wear and regulatory compliance.

FBC's 2023 and 2024 capital forecasts for Equipment have increased by $0.418 million and $0.329 million, respectively, compared to the Original Forecasts. The average unit cost per vehicle has risen significantly as supply of vehicles has reduced in relation to demand in the marketplace. In particular, FBC is experiencing the following changes to the average cost of the vehicles:

- Substantial reduction in volume-based concessions from manufacturers to all commercial fleet (from $10.5 thousand to $2.5 thousand per unit);
- Increased costs on steel, aluminum, glass and paint; and
- Inflationary surcharges on transport of materials, services and labour by manufacturers;

7.2.1.2.2 FACILITIES CAPITAL

Facilities capital expenditures include the acquisition or leasing of land, buildings, and building equipment. Facilities capital expenditures focus primarily on capacity planning, upgrading and replacement of end of life assets. The Facilities department ensures approved facilities projects are built to meet internal standards, building codes and regulations, and provide a long-term solution toward meeting the business requirements.

As shown in Table 7-9 above, FBC's 2023 and 2024 Facilities capital forecasts have increased by $1.959 million and $1.750 million in 2023 and 2024, respectively, compared to the Original

Forecasts. As further explained below, the majority of the increase is for the Kelowna Space Project. The remainder of the increase is related to: (i) energy management and GHG emissions reductions activities that FBC is planning to undertake to improve the adaptability and resiliency of FBC's facilities; and (ii) the installation of EV infrastructure at FBC's facilities.

Kelowna Space Project

FBC continues to experience capacity challenges at numerous locations for office, material storage and parking spaces and has been working to address these complex challenges. These capacity issues are impacting FBC's facilities across the Province and require different solutions depending on the location, as the challenges vary depending on the unique circumstances of each region. At the time of filing the MRP Application, FBC was in the process of developing a strategy for a cost-effective solution to the capacity issues in the Kelowna area, and therefore did not include this project in its Original Forecasts.

Both FEI and FBC have been experiencing space capacity challenges in the Kelowna region. Identifying solutions to address the space constraints has been very challenging, particularly due to the significant escalation in real estate costs to acquire new industrial land in the Kelowna area. However, the companies have now finalized a solution which leverages the use of FEI's and FBC's existing sites and results in the leasing of a new site for FEI's and FBC's Shared Services Departments. As further explained below, the Kelowna Space Project is a combined project for FEI and FBC, and the cost of the project has therefore been allocated between the two utilities accordingly. The total cost of the Kelowna Space Project is $13.930 million. Of this total, approximately $2.934 million is allocated to FBC based on employee count, with $1.209 million and $1.000 million reflected in FBC's Updated Forecasts for 2023 and 2024, respectively[39].

As part of the Kelowna Space Project, both FEI and FBC Shared Services Departments (Support Services) located in Kelowna will relocate to a new office lease facility approximately 25,000 ft^2 in size. Tenant improvements will be completed in 2023 and the Shared Services Departments will be relocated to this new leased facility. The allocation of leasing costs for this site will be determined using a cost driver approach based on the number of employees for FEI and FBC. In addition, FBC's Electrical Operations will move to the existing FEI-owned Springfield facility, as that location has a larger footprint and thus better aligns with the required Electrical Operations Space Program. FEI's Gas Operations will move to the existing FBC-owned Benvoulin property, as Gas Operations has a smaller footprint requirement. Broadly speaking, the Electrical and Gas Operations will "swap" locations.

Each building will require modifications to accommodate the Space Program requirements. Work will commence in late 2023 to complete the swap in 2025. Changes in building occupancy will be captured through new lease agreements where FEI will lease the entire Benvoulin building from

[39] There was also approximately $0.631 million and $0.094 million of actual costs related to the Kelowna Space Project allocated to FBC in 2020 and 2021, respectively, with the total allocation to FBC equaling approximately $2.934 million, including the forecast expenditures in 2023 and 2024.

FBC and FBC will lease the entire Springfield building from FEI. The buildings will remain operational while these changes are made.

The Kelowna Space Project results in a number of benefits for both FEI and FBC, including:

- Provision of sufficient space for both Operations and Support Services:
  - Support Services space requirement of 25,000 ft^2 of office at a new leased facility;
  - Gas Operations space requirement of 15,000 ft^2 of office and 12,000 ft^2 of industrial storage and shop space align with the sizing of the Benvoulin buildings and site; and
  - Electric Operations space requirement of 33,000 ft^2 of office and 13,000 ft^2 of industrial storage and shop space align with the sizing of the Springfield buildings and site;
- Retaining and updating the existing properties and adding a leased office facility results in a reasonable implementation timeline; changes are made at a measured pace to minimize business and employee disruption and do not require temporary relocation to another facility;
- The solution ensures Electric Operations remain located in an area that best supports their service territory; by not relocating this group farther from the city, potential inefficiencies are prevented;
- The solution is cost effective in contrast to other options such as purchasing new property or constructing a new Operation Hub, and utilizes FEI's and FBC's existing properties to the best extent possible; and
- Each Operations group is located in its own facility, increasing planning, operations, and management efficiencies.

Capital Expenditures to Support Energy Efficiency and GHG Reductions

The Updated 2023 and 2024 Forecasts include $0.750 million in each year for expenditures that are specifically in support of energy efficiency and GHG emissions reductions. These expenditures consist of projects that will result in reduced electrical and natural gas usage in FBC's facilities and/or will result in GHG emissions reductions. Where applicable, the planned projects are aligned with the ISO 50,001 Energy Management Standard, and enable FBC to prepare for the impacts of climate change and the transition to net-zero emissions. These planned projects will improve FBC's buildings' energy efficiency, support the adoption of electric vehicles, and contribute to efforts towards climate change and the Province's CleanBC Plan targets.

FBC is pursuing energy management and GHG emissions reduction opportunities for its buildings as part of the Company's climate action initiatives, including energy management activities related to climate adaptation, mitigation, and resiliency for buildings. FBC also plans to install EV charging infrastructure at FBC's facilities for fleet use.

Historically, the Facilities department has prioritized capital spending for capacity planning, end-of-life replacements, and meeting building codes and regulations. However, in light of the importance of addressing climate change, Facilities is now focusing on advancing climate action initiatives and strategies. Examples of advancements are installation of EV charging infrastructure, upgrading lighting to LED, completing energy audits to identify opportunities to inform capital planning, and incorporating energy efficiency components in long-term lease agreements.

7.2.1.2.3 INFORMATION SYSTEMS

FBC's Information Systems (IS) expenditures focus on enhancing, replacing, upgrading and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

As shown in Table 7-8 above, the actual/projected expenditures for 2020 through 2022 are generally consistent with what was forecast in the MRP Application. As such, FBC has not made any changes to the 2023 and 2024 IS capital forecasts (Table 7-9 above) compared to what was presented in the MRP Application as there have been no changes in circumstances or anticipated spending that would warrant revisions.

7.2.1.3 Summary of FBC's Updated Regular Capital for 2023 and 2024

FBC provided an updated forecast for regular growth, sustainment and other capital in 2023 and 2024. These Updated Forecasts are summarized in Table 7-10 below.

Table 7-10: Summary of 2023-2024 Updated Forecasts of Regular Capital

Line No.	Description	2023 Updated Forecast	2024 Updated Forecast
1	Growth Capital	30.973	24.568
2	Sustainment Capital	45.797	58.673
3	Other Capital	17.658	17.213
4	Total Regular Capital	94.428	100.454

For FBC's growth and sustainment capital, the Updated Forecasts reflect the significant and unanticipated cost pressures experienced over recent years. These pressures, generally experienced by North American utilities, are being driven by factors outside of FBC's control, and include, among others, the COVID-19 pandemic, supply chain pressures and the war in Ukraine, as well as growth-related expenditures and necessary reliability, refurbishment and end of life replacement projects. The Updated Forecasts will ensure FBC's ability to execute its planned growth and sustainment capital programs which are critical to ensuring the ongoing safe and reliable operation of FBC's system and ensuring that FBC is able to meet its customer's needs.

For FBC's other capital, the Updated Forecasts are primarily related to the Kelowna Space Project, as well as expenditures for activities at FBC's facilities related to energy efficiency and GHG emissions reductions.

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to Clean Growth initiatives, or because of the uncertainty in scope, costs and timing. The amounts for 2023 are shown in Table 7-11 below along with a comparison to 2022.

Table 7-11: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ -	$ 1.560	$ 0.248	
2	Exogenous Factor - MRS	0.935	0.870	-	
3	Forecast Capital Expenditures	$ 0.935	$ 2.430	$ 0.248	Section 11, Schedule 4, Line 10

7.2.2.1 EV DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[40], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 5-2 of Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

Table 7-11 above shows the EV DCFC stations capital expenditures for 2022 Approved[41], 2022 Projected, and 2023 Forecast. FBC originally did not forecast any EV DCFC station capital in 2022 during the 2022 Annual Review as FBC expected all construction activities to be completed in 2021. However, the originally planned construction activities in 2021 were delayed to 2022 mainly due to the flooding experienced in the latter part of 2021 which also led to FBC being required to undergo design changes to 16 of its DCFC sites to complete a required safety retrofit for the power supply kiosks. The flooding caused delays in construction and deployment for two planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21[42]. This resulted in an increase in capital expenditures for 2022 Projected when compared to 2022 Approved. FBC notes the reduction in expenditures for 2021 due to the delayed deployment of the Keremeos and Princeton stations was offset by the installation of two new DCFC stations in late 2021 at existing sites (i.e., Naramata and Grand Forks). Installations at Keremeos and Princeton are planned to be completed by the end of 2022, which by then will bring the total number of DCFC stations in service to 42 across the 23 sites. At this time, FBC is not expecting to construct any additional

[40] Order G-215-21 dated July 14, 2021.
[41] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 7-11 is the amount included in the Compliance Filing.
[42] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

stations or sites beyond the two additional DCFC stations noted above; however, station utilization will continue to be monitored to determine if any additional stations are warranted to meet customer demand. For 2023, FBC is forecasting to complete accessibility improvements for its existing EV DCFC sites. These improvements include new or additional lighting as the stations are available for use 24 hours a day, and paving for wheelchairs access to the charger.

The two new DCFC stations were installed at the existing Naramata and Grand Forks sites that only have a single DCFC station installed previously. Both Naramata and Grand Forks were identified in FBC's Revised Application for EV DCFC Service, and construction of these two additional stations was completed in late 2021. As directed by Order G-341-21[43], FBC is to include evaluation of any additional EV charging stations that were not originally identified in the Revised EV DCFC Service Application in FBC's Annual Review process, including review of whether the additional stations meet the criteria to be a prescribed undertaking under the GGRR and assessment of whether the levelized rate under RS 96 EV DCFC service will need to be recalculated as a result of the additional EV charging stations. Consistent with the information provided in FBC's Revised EV DCFC Application, Table 7-12 below shows that these two additional stations are prescribed undertakings and meet the requirements as set out in section 5 of the GGRR. Regarding the review of the levelized rate under RS 96 EV DCFC service, as discussed in Section 5.8, FBC is required to file a detailed assessment of the EV DCFC service by the end of December 31, 2022, which includes an update of the financial models with actual and forecast information as well as a detailed assessment of RS 96 and alternative rate design options. For the purposes of regulatory efficiency, FBC will address the review of the levelized rate under RS 96 EV DCFC service in the assessment report.

Table 7-12: Assessment of New EV DCFC Stations as Prescribed Undertakings Under the GGRR

	Greenhouse Gas Reduction Regulation Criteria						
GGRR Section	5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(a)(ii)	5(2)(c)
	Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that		For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
					The station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality? (Population – 2021 Census)	
Sites							
Naramata	Yes	Yes	Yes	Yes	Q4 2021	No[1]	Yes
Grand Forks	Yes	Yes	Yes	Yes	Q4 2021	No (4,112)	Yes

[43] Decision and Order G-341-21, p. 27.

Note to Table:

[1] Not located in a municipality as defined by the Community Charter.

7.2.2.2 Mandatory Reliability Standards Incremental Capital

As explained in Section 6.3.5, the incremental capital expenditures related to the adoption of MRS AR13 were approved for exogenous factor treatment in the 2022 Annual Review Decision. These costs are for the implementation of changes/additions, including the development and implementation of methods to monitor network traffic and software tools to support the changes/additions to the standards. The implementation of the required changes/additions requires the purchase and installation of hardware and software to assess and evaluate network traffic and the development of software tools to track risk assessments of any product or service procured for Bulk Electrical System assets.

Table 7-13 below shows the incremental capital expenditures related to MRS AR13 with a breakdown between labour, non-labour and contingency for 2022 Approved, 2022 Projected and 2023 Forecast.

Table 7-13: Incremental Capital Expenditures for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.580	$ 0.680	$ -	
2	Non-Labour	0.205	0.140	-	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.935	$ 0.870	-	Section 11, Schedule 4, Line 8

As shown in the table above, the 2022 Projected capital expenditures are approximately $0.065 million less than 2022 Approved. The reason for the variance is that FBC was able to purchase some software early (i.e., at the end of 2021 instead of 2022). Overall, there is no change to the original total estimate of $0.935 million (i.e., $0.065 million in 2021 Actual and $0.870 million in 2022 Projected).

As explained in the 2022 Annual Review[44], FBC is not expecting any incremental capital costs for 2023; therefore, the 2023 Forecast is zero. As the capital expenditures related to MRS AR13 are approved for flow-through treatment, any variances from Projected and Forecast amounts for the adoption of MRS AR13 will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in future years.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[45] the

[44] Exhibit B-3, BCUC IR1 24.2.
[45] MRP Decision and Order G-166-20, pp. 132-133.

BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

For 2023, FBC is forecasting capital expenditures related to the KBTA project only. However, FBC's 2023 Forecast rate base also includes the full-year impact of capital additions related to the Corra Linn Dam Spillway Gate Replacement project, the UBO Old Units Refurbishment project, and the Playmor Substation Upgrade project, all of which are expected to complete in 2022. Each of these approved projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The new transformer is scheduled to be in service by the end of 2022 or early 2023, with project close-out in 2023, at an estimated cost of $23.288 million, inclusive of AFUDC and cost of removal. FBC forecasts capital expenditures of $11.384 million and $1.710 million (excluding AFUDC) in 2022 and 2023, respectively, with $21.250 million to be added to rate base on January 1, 2023 and the remainder added to rate base on January 1, 2024.

Corra Linn Dam Spillway Gate Replacement Project

The Corra Linn Dam Spillway Gate Replacement project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. The project is expected to be complete in 2022 at a cost of $79.727 million, inclusive of AFUDC and cost of removal. Thus, FBC is not forecasting any capital expenditures related to this project in 2023. Since 2020, a total of $51.768 million has been added to FBC's rate base with the remaining $16.151 million forecast to be added to rate base in 2023. Overall, $67.919 million is forecast to be added to rate base by January 1, 2023 ($51.768 million of actual from 2020 to 2022 plus $16.151 million of 2023 Forecast), plus $11.808 million of cost of removal, for a total estimated project cost of $79.727 million including AFUDC and cost of removal.

UBO Old Units Refurbishment Project

The UBO Old Units Refurbishment project was approved by Order G-8-17 and involves the refurbishment of four generating units that are more than 100 years old. The refurbishments were completed in 2021 at an estimated total project cost of $34.180 million, inclusive of AFUDC and cost of removal. FBC is projecting approximately $0.002 million of remaining close-out costs in 2022 which will be added to rate base January 1, 2023. Overall, $32.290 million is forecast to be added to rate base by January 1, 2023 ($32.288 million of actual from 2018 to 2022 and $0.002 million of 2023 Forecast), plus $1.890 million of cost of removal, for a total estimated project cost of $34.180 million including AFUDC and cost of removal. As directed by the BCUC in the Annual Review for 2017 Rates, the UBO Refurbishment Project Final Report is included as Appendix B2.

Playmor Substation Upgrade Project

The Playmor Substation Upgrade project was approved by Order G-42-21 and involves rebuilding the Playmor substation in South Slocan, BC on an expanded station footprint in order to increase station capacity. The project is expected to be complete in 2022 at an estimated cost of $8.036 million, inclusive of AFUDC, and approximately $0.300 million of cost of removal. As the project is expected to complete in 2022, FBC is not forecasting any capital expenditures related to this project in 2023, and all project costs, estimated to be $8.036 million (including AFUDC) are forecast to enter rate base on January 1, 2023, with $0.300 million to be recorded to cost of removal.

7.4 2023 PLANT ADDITIONS

The 2023 Plant Additions are comprised of: (i) FBC's 2023 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-14: Reconciliation of 2023 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	Forecast 2023	Reference
1	Forecast Capital Expenditures	$ 94.428	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures	0.248	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures	94.676	Sum of Lines 1 and 2
4			
5	Capitalized Overhead	10.918	Section 11, Schedule 5, Line 16
6	AFUDC	0.243	Section 11, Schedule 5, Line 17
7	Change in Work in Progress	-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant	**105.837**	Sum of Lines 3 through 7
9			
10	Special Projects and CPCN Capital Expenditures		
11	Kelowna Bulk Transformer Capacity Addition	1.710	Section 11, Schedule 5, Line 7
12	AFUDC	0.049	Section 11, Schedule 5, Line 23
13	Change in Work in Progress	43.680	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant	**45.439**	Sum of Lines 11 through 13
15			
16	Total Plant Additions	**$ 151.276**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

The depreciation rates used for 2023, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, 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 by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2023 depreciation expense is calculated as $64.407 million.[46]

7.6 *DEFERRED CHARGES*

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[47] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

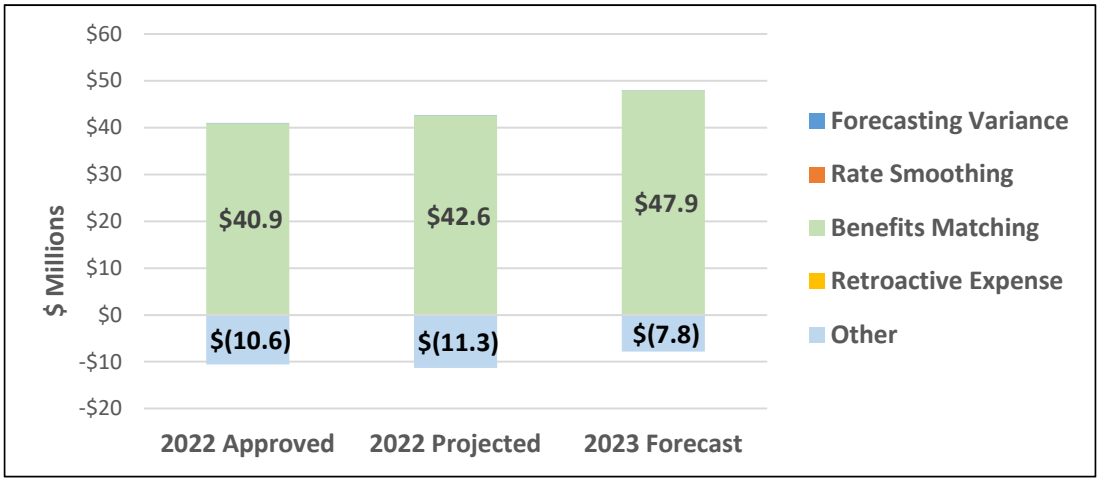
The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The 2023 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $40.045 million. The 2023 debit balance is driven largely by the balances in the Demand Side Management (DSM) and Deferred Debt Issue Costs deferral accounts, partially offset by the Pension and OPEB Liability deferral account.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[46] $69.474 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.067 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[47] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on amortizing the opening deferral account balances (rate base and non-rate base) using the approved and proposed amortization periods, the 2023 amortization expense is calculated as a credit of $3.277 million.[48] The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FBC is seeking approval to create one new rate base deferral account in this Application, as discussed below.

7.6.1.1 Joint Pole Use Audit 2023

Under the provisions of FBC's various joint use pole agreements, the parties are required to perform an audit of the joint use pole contacts once every five years, the last of which occurred in 2018.

Consistent with past treatment of costs for joint pole use audits, FBC is seeking approval to establish a rate base deferral account to capture costs incurred for the 2023 Joint Use Pole Audit, which are estimated at $0.435 million ($0.318 million after tax) to be incurred in 2023.

FBC is also requesting approval to amortize these costs over a five-year period beginning January 1, 2023, which represents the time period between the required audits.

Table 7-15 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to the above-described deferral account request.

[48] Section 11, Schedule 21, Column 3, Sum of Line 5 and 6.

Table 7-15: Deferral Account Filing Considerations

Item	Consideration	Joint Pole Use Audit 2023
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The 2023 Joint Pole Use Audit deferral account is a new deferral account, consistent with the past treatment of joint pole use audits in previous years.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The purpose of the requested account is to capture costs related to joint use pole audits that are required once every five years.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of the account encompasses the conduct of the audit and subsequent amortization period, equivalent to the term of the benefit.
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of a deferral account, the costs of the audit would have to be forecast as an O&M expense (outside of the MRP formula O&M since the 2018 audit costs were deferred and excluded from Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers a deferral account to be the more appropriate treatment since it permits the amortization of costs over the five-year period between audits.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	An audit of joint use poles is required at five-year intervals as a condition of FBC's agreements with the counter parties and is therefore outside of FBC's direct control.
b)	the degree of forecast uncertainty associated with the item;	FBC forecasts audit costs based on past experience. Actual costs are recorded in the account so that the actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	Refer to Section 7.6.1.1.
d)	any impact on intergenerational equity	FBC proposes to recover the deferred costs over the five-year period between the required audits.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC classifies this account as a benefit matching account since the costs are recovered over the period between audits.
VI.	Identify if the regulatory account is a cash or non-cash account.	The joint use pole audit account is a cash account.

Item	Consideration	Joint Pole Use Audit 2023
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Costs include incremental labour, vehicle, and staff expense in addition to FBC's share of common costs such as data input costs. See Section 7.6.1.1.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	FBC proposes to recover the deferred costs over the five-year period between the required audits.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings. Where requested within CPCNs or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on two existing deferral accounts and requests approval of an amortization period for one of them.

7.6.2.1 COVID-19 Customer Recovery Fund Deferral Account

7.6.2.1.1 DESCRIPTION AND FINANCIAL ESTIMATES

In June 2020, FBC received approval through Order G-133-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

1. any bill payment deferrals provided to customers due to the COVID-19 pandemic and subsequent payments of those deferred amounts;
2. any bill credits provided to customers due to the COVID-19 pandemic; and
3. any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

The following section provides 2022 and 2023 financial estimates and descriptions for each of the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account. FBC also proposes to commence amortization of the deferral account balance in 2023 and to discontinue quarterly reporting.

(a) Bill payment deferrals provided to residential and small commercial customers

The bill payment deferral program was offered to residential and small commercial customers affected by the COVID-19 pandemic. FBC experienced high collection rates in regard to this program, recovering approximately 85 percent of the outstanding balances through the regular monthly instalments. The remaining customer balances that were ultimately deemed unrecoverable have been designated as unrecoverable revenue and as such, a total of $0.119 million has been transferred to the COVID-19 Customer Recovery Fund Deferral Account. These additions to the deferral account are forecast in section (c), Table 7-18 *Unrecoverable Revenue Amounts*.

FBC ceased accepting new applications effective June 1, 2021 and is therefore not forecasting further additions related to this relief measure.

Table 7-16: Bill Payment Deferral Forecast Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.563	0.005	-
Additions	0.803	-	-	-
Repayments	(0.240)	(0.444)	-	-
Transfers	-	(0.114)	(0.005)	-
Ending Balance	0.563	0.005	-	-

(b) Bill credits provided to small commercial customers

The bill credit program offered to small commercial customers has been calculated using the existing balance of $0.132 million as of April 2022. Given the duration and period these credits were available for, as well as the June 1, 2021 closure of the program for new applications, FBC does not expect additional credits to be offered to customers throughout the remainder of 2022 or in 2023. As such, FBC is proposing to amortize the $0.132 million over three years, with the 2023 amortization amount shown in Table 7-17 below.

Table 7-17: Bill Credit Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.130	0.132	0.132
Additions	0.178	0.003	-	-
Tax	(0.048)	(0.001)	-	-
Amortization[49]	-	-	-	(0.044)
Ending Balance	0.130	0.132	0.132	0.088

[49] Based on a requested three-year amortization period, as discussed in Section 7.6.2.1.2.

(c) Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic

This portion of the deferral account forecast represents the amount of customer balances owing (i.e., account receivables) that are recognized as unrecoverable due to the COVID-19 pandemic. As such, these amounts are in excess of the normal course forecast bad debt expense that is recognized in indexed-based O&M.

Table 7-18: Unrecoverable Revenue Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.011	0.134	0.375
Transfers[50]	-	0.114	0.005	-
Additions[51]	0.015	0.054	0.325	-
Tax	(0.004)	(0.045)	(0.089)	-
Amortization[49]	-	-	-	(0.125)
Ending Balance	0.011	0.134	0.375	0.250

The unrecovered revenue recorded in the deferral account includes:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay (shown as the Transfers line in Table 7-18 above); and
- any unrecovered revenue from all customer classes due to the COVID-19 pandemic, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings (shown as the Additions line in Table 7-18 above).

The 2022 Projected transfers of $0.005 million represent the actual 2022 transfers for the months available and any remaining bill payment deferral loan balances that were not yet repaid. The 2022 Projected additions of $0.325 million have been calculated using actual additions for the months available with the remainder of the year forecast using an approach consistent with the prior year. That is, a factor of 15 percent has been applied to the total outstanding balance of customer accounts that are past due as at March 1, 2022. This approach was based on a pilot outreach program in 2021 where 15 percent of customers with an average balance of $800 confirmed that they were financially impacted by the COVID-19 pandemic and required support to bring their account into good standing.

[50] The actual 2021 unrecoverable revenue transfers of $0.114 million consist of $0.004 million of small commercial customer balances and $0.110 million of residential customer balances.

[51] The actual 2020 unrecoverable revenue additions of $0.015 million consist of $0.014 million of small commercial customer balances and $0.001 million of residential customer balances. The actual 2021 unrecoverable revenue additions of $0.054 million consist of $0.004 million of small commercial customer balances and $0.050 million of residential customer balances.

While the forecasts of the unrecovered revenue additions above rely on estimates and broader macroeconomic factors, the actual amounts that will be recorded in the deferral account will reflect actual balances that are attributable to specific customers that cannot make payment due to the COVID-19 pandemic.

In this regard, to support the development of a consistent and appropriate approach for identifying amounts deemed unrecoverable due to COVID-19, FBC has created an internal set of guidelines to be used by members of the customer service team with an objective to identify and support customers that have been financially impacted by the COVID-19 pandemic. The underlying goal and intent of this approach is for customers to be able to maintain their gas services while maximizing recoveries associated with any balances due. These internal guidelines include questions that help identify the extent to which the customer has been impacted by COVID-19 as well as payment arrangement guidelines that include partial or full recognition of receivable balances as unrecoverable due to the COVID-19 pandemic.

7.6.2.1.2 DISPOSITION OF DEFERRAL ACCOUNT

As indicated in the 2022 Annual Review, additions to the COVID-19 Customer Recovery Fund Deferral Account for unrecovered revenues resulting from customers being unable to pay their bills due to the COVID-19 pandemic were expected to continue into 2022. As such, FBC has continued to capture unrecovered revenues in this deferral account during 2022.

Since the 2022 Annual Review, conditions have improved such that most COVID-19 pandemic restrictions in BC have been lifted.[52] The Federal government support programs such as the Canada Emergency Response Benefit (CERB) and the Canada Emergency Wage Subsidy (CEWS) for businesses have ended as the impact of the COVID-19 pandemic lessens. This, along with the improved economic conditions, although somewhat tempered recently with inflationary and recessionary considerations, suggests that ongoing pandemic support is not needed anymore.

Additionally, FBC has resumed most of its collection practices in 2022 with no significant uptick in unrecoverable revenues from customers experienced so far, and FBC anticipates full resumption of normal collection practices by mid-2022.

As a result, based on the positive current outlook for the COVID-19 pandemic and the lessened impact, FBC does not anticipate any further additions to the deferral account after 2022 and proposes to commence amortization of the balance in the deferral account on January 1, 2023 using a three-year amortization period. FBC considers a three-year amortization period to be appropriate because it matches the number of years during which the COVID-19 Customer Recovery Fund Deferral Account was active (i.e., 2020 through 2022).

Should public health and economic conditions deteriorate significantly due to the resurgence of the COVID-19 pandemic later this year or in the future (i.e., another wave of the pandemic which causes shutdowns and job losses impacting individuals and businesses), FBC may seek BCUC

[52] See Section 12.2.1 for further discussion and details.

approval again for deferral account treatment for the same purpose and reasons set out in the 2020 application.

7.6.2.1.3 REQUEST TO DISCONTINUE REPORTING

FBC seeks approval to discontinue the existing quarterly reporting requirements for the COVID-19 Customer Recovery Fund Deferral Account filed with the BCUC. If approved, the final quarterly report would be for Q4 2022 and would be submitted in Q1 2023.

With more than two full years of reporting complete, the closure of the deferral and credit program to new applicants as of June 1, 2021, and the planned discontinuation of additions to the deferral account as of December 31, 2022, FBC does not see further value in providing separate detailed reporting for this account.

7.6.2.2 Indigenous Relations Agreement (Huth Substation)

As part of the Annual Review for 2020 and 2021 Rates Decision and Order G-42-21, FBC received approval to establish the Indigenous Relations Agreement (Huth Substation) deferral account to capture costs to address the Penticton Indian Band's (PIB) concerns regarding the Huth Substation in Penticton and the impacts the substation has had on Syilx[53] history and culture, such as the discovery of ancestral remains found at the Huth substation while performing construction works.

The Huth substation is a vital component of the South Okanagan area power system, providing direct service to both FBC customers and the municipal utility of the City of Penticton. This hub is connected to five major transmission lines (42L, 49L, 47L, 52L and 53L) and to two City of Penticton distribution substations. Given the importance of the substation to the supply of power in the South Okanagan and the historical value of the land to the PIB and the Syilx people, FBC has engaged in reconciliation efforts with the PIB, consistent with the recent legislation passed by the Provincial government.

FBC stated in the 2020-2021 Annual Review that it would update its progress with respect to this matter in future annual reviews and request approval for recovery of costs captured in this deferral account once an agreement with the PIB had been reached and the impacts could be communicated.

FBC has been unable to continue preliminary discussions with the PIB on reconciliation efforts on the Huth substation. Due to impacts on the community from the COVID-19 pandemic, followed by the unique circumstances that arose in 2021 with the Kamloops Residential School findings, and as the Penticton Indian Band and FortisBC Energy Inc. are currently in discussions regarding the proposed Okanagan Capacity Upgrade project, FBC chose not to pursue further efforts regarding the Huth Substation until both parties agreed to proceed. FBC will continue to provide updates on this matter and on the deferral account in future annual review filings.

[53] The PIB is a community of the Syilx people.

7.7 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). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings, and inventory of materials and supplies. 2023 amounts are forecast based on 2021 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.2.1, FBC requested approval of its updated 2023 and 2024 regular capital (growth, sustainment and other) forecasts; in Section 7.6.1, FBC requested approval of one new deferral account; and in Section 7.6.2, FBC discussed two existing accounts, including requesting amortization of one of these existing accounts. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN OF EQUITY

8.1 INTRODUCTION AND OVERVIEW

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI.

FBC is currently participating in the BCUC-initiated Generic Cost of Capital (GCOC) proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. As explained in Section 1.2, FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

The 2023 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 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

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 BCUC from time to time. Order G-47-14 approved a capital structure for FBC of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE, which was set at 8.75 percent by Order G-129-16; these approved capital structure and ROE values have been used to calculate rates in the Application.

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- and short-term debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. In March 2022, FBC issued long-term debt of $100 million at a rate of 4.16 percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Company's capital expenditure program. FBC

plans to issue additional long-term debt of approximately $75 million in 2023 and will use the funds for the same purposes. The 2023 debt issuance is reflected in the financial schedules in July 2023 at a rate of 4.90 percent.[54] The exact timing, amount and rate of the 2023 issuance will depend on future market conditions and capital expenditure requirements. 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 commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2026.[55] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its 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's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-Month T-Bill forecast for 2023 is 3.14 percent, which is a significant increase from the 0.47 percent approved in 2022. FBC is in a rising interest rate environment due to high inflation, Russia's invasion in Ukraine, and the removal of monetary policy actions that were prevalent during the initial years of the COVID-19 pandemic (i.e., 2020 and 2021). In addition, on July 13, 2022 the Bank of Canada completed its fourth rate hike of the year, raising the benchmark interest

[54] Section 11, Schedule 27, Line 10.
[55] On July 14, 2021, the credit facility was extended to April 27, 2026.

rate to 2.5 percent from 0.25 percent at the beginning of 2022 and signalling that more rate hikes will be announced in 2022. The market volatility is expected to persist given many ongoing elevated risk variables.

For 2023, FBC forecasts a similar level of other financing fees to the 2022 Approved amount. Other financing fees include the fees that FBC incurs for its letters of credit under the $150 million credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2022	Projected 2022	Forecasted 2023
3-Month T-Bill Rate [1]	0.47%	3.08%	3.14%
Spread to CDOR	0.39%	0.36%	0.36%
CDOR Rate	0.86%	3.44%	3.50%
Spread to CP	-0.32%	-0.36%	-0.36%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**0.64%**	**3.18%**	**3.24%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.39%	0.44%
Renewal Fee on Undrawn Credit	0.17%	0.11%	0.12%
Other Financing Fees	0.26%	0.35%	0.44%
ST Interest Rate on Fixed Financing Fee	**0.87%**	**0.84%**	**1.00%**
FBC Short Term Rate	**1.51%**	**4.02%**	**4.24%**

Notes to Table:

[1] 3-Month T-Bill Rate for 2023 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2022.

[2] Fixed financing fees represent the costs of maintaining the $150 million credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is reassessing its use of CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[56] The Canadian Alternative Reference Rate Working Group

[56] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

(CARR) was established to coordinate the transition to a new risk-free rate benchmark. It is anticipated that CDOR will transition to the Canadian Overnight Repo Rate Average (CORRA), a transaction-based overnight risk-free interest rate benchmark in existence since 1997.[57] FBC will work with its banking syndicate members to transition its credit facility agreement to CORRA and will revisit the methodology for short-term interest rate forecasting when such a transition is complete.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- 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. 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 2023 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2023

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	5.44%	4.24%	3.10%	4.24%
Long Term Debt	54.56%	4.78%	3.49%	4.78%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.85%	5.73%	6.50%

8.4 *SUMMARY*

FBC's equity financing and ROE have been forecast for 2023 at the same percentages as approved for 2022. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to decrease in 2023 as compared to 2022 Approved.

[57] https://www.bankofcanada.ca/wp-content/uploads/2021/12/CARR-Review-CDOR-Analysis-Recommendations.pdf.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2023, property taxes are forecast to increase by 2.1 percent from 2022 Approved, while income tax is forecast to decrease by 19.9 percent compared to 2022 Approved.

9.2 PROPERTY TAXES

Property taxes for 2023 of $18.260 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 2022	Projected 2022	Forecast 2023
1	Generating Plant	$ 3.210	$ 3.199	$ 3.253
2	Transmission and Distribution	7.428	6.950	7.189
3	Substation Equipment	3.948	4.156	4.208
4	Land and Buildings	1.165	1.201	1.322
5	In-Lieu	2.138	2.115	2.288
6	Total Property Taxes	$ 17.889	$ 17.621	$ 18.260
7				
8	Forecast Change from 2022 Approved			2.1%
9	Forecast Change from 2022 Projected			3.6%

As shown in the above table, in 2023 property taxes are forecast to increase by 2.1 percent from 2022 Approved and increase by 3.6 percent compared to 2022 Projected. In general, the 2023 increase from 2022 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. **Changes in Tax Rates.** Tax Rates are expected to change for 2023 as follows:

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

   b) School rates are expected to decrease by 1.0 percent;

   c) Rural rates are expected to decrease by 0.4 percent;

d) Tax rates on First Nations are expected to increase by 0.8 percent; and

e) Other rates are expected to decrease by 1.4 percent.

2. **Changes in Revenues to Calculate Grants In Lieu of Taxes.** Revenues reported to municipalities are expected to increase by 8.2 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual increase in revenues reported to municipalities increases the grants in-lieu of taxes due.

3. **Changes in Assessed Values.** Forecast changes in the assessed values of FBC's property are based on expected inflationary increases. These include:

a) A 5.2 percent increase in assessed values of distribution lines and a 2.5 percent increase in transmission lines;

b) A 2.5 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

c) A 0.5 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

d) Land values are expected to increase between 4.3 percent to 11.4 percent for right of ways and properties owned in fee simple.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered 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 BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. 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 are updated each year as part of the annual rate setting process.

Income tax for 2023 is forecast to decrease by $1.494 million or 19.9 percent compared to 2022 Approved. The 2023 Forecast decrease is primarily due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

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

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2023 rates, it is the 2021 formula O&M and 2021 earnings sharing amounts that are calculated and impact rates in 2023.

For 2023, FBC proposes to distribute a $0.911 million pre-tax credit ($0.665 million after-tax) to customers, comprised of:

- The $0.665 million credit difference between the projected 2021 deferral account after-tax credit addition of zero embedded in 2022 rates, and the actual 2021 deferral account after-tax credit addition of $0.665 million as provided in FBC's 2021 Annual Report to the BCUC. This amount is also shown in the opening 2023 balance[58] in the financial schedules in the Application.

FBC proposes to distribute $0.911 million to customers in 2023 as a reduction in 2023 revenue requirements through amortization of the projected 2023 opening after-tax balance of $0.665 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2022 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2022 ROE variance from approved.

[58] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

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SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2023
($millions)

Line No.	Particulars	2023 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (12.546)		
3	Change in Other Revenue	(0.409)	(12.955)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	19.796		
7	Wheeling	0.894		
8	Water Fees	(0.415)	20.275	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	4.757		
12	Capitalized Overhead Change	(0.741)	4.016	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.752	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.210)		
19	Deferrals	(4.835)	(5.045)	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	3.688		
23	Financing Ratio Changes	(1.049)		
24	Rate Base Growth	5.809	8.448	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.371		
28	Other Income Taxes Changes	(1.494)	(1.123)	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 16.368**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		409.840	Schedule 18, Line 7, Column 3
33	Rate Change		3.99%	

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Section 11

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,279,658	$ 2,375,297	$ 95,639	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	4,512	-	(4,512)	Schedule 6.1, Line 32, Column 4
3	Net Additions	105,010	134,666	29,656	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,389,180	2,509,963	120,783	
5					
6	Accumulated Depreciation Beginning	$ (659,517)	$ (693,759)	$ (34,242)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	(569)	-	569	Schedule 7.1, Line 32, Column 6
8	Net Additions	(33,657)	(47,865)	(14,208)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(693,743)	(741,624)	(47,881)	
10					
11	CIAC, Beginning	$ (232,291)	$ (243,101)	$ (10,810)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	(2,523)	-	2,523	
13	Net Additions	(11,712)	(11,628)	84	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(246,526)	(254,729)	(8,203)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 84,284	$ 89,140	$ 4,856	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	212	-	(212)	
18	Net Additions	4,857	5,067	210	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	89,353	94,207	4,854	
20					
21	Net Plant in Service, Mid-Year	$ 1,506,015	$ 1,567,697	$ 61,682	
22					
23	Adjustment for timing of Capital additions	$ 16,181	$ 22,720	$ 6,539	
24	Capital Work in Progress, No AFUDC	19,332	34,306	14,974	
25	Unamortized Deferred Charges	30,372	40,045	9,673	Schedule 11, Line 26, Column 8
26	Working Capital	6,258	6,100	(158)	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,749	4,563	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,582,907	$ 1,675,431	$ 92,524	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2023
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	Total for 2023 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		2.692%	1.596%	1.281%	4.940%		
3	AWE		2.881%	5.745%	6.455%	4.235%		
4	Labour Split							
5	Non Labour		38.000%	38.000%	37.000%	40.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.517%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	4.017%		
10								
11								
12	**Growth in Average Customer Calculation**							
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,417		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,417	150,563		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,541	3,145	10,647	
16								
17	Customer Growth Factor Multiplier	G-166-20					75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17					7,985	
19								
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020					139,916	
21								
22	Average Customer Forecast - 2023 Rate Setting Purposes	Line 18 + Line 20					147,901	

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Section 11

Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 30,973	
3	Sustainment Capital	45,797	
4	Other Capital	17,658	
5	Total Forecast Capital	$ 94,428	
6			
7	**Flow-Through Capital Expenditures**		
8	MRS Capital	$ -	
9	EV Charging Stations	248	
10	Total Flow-Through Capital	$ 248	
11			
12	**Total Regular Capital Expenditures**	$ 94,676	

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Schedule 5

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	94,428	
3	Flow-Through Capital		248	
4	Total Regular Capital Expenditures	$	94,676	Schedule 4, Column 2, Line 12
5				
6	**Special Projects and CPCN's**			
7	Kelowna Bulk Transformer Capacity Addition	$	1,710	
8	Total Special Projects and CPCN's	$	1,710	
9				
10	**Total Capital Expenditures**	$	96,386	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	94,676	Line 4
16	Add - Capitalized Overheads		10,918	Schedule 20, Column 4, Line 23
17	Add - AFUDC		243	
18	Gross Capital Expenditures		105,837	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,837	
21				
22	Special Projects and CPCN's Capital Expenditures	$	1,710	Line 8
23	Add - AFUDC		49	
24	Gross Capital Expenditures		1,759	
25	Change in Work in Progress		43,680	
26	**Total Special Projects and CPCN Additions to Plant**	$	45,439	
27				
28	**Grand Total Additions to Plant**	$	151,276	Schedule 6.1, Columns 5 + 6, Line 32

FORTISBC INC.

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Section 11

Schedule 6

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	22,045	-	-	167	(12)	22,200	
4	332	Reservoirs, Dams & Waterways	119,076	-	16,151	7,747	(782)	142,192	
5	333	Water Wheels, Turbines and Gen.	105,453	-	2	699	(142)	106,012	
6	334	Accessory Equipment	51,357	-	-	128	(38)	51,447	
7	335	Other Power Plant Equipment	48,572	-	-	5	(1)	48,576	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 348,752	$ -	$ 16,153	$ 8,746	$ (975)	$ 372,676	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,767	$ -	$ -	$ 118	$ -	$ 10,885	
13	350.1	Land Rights-Clearing	9,992	-	-	118	-	10,110	
14	353	Station Equipment	243,150	-	21,250	3,446	(305)	267,541	
15	355	Poles Towers & Fixtures	127,975	-	-	6,450	(291)	134,134	
16	356	Conductors and Devices	123,228	-	-	6,449	(313)	129,364	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 516,071	$ -	$ 21,250	$ 16,581	$ (909)	$ 552,993	

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,185	$ -	$ -	$ 817	$ -	$ 8,002	
3	360.1	Land Rights-Clearing	11,630	-	-	374	-	12,004	
4	362	Station Equipment	304,310	-	8,036	13,065	(885)	324,526	
5	364	Poles Towers & Fixtures	258,898	-	-	13,410	(570)	271,738	
6	365	Conductors and Devices	436,812	-	-	20,531	(728)	456,615	
7	368	Line Transformers	193,494	-	-	14,165	(1,815)	205,844	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,459	-	-	532	-	41,991	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,178	-	-	170	(42)	14,306	
12	372	EV Stations Kiosks & Charger Connectors	5,993	-	-	-	-	5,993	
13			$ 1,284,418	$ -	$ 8,036	$ 63,064	$ (4,040)	$ 1,351,478	
14									
15		**General Plant**							
16	389	Land	$ 11,184	$ -	$ -	$ -	$ -	$ 11,184	
17	390.1	Structures - Masonry	48,652	-	-	2,785	(319)	51,118	
18	390.2	Operation Building	19,432	-	-	609	(23)	20,018	
19	390.1	Leasehold Improvements	2,872	-	-	-	-	2,872	
20	391	Office Furniture & Equipment	5,399	-	-	215	(237)	5,377	
21	391.1	Computer Hardware	13,614	-	-	3,330	(3,016)	13,928	
22	391.2	Computer Software	41,906	-	-	7,033	(4,015)	44,924	
23	391.2	AMI Software	13,439	-	-	(3)	-	13,436	
24	392.1	Light Duty Vehicles	5,967	-	-	549	(484)	6,032	
25	392.1	Heavy Duty Vehciles	28,678	-	-	1,523	(351)	29,850	
26	394	Tools and Work Equipment	8,507	-	-	724	(587)	8,644	
27	397	Communication Structures & Equipment	15,707	-	-	681	(1,456)	14,932	
28	397.1	Fibre	5,729	-	-	-	(198)	5,531	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 226,056	$ -	$ -	$ 17,446	$ (10,686)	$ 232,816	
31									
32		**Total Plant in Service**	$ 2,375,297	$ -	$ 45,439	$ 105,837	$ (16,610)	$ 2,509,963	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (382)	$ -	$ 10	$ -	$ -	$ -	$ (372)	
3	331	Structures and Improvements	22,045	1.68%	5,718	-	370	(12)	-	-	6,076	
4	332	Reservoirs, Dams & Waterways	135,227	1.90%	7,278	-	2,569	(782)	(1,857)	-	7,208	
5	333	Water Wheels, Turbines and Gen.	105,455	1.79%	20,564	-	1,888	(142)	(3)	-	22,307	
6	334	Accessory Equipment	51,357	3.13%	15,121	-	1,607	(38)	(130)	-	16,560	
7	335	Other Power Plant Equipment	48,572	2.12%	20,171	-	1,030	(1)	-	-	21,200	
8	336	Roads, Railroads and Bridges	1,287	1.44%	476	-	19	-	-	-	495	
9			$ 364,905		$ 68,946	$ -	$ 7,493	$ (975)	$ (1,990)	$ -	$ 73,474	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,767	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	9,992	1.27%	2,485	-	127	-	-	-	2,612	
14	353	Station Equipment	264,400	2.33%	101,920	-	6,161	(305)	(159)	-	107,617	
15	355	Poles Towers & Fixtures	127,975	2.52%	39,342	-	3,225	(291)	(469)	-	41,807	
16	356	Conductors and Devices	123,228	2.52%	24,036	-	3,105	(313)	(469)	-	26,359	
17	359	Roads and Trails	959	1.96%	432	-	19	-	-	-	451	
18			$ 537,321		$ 168,215	$ -	$ 12,637	$ (909)	$ (1,097)	$ -	$ 178,846	

FORTISBC INC.

Schedule 7.1

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,185	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	11,630	1.25%	2,935	-	145	-	-	-	3,080	
4	362	Station Equipment	312,346	2.61%	93,321	-	8,152	(885)	(156)	-	100,432	
5	364	Poles Towers & Fixtures	258,898	2.73%	80,092	-	7,068	(570)	(567)	-	86,023	
6	365	Conductors and Devices	436,812	2.38%	129,625	-	10,396	(728)	(914)	-	138,379	
7	368	Line Transformers	193,494	3.13%	45,961	-	6,056	(1,815)	(347)	-	49,855	
8	369	Services	9,521	0.51%	6,807	-	49	-	-	-	6,856	
9	370.1	AMI Meters	41,459	6.25%	12,897	-	2,591	-	-	-	15,488	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,178	4.95%	6,259	-	702	(42)	-	-	6,919	
12	372	EV Stations Kiosks & Charger Connectors	5,993	10.00%	914	-	599	-	-	-	1,513	
13			$ 1,292,454		$ 379,748	$ -	$ 35,758	$ (4,040)	$ (1,984)	$ -	$ 409,482	
14												
15		**General Plant**										
16	389	Land	$ 11,184	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	48,652	2.53%	13,006	-	1,231	(319)	-	-	13,918	
18	390.2	Operation Building	19,432	1.63%	7,081	-	317	(23)	-	-	7,375	
19	390.1	Leasehold Improvements	2,872	1.63%	2,700	-	47	-	-	-	2,747	
20	391	Office Furniture & Equipment	5,399	4.42%	1,501	-	239	(237)	-	-	1,503	
21	391.1	Computer Hardware	13,614	21.60%	4,496	-	2,941	(3,016)	-	-	4,421	
22	391.2	Computer Software	41,906	8.96%	16,368	-	3,755	(4,015)	-	-	16,108	
23	391.2	AMI Software	13,439	10.00%	7,627	-	1,344	-	-	-	8,971	
24	392.1	Light Duty Vehicles	5,967	3.81%	2,528	-	227	(484)	77	-	2,348	
25	392.1	Heavy Duty Vehciles	28,678	6.50%	8,066	-	1,864	(351)	-	-	9,579	
26	394	Tools and Work Equipment	8,507	4.11%	3,500	-	350	(587)	-	-	3,263	
27	397	Communication Structures & Equipment	15,707	3.44%	5,067	-	540	(1,456)	(5)	-	4,146	
28	397.1	Fibre	5,729	6.97%	2,486	-	399	(198)	-	-	2,687	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,390	-	332	-	-	-	2,722	
30			$ 226,056		$ 76,850	$ -	$ 13,586	$ (10,686)	$ 72	$ -	$ 79,822	
31												
32		**Total**	$ 2,420,736		$ 693,759	$ -	$ 69,474	$ (16,610)	$ (4,999)	$ -	$ 741,624	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
3	**Total**	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
4								
5	**Amortization**							
6	Amortization	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
7	**Total**	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
8								
9	**Net CIAC**	$ 153,961	$ -	$ -	$ 6,561	$ -	$ 160,522	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 32	$ -	$ -	$ -	$ (32)	$ -	$ 16	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges	$ 2,646	$ -	$ (439)	$ -	$ -	$ 2,207	$ 2,427	Note 1
8	Demand Side Management	37,219	-	14,455	(3,903)	(5,829)	41,942	39,581	
9	Deferred Debt Issue Costs	4,074	-	600	(111)	(167)	4,396	4,235	
10	Joint Pole Use Audit 2023	-	-	435	(117)	(64)	254	127	
11	2021 Generic Cost of Capital Proceeding	675	-	450	(122)	-	1,003	839	
12	Annual Reviews for 2020-2024 Rates	154	-	200	(54)	(154)	146	150	
13	2021 Long Term Electric Resource Plan	264	-	250	(68)	(113)	333	298	
14	BCUC Initiated Inquiry Costs	109	-	100	(27)	(109)	73	91	
15	Mandatory Reliability Standards 2021 Audit	157	-	-	-	(79)	78	118	
16		$ 45,298	$ -	$ 16,051	$ (4,402)	$ (6,515)	$ 50,432	$ 47,866	
17									
18	**4. Retroactive Expense Accounts**								
19									
20	**5.Other Accounts**								
21	Pension and OPEB Liability	$ (10,592)	$ -	$ 4,664	$ -	$ -	$ (5,928)	$ (8,260)	
22	COVID-19 Customer Recovery Fund	507	-	-	-	(169)	338	423	
23	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
24		$ (10,085)	$ -	$ 4,664	$ -	$ (169)	$ (5,590)	$ (7,837)	
25									
26	**Total Rate Base Deferral Accounts**	$ 35,245	$ -	$ 20,715	$ (4,402)	$ (6,716)	$ 44,842	$ 40,045	
27									

28 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $0.851 million - transfer of $1.290 million = $(0.439) million.

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 12

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	**1. Forecasting Variance Accounts**								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ 1,493	$ -	$ -	$ -	$ (604)	$ 889	$ 1,191	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	31	-	-	-	(31)	-	15	
10		$ 31	$ -	$ -	$ -	$ (31)	$ -	$ 15	
11									
12	**4. Retroactive Expense Accounts**								
13									
14	**5.Other Accounts**								
15									
16	**Total NRB Deferral Accounts at Short Term Interest**	$ 1,524	$ -	$ -	$ -	$ (635)	$ 889	$ 1,206	
17									
18	Financing Costs at STI	$ 8	$ -	$ 37	$ -	$ (8)	$ 37	$ 23	

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 12.1

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	**1. Forecasting Variance Accounts**								
4									
5	**2. Rate Smoothing Accounts**								
6									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 980	$ -	$ 450	$ -	$ -	$ 1,430	$ 1,205	
9	2017 Rate Design Application	236	-	-	-	(118)	118	177	
10	2020 - 2024 Multi-Year Rate Plan Application	290	-	-	-	(145)	145	217	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	127	-	-	-	(59)	68	98	
12		$ 1,633	$ -	$ 450	$ -	$ (322)	$ 1,761	$ 1,697	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17	US GAAP Pension and OPEB Transition Obligation	$ 348	$ -	$ (348)	$ -	$ -	$ -	$ 174	
18	Advanced Metering Infrastructure Radio-Off Shortfall	25	-	-	-	(25)	-	12	
19		$ 373	$ -	$ (348)	$ -	$ (25)	$ -	$ 186	
20									
21	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,006	$ -	$ 102	$ -	$ (347)	$ 1,761	$ 1,883	
22									
23	Financing Costs at WACD	$ 64	$ -	$ 66	$ -	$ (64)	$ 66	$ 65	

24 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	**1. Forecasting Variance Accounts**								
4	2020 - 2024 Flow-Through Deferral Account	$ (9,625)	$ -	$ -	$ -	$ 9,625	$ -	$ (4,813)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	On Bill Financing (OBF) Participant Loans	$ 1	$ -	$ (1)	$ -	$ -	$ -	$ 1	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (665)	$ -	$ -	$ -	$ 665	$ -	$ (333)	
15									
16	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (10,289)	$ -	$ (1)	$ -	$ 10,290	$ -	$ (5,145)	
17									
18	Financing Costs at AFUDC	$ (757)	$ -	$ (317)	$ -	$ 757	(317)	(537)	
19									
20	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
21									
22									
23	**Total Non Rate Base Deferral Accounts (including financing)**	**$ (7,394)**	**$ -**	**$ (113)**	**$ -**	**$ 9,993**	**$ 2,487**	**$ (2,455)**	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 7,065	$ 6,850	$ (215)	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	329	353	24	
6	Employee Loans	443	570	127	
7	Inventories - Materials and Supplies	612	649	37	
8	Employee Withholdings	(2,191)	(2,322)	(131)	
9	Total	$ 6,258	$ 6,100	$ (158)	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 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	$ 205,868	56.0	$ 11,528,608		
4	Commercial Tariff Revenue	110,473	45.1	4,982,332		
5	Wholesale Tariff Revenue	54,109	37.5	2,029,088		
6	Industrial Tariff Revenue	49,767	38.0	1,891,146		
7	Lighting Tariff Revenue	2,295	34.6	79,407		
8	Irrigation Tariff Revenue	3,696	47.0	173,712		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,108	90.0	$ 549,720		
12	Contract Revenue	2,367	62.2	147,227		
13	Transmission Access Revenue	1,834	65.2	119,577		
14	Late Payment Charges	994	54.0	53,658		
15	Connection Charges	553	30.5	16,867		
16	Other Utility Income	385	63.4	24,409		
17	Total	$ 438,449		$ 21,595,751		49.3
18						
19	**EXPENSES**					
20	Power Purchases	$ 163,575	(51.5)	$ (8,424,126)		
21	Wheeling	6,987	(46.9)	(327,699)		
22	Water Fees	11,543	(1.4)	(16,160)		
23	Operating and Maintenance	61,871	(28.6)	(1,769,501)		
24	Property Taxes	18,260	(4.9)	(89,474)		
25	GST	593	(45.4)	(26,900)		
26	Income Tax	6,005	(15.2)	(91,276)		
27	Total	$ 268,833		$ (10,745,136)		(40.0)
28						
29	Net Lag (Lead) Days					9.3
30	Total Expenses				$	268,833
31						
32	Cash Working Capital				$	6,850

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 16

Line No.	Particulars	2022 Approved	2023 Forecast at 2022 Approved Rates	Revised Revenue	2023 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,306	3,476	-	3,476	170	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 397,294	$ 409,840	$ -	$ 409,840	$ 12,546	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	16,368	16,368	16,368	
7	Total	397,294	409,840	16,368	426,208	28,914	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 161,830	$ 182,105	$ -	$ 182,105	$ 20,275	Schedule 19, Line 30, Column 3
11	O&M Expense (net)	57,855	61,871	-	61,871	4,016	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	63,609	61,316	-	61,316	(2,293)	Schedule 21, Line 11, Column 3
13	Property Taxes	17,889	18,260	-	18,260	371	Schedule 22, Line 6, Column 3
14	Other Revenue	(11,832)	(12,241)	-	(12,241)	(409)	Schedule 23, Line 9, Column 3
15	Utility Income Before Income Taxes	107,943	98,529	16,368	114,897	6,954	
16							
17	Income Taxes	7,499	1,589	4,416	6,005	(1,494)	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 100,444	$ 96,940	$ 11,952	$ 108,892	$ 8,448	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,582,907	$ 1,675,028		$ 1,675,431	$ 92,524	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.35%	5.79%		6.50%	0.15%	Schedule 26, Line 5, Column 6

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VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,283	1,301	18	
3	Commercial	946	973	27	
4	Wholesale	560	578	18	
5	Industrial	470	575	105	
6	Lighting	10	9	(1)	
7	Irrigation	37	39	2	
8	Total	3,306	3,476	170	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 195,058	$ 197,962	$ 2,904	
12	Commercial	104,380	106,230	1,850	
13	Wholesale	51,255	52,031	776	
14	Industrial	40,804	47,856	7,052	
15	Lighting	2,411	2,207	(204)	
16	Irrigation	3,386	3,554	168	
17	Total	$ 397,294	$ 409,840	$ 12,546	

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Schedule 18

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Revenue	2023 Forecast Revenue at 2022 Approved Rates	2023 Forecast Effective Increase	2023 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 195,058	$ 197,962	$ 7,906	$ 205,868	130,787	1,301	
2	Commercial	104,380	106,230	4,243	110,473	17,267	973	
3	Wholesale	51,255	52,031	2,078	54,109	6	578	
4	Industrial	40,804	47,856	1,911	49,767	42	575	
5	Lighting	2,411	2,207	88	2,295	1,358	9	
6	Irrigation	3,386	3,554	142	3,696	1,103	39	
7	Total	$ 397,294	$ 409,840	$ 16,368	$ 426,208	150,563	3,476	
8								
9	**Effective Increase**			3.99%				

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COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,591	3,775	184	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 41,841	$ 44,050	$ 2,209	
6	BC Hydro PPA	44,062	71,302	27,240	
7	Waneta Expansion	42,701	41,834	(867)	
8	Market and Contracted Producers	15,102	6,326	(8,776)	
9	Independent Power Producers	73	62	(11)	
10	Self-Generators	-	-	-	
11	CPA Balancing Pool	-	-	-	
12	Total	$ 143,779	$ 163,575	$ 19,796	
13					
14	**WHEELING**				
15	**Wheeling Nomination (MW months)**				
16	Okanagan Point of Interconnection	2,475	2,670	195	
17	Creston	420	420	-	
18					
19	**Wheeling Expense**				
20	Okanagan Point of Interconnect	$ 4,903	$ 5,555	$ 652	
21	Creston	542	570	28	
22	Other	648	863	215	
23	Total	$ 6,093	$ 6,987	$ 894	
24					
25	**WATER FEES**				
26	Plant Entitlement Use in previous year (GWh)	1,679	1,571	(108)	
27					
28	Water Fees	$ 11,958	$ 11,543	$ (415)	
29					
30	Total	$ 161,830	$ 182,105	$ 20,275	

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Schedule 20

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2022 Base Unit Cost O&M	$ 455			
3	2023 Net Inflation Factor	4.017%			Schedule 3, Line 9, Column 6
4	2023 Base Unit Cost O&M	$ 473			Line 2 x (1 + Line 3)
5					
6	2023 Average Customer Forecast - Rate Setting Purpose	147,901			Schedule 3, Line 22, Column 7
7					
8	2023 Inflation Indexed O&M before prior year True-up	$ 69,957			Line 4 x Line 6 / 1,000
9					
10	2021 Average Customer True-up	509			
11					
12	2023 Inflation Indexed O&M	$ 70,466		$ 70,466	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (1,297)		
16	Insurance Premiums		2,457		
17	BCUC Levies		385		
18	MRS		585		
19	EV Charging Stations		193		
20	Sub-total		$ 2,323	2,323	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 72,789	Line 12 + Line 20
23	Capitalized Overhead			(10,918)	-15 % x Line 22
24	**Net O&M Expense**			$ 61,871	Sum of Lines 22 and 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 66,722	$ 69,474	$ 2,752	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 5,913	$ 6,716	$ 803	Schedule 11, Line 26, Column 6
6	Non-Rate Base Deferrals	(4,355)	(9,993)	(5,638)	Schedule 12.2, Line 23, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(4,857)	(5,067)	(210)	Schedule 9, Line 7, Column 5
9		(3,113)	(8,158)	(5,045)	
10					
11	Total	$ 63,609	$ 61,316	$ (2,293)	

FORTISBC INC.

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Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,210	$ 3,253	$ 43	
2	Transmission and Distribution	7,428	7,189	(239)	
3	Substation Equipment	3,948	4,208	260	
4	Land and Buildings	1,165	1,322	157	
5	1% In-Lieu of Municipal Taxes	2,138	2,288	150	
6	Total	$ 17,889	$ 18,260	$ 371	

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OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,018	$ 6,108	$ 90	
2	Contract Revenue	2,277	2,367	90	
3	Transmission Access Revenue	1,771	1,834	63	
4	Interest Income	20	30	10	
5	Late Payment Charges	875	994	119	
6	Connection Charges	505	553	48	
7	Other Recoveries	366	355	(11)	
8	EV Carbon Credits	-	-	-	
9	Total	$ 11,832	$ 12,241	$ 409	

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Section 11

Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 100,444	$ 108,892	$ 8,448	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(42,510)	(47,571)	(5,061)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(37,660)	(45,084)	(7,424)	Line 32
4	Accounting Income After Tax	$ 20,274	$ 16,237	$ (4,037)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 27,773	$ 22,242	$ (5,531)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 7,499	$ 6,005	$ (1,494)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 7,499	$ 6,005	$ (1,494)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 66,722	$ 69,474	$ 2,752	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	1,558	(3,277)	(4,835)	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	84	(528)	(612)	
22	OPEB Expense	1,607	1,119	(488)	
23					
24	Deductions:				
25	Capital Cost Allowance	(86,398)	(89,854)	(3,456)	Schedule 25, Line 19, Column 6
26	CIAC Amortization	(4,857)	(5,067)	(210)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,419)	(4,203)	216	
28	OPEB Contributions	(655)	(705)	(50)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,177)	(10,918)	(741)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (37,660)	$ (45,084)	$ (7,424)	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Class	CCA Rate	12/31/2022 UCC Balance	2023 Additions & Opening Adjt	UCC Adjustment for AIIP *	2023 CCA	Forecast 12/31/2023 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 154,085	$ -	$ -	$ (6,163)	$ 147,922
2	1(b)	6%	33,091	3,043	1,521	(2,259)	33,875
3	2	6%	11,403	-	-	(684)	10,719
4	3	5%	648	-	-	(32)	616
5	6	10%	2	-	-	-	2
6	8	20%	3,694	842	421	(991)	3,545
7	10	30%	4,709	1,857	929	(2,250)	4,316
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,926	-	-	(485)	6,441
10	14.1 (post 2016)	5%	3,951	1,280	640	(294)	4,937
11	17	8%	156,652	22,036	11,018	(15,177)	163,511
12	42	12%	9,649	610	305	(1,268)	8,991
13	43.1	30%	566	(155)	-	(123)	288
14	45	45%	1	-	-	-	1
15	46	30%	2,708	-	-	(812)	1,896
16	47	8%	494,831	87,737	43,868	(50,115)	532,453
17	50	55%	2,800	9,286	4,643	(9,201)	2,885
18							
19	Total		$ 885,727	$ 126,536	$ 63,345	$ (89,854)	$ 922,409
20							
21	* Note - Accelerated Investment Incentive Property						

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Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Earned Return	Amount	Ratio	2023 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 41,155	$ 914,178	54.56%	4.78%	2.61%	$ 43,709	$ 2,554	Schedule 27, Line 12, Column 6
2	Short Term Debt	1,355	91,081	5.44%	4.24%	0.23%	3,862	2,507	
3	Common Equity	57,934	670,172	40.00%	9.15%	3.66%	61,321	3,387	
4									
5	Total	$ 100,444	$ 1,675,431	100.00%		6.50%	$ 108,892	$ 8,448	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

FORTISBC INC.

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Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2023
($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	1993 Debt Issue - Series G	August 28, 1993	August 28, 2023	$ 16,370	8.800%	$ 1,441	
2	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
3	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
4	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
5	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
6	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
7	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
8	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
9	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
10	2023 Debt Issue - MTN - 23	July 1, 2023	July 1, 2053	37,808	4.900%	1,853	
11							
12	Total			$ 914,178		$ 43,709	
13							
14	Average Embedded Cost				4.78%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP, providing an update on the exogenous factor treatment for the impacts of the COVID-19 pandemic. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

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

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

In the Annual Review for 2020 and 2021 Rates, FBC identified the COVID-19 pandemic as a potential exogenous factor affecting 2020 and future years, and the BCUC approved FBC's request to record COVID-19 pandemic incremental costs and cost reductions from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account.[59] FBC also stated in the Annual Review for 2020 and 2021 Rates application that it would review the amounts in 2021 when actual 2020 amounts and forecasts for future years could be ascertained, and an appropriate recovery method could be determined. In the Annual Review for 2022 Rates application, FBC provided a status update on the COVID-19 pandemic net incremental costs (costs less cost reductions). In the following section, FBC reports on the net incremental cost reductions and proposes to return these cost reductions to customers.

[59] FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

12.2.1 COVID-19 Pandemic

During the COVID-19 pandemic, FBC has taken the necessary steps as a critical infrastructure service provider to ensure the health, safety and well-being of its customers, employees and their communities, and to continue to operate its system safely and reliably. This has resulted in net incremental O&M impacts.

12.2.1.1 FBC Has Reasonably Tracked the Impact of the COVID-19 Pandemic on Net Operating Costs

Consistent with the MRP, FBC's general approach to managing its formula O&M funding is at an overall Company level. O&M funding is prioritized and allocated as required to meet the business environment, conditions and requirements the Company faces. Funding utilized for a specific purpose in one year may be used differently in the following year. As a result, this makes the determination of COVID-19 pandemic net incremental O&M costs from year to year challenging and fluid, particularly for cost reductions, as the Company reprioritizes its funding regularly to meet its needs to provide safe and reliable operations.

Further, the COVID-19 pandemic has a broad impact throughout the organization, making the determination of the incremental costs more challenging. The impact of the COVID-19 pandemic varies in different parts of the business. For example, there may be additional overtime costs in departments that are indirectly influenced by the pandemic (e.g., less internal resources available due to reassignment to assist with other priorities), which are difficult to specifically identify. Also, there may be delays in work scheduled as a result of the pandemic that may increase the total cost of the work required, which are not specifically identified as COVID-19 pandemic related.

Recognizing the above circumstances, FBC has undertaken its best efforts to track and report on the net incremental O&M costs that are directly related to the COVID-19 pandemic. FBC has included below all costs that are specifically identifiable as attributable to activities required to respond to the COVID-19 pandemic as part of the overall net incremental costs (costs less cost reductions). While acknowledging there are uncertainties, the following summary of net incremental cost reductions provides a reasonable representation of the overall COVID-19 pandemic impact on the Company.

12.2.1.2 Summary of Net Incremental Costs

The combined impact in 2020 and 2021 as a result of the COVID-19 pandemic is a decrease by approximately $1.03 million in FBC's net incremental O&M expense (costs less cost reductions).

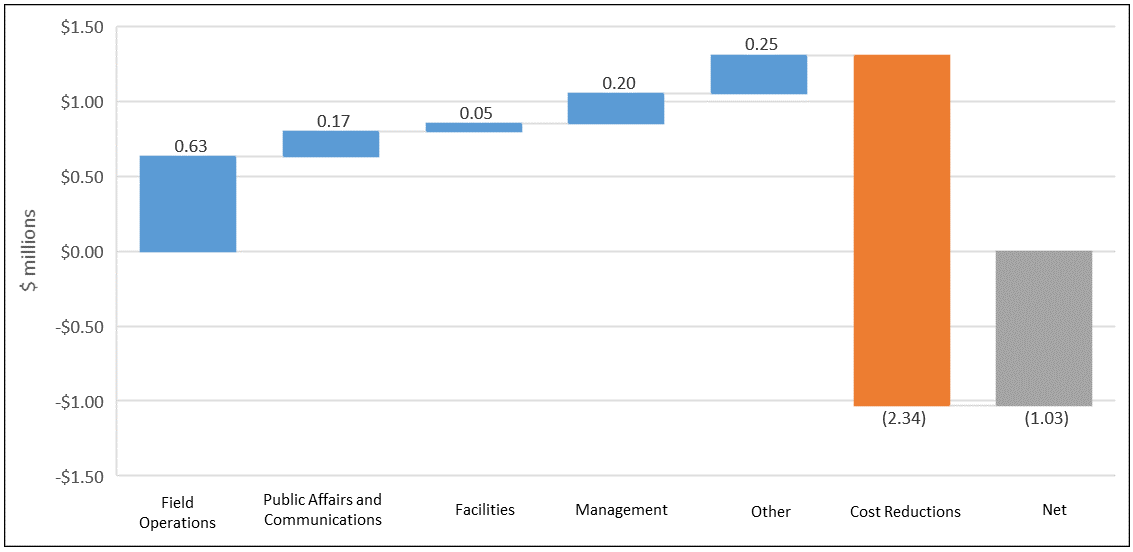
Table 12-1: Net Incremental Cost Reductions ($ millions)

	2020	2021	2020/2021
Direct Costs			
Field Operations	$ 0.46	$ 0.18	$ 0.63
Public Affairs and Communications	$ 0.16	$ 0.01	$ 0.17
Facilities	$ 0.04	$ 0.01	$ 0.05
Management	$ 0.10	$ 0.10	$ 0.20
Other	$ 0.18	$ 0.07	$ 0.25
Total Direct Costs	$ 0.94	$ 0.36	$ 1.31
Cost Reductions	$ (1.05)	$ (1.29)	$ (2.34)
Net difference	$ (0.10)	$ (0.93)	$ (1.03)

12.2.1.3 2020 and 2021 COVID-19 Pandemic Impact

While the COVID-19 pandemic increased many areas of O&M costs in 2020 and 2021, these costs were more than offset by lower employee related expenses. In 2020 and 2021, FBC incurred approximately $1.31 million in O&M costs related to the COVID-19 pandemic. These costs were primarily to ensure the health, safety and well-being of FBC's customers, employees, and their communities, and to continue to operate the system safely and reliably. The incremental costs were offset by approximately $2.34 million in employee expense related reductions. The figure below shows the categories of costs incurred and the offsetting savings. Each of the categories is described further below.

Figure 12-1: FBC COVID-19 Pandemic 2020 and 2021 Net O&M Cost Reductions



12.2.1.3.1 INCREASED O&M EXPENDITURES DUE TO THE COVID-19 PANDEMIC

In the Field Operations area, FBC incurred approximately $0.63 million related to the COVID-19 pandemic, with the majority of the costs related to the sequestering of system control centre employees from having to return to their homes and separation of the operators between the system control centre and Kootenay operating centre sites to ensure a safe and healthy work environment for this critical function. FBC also incurred costs for personal protective equipment (i.e., masks, gloves and sanitizers).

In the Public Affairs and Communications area, FBC incurred approximately $0.17 million for activities to keep customers and key stakeholders informed of the Company's assistance available during the COVID-19 pandemic, including the support required to develop the materials and to monitor and maintain messaging as needed. The costs were for advertising, various communication materials such as bill inserts, and labour and consultant services required to develop the materials and to monitor and maintain messaging as needed.

FBC incurred approximately $0.05 million for Facilities-related resources and activities including safety supplies, additional cleaning, first aid coverage, and signage.

Under the category of Management, approximately $0.20 million in management resource costs were added to support the following areas: the operation of the Emergency Operating Centre (EOC); the Human Resources and Environmental, Health and Safety groups' response to COVID-19 pandemic incidents and issues for employees and contractors; and the increased needs of supporting departments such as Information Systems, Supply Chain, Communications, and Business Continuity. The resources were necessary to respond to the COVID-19 pandemic and to address the various needs of the health authorities, regulators, and organizations like Emergency Management BC.

The Other category of approximately $0.25 million includes miscellaneous items such as different support group costs (e.g., Information Systems and TELUS Babylon health service).

12.2.1.3.2 O&M COST REDUCTIONS OFFSET INCREASED COSTS

The cost reductions that FBC achieved consist primarily of lower employee expenses, in part as a response to the travel restrictions, including in and out of Province travel, and the effect that the COVID-19 pandemic has had on social interactions. Employee expenses that were not incurred include course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses.

For the years 2020 and 2021, the reduced employee expenses were estimated at approximately $2.34 million.

12.2.1.3.3 CUMULATIVE NET IMPACT

The variances for the 2020 and 2021 net incremental O&M (costs less cost reductions) total to a net decrease of approximately $1.03 million.

Accordingly, FBC requests approval to return the exogenous factor savings of $1.03 million to customers in 2023, as further described below.

12.2.1.4 2022 COVID-19 Pandemic Impact

With the Company's transition to normal operations, FBC does not anticipate further impacts on its costs in 2022 requiring exogenous factor treatment. As mentioned in FBC's 2022 Annual Review, FBC started the transition to normal operations in September 2021 with the Province achieving Step 4 of the Province of BC Four Step Restart Plan. Step 4 included the lifting of restrictions with normal social contact allowed and workplaces fully reopened. For FBC, this meant having its employees return to offices and worksites starting September 7, 2021 with 100 percent of employees on site at least 50 percent of the time while maintaining building capacity at 50 percent.

The transition to normal operations continued into early 2022 with the provincial government lifting the workplace safety order on April 8, 2022, enabling businesses to transition back to communicable disease plans to reduce risk of all communicable disease, instead of maintaining a COVID-19 safety plan. At the same time, the provincial government also removed restrictions on gatherings and events, including at restaurants, bars, pubs and nightclubs. With the lifting of the workplace safety order, FBC accordingly adjusted its existing COVID-19 safety protocols at its worksites to balance safety with the return to normal operations. The adjustments included suspension of COVID-19 daily health check confirmation and the removal of mandatory mask wearing, although the practice of wearing a mask is still recommended. As of July 4, 2022, employees have returned to a primarily office-based work model. Employee-related activities and expenses for business purposes (i.e., travel, accommodation, etc.) have also returned to normal.

12.2.1.5 Mechanism to Return Cost Reductions to Customers

As part of the Annual Review for 2020 and 2021 Rates, FBC proposed (and was approved by Order G-42-21) to include the amounts related to incremental COVID-19 costs and cost reductions in the previously approved COVID-19 Customer Recovery Fund Deferral Account.

However, upon further review of FBC's original proposal, FBC has concluded that a better approach is to record these amounts in the Flow-through deferral account. This approach is preferable for three reasons:

1. It is consistent with the treatment of other exogenous items;
2. It will allow the O&M reported in the Annual Reports to be more reflective of the actual amounts incurred, as using the Flow-through deferral account does not result in direct adjustments to O&M, but rather one catch-all account for all flow-through adjustments. Alternatively, transferring the actual O&M savings directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those O&M actual amounts being effectively booked back to the forecast amounts; and

3. The COVID-19 incremental savings will be returned to customers immediately in 2023, as opposed to over three years, which is the amortization period being proposed for the COVID-19 Customer Recovery Fund Deferral Account in Section 7.6.2.1.

From a customer perspective, there is no negative impact from the proposed change in treatment as customers will still have the full net savings returned to them. The benefit of the proposed treatment, as described above, is that the net savings will be returned to customers over one year as opposed to three years.

As such, FBC has included the O&M savings shown above in the 2022 Flow-through projection provided in Table 12-3 below, on Line 15, so that the net amount will be returned to customers in 2023 via the amortization of the Flow-through deferral account forecast in this Application.

Accordingly, FBC seeks a variance to Directive 6 of Order G-42-21. FBC requests that Directive 6 be varied as followed: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account."

12.2.1.6 Conclusion

FBC proposes to refund to customers for years 2020 and 2021, via the Flow-through deferral Account, the cumulative net variance of the net incremental O&M (costs less reductions) of $1.03 million in 2023.

12.3 *ACCOUNTING MATTERS*

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

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, the BCUC 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." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2023; however, FBC provides an update on its exemptive relief to report under US GAAP.

12.3.1.1 Ontario Securities Commission Exemption to use US GAAP

FBC follows US GAAP for both financial and regulatory accounting purposes. Since 2011, FBC has made use of an exemption from the Ontario Securities Commission (OSC) permitting FBC to prepare and file its financial statements in accordance with US GAAP. Like other reporting issuers, FBC also has the option to obtain an exemption permitting the use of US GAAP by

qualifying as a US Securities and Exchange Commission Issuer (SEC Issuer) pursuant to Canadian securities law. During 2022, FBC sought and received approval from its primary securities regulator, the BC Securities Commission (BCSC), for the same exemptive relief as the 2011 OSC exemption. FBC's original exemption from 2011 was filed jointly with FBC's parent company Fortis Inc., whose primary securities regulator is the OSC; however, Fortis Inc. is now an SEC Issuer and no longer makes use of the OSC exemption. As a result, FBC obtained an exemption on a stand-alone basis from the BCSC.

The BCUC has approved FBC's use of US GAAP for regulatory accounting purposes since 2011.[60] As part of the most recent BCUC approval to use US GAAP, the BCUC directed the following:[61]

> Approval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC considers that the intention of the above direction was to ensure that FBC has an exemption from its securities regulator to use US GAAP, and not that an exemption specifically from the OSC was required, as opposed to a different securities regulator that had jurisdiction. It was not contemplated at the time of the above direction that FBC would make use of a BCSC exemption rather than an OSC exemption.

To ensure that FBC has approval from the BCUC to use US GAAP for regulatory accounting purposes, FBC is seeking a variance of Directive 2 to Order G-83-14 to remove the reference to the OSC, so that it removes the reference to the Ontario Securities Commission, and states:

> Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC notes that there have been no other changes in circumstances beyond the change in the regulatory body granting exemptive relief. However, similar to the original 2011 OSC exemptive relief, the 2022 BCSC exemptive relief is not permanent and would expire January 1, 2027 unless extended further. Should FBC plan to no longer report under US GAAP (e.g., convert from US GAAP to IFRS), it would file an application for approval from the BCUC at that time

12.4 *NON-RATE BASE DEFERRAL ACCOUNTS*

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

[60] Order G-117-11 dated July 7, 2011 and Order G-83-14 dated July 3, 2014.
[61] Order G-83-14, Directive 2.

In the following section, FBC provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, 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 forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

Table 12-2: Variances Captured in the Flow-through Deferral Account

	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 Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2022 Projected Flow-through amount of $5.007 million credit is shown in Table 12-3 below. To calculate the amount to be distributed to customers, FBC has also included the following adjustment:

- The $4.618 million credit difference between the projected ending 2021 deferral account credit balance of $3.927 million[62] embedded in 2022 rates, and the actual ending 2021 deferral credit balance of $8.545 million. A more detailed breakout of the 2021 variance is provided in Table 12-4 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 18.

Table 12-3: 2022 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Approved	2022 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (397.294)	$ (414.292)	$ (16.998)
2				
3	**Total Power Purchase Expense**	143.779	153.164	9.385
4				
5	**Total Wheeling**	6.093	6.330	0.237
6				
7	**Total Water Fees**	11.958	11.916	(0.042)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.223	2.291	0.068
12	BCUC Fees	0.373	0.373	-
13	MRS	0.765	0.500	(0.265)
14	EV DCFC	0.187	0.187	-
15	COVID-19 Pandemic	-	(1.030)	(1.030)
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	17.889	17.621	(0.268)
24				
25	**Other Revenues**			
26	EV Carbon Credits	-	(0.625)	(0.625)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.155	41.794	0.639
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
31	Short-term debt rate variance	-	2.253	2.253
32	Short-term debt volume variance from long-term debt issue variance	-	(1.005)	(1.005)
33	Short-term debt timing variance from long-term debt issue timing	-	0.793	0.793
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	1.852	1.852
39				
40	**2022 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(5.007)**
41				
42	2021 Ending Deferral Account Balance True-up			(4.618)
43				
44	**2023 After-Tax Amortization**			**(9.625)**

[62] FBC Annual Review for 2022 Rates, Compliance Filing financial schedules, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2022 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2022 Projected flow-through variances shown in Table 12-3 above:

- The variance in revenue is due to increased industrial, commercial, wholesale and residential loads;
- The variance in power purchase expense is primarily due to an increase in gross load. Increasing gross load drove additional market purchases as well as BC Hydro PPA energy and capacity purchases at a higher than anticipated total cost. Rising rates further contributed to the increase in power purchase expense;
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC issuing long-term debt later in 2022 than forecast, but at a higher amount and higher rate than forecast, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2022 subject to flow-through will be recorded in the deferral account in 2022 and amortized in 2024 rates.

12.4.2.1.2 2021 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FBC is also providing a breakdown of the 2021 true-up amount of $4.618 million credit in Table 12-4 below, along with an explanation of the variances.

Table 12-4: 2021 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2021 Projected	2021 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (389.100)	$ (404.247)	$ (15.147)
2				
3	**Total Power Purchase Expense**	141.747	152.473	10.726
4				
5	**Total Wheeling**	5.836	6.000	0.164
6				
7	**Total Water Fees**	10.878	10.741	(0.137)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	0.775	0.775	-
11	Insurance	2.022	1.924	(0.098)
12	BCUC Fees	0.350	0.350	-
13	MRS	0.100	0.052	(0.048)
14	2021 Wildfires	0.155	0.155	-
15	Capitalized Overhead	(9.795)	(9.795)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	5.110	5.110	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.301)	(0.301)
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	17.225	17.262	0.037
23				
24	**Interest Expense**			
25	Long-term debt interest expense variance	40.698	40.251	(0.447)
26	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.059)	(0.059)
27	Short-term debt rate variance	(0.500)	(0.593)	(0.092)
28	Short-term debt volume variance from long-term debt issue variance	-	0.303	0.303
29	Short-term debt timing variance from long-term debt issue timing	0.910	-	(0.910)
30				
31	**Income Tax Expense**			
32	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.048	0.048
33	Income tax/CCA rate changes	-	-	-
34	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.571	3.097	1.526
35				
36	EV DCFC Service Application 2018-2021 adjustment	0.107	(0.074)	(0.181)
37				
38	**2021 Ending Deferral Account Balance True-up**			**(4.618)**

The 2021 Actual variances shown in Table 12-4 above are described as follows:

- The favourable variance in revenue of $15.147 million was due to higher than projected residential, commercial, wholesale and irrigation loads, mainly due to weather variations. Favourable variances in residential ($12.209 million), commercial ($2.614 million), wholesale ($1.552 million), and irrigation ($0.815 million) revenue were partially offset by unfavourable variances in industrial ($1.939 million) and lighting ($0.104 million) revenue;
- The increase in power purchase expense of $10.726 million was due several factors including increased market expenses, increased load, and reduced generation availability. Increased load and market expenses were primarily due to several extreme weather events, such as the June 2021 heat dome event. This increase was partially offset by increased surplus capacity sales under the CEPSA Agreement;
- The increase in wheeling costs of $0.164 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;
- The decrease in water fees of $0.137 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.146 million lower than projected, with all items comparable to the projected amounts;
- Actual property tax expense was relatively consistent with the projected amount;
- The variance between the actual (0.81 percent) and projected (1.03 percent) short-term debt interest rates results in an amount to be returned to customers of $0.092 million,[63] shown on Line 27 of the table above. The long-term debt interest expense variance of $0.447 million to be returned to customers is due to the projected 2021 long-term debt issuance not actually occurring. The net variance of $0.607 million to be returned to customers on Lines 28 and 29 of Table 12-4 above is due to the impact of a lower actual short-term interest rate than projected, partially offset by the delay in the 2021 long-term debt issuance;
- The unfavourable income tax variance of $1.526 million is calculated as 27 percent of the aforementioned variances;
- The favourable variance of $0.181 million for the EV DCFC Service Application 2018-2021 adjustment relates to the true-up of the 2021 cost of service amounts. As discussed in the Compliance Filing to the 2022 Annual Review Decision, FBC estimated the 2018-2021 EV cost of service amounts to be a $0.107 million debit recoverable from customers, using the 2018-2020 actual cost of service amounts and a 2021 projected amount. The actual 2021 EV cost of service was lower than projected, mainly related to favourable taxes, resulting in the $0.181 million overall credit true-up amount to be returned to customers; and
- The combined favourable variance of $0.312 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 19, 20, 26 and 32, respectively, were derived for 2021 by comparing the actual 2021 cost of service impacts of the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FBC has requested approval to return the incremental net cost reductions related to the COVID-19 pandemic exogenous factor to customers in 2023 through inclusion in the Flow-through deferral account. FBC has also provided an update on certain accounting related matters, and included information on the Flow-through deferral account.

[63] (0.81% - 1.03%) x $42.042 million forecast 2021 short-term debt in Schedule 26 of October 28, 2020 Evidentiary Update financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FBC reports on its 2021 and June 2022 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[64] FBC has provided 2021 and year-to-date 2022 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FBC's actual 2022 SQI performance in the Annual Review for 2024 Rates when actual SQI results are known. FBC also notes that it will provide information on the 2023 year-to-date SQI results in the Annual Review for 2024 Rates.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2021 and June year-to-date performance for 2022 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2021 and June year-to-date results for 2022 are also provided for the four informational SQIs.

[64] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs."

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

Performance Measure	Description	Benchmark	Threshold	2021 Results	June 2022 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	93%	95%
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	0.67	0.80
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	82%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.12	0.14
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	70%	63%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.4
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	65	98
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[65]	4.52	4.27	2.94
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	2.08	1.58
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.23%	0.85%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.90%	99.91%

[65] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2021 and 2022. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

13.2.1.1 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 time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2021 result was 93 percent which met the benchmark. The June 2022 year-to-date performance is 95 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage 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	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	95%
Benchmark	93%								
Threshold	90.6%								

13.2.1.2 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 2021 (three-year rolling average) result was 0.67 which was better than the benchmark of 1.64. The 2021 annual AIFR was 0.89 which reflected 3 Medical Treatments and 1 Lost Time Injury.

The June 2022 year-to-date performance (three-year rolling average) result is 0.80 which is better than the benchmark. The June 2022 year-to-date performance (annual) is 1.25 and reflects 2 Medical Treatments and 1 Lost Time Injury.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve through the implementation and sustainment of robust safety barriers and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	1.25
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	0.80
Benchmark	1.64								
Threshold	2.39								

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact 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 2021 result was 82 percent which was better than the benchmark of 78 percent. The June 2022 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	78%
Benchmark	78%								
Threshold	72%						74%		

13.2.2.2 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 2021 result was 0.12 which was better than the benchmark of 3.0. No significant billing issues occurred in 2021. The June 2022 year-to-date result is 0.14, which is also better than the benchmark.

The 2021 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2021 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),100*(1.05-PA))	=5000*(1-99.99885%)	0.06

Billing sub-measure	Percent Achieved (PA)	Formula		Result
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%	99.60%	(100%-PA)*100	=(100%-99.69%)*100	0.31
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.06+0+0.31) /3	0.12

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14
Benchmark	5.0						3.0		
Threshold	5.0								

13.2.2.3 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 2021 result was 99 percent, which was better than the benchmark of 98 percent. The June 2022 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%		
Threshold	94%						96%		

13.2.2.4 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 2021 result was 70 percent which met the benchmark. The June 2022 year-to-date performance is 63 percent, which is below the threshold.

Several challenging circumstances were faced in the first quarter of 2022 that have contributed to a year-to-date performance in the non-emergency TSF below threshold. These challenges include higher than normal attrition levels being experienced in the contact centre coupled with colder weather that resulted in approximately 27 percent more high bill inquiries in the first quarter than the average of the preceding two years[66]. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 20 percent of its Customer Service Representatives in 2021.[67] All exits were in the last half of 2021, resulting in fewer and less experienced employees prepared to support call volumes in the first quarter of 2022. To mitigate the impact of this, FBC accelerated the timing of planned new hire classes as well as the size of new hire classes in both 2021 and 2022. While

[66] FBC experienced approximately 1,000 high bill inquiries in Q1 2022 which compares to an average of approximately 790 in the first quarter for the two-year period 2020-2021.

[67] On average, FBC has approximately 20 customer service representatives, and 4 left the organization in the latter part of 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

some success has been achieved, FBC has continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes on average approximately 12 months for new employees to be proficient and fully trained in order to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical, carrying into April instead of early March. This particular call type is often longer in duration and may also result in follow-up work and investigation. As noted above, there were fewer and less experienced employees prepared to support these types of calls. Thus, the contact centre experienced the compounding impact of fewer employees along with a higher volume of this call type, resulting in overall longer average wait times and a lower percentage of calls answered within thirty seconds or less.

Although the start of 2022 has been challenging, strong performance in first contact resolution, in addition to the promotion of self-service and the call back feature, continues to mitigate the impacts of lower TSF on customer experience and service quality. Further, the recovery of the non-emergency TSF remains a focus, with FBC expecting to recover to threshold levels on a year-to-date basis within the fourth quarter. Finally, the customer service index has remained high throughout 2021 and 2022 to date, indicating that the mitigation measures and focus on first contact resolution continue to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by 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	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	63%
Benchmark					70%				
Threshold					68%				

13.2.2.5 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is 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.

The annual CSI score for 2021 was 8.4, slightly lower than that obtained in 2020. There were no statistically significant shifts from 2020 to 2021 in the five measures that make up the overall customer satisfaction score. The score for overall satisfaction, which has the highest weighting, decreased from 8.5 in 2020 to 8.4 in 2021. The scores for satisfaction with the energy conservation information and contact centre metrics decreased from 7.6 in 2020 to 7.5 in 2021, and 8.5 in 2020 to 8.4 in 2021, respectively. In addition, the scores for the satisfaction with the accuracy of meter reading and field services metrics remained static at 8.2 and 9.0 in 2021, respectively.

The score for 2022 year-to-date is 8.4, consistent with the annual score recorded for 2021. Of the five measures that make up the overall customer satisfaction score, the results for June 2022 year-to-date were higher in one area, lower in one, and static in three when compared to the annual 2021 scores. The score for the satisfaction with the accuracy of meter reading metric increased from 8.2 to 8.3. The score for the satisfaction with field services metric decreased from 9.0 to 8.8. The scores for the overall satisfaction, energy conservation information, and contact centre metrics were static at 8.4, 7.5 and 8.4, respectively, from results achieved in 2021. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4
Benchmark	n/a								
Threshold	n/a								

13.2.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2021 result was 65 seconds, and the June 2022 year-to-date performance is 98 seconds.

As with previous years, 2021 remained within a reasonable range from a customer experience perspective in that, on average, calls to the contact centre were answered in and around the one-minute mark. With respect to 2022, the year-to-date performance reflects the challenging circumstances in the first quarter of the year described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA back towards normal performance is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.[68]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	226	49	48	49	49	49	71	65	98
Benchmark	n/a								
Threshold	n/a								

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to 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. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, 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.

[68] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

13.2.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

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

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

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

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 4.27 which was better than the threshold of 4.52 but below the benchmark of 3.22. The June 2022 year-to-date performance is 2.94 which is better than the benchmark. The 2021 results were negatively impacted by multiple external factors which did not meet the threshold for normalization.

The July 2021 results were nearly five times the three-year average and were heavily influenced by several factors that did not meet the threshold for normalization. The largest single event that influenced the July results was the collapse of a construction crane on July 12 in downtown Kelowna. The immediate response to this event was to de-energize a large portion of the surrounding area so that first responders could safely attend to the scene. This incident interrupted power to over 2,600 customers and accounted for over 36,000 customer hours interrupted.

British Columbia also experienced an unprecedented run of extreme heat at the end of June and early July which dried forest fuels earlier than usual and led to one of the worst fire seasons on record. FBC transmission and distribution infrastructure were both impacted by the wildfires with dozens of structures burned to the ground. The largest single outage due to these fires was in the Oliver area and contributed over 21,000 customer hours to July.

In addition to the damaged infrastructure, FBC Operations proactively de-energized portions of the system at the request of BC Wildfire Services to assist in fire suppression efforts. System operations were also impacted by proactively disabling automatic line reclosing in parts of the system to reduce the risk of igniting a fire from trees contacting FBC lines. This led to larger and longer outages in areas of the system where automatic line reclosing was disabled to allow field crews time to assess the cause and confirm that it was safe to re-energize the system. FBC estimates that the combination of fire damage, proactive de-energization, and disabling of automatic line reclosing contributed to over 52,000 customer hours of interruption in July.

There were three Major Event Days that met the threshold for normalization in 2021:

- On January 13, a major windstorm across the Okanagan and Kootenays caused approximately 11,000 customer-interruptions and totalled over 155,000 customer-hours of interruption.
- On April 18, a major windstorm across the West Kootenays qualified for a Major Event Day causing approximately 19,800 customer-interruptions and totalled over 200,800 customer-hours of interruption.
- On November 15, a major storm affected multiple areas in the Okanagan causing approximately 27,474 customer-interruptions and totalled over 218,720 customer-hours of interruption. This event is the highest total customer-hours of interruption FBC has on record (back to 2003).

There have been no Major Event Days in 2022 to-date.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[69]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.94
Benchmark	2.22						3.22		
Threshold	2.62						4.52		

13.2.3.2 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.

[69] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 2.08 and the June 2022 year-to-date performance is 1.58, with both better than the threshold of 2.19. The 2021 results for SAIFI were similarly impacted by the crane collapse, wildfires and storms that were discussed in the SAIDI section. FBC also completed system upgrades on several radial transmission lines where no alternate supply was available which impacted a large number of customers. These outages were scheduled in advance during "off peak" hours to minimize the impact to homes and businesses.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[70]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.58
Benchmark	1.64						1.57		
Threshold	2.50						2.19		

13.2.3.3 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 the CEA as follows:

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

The 2021 result for GFOR was 0.23 percent. The June 2022 year-to-date performance is 0.85 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

[70] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.23%	0.85%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.60	TBD	

13.2.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are twelve points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The 2021 result of 99.90 percent and June 2022 year-to-date result of 99.91 percent are generally consistent with prior years' results. The City of Nelson interconnection at Coffee Creek was negatively impacted by two of the three Major Events on the FBC system described previously in the SAIDI section. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.91%
Benchmark	n/a								
Threshold	n/a								

13.3 *SUMMARY*

In summary, FBC's 2021 and June 2022 year-to-date SQI results indicate that the Company's overall performance meets service quality requirements. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Products and product groups[3, 4]	All-items
Reference period	
	2002=100
July 2020	132.6
August 2020	132.4
September 2020	132.5
October 2020	132.9
November 2020	133.3
December 2020	132.8
January 2021	133.6
February 2021	134.1
March 2021	134.9
April 2021	135.2
May 2021	135.1
June 2021	135.8
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5

Table A1-2: Average Weekly Earnings (AWE)

North American Industry Classification System (NAICS)[5]		Industrial aggregate excluding unclassified businesses[6, 7]
Geography	Reference period	
		Dollars
British Columbia (map)	July 2020	1,093.72[B]
	August 2020	1,089.35[B]
	September 2020	1,093.75[B]
	October 2020	1,095.32[B]
	November 2020	1,102.95[B]
	December 2020	1,110.36[B]
	January 2021	1,113.22[B]
	February 2021	1,114.21[B]
	March 2021	1,107.66[B]
	April 2021	1,112.04[B]
	May 2021	1,118.59[B]
	June 2021	1,115.40[B]
	July 2021	1,140.52[B]
	August 2021	1,142.40[B]
	September 2021	1,139.64[B]
	October 2021	1,136.85[B]
	November 2021	1,132.25[B]
	December 2021	1,134.84[B]
	January 2022	1,157.19[B]
	February 2022	1,153.88[B]
	March 2022	1,161.22[B]
	April 2022	1,176.54[B]

Table A1-3: British Columbia Two-Year Outlook 2022

Key Economic Indicators: British Columbia, 2021-23
(forecast completed February 18, 2022)

	2021Q1	2021Q2	2021Q3	2021Q4	2022Q1	2022Q2	2022Q3	2022Q4	2023Q1	2023Q2	2023Q3	2023Q4	2021	2022	2023
GDP at market prices ($ millions)	328,577	329,385	334,551	339,673	343,417	348,045	350,673	353,935	356,447	359,588	361,919	364,178	333,047	349,017	360,533
	1.5	*0.2*	*1.6*	*1.5*	*1.1*	*1.3*	*0.8*	*0.9*	*0.7*	*0.9*	*0.6*	*0.6*	*7.7*	*4.8*	*3.3*
GDP at market prices (2012 $ millions)	278,978	277,225	279,564	281,275	283,897	288,030	290,551	293,351	295,260	297,122	298,139	299,057	279,261	288,957	297,395
	0.7	*-0.6*	*0.8*	*0.6*	*0.9*	*1.5*	*0.9*	*1.0*	*0.7*	*0.6*	*0.3*	*0.3*	*4.7*	*3.5*	*2.9*
GDP at basic prices (2012 $ millions)	258,225	257,607	258,824	259,977	262,651	266,678	269,275	272,107	273,828	275,566	276,523	277,352	258,659	267,678	275,817
	0.5	*-0.2*	*0.5*	*0.4*	*1.0*	*1.5*	*1.0*	*1.1*	*0.6*	*0.6*	*0.3*	*0.3*	*4.8*	*3.5*	*3.0*
Consumer price index (2002 = 1.000)	1.342	1.354	1.370	1.380	1.401	1.412	1.424	1.433	1.441	1.449	1.456	1.463	1.361	1.418	1.452
	0.9	*0.9*	*1.2*	*0.7*	*1.6*	*0.7*	*0.9*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*2.8*	*4.1*	*2.5*
Implicit price deflator—GDP at market prices	1.178	1.188	1.197	1.208	1.210	1.208	1.207	1.207	1.207	1.210	1.214	1.218	1.193	1.208	1.212
(2012 = 1.000)	*0.8*	*0.9*	*0.7*	*0.9*	*0.2*	*-0.1*	*-0.1*	*0.0*	*0.1*	*0.2*	*0.3*	*0.3*	*2.9*	*1.3*	*0.4*
Wages and salary per employee ($ 000s)	54.6	55.5	56.8	57.2	57.3	57.2	57.3	57.6	57.9	58.1	58.5	58.8	56.0	57.3	58.3
	1.2	*1.7*	*2.2*	*0.8*	*0.1*	*-0.1*	*0.2*	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*4.1*	*2.3*	*1.7*
Primary household income ($ millions)	232,341	235,256	242,425	248,720	249,890	251,061	252,734	254,925	256,921	259,217	261,239	263,382	239,685	252,153	260,190
	1.9	*1.3*	*3.0*	*2.6*	*0.5*	*0.5*	*0.7*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*	*9.1*	*5.2*	*3.2*
Household disposable income ($ millions)	210,080	211,206	215,909	216,925	215,827	216,553	218,063	219,981	220,758	222,983	224,889	226,886	213,530	217,606	223,879
	1.2	*0.5*	*2.2*	*0.5*	*-0.5*	*0.3*	*0.7*	*0.9*	*0.4*	*1.0*	*0.9*	*0.9*	*2.4*	*1.9*	*2.9*
Household net savings rate (per cent)	7.3	7.8	4.5	4.2	3.3	2.9	3.1	3.3	2.8	2.8	2.6	2.5	6.0	3.1	2.7
Population (000s)	5,164	5,186	5,215	5,250	5,259	5,268	5,276	5,284	5,296	5,307	5,320	5,332	5,204	5,272	5,314
	0.1	*0.4*	*0.6*	*0.7*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*	*1.3*	*0.8*
Employment (000s)	2,629	2,631	2,669	2,696	2,694	2,685	2,690	2,698	2,704	2,714	2,718	2,723	2,656	2,692	2,715
	1.6	*0.1*	*1.4*	*1.0*	*-0.1*	*-0.3*	*0.2*	*0.3*	*0.2*	*0.4*	*0.2*	*0.2*	*6.6*	*1.3*	*0.9*
Labour force (000s)	2,836	2,825	2,846	2,852	2,850	2,858	2,866	2,872	2,877	2,882	2,887	2,892	2,840	2,862	2,884
	1.4	*-0.4*	*0.8*	*0.2*	*-0.1*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*3.7*	*0.8*	*0.8*
Labour force participation rate (per cent)	65.6	65.2	65.3	65.0	64.8	64.8	64.9	64.8	64.8	64.7	64.7	64.7	65.3	64.8	64.7
Unemployment rate (per cent)	7.3	6.9	6.2	5.5	5.5	6.1	6.1	6.0	6.0	5.8	5.8	5.8	6.5	5.9	5.9
Retail sales ($ millions)	98,731	99,233	98,267	96,315	95,494	95,987	96,084	97,049	97,750	98,331	99,140	99,888	98,136	96,153	98,777
	3.7	*0.5*	*-1.0*	*-2.0*	*-0.9*	*0.5*	*0.1*	*1.0*	*0.7*	*0.6*	*0.8*	*0.8*	*12.1*	*-2.0*	*2.7*
Housing starts (units, 000s)	52,902	49,795	45,224	42,507	40,000	39,536	36,171	35,850	35,530	35,209	34,889	34,568	47,607	37,889	35,049
	30.7	*-5.9*	*-9.2*	*-6.0*	*-5.9*	*-1.2*	*-8.5*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*26.2*	*-20.4*	*-7.5*
Net interprovincial migration (000s)	16.7	17.4	17.7	31.4	15.2	10.4	7.1	5.2	7.9	7.5	7.1	6.8	20.8	9.5	7.3
Net international migration (000s)	52.6	52.2	19.8	18.8	20.9	22.2	24.4	27.3	35.2	38.2	40.3	41.6	35.8	23.7	38.8

Shaded area represents forecast data, *italics indicate percentage change*.
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.

Note: Table above is from the Conference Board of Canada, British Columbia Two-Year Outlook, March 30, 2022.



Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 show 10 years of historical data and the before-savings and after-savings forecast for 2022S and 2023F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2023F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2016 to 2021 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2016. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2019 to 2021. Finally, Table 6.6 shows the system load factor from the years 2016 to 2021 and the forecast load factor for 2022S and 2023F.

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 includes Normalized loads to December 2021.
- after-savings – the load after DSM and includes Normalized loads to December 2021.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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	363,947	304,540	303,886	253,159	241,999	242,933	284,643	269,971	229,496	256,060	300,844	381,603	3,433,082
2015	365,681	319,636	299,774	250,449	249,965	245,501	286,189	276,449	233,713	256,762	300,047	361,987	3,446,152
2016	363,248	311,848	292,351	268,698	248,319	242,786	289,259	280,588	234,770	266,284	332,085	350,062	3,480,297
2017	361,265	295,737	307,586	263,795	249,642	251,284	299,544	288,941	246,701	265,695	326,103	355,527	3,511,820
2018	375,664	309,496	306,028	264,140	273,621	256,591	308,227	297,251	231,377	262,531	302,555	376,342	3,563,824
2019	372,224	288,274	315,330	261,324	268,354	257,653	298,081	293,227	260,757	291,917	313,593	371,724	3,592,459
2020	382,181	332,609	303,499	246,152	239,601	248,354	309,611	303,017	260,523	282,780	333,207	374,349	3,615,884
2021	378,637	338,019	319,817	276,739	257,155	259,320	306,943	294,834	257,175	285,567	334,065	368,654	3,676,926
Before-Savings													
2022S	393,190	335,138	331,640	280,553	267,153	271,396	321,383	310,626	274,609	295,951	337,171	383,507	3,802,317
2023F	396,339	337,950	334,411	282,950	269,568	273,870	324,232	313,473	277,139	298,596	340,037	386,627	3,835,192
After-Savings													
2022S	390,444	332,413	328,981	277,979	264,668	268,968	318,980	308,194	272,123	293,371	334,512	380,802	3,771,436
2023F	390,866	332,540	329,150	277,874	264,687	269,119	319,544	308,746	272,326	293,617	334,927	381,448	3,774,844

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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	330,080	277,952	279,588	235,366	226,108	226,460	263,122	250,470	214,691	238,394	276,319	344,675	3,163,224
2015	331,359	290,442	275,968	232,925	232,996	228,619	264,346	255,968	218,317	238,919	275,526	328,297	3,173,683
2016	329,697	284,239	269,871	248,933	231,743	226,433	267,219	259,761	219,415	247,393	302,834	318,710	3,206,245
2017	327,600	270,353	282,545	244,429	232,661	233,596	275,700	266,639	229,612	246,617	297,428	322,834	3,230,015
2018	340,082	282,343	281,627	245,049	253,803	238,507	283,500	274,131	216,479	244,187	277,988	340,643	3,278,339
2019	337,457	264,607	289,706	242,736	249,368	239,550	274,993	270,833	242,244	269,708	287,514	337,042	3,305,758
2020	346,177	302,227	279,953	229,763	224,464	231,690	285,178	279,540	242,297	262,136	304,435	339,684	3,327,545
2021	345,746	308,157	294,337	255,440	238,210	239,708	282,793	272,125	237,826	263,832	306,218	337,045	3,381,436
Before-Savings													
2022S	356,872	305,644	305,096	260,549	249,414	252,595	296,341	287,118	255,390	274,469	309,030	348,812	3,501,329
2023F	359,759	308,223	307,659	262,783	251,668	254,896	298,970	289,745	257,738	276,922	311,668	351,673	3,531,705
After-Savings													
2022S	354,335	303,127	302,639	258,171	247,118	250,352	294,120	284,871	253,093	272,084	306,573	346,312	3,472,795
2023F	354,702	303,224	302,798	258,093	247,157	250,505	294,638	285,378	253,291	272,322	306,947	346,888	3,475,944

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
Before-Savings													
2022S	149,350	118,436	116,520	92,400	89,399	86,970	106,340	99,003	84,580	98,837	120,281	146,323	1,308,438
2023F	149,488	118,545	116,628	92,485	89,481	87,050	106,438	99,094	84,658	98,928	120,392	146,458	1,309,643
After-Savings													
2022S	148,891	117,988	116,106	92,031	89,075	86,679	106,062	98,712	84,257	98,468	119,867	145,876	1,304,011
2023F	148,568	117,647	115,796	91,743	88,830	86,464	105,876	98,507	84,003	98,180	119,551	145,549	1,300,714

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Normliazed Actuals													
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	80,917	72,012	69,241	70,566	73,379	72,714	75,404	74,677	66,669	60,028	65,444	82,026	863,078
2015	81,041	74,201	68,933	64,674	71,533	72,581	71,204	71,712	68,657	62,650	66,828	79,463	853,478
2016	82,612	75,915	71,711	71,671	69,996	66,744	76,904	77,981	68,748	70,333	81,859	90,367	904,841
2017	85,017	74,211	77,360	69,012	70,513	72,529	81,817	81,344	72,335	73,835	78,070	78,916	914,960
2018	87,447	74,470	78,245	70,839	73,624	72,175	81,335	82,374	71,079	73,218	76,070	85,202	926,078
2019	86,215	75,958	80,152	69,784	72,863	72,688	80,601	81,248	73,015	75,305	77,661	86,230	931,722
2020	88,558	80,807	76,026	63,736	65,028	67,948	79,777	81,941	74,160	76,659	80,994	86,252	921,886
2021	88,860	79,418	80,125	72,153	73,680	74,618	79,949	69,139	96,038	76,264	81,554	87,844	959,641
Before-Savings													
2022S	91,281	81,781	81,825	71,225	73,270	74,552	85,487	85,537	76,428	79,040	83,178	90,148	973,752
2023F	93,329	83,616	83,662	72,825	74,916	76,228	87,409	87,461	78,147	80,815	85,045	92,172	995,624
After-Savings													
2022S	90,298	80,801	80,856	70,272	72,331	73,624	84,563	84,609	75,489	78,086	82,209	89,168	962,307
2023F	91,368	81,668	81,740	70,935	73,057	74,392	85,584	85,632	76,304	78,952	83,163	90,278	973,073

Note: The commercial class is normalized from 2014 to 2020 since weather correlation appeared in the data at that time, all numbers before 2014 are actuals.

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
Before-Savings													
2022S	64,807	54,940	51,149	42,542	37,128	36,250	46,538	46,193	38,848	45,583	55,516	63,082	582,577
2023F	65,192	55,265	51,454	42,796	37,362	36,483	46,834	46,485	39,088	45,858	55,846	63,460	586,125
After-Savings													
2022S	64,456	54,593	50,813	42,220	36,821	35,954	46,246	45,897	38,540	45,261	55,180	62,735	578,717
2023F	64,492	54,573	50,785	42,156	36,752	35,895	46,253	45,897	38,481	45,223	55,184	62,779	578,470

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
Before-Savings													
2022S	49,922	49,087	54,123	51,558	43,838	48,000	48,703	47,580	50,264	47,957	48,513	47,775	587,321
2023F	50,238	49,396	54,438	51,852	44,129	48,312	49,017	47,901	50,575	48,269	48,844	48,099	591,072
After-Savings													
2022S	49,195	48,360	53,402	50,840	43,130	47,296	48,007	46,881	49,566	47,241	47,795	47,067	578,779
2023F	48,797	47,968	53,031	50,464	42,773	46,975	47,708	46,597	49,287	46,956	47,539	46,827	574,920

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
Before-Savings													
2022S	820	759	817	809	839	797	813	829	798	830	782	789	9,682
2023F	820	759	817	809	839	797	813	829	798	830	782	789	9,682
After-Savings													
2022S	804	743	802	795	826	784	801	816	785	816	766	773	9,511
2023F	788	728	788	783	816	775	792	808	777	807	758	765	9,385

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
Before-Savings													
2022S	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
2023F	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
After-Savings													
2022S	691	641	660	2,013	4,935	6,015	8,442	7,956	4,456	2,213	756	693	39,471
2023F	690	640	659	2,011	4,930	6,004	8,425	7,936	4,440	2,204	752	691	39,382

2.9 SYSTEM PEAK (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
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	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
Before-Savings														
2022S	725	687	608	516	488	588	658	661	502	537	645	722	783	679
2023F	732	693	614	521	493	593	664	667	506	542	650	728	788	685
After-Savings														
2022S	725	686	608	515	488	587	657	660	501	536	644	721	782	678
2023F	730	692	612	519	491	592	662	665	505	540	649	727	786	684

Note: The peaks shown in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
Industrial	39	47	49	50	50	50	52	51	43	42	42	42
Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
Total Direct	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.2 CUSTOMER ADDITIONS

Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	912	12,634	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,658	2,679
Commercial	106	1,851	701	613	97	325	280	278	209	429	401	501
Wholesale	-	(1)	-	-	-	-	-	-	-	-	-	-
Industrial	1	8	2	1	-	-	2	(1)	(8)	(1)	-	-
Lighting	(27)	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(28)	(30)
Irrigation	17	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-
Total Direct	1,009	14,403	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	3,031	3,150

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

MWh/Customer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.58	10.19	9.95

5. LOAD

5.1 NORMALIZED AFTER-SAVINGS LOAD

Energy (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	681	788	863	853	905	915	926	932	922	960	962	973
Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
Industrial	291	352	381	380	373	363	403	495	441	472	579	575
Lighting	13	13	16	16	16	16	13	11	11	10	10	9
Irrigation	38	40	40	46	42	42	39	36	37	44	39	39
Net	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
Gross	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak (MW)												
Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021S	2022F
BCH Lardeau	6	6	6	6	6	8	8	7	6	6	7	7
BCH Kingsgate	5	5	5	5	5	5	5	5	5	4	5	5
City of Grand Forks	41	41	39	41	41	39	46	37	38	36	36	36
City of Nelson	80	83	81	83	80	86	88	84	82	86	79	78
City of Penticton	341	348	342	348	345	338	340	338	340	337	351	351
District of Summerland	95	98	94	97	98	98	99	95	99	97	101	101
City of Kelowna	332	94	-	-	-	-	-	-	-	-	-	-
Total	899	675	567	580	574	574	585	566	569	566	579	578

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2017	2018	2019	2020	2021	2022S	2023F
Demand Side Management	(28)	(31)	(26)	(26)	(30)	(28)	(56)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2016	2017	2018	2019	2020	2021
Actual						
Residential	115,772	117,748	120,291	122,465	124,966	126,678
Commercial	15,073	15,398	15,678	15,956	16,165	16,594
Wholesale	6	6	6	6	6	6
Industrial	50	50	52	51	43	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103
Total	133,550	135,793	138,587	141,027	143,714	145,830
Forecast						
Residential	115,758	116,031	117,774	120,405	124,076	124,603
Commercial	15,042	15,813	16,122	16,405	16,220	16,579
Wholesale	6	6	6	6	6	6
Industrial	49	50	50	51	57	59
Lighting	1,620	1,590	1,559	1,511	1,425	1,393
Irrigation	1,103	1,095	1,090	1,080	1,082	1,082
Total	133,578	134,585	136,602	139,459	142,865	143,721
Variance (customers)						
Residential	14	1,717	2,517	2,060	890	2,075
Commercial	31	(415)	(444)	(449)	(55)	15
Wholesale	0	0	0	0	0	0
Industrial	1	0	2	0	(14)	(17)
Lighting	(61)	(79)	(77)	(44)	18	14
Irrigation	(13)	(15)	(12)	2	9	21
Total	(28)	1,208	1,986	1,569	849	2,109
Variance (%)						
Residential	0.0%	1.5%	2.1%	1.7%	0.7%	1.6%
Commercial	0.2%	-2.7%	-2.8%	-2.8%	-0.3%	0.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	2.0%	0.0%	3.8%	0.0%	-32.6%	-40.5%
Lighting	-3.9%	-5.2%	-5.2%	-3.0%	1.3%	1.0%
Irrigation	-1.2%	-1.4%	-1.1%	0.2%	0.8%	1.9%
Total	0.0%	0.9%	1.4%	1.1%	0.6%	1.4%

6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Energy (GWh)	2016	2017	2018	2019	2020	2021
Normalized						
Residential	1,296	1,320	1,313	1,266	1,347	1,330
Commercial	905	915	926	932	922	960
Wholesale	574	574	585	566	569	566
Industrial	373	363	403	495	441	472
Lighting	16	16	13	11	11	10
Irrigation	42	42	39	36	37	44
Net	3,206	3,230	3,278	3,306	3,328	3,381
Gross	3,480	3,512	3,564	3,592	3,616	3,677
Forecast						
Residential	1,367	1,353	1,280	1,349	1,326	1,255
Commercial	871	879	912	935	902	952
Wholesale	579	587	586	594	567	584
Industrial	393	407	379	385	453	537
Lighting	13	14	15	13	11	10
Irrigation	39	40	41	42	35	36
Net	3,262	3,282	3,213	3,319	3,294	3,374
Gross	3,540	3,559	3,485	3,602	3,602	3,664
Variance (GWh)						
Residential	(71)	(33)	33	(83)	21	75
Commercial	34	36	14	(3)	20	7
Wholesale	(5)	(13)	(1)	(28)	2	(18)
Industrial	(20)	(44)	24	110	(12)	(64)
Lighting	3	1	(2)	(2)	0	(0)
Irrigation	3	2	(2)	(6)	2	8
Net	(56)	(52)	65	(13)	34	8
Gross	(59)	(47)	79	(10)	14	13
Variance (%)						
Residential	-5.5%	-2.5%	2.5%	-6.6%	1.6%	5.6%
Commercial	3.8%	3.9%	1.5%	-0.4%	2.2%	0.8%
Wholesale	-0.8%	-2.3%	-0.2%	-5.0%	0.4%	-3.1%
Industrial	-5.3%	-12.3%	5.9%	22.2%	-2.7%	-13.6%
Lighting	16.3%	9.4%	-13.4%	-17.8%	2.1%	-2.8%
Irrigation	7.7%	3.9%	-5.2%	-16.7%	5.3%	17.9%
Net	-1.7%	-1.6%	2.0%	-0.4%	1.0%	0.2%
Gross	-1.7%	-1.3%	2.2%	-0.3%	0.4%	0.4%

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	905	915	926	932	922	960	962	973
Wholesale	574	574	585	566	569	566	579	578
Industrial	373	363	403	495	441	472	579	575
Lighting	16	16	13	11	11	10	10	9
Irrigation	42	42	39	36	37	44	39	39
Net	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	274	282	285	287	288	295	299	299
Gross	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak								
Winter Peak (MW)	755	714	682	732	731	685	782	786
Summer Peak (MW)	593	605	631	639	666	653	678	684

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	0%	2%	-1%	-4%	6%	-1%	-2%	0%
Commercial	6%	1%	1%	1%	-1%	4%	0%	1%
Wholesale	-1%	0%	2%	-3%	1%	-1%	2%	0%
Industrial	-2%	-3%	11%	23%	-11%	7%	23%	-1%
Lighting	0%	0%	-17%	-17%	-2%	-11%	-2%	-1%
Irrigation	-9%	0%	-7%	-8%	4%	17%	-10%	0%
Net	1%	1%	1%	1%	1%	2%	3%	0%
Losses & Company Use	1%	3%	1%	0%	1%	2%	1%	0%
Gross	1%	1%	1%	1%	1%	2%	3%	0%
System Peak								
Winter Peak (MW)	10%	-5%	-4%	7%	0%	-6%	14%	0%
Summer Peak (MW)	-3%	2%	4%	1%	4%	-2%	4%	1%

Customer Count	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	50	52	51	43	42	42	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407	1,103	1,103
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103	1,379	1,349
Total Direct	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1%	2%	2%	2%	2%	1%	2%	2%
Commercial	1%	2%	2%	2%	1%	3%	2%	3%
Wholesale	0%	0%	0%	0%	0%	0%	0%	0%
Industrial	0%	0%	4%	-2%	-16%	-2%	0%	0%
Lighting	-2%	-3%	-2%	-1%	-2%	-2%	-22%	0%
Irrigation	0%	-1%	0%	0%	1%	1%	25%	-2%
Total Direct	1%	2%	2%	2%	2%	1%	2%	2%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2019	2020	2021
After- Savings Normalized Actual UPC	10.43	10.89	10.58
Forecast	11.27	10.75	10.10
Variance	(0.84)	0.13	0.49
Variance (%)	-8.0%	1.2%	4.6%

6.5 WINTER PEAK , ACTUAL TO FORECAST

Winter Peak (MW)	2019	2020	2021
After- Savings Actual Peak	732	725	777
Forecast	764	737	748
Variance	(32)	(12)	29
Variance (%)	-4%	-2%	4%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

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

Year	Energy (MWh)	Peak (MW)	Load Factor
2016	3,480,297	755	0.53
2017	3,511,820	714	0.56
2018	3,563,824	682	0.60
2019	3,592,459	732	0.56
2020	3,615,884	731	0.56
2021	3,676,926	685	0.61
2022S	3,771,436	782	0.55
2023F	3,774,844	786	0.55

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.



Appendix A3

Load Forecast Methods

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1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in Section 3 of the Application is based.

In the figures provided in this appendix, 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 2023 Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- 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 filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- 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, 2023 is the Forecast Year (2023F).

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load 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[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential, wholesale and commercial[3] load classes; therefore these classes are normalized. The irrigation class shows a low R^2 value for the winter, summer and fall seasons; therefore, this class was not normalized.

[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.
[2] Industrial and lighting loads are typically insensitive to the weather.
[3] The commercial class data is normalized from 2014 to 2021 since a strong correlation was present in those years. All commercial data prior to 2014 is actual because it did not show a correlation to weather at that time.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	39,370	66,140	70,359	64,926
Slope HDD	172	109	-	92
Slope CDD	-	-	245	-
Adjusted R^2	0.72	0.76	0.84	0.77

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	61,401	57,123	58,803	60,135
Slope HDD	58	47	-	36
Slope CDD	-	-	90	-
Adjusted R^2	0.91	0.92	0.85	0.91

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	48,156	51,092	49,674	54,643
Slope HDD	24	16	-	(0)
Slope CDD	-	-	78	-
Adjusted R^2	0.58	0.54	0.68	0.53

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,634	5,218	5,079	6,034
Slope HDD	(1)	(11)	-	(10)
Slope CDD	-	-	23	-
Adjusted R^2	0.04	0.76	0.45	0.43

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[4] and Cooling Degree Days (CDD)[5] 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, wholesale and commercial classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring (March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate

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

regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2021:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2012-2021) 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, commerical or wholesale).

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

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

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

And

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

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

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings[6]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2021) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

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

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

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

[6] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2021".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2012 to 2021. FBC reviews the forecast methods on an annual basis. As FBC found that there was a strong correlation, it therefore applied a 10-year trend.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2012
End Year	2021
R^2	0.84
Adjusted R^2	0.82
df	9
Intercept	414
Slope UPC	-0.20

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

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

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

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

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-6: Results of Residential Regression

Regression	Residential
Start Year	2019
End Year	2021
R^2	1.00
Adjusted R^2	0.99
df	2
Intercept	(118,476)
Slope Population	0.88

The residential class represented 39.3 percent of the net load in 2021.

1.2.2 Commercial

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

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2007 to

2021 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 28.4 percent of the net load in 2021.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2007
End Year	2021
R^2	0.99
Adjusted R^2	0.99
df	14
Intercept	123,607
Slope GDP	3
Slope CoK Event	132,847

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers except one. This customer was contacted multiple times but did not respond. Since there was no response, FBC kept their load at 2021 levels. 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 load requirements, etc. The wholesale class represented 16.7 percent of the net load in 2021.

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. 81 percent of FBC's industrial customers responded to the surveys, accounting for 90 percent of 2021 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group. The industrial class represented 14.0 percent of the net load in 2021.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2021 are included in the forecast but do not overly influence it. The irrigation class represented 1.3 percent of the net load in 2021.

1.2.6 Lighting

The before-savings lighting load uses the 2021 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2021. The lighting class represented 0.3 percent of the net load in 2021.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019-2022 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the 10-year average (2012-2021) 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. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

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

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES						
1.	21	6	Upper Bonnington Old Units Refurbishment Project	The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Complete (Final Report filed in this Annual Review)	Appendix B2
G-165-20 AND G-166-20 – FEI AND FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
2.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2.1

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
3.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a
4.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
5.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
6.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
7.	131	49	Forecast Capital Expenditures	The Panel directs FortisBC to file an updated forecast of the 2023 to 2024 capital expenditures in the 2023 Annual Review.	Complete	Section 7.2.1
G-42-21 – FBC ANNUAL REVIEW FOR 2020 AND 2021 RATES						
8.	21		COVID-19 Customer Recovery Fund Deferral Account	The Panel approves the following deferral account requests: f. Recording of the COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund deferral account, as discussed in Section 12.2.1 of the Application.	Status of COVID-19 exogenous factor treatment provided in this Application	Section 12.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
9.	32	7	Wholesale Customer Load Forecast	The Panel directs FBC to provide details of any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts.	Complete	Section 3.4.3
10.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Section 6.3.4

Appendix B2

FortisBC Inc.

Upper Bonnington Old Units Refurbishment Project

Final Report

August 2022

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1. PROJECT STATUS

1.1 *PROJECT BACKGROUND*

On January 20, 2017, the British Columbia Utilities Commission (BCUC) approved capital expenditures related to the Upper Bonnington (UBO) Old Units Refurbishment (UBO Refurbishment Project, or the Project) in Order G-8-17. Directive 6 of Order G-8-17 required FBC to file specific information on the Project's updated scope, progress and costs as part of FBC's future annual review applications. Specifically, the BCUC directed FBC to provide the following information about the progress of the Project:

- The status of both the UBO Refurbishment Project as a whole and of the individual units, including a comparison of the Project timeline provided in the [Annual Review for 2017 Rates] Application to any updated Project timeline as at the time of filing each annual review application.
- Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or Project scope.
- Actual costs incurred to date on the UBO Refurbishment Project as a whole and on each individual unit as at the time of filing each annual review application.
- Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.[1]

The UBO Refurbishment Project involved the refurbishment of generating Units 1-4 (the Old Units), which are over 100 years old, in order to extend their lives for an additional 20 years or more. The Project also reduced the safety and environmental risks associated with failures of the aged equipment.

FBC submits the following final report regarding the UBO Refurbishment Project in compliance with Directive 6 of Order G-8-17, including final Project costs (Final Report).

The Project scope of work was completed and closed out in Q4 2021. The four generating units and associated equipment have been put into commercial operation and are performing well.

The Project successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant.

[1] Order G-8-17, Appendix A, page 21.

With regard to the major environmental and safety accomplishments achieved during Project execution, FBC reports that it followed the Environmental Management Plan (EMP) developed in 2017 and the Project had no reportable environmental incidents. Further, the Project accumulated approximately 160 thousand hours without a lost time incident. The majority of the effort on the Project was internal FBC labour, with approximately 19 thousand hours supplied externally. While the COVID-19 pandemic presented challenges during the second half of the Project, the policies and procedures implemented by FBC minimized the risk of infection and Project interruption.

1.2 *WORK COMPLETED SINCE AUGUST 2021 STATUS REPORT*

The following is a brief summary of the work completed since the August 2021 status report filed as Appendix B2 to FBC's Annual Review for 2022 Rates application.

Balance of Plant

The scope of the balance of plant work evolved as the Project progressed and included the following:

Floor modifications – As equipment was removed, the concrete bases were demolished and floor repairs were completed. The plant floor loadings, drawings, demarcation, procedures and site signage updates were completed.

Ventilation access walkway – With the removal of the old switchgear concrete structure, both wall and floor repairs were required. The switchgear concrete structure provided access to plant ventilation systems; with the removal of this concrete, new access walkways and ladders were designed and installed.

Water wheel excitation decommissioning – The water wheel exciters and associated equipment were removed and the intakes were plugged with concrete. The holes through the generator and turbine floors were capped with steel plates. The exciter rheostats and buss were removed and the rheostat room was repurposed for plant equipment storage.

Units 2 and 3

Minor work was completed on Units 2 and 3 which was intentionally delayed until site conditions were preferable in 2021. The work included painting, hazardous materials removal, and the rotor oil leak repair on Unit 3.

Project Close

The Project was closed in Q4 2021 with all equipment and plant transferred back to generation operations.

2. PROJECT SCHEDULE

The following table is updated to show the final completion dates for each unit as well as the balance of plant work.

Table B2-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering			
Mechanical Components – Machining and Fabrication Specifications	Q4, 2017	Q4, 2017	Complete
All Units Detailed Engineering	Q1, 2018	Q1, 2018	Complete
Balance of Plant Engineering	Q3, 2020	Q4, 2020	Complete
Procurement of All Major Mechanical/Electrical	Q2, 2020	Q2, 2020	Complete
Construction			
Refurbishment of Unit 3	Q4, 2017	Q4, 2017	Complete
Refurbishment of Unit 4	Q4, 2018	Q4, 2018	Complete
Refurbishment of Unit 1[1]	Q4, 2020	Q4, 2019	Complete
Refurbishment of Unit 2[1]	Q4, 2019	Q4, 2020	Complete
U3 Oil Leak Deficiency Repair	Q1, 2021	Q2, 2021	Complete
Balance of Plant Work	Q2, 2021	Q3, 2021	Complete
Closeout	Q3, 2021	Q4, 2021	Complete

Note:

[1] *Units 1 and 2 construction years were changed from the original schedule to gain efficiencies by removing equipment while operating a live plant.*

2.1 *SCHEDULE SUMMARY*

The rotor oil leak repair work on Unit 3 delayed portions of the Balance of Plant scope of work from Q2 2021 to Q3 2021. The work completed on Units 2 and 3 as outlined above in Section 1.2 was completed in parallel with the Balance of Plant work, and the Project was closed in Q4 2021.

While some of the work was re-scheduled around sequencing concerns and operational constraints, the overall Project duration was as originally planned.

3. PROJECT COSTS

The following table outlines the final Project expenditures.

Table B2-2: Cost Summary

Description	Application/ Control Budget	Final Costs	Variance	Variance
	($000s)			(%)
Unit 4	6,634	8,058	1,424	21%
Unit 3	4,079	6,529	2,450	60%
Unit 2	5,641	6,606	965	17%
Unit 1	8,050	8,287	237	3%
Balance of Plant	860	1,657	797	93%
Subtotal - Construction	25,264	31,137	5,873	23%
Cost of Removal	1,880	1,840	-40	-2%
Project Contingency	3,771	-	-3,771	-
Subtotal - Construction & Removal	30,916	32,997	2,062	7%
AFUDC	867	1,174	307	35%
Total Project Cost	31,783	34,151	2,369	7%

3.1 *PROJECT COST SUMMARY*

The UBO Refurbishment Project was approved with a Class 4 capital cost estimate of $31.783 million in as-spent dollars (including $0.867 million of AFUDC and $1.880 million of removal costs). The Project's cost estimate was at an AACE Class 4 estimate class because of the difficulty in defining the full scope without dismantling the units. Final Project costs (including $1.174 million of AFUDC and $1.840 million of removal costs) are $34.151 million, which is 7 percent or approximately $2.4 million over the control budget. This is well within the typical accuracy range of an AACE Class 4 cost estimate as stated in AACE Recommended Practice 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry. As reported in the August 2020 status report, this approximately $2.4 million variance resulted primarily from higher than planned costs to rewind the generators and to refurbish the concealed turbine components.

The cost variances in each Project category are further described below.

Units 1-4 – These variances are explained in the August 2020 status report. In 2021, both Units 2 and 3 painting scope of work that had been delayed was completed. Unit 3 rotor oil leak repair work was completed for a final cost of approximately $0.252 million. These completed scopes are included in the final costs presented in Table B2-2.

Balance of Plant Work – The balance of plant work scope of work was completed with an unfavourable variance of $0.797 million. The Balance of Plant scope of work evolved as the

Project progressed. The installation of new equipment and removal of old equipment within an operating facility presented unanticipated challenges that were not able to be defined during the planning stage. This variance is primarily due to the extra effort required to remove equipment and cabling which was not expected to contain asbestos and the additional civil structural scopes, as well as the floor modifications required to facilitate the new plant equipment.

Cost of Removal – The forecast total for cost of removal is $1.840 million, which represents a favourable variance of $0.040 million.

Contingency – Project contingency has been utilized to offset the variances that were encountered among the different Units.

AFUDC – The total cost for AFUDC is $1.174 million, which represents an unfavourable variance of $0.307 million due to the higher overall Project costs.

3.2 *PROJECT SCOPE CHANGE SUMMARY*

Throughout the Project, FBC made adjustments to address unforeseen challenges and issues which were either not considered or not accessible during the planning stage. These adjustments totalled approximately $2.015 million and were explained in the August 2020 status report.

4. CONCLUSION

The UBO Refurbishment Project is complete and has successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant. The Project maintained schedule and returned the Units to commercial service within the year planned. The final Project costs were well within the typical accuracy range of an AACE Class 4 cost estimate and totalled $34.151 million. This approximately $2.4 million increase was required to complete scope and ensure the units could operate safely for 20 years or more, as originally planned.

Appendix C
PROJECTS AND MARKET REPORT

Market Report: Gas and Electric Transmission and Distribution Cost Impacts 2020-2024

May 2022

The Engagement

FortisBC has engaged Wood Mackenzie Supply Chain Consulting to provide a market report detailing how market factors have impacted and are anticipated to impact North American utility spend between 2020 and 2024. Wood Mackenzie is a global research and consulting firm that provides energy clients with data, analytics, and insights that they rely on for their decision making. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable our clients to leverage data analysis and assist them in navigating an ever-changing marketplace.

Market dynamics over the last two years have created significant inflationary pressures across both materials and services. This market report is specific to two portfolios: electric transmission and distribution (T&D) and gas T&D capital expenditures at Canadian utilities, with labour specific to British Columbia, Canada. In both portfolios, market escalation has been observed since FortisBC's initial Multi-Year Rate Plan (MRP) filing (Quarter 1, 2020 through Quarter 1, 2022). This report also includes a forecast of potential impacts from Quarter 2, 2022 through Quarter 4, 2024.

Qualifications

Wood Mackenzie Supply Chain Intelligence is a suite of cloud-based software solutions that includes a product, Cost Intelligence, which enables our clients to identify market-based risks and opportunities. Cost Intelligence includes thousands of cost models and indices that enable users to understand what a project or item should cost in a dynamic market. Wood Mackenzie Cost Intelligence models were developed to support the energy market. The Wood Mackenzie team starts with industry specifications, technical drawings, supplier 10ks, and other industry information to develop detailed items that tie cost inputs to dynamic market indices. Those indices are then weighted and loaded on the cloud-based platform. The items are combined into categories and sub-categories that reflect clients spend profiles, or specific capital project expenditures.

Methodology

North American Gas and Electric Utility Cost Models

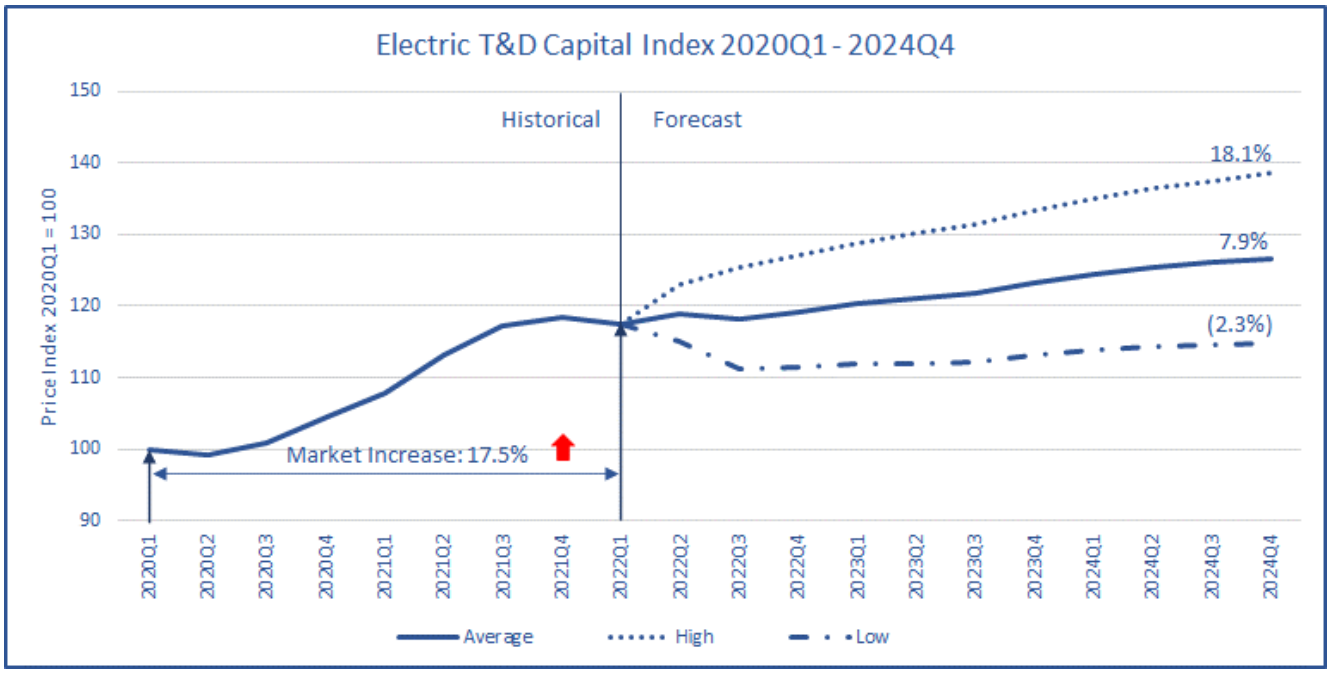
Wood Mackenzie built two customized cost models – Electric Transmission and Distribution and Gas Transmission and Distribution. Each cost model is built from aggregated spend from utilities across North America and over $550M (CAD) in total spend. The models apply indices to spend at an item level and roll up to sub-category, category, and facility level. Each model incorporates over 150 indices tracked monthly by Wood Mackenzie.

Customization for British Columbia Specific Labour Pool

British Columbia (BC) has a unique labour pool and, where appropriate, the models incorporate indices specific to BC, particularly around trade labour and any other labour activities specific to the BC province.

Market Insights

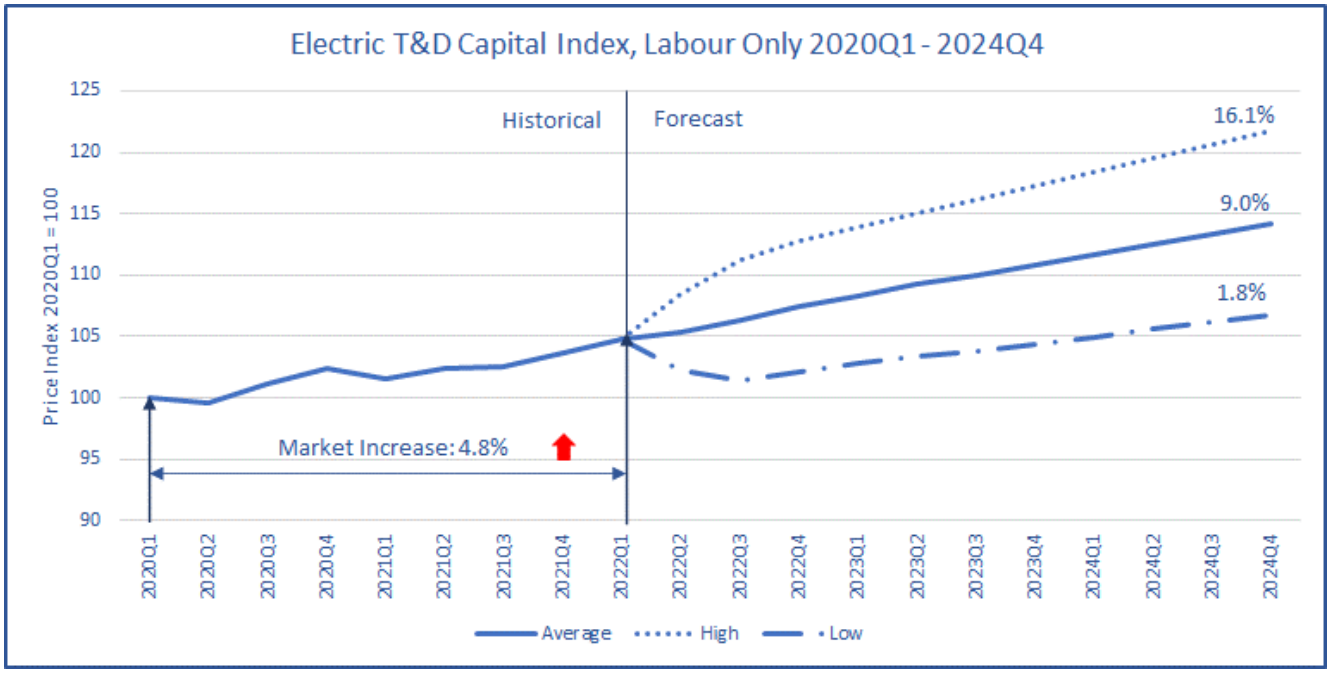
Electric Transmission and Distribution 2020Q1-2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

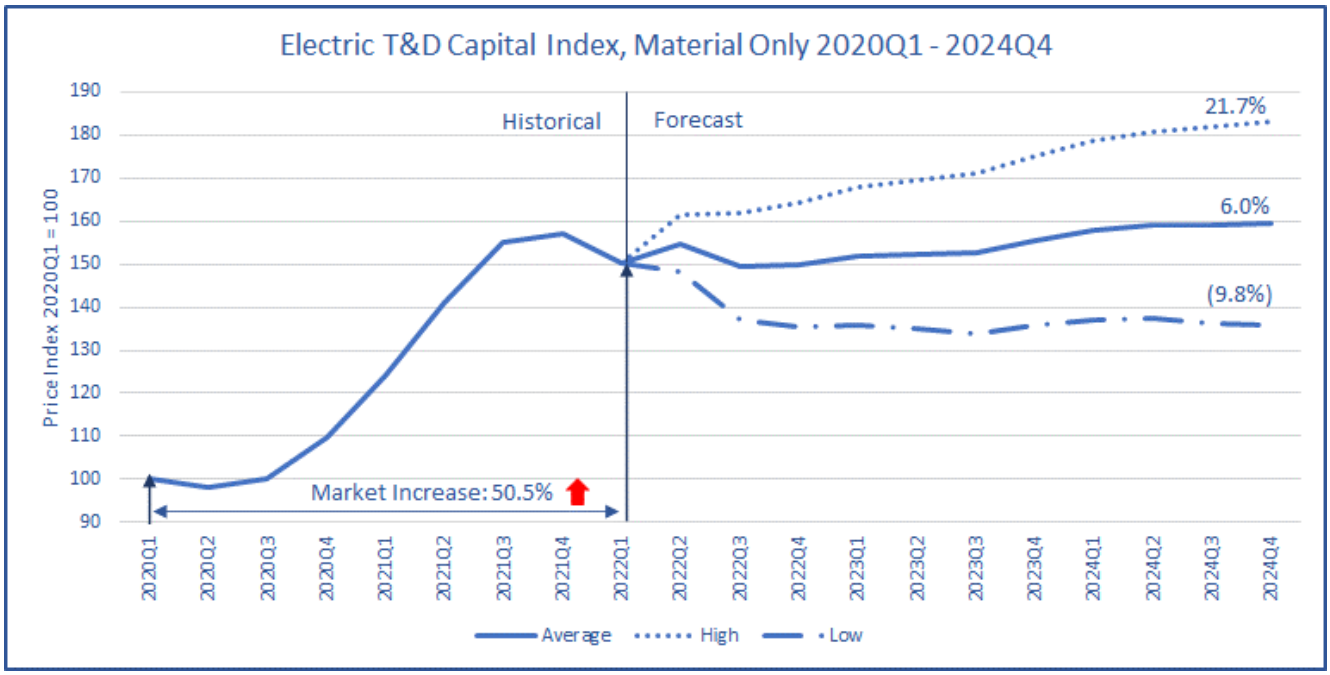
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for electric T&D of 17.5%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 7.9%. Table 1 shows the ten most impactful commodities and services in the electric T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Electric T&D between labour and materials is 65% and 35% respectively. Labour costs are expected to continue to rise, while material costs level out.

Electric Transmission and Distribution - Labour 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Electric Transmission and Distribution - Material 2020Q1-2024Q4



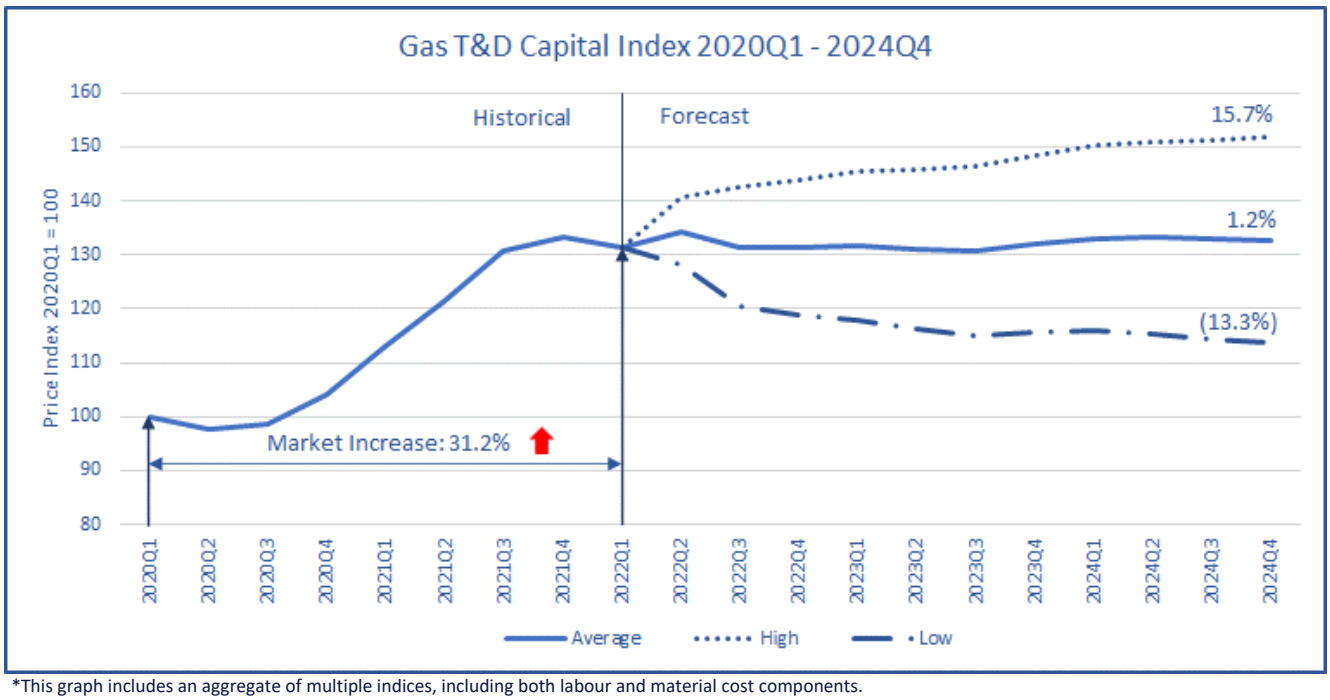
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 1. Electric T&D High-impact Commodities and Services

Electric T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 (%)
AHE: Mechanical and Electrical Trades, Basic Construction Union Wages, BC	1.5
AHE: Construction, Private Compensation, BC	10.8
ECEC: Benefits, Private Construction	3.3
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Cement, Canada	(3.4)
AHE: Heavy Equipment Operator, Basic Construction Union Wages, BC	2.6
AWE: Repair and Maintenance, BC	4.3
SPM: Aluminum, High Grade	83.2
PPI: Springs and Wire Products, Canada	42.2
IM: Transmission Conductor	160.4

AHE: Average Hourly Earnings, Employer Costs for Employee Compensation, SPM: Spot Price Metal, IPPI: Producer Price Index, AWE: Average Weekly Earnings, IM: Industry Margin

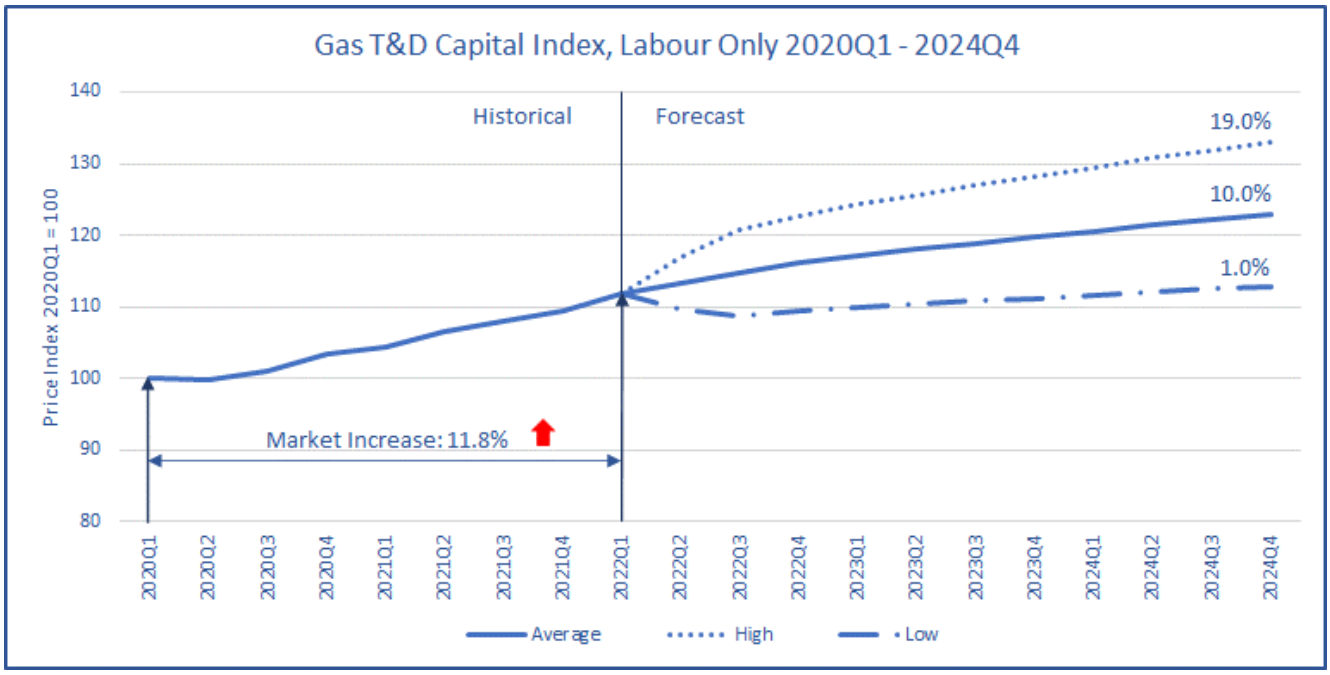
Gas Transmission and Distribution 2020Q1 – 2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

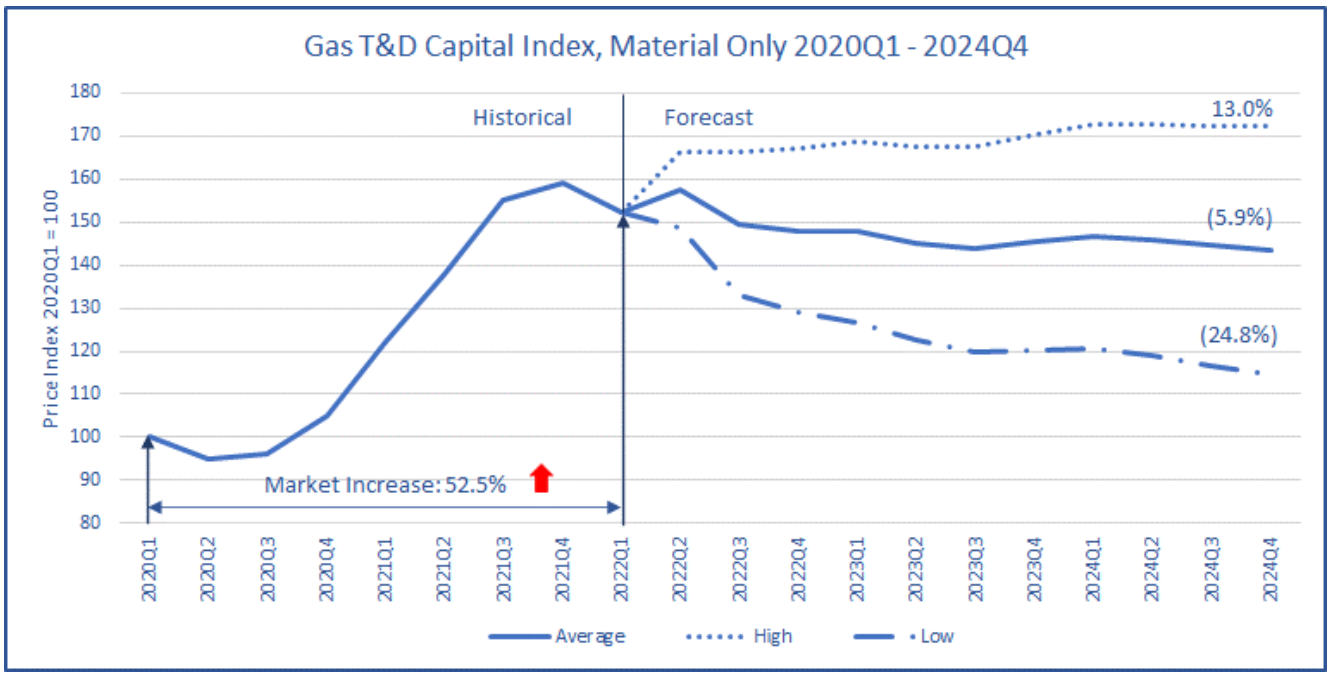
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for gas T&D of 31.2%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 1.2%. Table 2 shows the ten most impactful commodities and services in the gas T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Gas T&D Construction between labour and materials is 44% and 56% respectively. Labour costs are expected to continue to rise, while material costs are expected to drop slightly, driven by declining steel prices.

Gas Transmission and Distribution - Labour 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Gas Transmission and Distribution - Material 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 2. Gas T&D High-impact Commodities and Services

Gas T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 Escalation (%)
AHE: Construction, Private, Compensation, BC	10.8
SPM: Steel Plate, Cut-to-Length	173.7
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Hand and Edge Tools	2.7
PPI: Commercial and Industrial Machinery and Equipment Rental	(2.2)
AHE: Professional, Scientific and Technical Services, BC	11.6
SPM: Steel Plate, Coiled	117.3
AHE: Architectural and Finishing Trades, Basic Construction, BC	1.4
AHE Manufacturing, BC	9.8
PPI: Metal Building and Construction Materials, Canada	51.1

AHE: Average Hourly Earnings, SPM: Spot Price Metal, PPI: Producer Price Index

Pre-MRP Market Escalations

The market conditions for both electric and gas T&D vary significantly from the five years prior to the execution of the MRP. Table 3 uses the same models as above to observe the market between Q1 2015 through Q4 2019. Two years (2015 and 2019) experienced a decrease in market price, and the total escalations over this period were 7.6% and 7.5% for electric T&D and gas T&D, respectively.

Table 3. Annual Market Adjustments for Electric and Gas T&D

Year Q1 – Q4	Electric T&D Market Change (%)	Gas T&D Market Change (%)
2019	(0.2)	(3.6)
2018	1.0	4.5
2017	1.8	1.2
2016	4.1	3.6
2015	(1.7)	(3.5)

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Appendix C2

Project Descriptions for Forecast Growth and Sustainment Capital

August 2022

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1. INTRODUCTION

In this appendix, FBC provides descriptions of growth and sustainment capital projects over $1 million.

As described in Section 7 of the Application, FBC's growth capital is divided into the following portfolios:

1. Transmision Growth;
2. Distribution Growth; and
3. New Connects.

FBC's sustainment capital is divided into the following portfolios:

1. Generation;
2. Transmission Sustainment;
3. Stations Sustainment;
4. Distribution Sustainment; and
5. Telecommunications.

The projects over $1 million in each of these categories are described below.

2. GROWTH CAPITAL

2.1 *TRANSMISSION GROWTH*

Regular Transmission Growth capital consists of discrete projects as dictated by transmission system capacity requirements based on forecast load for adequate supply during periods of peak demand and adverse weather conditions.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[1]

[1] MRP Application, Section 3.4.1.1.1, Table C3-23, pp. C-82 and C-83.

Table C2-1: FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	4,633	-	-	-	-
Summerland Transformer Replacement	539	2,063	-	-	-
Beaver Park Substation Upgrade	-	-	2,740	5,195	-
DG Bell 2nd Transformer Addition	-	-	-	-	1,086

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-2: Updated FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	5,311	66	-	-	-
Beaver Park Substation Upgrade	-	636	4,936	6,223	-
Duck Lake 2nd Transformer Addition	-	-	-	-	1,088

Each of these projects is described further below.

- **Sexsmith Second Transformer Addition:** Peak load on the existing 32 MVA Sexsmith T1 transformer was forecast to exceed nameplate capacity in 2020. In order to continue to maintain the current levels of reliability and meet the planning criteria for this area of Kelowna, a second transformer was installed and put into service at the Sexsmith substation in 2020. The actual costs of this project were approximately $5.3 million with the bulk of capital expenditures occurring in 2020.
- **Summerland Transformer Replacement:** The existing 20 MVA Summerland substation transformer supplies one of two wholesale delivery points to the District of Summerland municipal utility. Due to anticipated new commercial development in Summerland, peak load at this wholesale delivery point was previously forecast to exceed 95 percent of the contract demand limit during the MRP term. Since the most recent load forecast projects that peak load will not exceed this threshold until 2026, no project expenditures are planned during the MRP term. FBC will continue to engage with the District of Summerland municipal utility to discuss options to increase wholesale capacity. This project is thus not included in Table C2-2.
- **Beaver Park Substation Upgrade:** This project is driven by load growth in the Trail area and equipment condition issues as the BEP T1 transformer tap changer cannot be adequately maintained. The project seeks to rebuild the Beaver Park substation on an expanded station footprint. To meet planning criteria and continue to provide a reliable supply, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is approximately $11.8

million. The total project costs have increased since the MRP Application filing in 2019 due to several factors, including archaeological requirements and increases in engineering, materials and construction costs. Commodity cost increases have placed significant pressure on materials.

- **Duck Lake Second Transformer Addition:** This project is driven by significant development occurring in the area served by the Duck Lake substation. FBC planning studies indicate that a second distribution transformer is required at Duck Lake to maintain the current level of reliability and support distribution contingency planning criteria. As the pace and scale of development has exceeded what was anticipated when the MRP Application was filed, this project has now been advanced ahead of the DG Bell project described below. The estimated cost of this project is $5.3 million; however, the cost could increase further as a result of potential commodity cost increases impacting the cost of materials.
- **DG Bell Second Transformer Addition:** FBC planning studies indicate that a second distribution transformer is required at DG Bell to maintain the current level of reliability and support distribution contingency planning criteria. This project has been deferred from the original 2024-25 construction schedule to accommodate the Duck Lake Second Transformer Addition. This project is now planned for 2025-26 with an estimated in-service date of 2026. This project is thus not included in Table C2-2.

2.2 *DISTRIBUTION GROWTH*

Similar to its transmission system, FBC evaluates distribution system capacity on an annual basis, based on the projected loads. FBC's Distribution Growth capital includes two ongoing programs, small (planned) growth projects and unplanned growth projects. Larger individual distribution growth projects are also included.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[2]

Table C2-3: FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	1,970	-	-	-	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

[2] MRP Application, Section 3.4.1.1.2, Table C3-24, pp. C-83 and C-84.

Table C2-4: Updated FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	-	26	1,870	-	-
Huth CoP 13KV Supply	1,219	62	-	-	-

Each of these projects is described further below.

- **DG Bell Feeder 4 Addition:** This project was deferred due to the timing of City of Kelowna road construction from 2020 to 2022; however, the total actual project cost is lower than forecast in the MRP Application.
- **Huth CoP 13KV Supply:** This project was added in 2020. The project was required to ensure that FBC continues to meet the terms of its Wholesale Agreement with the City of Penticton at the Huth substation Point of Delivery.

2.3 *NEW CONNECTS*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3. SUSTAINMENT CAPITAL

3.1 *GENERATION SUSTAINMENT*

FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC's Generation capital is grouped into four capital programs: (i) Hydraulic Dam Structures; (ii) Generating Equipment; (iii) Generation Auxiliary Equipment; and (iv) Buildings and Structures.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[3].

Table C2-5: FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	685	821	979	1,128	1,019
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,467	1,396	-	-	-

[3] MRP Application, Section 3.4.1.2.1, pp. C-84 to C-88.

	Category	2020	2021	2022	2023	2024
Other Gates Upgrades	Hydraulic Dam Structures	481	100	414	241	545
Dam Safety Instrumentation	Hydraulic Dam Structures	715	765	-	-	806
Guarding of Rotating Parts	Hydraulic Dam Structures	194	324	458	295	287
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	35	582	2,035	-
Generator Excitation System and Control Systems	Generating Equipment	-	67	556	556	-
Generator Thrust Bearing Cooling System	Generating Equipment	247	271	295	198	198
Dewatering and Drainage Systems	Generation Auxiliary Equipment	116	349	349	349	349
Station Service Upgrade	Generation Auxiliary Equipment	333	495	286	286	300
COR Annex Building Replacement	Buildings and Structures	-	-	-	198	1,606

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-6: Updated FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	715	745	1,128	651	1,061
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,436	2,893	-	-	-
Dam Safety Instrumentation	Hydraulic Dam Structures	896	287	1,059	100	100
Rehabilitation of Dam Stability Anchors	Hydraulic Dam Structures	78	442	392	326	-
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	22	501	1,395	2,085
Generator Excitation System and Control Systems	Generating Equipment	-	271	344	485	836
Dewatering and Drainage Systems	Generation Auxiliary Equipment	126	217	655	1,166	222

	Category	2020	2021	2022	2023	2024
Station Service Upgrade	Generation Auxiliary Equipment	298	577	834	512	260
COR Annex Building Replacement	Buildings and Structures	4	4	186	200	1,606

Each of these projects is described in further detail below:

- **Concrete Structures Rehabilitation Project:** This is a continuation of the program started in 2014 to address requirements of the BC Dam Safety Regulation and deterioration of concrete structures. The cost for this project is $0.332 million lower than forecast in the MRP Application due mainly to reduced scope at the Lower Bonnington Dam as safety issues are restricting access to lower areas of the construction scaffold in the tailrace during unit start-up. FBC is working on designing a solution to this issue.
- **Lower Bonnington Dam (LBO) Spillway Gates Refurbishment Project:** This project was completed in 2021 at a higher cost than forecast due to complexities encountered during construction and the implementation of a monorail system for the installation of stoplogs that was not considered initially.
- **Other Gates Upgrade Project:** This project is now forecast to cost less than $1 million due to FBC implementing a simpler solution for strengthening the LBO intake superstructure. This project is thus not included in Table C2-6.
- **Dam Safety Instrumentation Project:** This project addresses the requirement in section 19(1) of the BC Dam Safety Regulation for instrumentation to adequately monitor the dam and the area surrounding or adjacent to the dam. The project began in 2018 and includes the installation of dam monitoring systems at FBC's plants. FBC has thus far completed the installation of dam safety instrumentation at LBO and UBO and will complete the installation of dam safety instrumentation at South Slocan (SLC) in 2022. The higher costs are primarily due to higher drilling costs. The installation of the dam safety instrumentation at Corra Linn (COR) has been delayed with only the engineering being planned to occur in 2023-2024.
- **Guarding of Rotating Parts Project:** This project is now forecast to cost less than $1 million due to a reduction in scope. The original forecast included installing guards on spillway and intake gates, but during detail design, more effective administrative and operational methods were developed and implemented which have resulted in cost reductions. This project is thus not included in Table C2-6.
- **Rehabilitation of Dam Stability Anchors:** This project was included in the Other Hydraulic Dam Structures Projects category in the MRP Application, as at the time of filing it was expected to cost less than $1 million. However, the scope of work has increased from $0.302 million to $1.238 million due to damage to the anchors' heads being more extensive and the number of anchor heads that required repairs being higher than initially anticipated; the degree of the anchor head damage could only be established while

inspecting the anchors which are located on the overflow spillway. The rehabilitation of the LBO dam stability anchors will be competed in 2022. Rehabilitation of the COR dam stability anchors will commence in 2023 and will complete in 2025.

- **Upper Bonnington Dam (UBO) Unit 6 Turbine Runner Replacement Project:** This project includes the replacement of the UBO Unit 6 turbine runner that has reached the end of its service life. Work on this project was accelerated to mitigate the anticipated delays in the global supply chain due to the COVID-19 pandemic. The estimated cost of this project is approximately $1.445 million higher than originally forecast due to the costs of the runner being higher. The expected in-service date is December 2024.
- **Generator Excitation System and Control System Replacement Project:** This project addresses the replacement of some of the generator excitation systems beginning in 2022 with Unit 6 at UBO. The updated cost of this project is approximately $0.765 million higher due mainly to higher costs with the procurement of the control and excitation systems.
- **Generator Thrust Bearing Cooling System Upgrade Project:** This project is now forecast to cost less than $1 million as FBC has implemented a better designed solution that has resulted in cost savings. This project is thus not included in Table C2-6.
- **Dewatering and Drainage Systems Rehabilitation Project:** This project was budgeted based on costs including rehabilitation of pipes valves and other components of the dewatering and drainage systems. During detail design it was discovered that this solution was not feasible and a new solution was designed and is being implemented which is based on a pump in gate design that has an increased cost of $0.690 million. The first system is planned to be put in service at SLC in 2023 and engineering for the next plant will occur in 2024.
- **Station Service Upgrade Project:** This project includes upgrading the protection system of FBC's station service system and neutral grounding in order to address safety hazards, replacement of station service transformers that have reached the end of their service life and other small station service improvements. The estimated cost of this project is $0.186 million higher due to the need to address deficiencies related to LBO powerhouse grounding and bonding issues that were uncovered while doing investigations in 2021.
- **Corra Linn Annex Building Replacement Project:** FBC has decided to start the preliminary engineering in 2022 and is planning to complete the project in 2024.

3.2 *TRANSMISSION SUSTAINMENT*

Transmission Sustainment expenditures are required to proactively manage the condition and integrity of FBC's transmission line facilities, manage the risk to employees and public safety, and maintain an acceptable level of service for customers.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[4].

Table C2-7: FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,100	-	-	-	-
30, 32, 19 Lines Right of Way	647	651	658	656	652

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-8: Updated FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,087	91	-	-	-
30, 32, 19 Lines Right of Way	458	637	652	652	648

Each of these projects is described in further detail below:

- **30 Line Rehabilitation between the South Slocan and Coffee Creek Substations:** This project included expenditures for structural stabilization of the transmission line, based on the 2018 condition assessment, including stubbing poles and replacing poles and cross-arms. The project was completed as planned in 2020.
- **30, 32 and 19 Line Right of Way Improvements:** The scope of this multi-year project involves acquiring an additional right of way predominantly upslope of the existing right of way for 30 Line (Nelson to Coffee Creek Substation), 32 Line (Creston to Crawford Bay), and 19 Line (Slocan Valley) and clearing the additional right of way to reduce the number of tree-related outages. Portions of these lines are in steep terrain. Of FBC's 72 transmission lines, tree contacts on 30 Line account for 17 percent of the transmission related outages. Tree contacts on 32 Line and 19 Line each account for approximately 8 percent of FBC's transmission related outages. These projects are in progress, with FBC implementing land owner agreements to widen the right of way.

3.3 *STATIONS SUSTAINMENT*

FBC's substation sustainment capital expenditures are driven by a combination of time-based and condition-based scheduling. Currently, FBC employs a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC's substation assets and is used to assist in scheduling maintenance tasks.

[4] MRP Application, Section 3.4.1.2.2, pp. C-89 and C-90.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[5]

Table C2-9: FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
AS Mawdsley Tranformer Replacement	-	-	-	-	3,802
Trout Creek Transformer Replacement	2,263	-	-	-	-
Kaleden Transformer Replacement	-	-	-	-	2,716
Salmo Station Upgrade	3,718	7,154	-	-	-
Fruitvale Station Upgrade	-	-	-	-	3,802

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-10: Updated FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Trout Creek Transformer Replacement	153	2,660	1,568	-	-
Keremeos 2nd Transformer Addition	-	-	-	543	2,700
Salmo Station Upgrade	4,778	5,143	-	-	-
Fruitvale Station Upgrade	-	-	-	1,087	7,021

Each of these projects is described in further detail below:

- **AS Mawdsley Transformer Replacement:** FBC is now planning to file a Certificate of Public Convenience and Necessity (CPCN) application for this project as the cost is forecast to be above the $20 million materiality threshold. This project is thus not included in Table C2-10.
- **Trout Creek Transformer Replacement:** This project is driven by asset condition, as the transformer is 52 years old and uses the most unreliable Load Tap Changer (LTC) in the FBC fleet (Pioneer TC546). The acetylene levels and a barrel collecting the excess oil moving from the main tank to LTC indicated a cracked LTC terminal board. The project is currently in execution with an estimated in-service date of 2022. Increases in project costs are due to delays related to the lands purchase and ALR approval, along with significant additional work related to other end of life station equipment. Further

[5] MRP Application, 3.4.1.2.3, Tables C3-34 and C3-35, pp. C-91 to C-93.

investigation of the station after the MRP proceeding revealed that the entire station was in a similar condition as the transformer which resulted in a rebuild of the station.

- **Keremeos Second Transormer Addition:** This project is driven by asset condition. The Keremeos transformer has a 48 year old LTC that is not functioning. Based on the resulting operational challenges with the control of customer voltages, this transformer replacement is a high priority.
- **Kaleden Transformer Replacement:** This project has been deferred until after the end of the MRP term to accommodate the previously unforeseen Keremeos Transformer Replacement project. The existing Keremeos transformer presents a larger risk at this time, but planning remains underway for replacement of the Kaleden transformer in 2025-26. This project is thus not included in Table C2-10.
- **Salmo Station Upgrade:** This project was driven by equipment condition issues and aging infrastructure at the Salmo and Ymir substations. The project rebuilt the Salmo substation on the existing station footprint and decommissioned the Ymir substation. The Ymir substation customers were permanently transferred to the Salmo substation. Construction began in 2020 and was completed in 2021. The total cost of this project was $9.9 million. The overall total project cost was less than forecast due primarily to lower actual costs for the distribution and transmission line work. The replacement of the Salmo Station 13 kV Switchgear was also included in this project.
- **Fruitvale Station Upgrade:** This project is driven by equipment condition issues and aging infrastructure at the Fruitvale and Hearns substations. The Hearns single phase transformer units are approximately 72 years old, and the Fruitvale metal-clad switchgear is approximately 55 years old; this equipment is at risk of failing. The project seeks to rebuild and relocate the Fruitvale substation, while decommissioning the Hearns substation. The Hearns substation customers would be permanently transferred to the Fruitvale substation. The existing Fruitvale substation footprint is too small to accommodate the rebuild, and land will need to be acquired for the upgrade. To meet planning criteria and continue to provide a reliable supply to the Fruitvale area, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is $12.5 million. FBC forecasts spending $1.1 million in 2023, $7.0 million in 2024, and $4.4 million in 2025 with an estimated in-service date of 2025. The total project costs have increased since the MRP Application due to several factors, including land acquisition requirements and increases in engineering, material and construction costs.

3.4 *DISTRIBUTION SUSTAINMENT*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3.5 TELECOMMUNICATIONS SUSTAINMENT

FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[6].

Table C2-11: FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	937	953	-
SCADA System Replacement	Systems Upgrades and Replacements	-	1,086	2,192	2,188	1,086
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	548	875	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-12: Updated FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	-	841	853
SCADA System Replacement	Systems Upgrades and Replacements	-	-	-	543	1,080
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	-	-	540

Each of these projects is described in further detail below:

- **Backbone Transport Technology Migration:** This project will replace FBC's existing SONET network with a new high-speed data network supporting all present and anticipated future applications needed to provide safe and reliable service. The project, which was originally forecast to start in 2022, is now expected to commence in 2023.
- **SCADA System Replacement Project:** This project was planned to start in 2021; however, due to limited resources the business analysis was not initiated until late 2021,

[6] MRP Application, Section 3.4.1.2.5, pp. C-99 to C-101.

resulting in delays to determine the best SCADA solution. The estimated cost of this project has decreased to approximately $6 million.

- **VHF Radio System Replacement Project:** The existing FBC Electric VHF Radio system is at the end of its service life (>20 years old) and the technology is obsolete. Parts are still available but are becoming more difficult to source and the legacy technology is difficult to support as new hires are not trained or experienced with the legacy technology. New 2-way radio technologies bring significant benefits with respect to sharing of channels, ease of maintenance, superior coverage and ability to send data in addition to voice. In 2024, the first stages of the VHF radio replacement project are expected to start, with the project continuing into 2025.

Appendix D
DRAFT ORDER

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Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2023 Rates

BEFORE:
E. B. Lockhart, Panel Chair
C. M. Brewer, Commissioner
A. Pape-Salmon, Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-166-20 approving a Multi-Year Rate Plan (MRP) for 2020 through 2024 (2020-2024 MRP Decision) for FortisBC Inc. (FBC). In accordance with the 2020-2024 MRP Decision, FBC is to conduct an annual review (Annual Review) process to set its rates for each year;

B. By letter dated June 28, 2022, FBC proposed a regulatory timetable for the Annual Review of its 2023 rates;

C. By Order G-193-22 dated July 15, 2022, the BCUC established the regulatory timetable for the Annual Review of FBC's 2023 rates, which included FBC filing its Annual Review materials, intervener registration, one round of information requests, a workshop, FBC's responses to undertakings at the workshop, and written final and reply arguments;

D. On August 5, 2022, FBC submitted its materials for the Annual Review for 2023 Rates Application (Application). In the Application, FBC requests a 3.99 percent rate increase over 2022 rates, effective January 1, 2023, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determination.

NOW THEREFORE pursuant to sections 59 to 61, 89 and 99 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of Stage 1 of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.

2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1, is approved.

3. FBC is approved to:

    a. Create a rate base deferral account for the 2023 Joint Pole Use Audit and amortize the deferral account over five years commencing January 1, 2023; and

    b. Amortize the existing COVID-19 Customer Recovery Fund Deferral Account over three years commencing January 1, 2023.

4. FBC is approved to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account.

5. Directive 6 of Order 42-21 is varied as follows: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account".

6. Directive 2 of Order G-83-14 is varied as follows: "Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes".

7. FBC is directed to file with the BCUC as a compliance filing, within 15 days of the issuance of this order, amended tariff pages and finalized financial schedules for 2023, in accordance with the terms of this order.

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

FBC 2024 ANNUAL REVIEW OF RATES
EXHIBIT B-2

Sarah Walsh
Director, Regulatory Affairs

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August 4, 2023

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2024 Rates

In accordance with the MRP Plan and BCUC Order G-191-23 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2024 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners in the FBC Annual Review for 2023 Rates proceeding.

FORTIS BC™

FORTISBC INC.

Multi-Year Rate Plan for 2020 through 2024

Annual Review for 2024 Rates

August 4, 2023

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 INTRODUCTION

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10 of the Application, FBC proposes to distribute $2.396 million pre-tax ($1.749 million after-tax) in earnings sharing to customers in 2024.

The proposed rates for 2024 flowing from the forecasts and approved formulas set out in the Application, including returning the actual 2022 earnings sharing to customers, result in a 4.83 percent rate increase from 2023 rates. The increase is primarily due to an increase in power purchase expense (PPE), followed by an increase in income tax expense.

In the subsections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FBC's 2022 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2024 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 APPROVALS SOUGHT

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

1. Approval to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.
2. Creation of the following rate base deferral accounts, as described in Section 7.6:
    - 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

- 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;
- PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;
- BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and
- Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

A draft order is included in Appendix C.

1.3 REQUIREMENTS FOR THE ANNUAL REVIEW

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13

Item	Description	Response or Reference
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES

1.4.1 Overview of 2022 Formula O&M Savings

For 2022, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.7 million, excluding the COVID-19 pandemic approved exogenous factor credit for net O&M cost reductions of approximately $1.0 million.

Of the approximate $3.7 million in formula O&M savings realized in 2022, approximately $3 million are due to labour savings, including overtime. The remaining savings are due to a variety of factors including reduced postage and printing costs from paperless billing and general timing of non-labour expenditures. While some of the savings are one-time in nature (e.g., required time to fill vacancies from turnover), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As described in FBC's Annual Review for 2022 Rates, in 2021, FBC and FortisBC Energy Inc. (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying productivity initiatives. Following is a summary of these productivity initiatives.

1. **Field Operations Improvements:** A review of the meter reading routes was undertaken and updated to achieve optimized routes, resulting in reduced overtime and increased employee safety. In addition to optimizing meter reading routes, range extenders continue to be added to reduce the number of manual meter reads required, resulting in reduced travel time for meter readers and consistent, reliable meter readings for customers. Additionally, Operations is undertaking work to accurately map meters to their corresponding transformer which has operational benefits. Mapping the transformer-to-meter relationship provides accurate capacity information which can be used to determine

where EV charging load growth is and where it can be added to utilize existing infrastructure. Another benefit is that customer outage mapping improves the ability for technicians to more effectively and quickly troubleshoot system trouble calls.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC's contract resources that are tasked with performing transmission line condition assessments continue to rely on the use of UAVs to aid in the completion of this work. Although UAVs have not eliminated the need for human resources to complete condition assessment work, primarily due to limitations on the operation of UAVs beyond visual line of sight, they have allowed FBC to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from a ground-based inspection. Additionally, FBC has equipped its Operations crews with small drones that allow for visual inspections during trouble or outage events where ground access may be difficult or restricted. FBC will continue to monitor industry developments regarding the use of UAVs for supporting utility operations.

3. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. FortisBC uses data to inform decision making, but its current data is spread across dozens of disparate systems. Data is often siloed within departments and the volume, variety, and velocity of data coming into FortisBC is increasing. It can be difficult and time consuming to gather, clean, and filter the data needed to create useful information. As part of the solution, Enterprise Analytics creates a data fabric atop core FortisBC source and storage systems to facilitate advanced analytics opportunities. It addresses key barriers by integrating existing data into a single, scalable platform to deliver easily accessible and reliable data. It also simplifies connecting data assets to reduce cost and effort to create reports that can be easily updated and enables automation of reporting. Enterprise Analytics enables improvement in key performance indicators selected by each business area, and provides enhanced data quality, and work efficiency. Benefits are realized from shared information and sharing of insight across business units. Additionally, quality assurance is better enabled as information is reconciled and standardized.

   In 2022, efforts focused on developing solutions for three business areas: Customer Service, Major Projects, and Energy Supply. For Customer Service, Enterprise Analytics is delivering a new reporting dashboard displaying key Customer Service data all in one place (gas and electric). Benefits include providing a clear and easily accessible view of factors contributing to performance, insights identifying strengths and opportunities to grow FortisBC's relationships with its customers, operational savings through more efficient customer interactions, and less effort to share metrics with parties outside of customer service. This is only the starting point, as more data sources could be included, and new ways of using the dashboard will be discovered, providing the potential to optimize continuous improvement with additional available, integrated data. For the Major Projects area, Enterprise Analytics is enabling it to provide analytical insight through dashboarding and reporting on Major Projects project budgets, schedule, and project development. Lastly, for the Energy Supply area, Enterprise Analytics is providing analytic

insights for energy loss, broadly accounting for power at different points within the FBC electricity supply chain, leveraging FBC AMI data to estimate unbilled power, improve the assignment of costs to customers, inform rate design and power purchases, and identify system losses more accurately. FBC expects to realize total O&M savings of approximately $0.125 million by the end of 2025.

Enterprise Analytics will also support streamlining existing reporting processes for financial and management reporting. Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Enterprise Analytics provides an automated solution that reduces the effort required to generate reports, with expected productivity gains. This automation is achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service. FBC plans to implement two or three automated reporting solutions in 2023.

4. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FortisBC are challenged.

   In 2022, the Company initiated the first phase of RPA implementation, working to automate several repetitive and manual processes in the Finance department and one in the Engineering department. The processes chosen were small, low-risk opportunities to introduce RPA to the organization. The first Finance process went into production in mid-2022 with others following throughout the remainder of the year. The Engineering process went into production in the first half of 2023. The automation of the Finance processes has resulted in:

   - faster and more timely processing of monthly journal entries, allowing for earlier and increased analysis and review time;
   - a shift in how time is spent, moving from data-entry-style rote work on several processes;
   - a reduction in time spent reperforming work due to human errors; and
   - an overall reduction in time spent on certain processes.

   The operational efficiency value gained by RPA is incremental but compounds as more processes are automated.

   In 2023, the Company is adding to automation within the Finance area as well as evaluating opportunities in other business areas to grow the RPA initiative. Additional process opportunities include populating Financial and Internal Audit reports and filings, application of customer bill payments, net-metering amendment of Electric bills, processing of rebate applications, onboarding of new users within IS systems, and automating manual document control processes within Engineering projects. A

governance structure will also be established to prioritize and control RPA implementations, as well as ensuring that RPA implementations align with the overall business strategy and objectives, and that the necessary resources and support are available for successful implementation and ongoing maintenance of the automated processes. FBC expects to realize total O&M savings of approximately $0.025 million by the end of 2024.

5. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2022, FBC had approximately 77,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 6,500 customers choosing this option in 2022. This increase equates to approximately $0.05 million in printing and postage cost savings for FBC in 2022 as compared to 2021.[1]

6. **Other Initiatives:** FortisBC is continuously looking for efficiencies and improvements in its activities, in a larger scale as the initiatives described above, or at a smaller scale as described in the following initiatives.

Mobile enabling applications: FortisBC has different initiatives to digitize forms and provide the ability to complete these forms on mobile devices in the field or office. Digitizing these forms supports effective data capture, and improves consistency, reliability, comprehension of data collected and reduces risk of manual errors. Additionally, it reduces the administrative efforts that occur with paper forms. FortisBC expects to realize minor savings by the end of 2023, and additional savings will be realized as FortisBC continues to mobile-enable and digitize other paper forms.

Automated patching: FortisBC has started taking advantage of technologies for automated patching. Moving to automated patching has streamlined the patching process for several applications in the FortisBC environment. With automated patching, the process can be scheduled to run during a more appropriate business outage window with no user involvement required. Repetitive tasks can be automated, eliminating human error, increasing productivity, and decreasing administrative costs. FortisBC expects to realize minor O&M savings by the end of 2023 with increased patch cadence and accuracy. Additional time savings will be seen as more systems transition to automated patching.

[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.21 per bill.

Other IS Initiatives: A High Availability (HA) operating environment enables applications to continue to operate even if one of the information technology components fails, and to ensure continuous operation and uptime. HA allows IS to schedule upgrades, patches, and release tasks during business hours, ultimately improving business operations and reducing overtime costs. IS has also expanded the use of automated testing. The expanded use of automation allows for an increase in system testing and improved product quality with a decrease in proportionate need for additional testing resources. Automation is expected to continue to expand in use at FortisBC in the future.

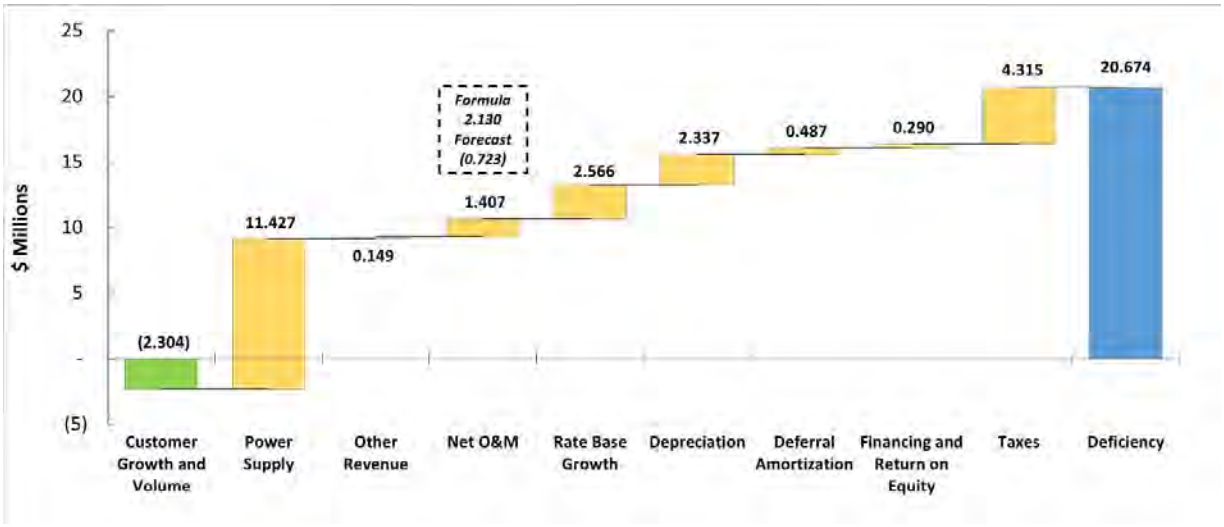
Customer Service Initiatives: Ongoing smaller initiatives include automating the tracking of collections and refund cases, improving training materials for high volume call types, and introducing emails for electric collections customers. While on a smaller scale, these initiatives contribute to improving customers' experience with FortisBC and the Company maintaining a focus on being cost effective in its use of resources.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2024

The revenue requirement components set out in the Application result in an effective rate increase of 4.83 percent for 2024 compared to 2023. The effective rate increase results from a revenue deficiency of $20.674 million.

The following chart summarizes the items that contribute to the 2024 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2024 deficiency of $20.674 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2024 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2024, FBC forecasts the net load to decrease by approximately 1 GWh when compared to 2023 Approved, with the forecast increases from the wholesale and commercial customer classes completely offset by decreases in the residential, industrial, and irrigation customer classes. Despite the slight decrease in net load of 1 GWh forecast for 2024, FBC is forecasting a small increase in revenue of $2.304 million, primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charges). FBC's 2024 Forecast revenue at 2023 approved rates is $428.377 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $11.427 million in 2024 compared to 2023 Approved. This increase is primarily due to the higher purchase rates for power from the market and contracted producers (included as part of the power purchase expense), followed by smaller increases in the BC Hydro Power Purchase Agreement (PPA), wheeling expenses, and water fees.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase the 2024 revenue deficiency by $0.149 million, primarily due to reduced contract revenue and transmission access revenue.

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

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 3.580 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers.[2] The 2024 Formula O&M net of capitalized overhead has increased by $2.130 million[3] when compared to the 2023 Formula O&M, which is partially offset by a decrease in net O&M forecast outside of the formula by approximately $0.723 million,[4] primarily due to a decrease in pension and OPEB expense. Overall, the 2024 increase in total O&M expense net of capitalized overhead is $1.407 million (2.3 percent).

1.5.5 Rate Base Growth (Section 7)

The 2024 rate base is forecast to increase by approximately $39.492 million when compared to the 2023 Approved rate base, resulting in an increase to the 2024 Forecast earned return and the 2024 revenue deficiency of approximately $2.566 million. The increase in rate base is primarily due to the mid-year impact of FBC's 2024 regular capital additions to plant, followed by, to a lesser extent, the full-year impact of FBC's major capital project additions, including the Kelowna

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $2.506 million (3.6 percent) compared to 2023 Approved.
[4] Decrease in gross forecast O&M of $0.850 million (-36.2 percent) compared to 2023 Approved.

Bulk Transformer Additions (KBTA) project and the Corra Linn Dam Spillway Gates Replacement project.

1.5.6 Depreciation (Section 7)

Depreciation expense in 2024 is forecast to increase the 2024 revenue deficiency by $2.579 million compared to 2023 Approved. This increase is due to the forecast increase in rate base discussed above. The increase in depreciation expense is partially offset by approximately $0.242 million of CIAC from net additions, resulting in a net increase of $2.337 million in depreciation expense.

1.5.7 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2024 is forecast to increase by $0.487 million, primarily due to a reduction in the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account. This increase in amortization expense due to the reduced credit amortization from the Flow-through deferral account is partially offset by an increase in credit amortization from the MRP Earnings Sharing deferral account as well as the amortization of credit balances in the Princeton Office Disposition deferral account, the proposed BC Cost of Living Credit deferral account, and the proposed PST Rebate on Select Machinery and Equipment deferral account.

1.5.8 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2024 deficiency by $0.290 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2024, FBC is forecasting a short-term debt rate of 5.21 percent, which is an increase from the short-term debt rate embedded in the 2023 Approved revenue requirement of 4.24 percent. Overall, FBC's revenue deficiency is increased by $0.346 million from financing rate changes, which is offset by $0.056 million from the ratio change between long-term and short-term debt.

In calculating its 2024 revenue deficiency, FBC has utilized its currently approved capital structure and return on equity (ROE) of 40 percent and 9.15 percent, respectively, as approved by Orders G-129-16 and G-47-14. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which is expected to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

1.5.9 Taxes (Section 9)

FBC's 2024 property taxes are forecast to increase by 1.7 percent or $0.313 million from 2023 Approved. The increase is primarily due to changes in tax rates and increases in assessed values.

There has been no change in the income tax rate of 27 percent from 2023. Taxes are forecast to increase in 2024 by $4.002 million. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA), which led to an increase in income tax expense by approximately $2.849 million. The lower CCA is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024). Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

1.6 SERVICE QUALITY INDICATORS (SECTION 13)

FBC reports on its 2022 and June 2023 year-to-date SQI results in Section 13. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution SQI better than the threshold and the Telephone Service Factor (Non-Emergency) SQI lower than the threshold. For the four SQIs that are informational only, the Average Speed of Answer results were higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), while performance in 2022 for the other three informational metrics generally remained at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2024 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and determined that a growth factor multiplier of 75 percent for formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2024, FBC has used July 2021 through June 2023 inflation data for the 2024 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FBC determined the 2024 Inflation Factor based on prior years' BC-CPI and BC-AWE, and Section 2.3 below explains how FBC determined the average customer count. Both the inflation factor and the average customer count are used to calculate the formula O&M discussed in Section 6.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2023 for AWE-BC has been used as a placeholder, as results to June 2023 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2022 labour weighting of 57 percent, the calculation of the 2024 I-Factor is (6.031 percent x 43 percent) + (2.609 percent x 57 percent) = 4.080 percent.

[5] FBC's most recent year of completed actuals is 2022 so that ratio has been used for the 2024 I-Factor calculation.
[6] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2021	136.7	1,143.76								
2	Aug-2021	137.0	1,143.96								
3	Sep-2021	137.2	1,142.37								
4	Oct-2021	137.9	1,140.94								
5	Nov-2021	138.1	1,129.51								
6	Dec-2021	138.0	1,132.93								
7	Jan-2022	139.4	1,155.32								
8	Feb-2022	140.4	1,153.57								
9	Mar-2022	143.0	1,161.00								
10	Apr-2022	144.2	1,164.51								
11	May-2022	146.1	1,159.89								
12	Jun-2022	146.5	1,167.14	140.4	1,149.58						
13	Jul-2022	147.6	1,162.26								
14	Aug-2022	147.0	1,171.52								
15	Sep-2022	147.8	1,171.94								
16	Oct-2022	148.6	1,174.29								
17	Nov-2022	148.1	1,176.97								
18	Dec-2022	147.1	1,153.31								
19	Jan-2023	148.1	1,180.04								
20	Feb-2023	149.1	1,175.83								
21	Mar-2023	149.7	1,191.20								
22	Apr-2023	150.4	1,199.14								
23	May-2023	151.0	1,199.14								
24	Jun-2023	151.6	1,199.14	148.8	1,179.57	6.031%	2.609%	43%	57%	4.080%	2024

2.3 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M.

The calculation of average customers used to determine 2024 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2024 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2024 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024	Total for 2024 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,435	150,761		Appendix A2 - Section 3.1 Customers
2								
3	Additions:							
4	January	292	257	226	162	192		
5	February	174	89	194	189	194		
6	March	8	123	122	192	191		
7	April	110	113	178	169	193		
8	May	173	319	(25)	277	185		
9	June	172	116	353	121	192		
10	July	522	308	352	245	193		
11	August	129	187	204	193	191		
12	September	83	136	155	195	193		
13	October	545	132	261	197	195		
14	November	234	217	319	190	188		
15	December	245	119	266	197	195		
16	Total Additions	2,687	2,116	2,605	2,326	2,302		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,282	1,242	1,245		
18								
19	Current Year Ending Customer Count	143,714	145,830	148,435	150,761	153,063		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20								
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,112	149,677		2020: G-42-21; Sch 3, Line 13; 2021-2024: Prior Year, Line 22
22	Average Customers for the Year	142,321	144,877	147,112	149,677	152,006		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,235	2,565	2,329	**12,090**	Sum of Annual Change in Average Customers on Line 23
24								
25	Growth Factor Multiplier						**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes						**9,068**	Line 25 x Line 23
27								
28	Average Customers Used to Determine the Starting UCOM						**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**						**148,984**	Line 28 + Line 26
30								
31	2022 Approved Average Customers for Rate Setting			145,378				2022: G-374-21; Sch 3, Line 22
32	2022 Actual Average Customers for Rate Setting			145,313				Line 21 (2020) + Sum of Line 23 (2020, 2021, 2022) x 0.75
33	**2022 True Up**			**(65)**				Line 32 - Line 31

2.4 INFLATION AND GROWTH CALCULATION SUMMARY

A summary of the factors used to determine formula O&M for 2024 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2024	Reference
1	CPI	6.031%	Table 2-1, Line 24
2	AWE	2.609%	Table 2-1, Line 24
3			
4	Non Labour	43%	Table 2-1, Line 24
5	Labour	57%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.080%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	3.580%	Line 7 + Line 9
12			
13	Average Customer Forecast for Formula O&M purposes	148,984	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2024 is 3.580 percent and formula O&M for 2024 is determined using average customers of 148,984.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 INTRODUCTION AND OVERVIEW

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting a decrease in consumption in the 2024 Forecast (2024F) compared to the 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is 2 GWh lower than the 2023 Approved gross load. The decrease is primarily due to a reduction in loads from the residential, industrial, and irrigation classes, which almost completely offsets the increase in loads from the wholesale and commercial customers. Despite the decrease in the 2024 Forecast gross load, FBC is forecasting the 2024 revenue to be $428.377 million, which is an increase of $2.304 million when calculated based on the 2023 Approved rates for each customer class. The increase in revenue for 2024 is primarily due to the forecast increase in load from the wholesale customers, as well as an increase in recoveries from the fixed monthly/bimonthly customer charges resulting from the forecast increase in customer counts in the residential and commercial classes.

FBC has provided further information supporting its load forecast in Appendix A of the Application.

3.2 OVERVIEW OF FORECAST METHODS

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the UPC forecast is multiplied by the corresponding forecast of the number of annual average customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Finally, wholesale and industrial forecasts are primarily based on customer-specific survey results.

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

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2022 calendar year.

- 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 filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.

- Forecast Year: 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, the forecast year is 2024 (2024F).

- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2023 Rates.

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

3.3 DEMAND SIDE MANAGEMENT SAVINGS

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2022.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast incremental DSM savings for 2024 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[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 Incremental 2024 DSM Savings (GWh)

Line No.	Description	DSM 2024
1	Residential	(9.1)
2	Commercial	(22.3)
3	Wholesale	(7.6)
4	Industrial	(13.5)
5	Lighting	(0.2)
6	Irrigation	(0.2)
7	Net	(52.9)
8	Losses	(4.3)
9	Gross Load	(57.2)

3.4 LOAD FORECAST

FBC's total load consists of the weather normalized residential and wholesale load and the actual commercial,[8] industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2022 was 4.7 percent, which was primarily due to higher industrial loads and more residential customers coming onto the system than forecast. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,473.9 GWh in 2024F, which is 1.8 GWh less than 2023S and 1.4 GWh less than 2023 Approved.

[8] Commercial loads are tested for weather sensitivity each year. For 2024, there is a low correlation with weather and as a result, the actual historic commercial loads are used in the preparation of Figures 3-1 and 3-5. Please refer to Section 1.1 of Appendix A-3 for further detail.

Figure 3-1: Total Net Load (GWh)

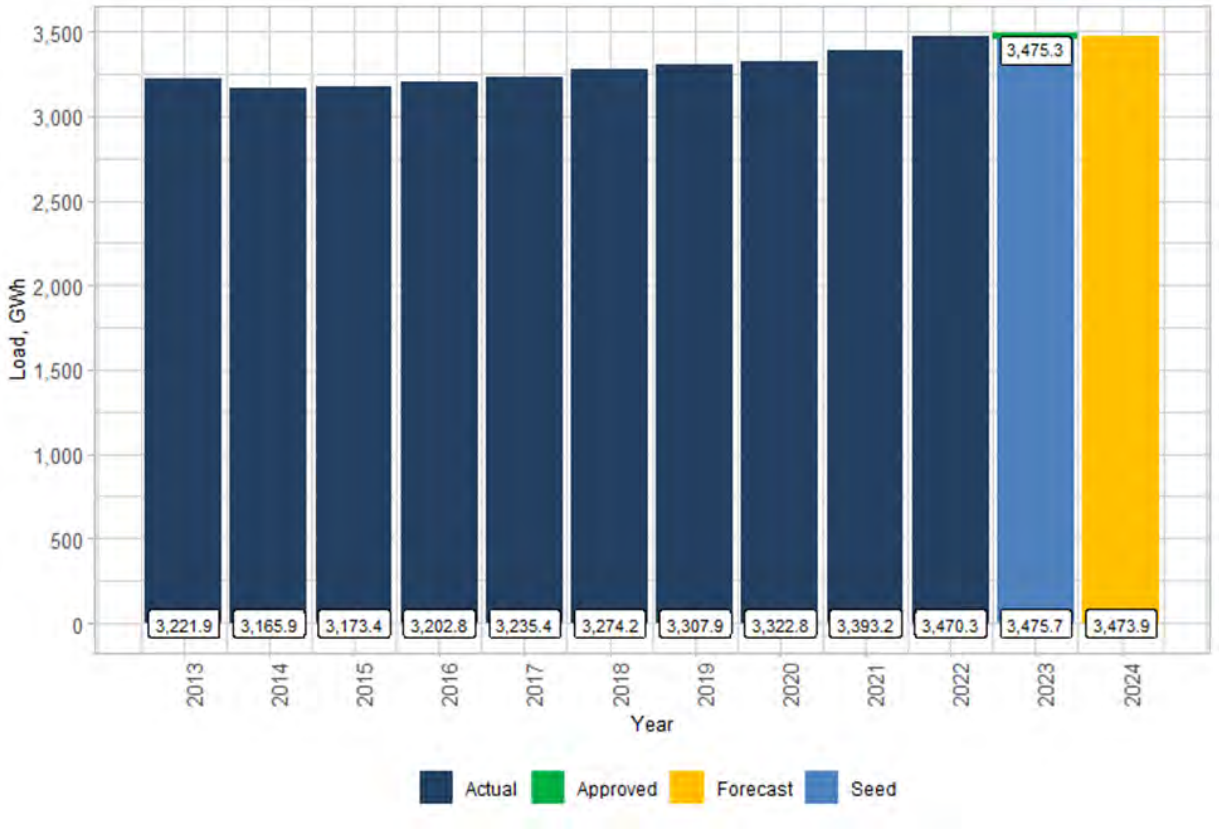


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2024F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: After-Savings Gross Load and System Peak[9]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
	Energy (GWh)												
1	Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
2	Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
3	Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
4	Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
5	Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
6	Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
7	Net Load	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
8	Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
9	Gross Load	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
10													
11	System Peak (MW)												
12	Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
13	Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

[9] The system peaks shown on Lines 12 and 13 are weather-normalized winter and summer peaks. Refer to Section 3.4.8 for further details.

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

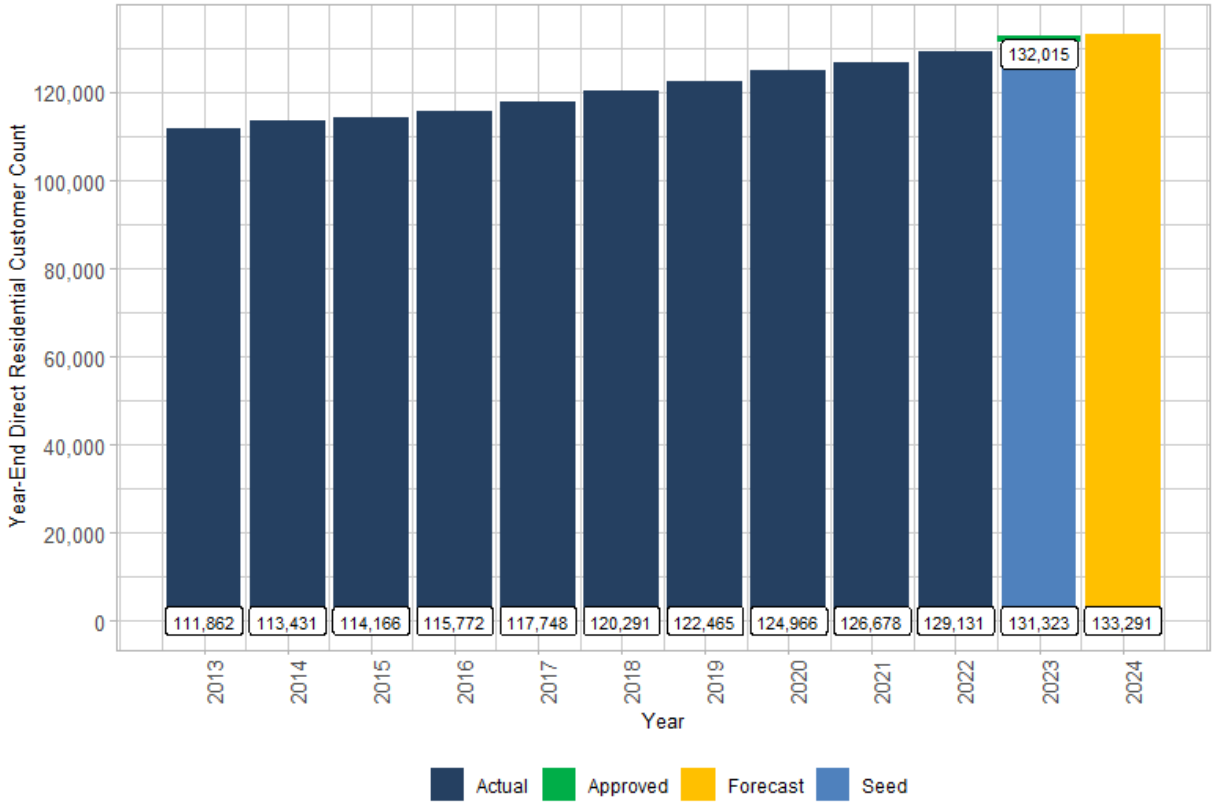
3.4.1 Residential

3.4.1.1 Residential Customers

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

Figure 3-2 shows the year-end direct residential customer count for FBC.

Figure 3-2: Year-End Direct Residential Customer Count



3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a 10-year trend to the normalized historical UPCs. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2022, are then deducted

from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average customer count.

As shown in Figure 3-3 below, the residential after-savings UPC is forecast to decrease by 0.22 MWh in 2024F from 2023S and decrease by 0.13 MWh from 2023 Approved.

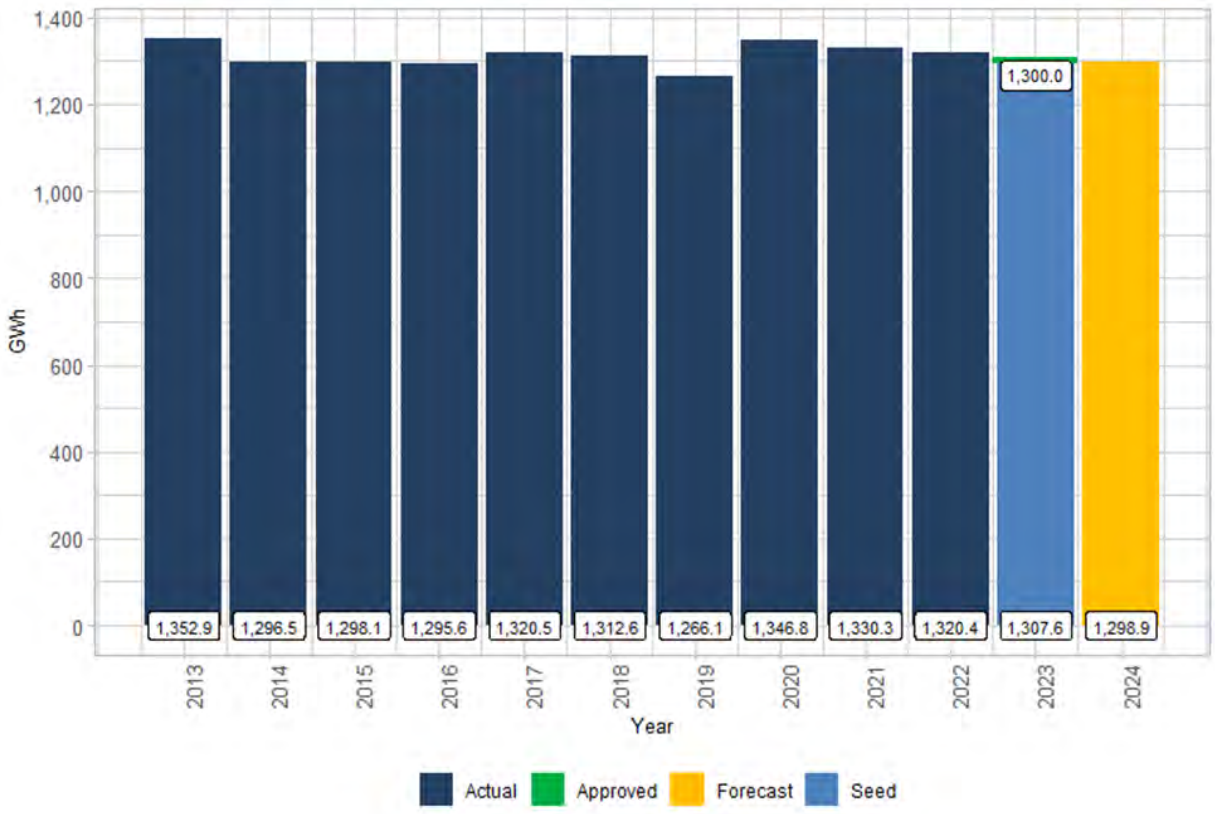
Figure 3-3: Normalized After-Savings Residential UPC (MWh)



3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings. As shown in Figure 3-4 below, residential after-DSM savings load is forecast to decrease by 8.7 GWh in 2024F from 2023S and decrease by 1.1 GWh from 2023 Approved levels.

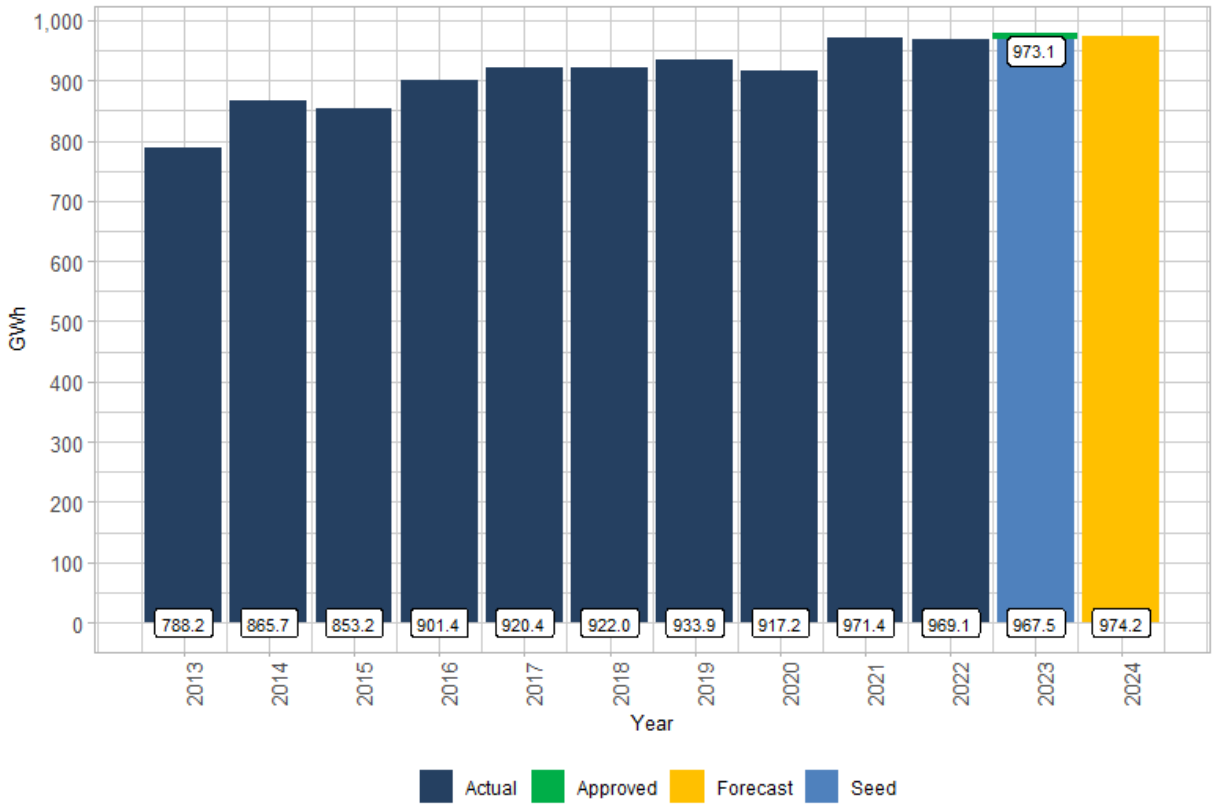
Figure 3-4: Normalized After-Savings Residential Load (GWh)



3.4.2 Commercial

The commercial class load and customer forecasts are based on regressions against the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2023S and 2024F and account for a less than 1 GWh increase in both 2023S and 2024F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 6.7 GWh in 2024F from 2023S and increase by 1.1 GWh in 2024F from 2023 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

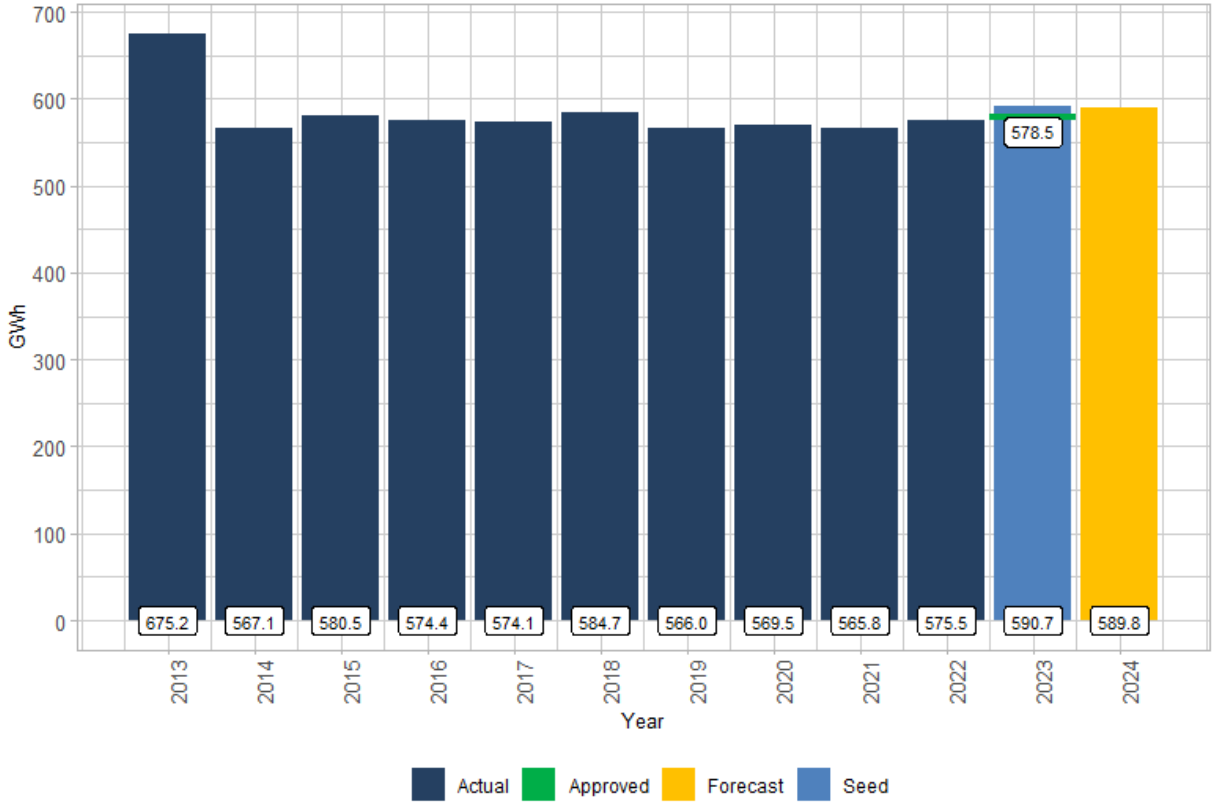
FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2024, all wholesale customers responded with their load forecasts.

Consistent with the approach taken when preparing last year's wholesale load forecast (i.e., the load forecast presented in the Annual Review for 2023 Rates), FBC once again invited each wholesale customer to a workshop. In April 2023, workshops were completed with both the City of Penticton and the City of Nelson. The remainder of the wholesale customers declined the invitation. FBC continues to find these information sharing sessions valuable and plans to continue them in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 0.9 GWh in 2024F from 2023S and increase by 11.3 GWh in 2024F from 2023 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



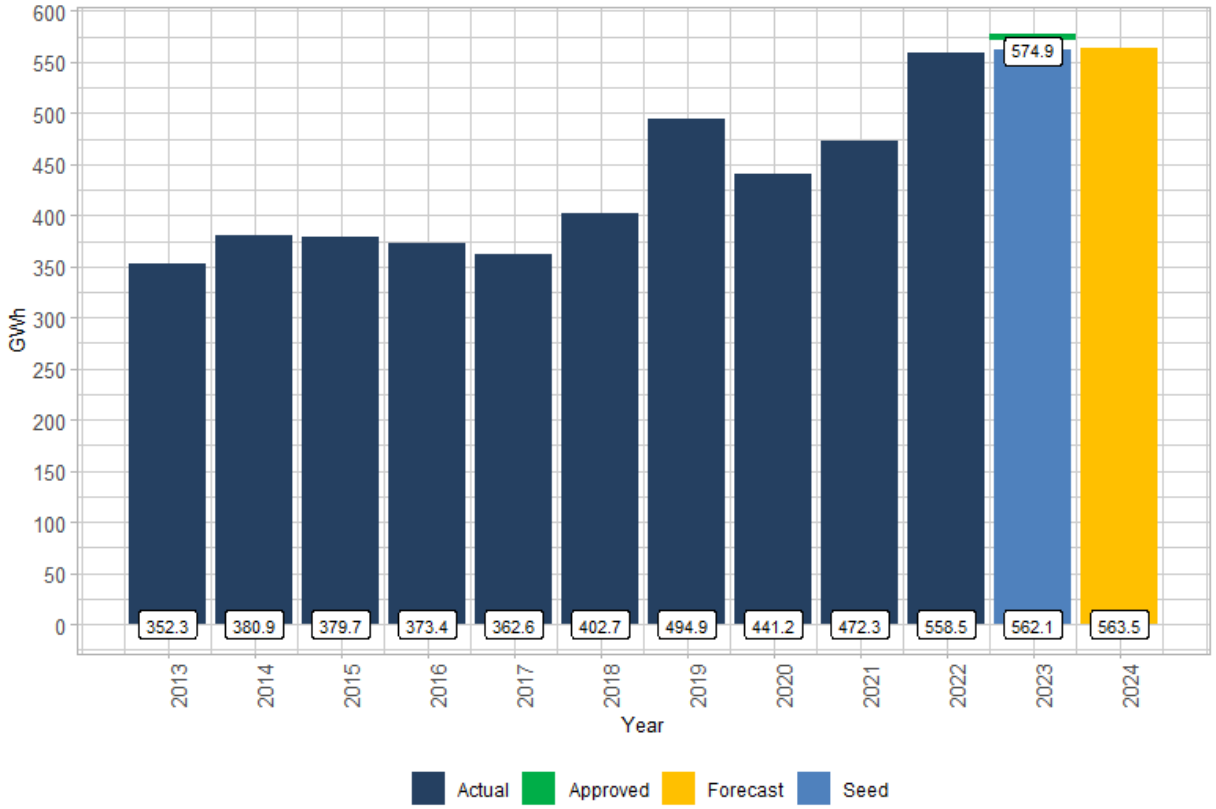
3.4.4 Industrial

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 existing industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 76 percent (32 of 42) of the surveys sent out. The responding customers represent approximately 91 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to increase by 1.4 GWh in 2024F when compared to 2023S and decrease by 11.4 GWh in 2024F compared to 2023 Approved.

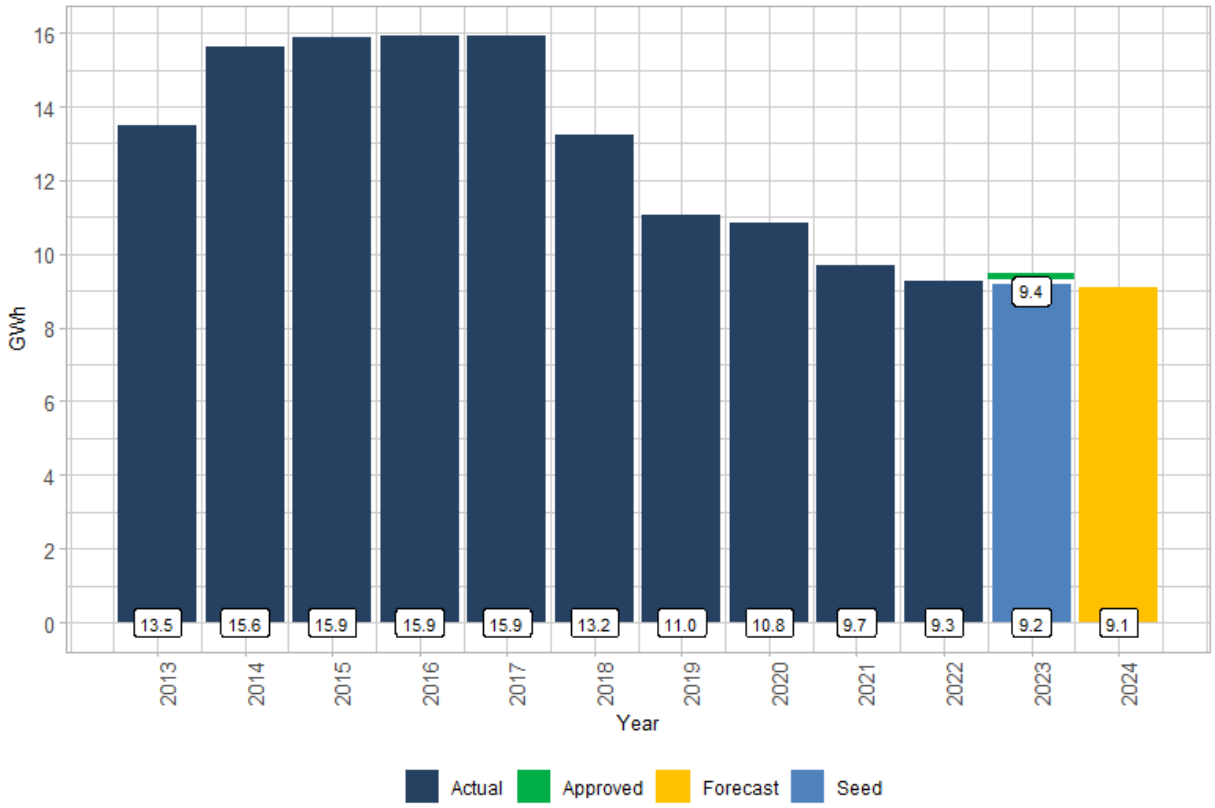
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has been declining since 2017. FBC used the 2022 actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2024F from 2023S and decrease by 0.3 GWh when compared to 2023 Approved.

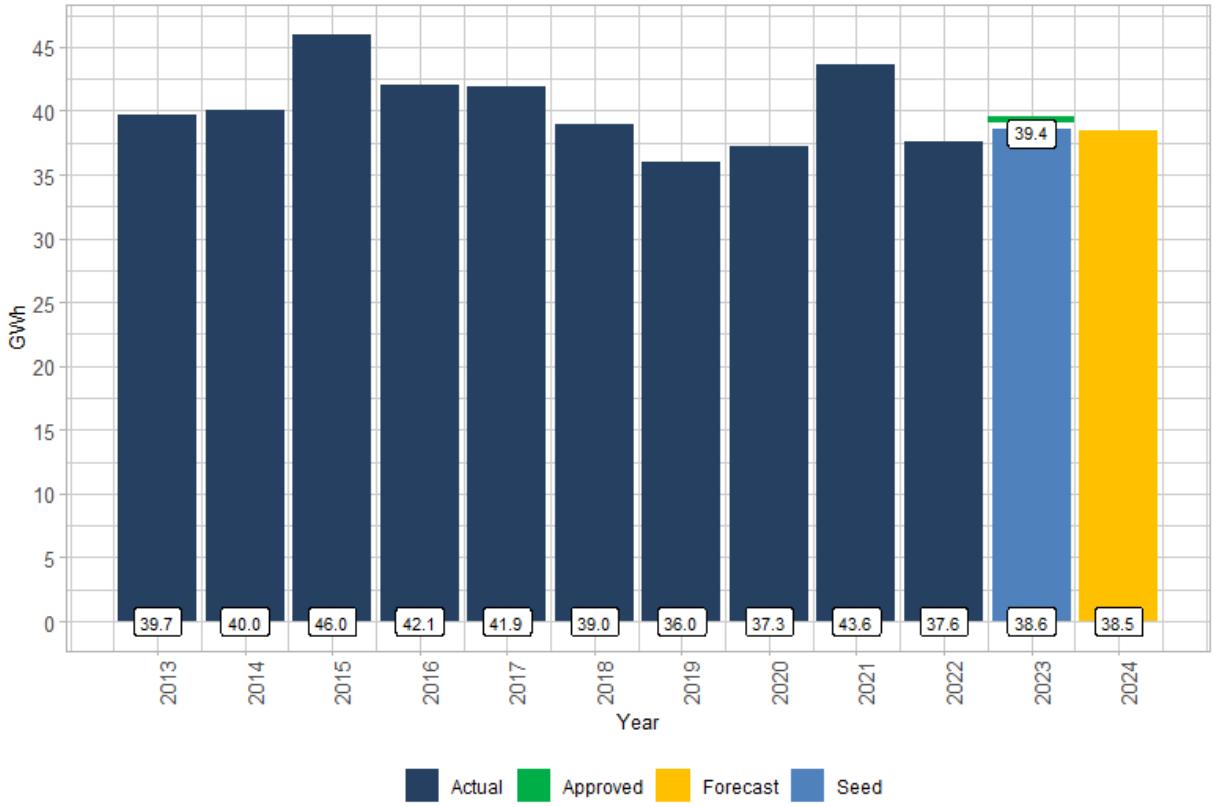
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease by 0.1 GWh from 2023S to 2024F and decrease by 0.9 GWh in 2024F when compared to 2023 Approved.

Figure 3-9: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

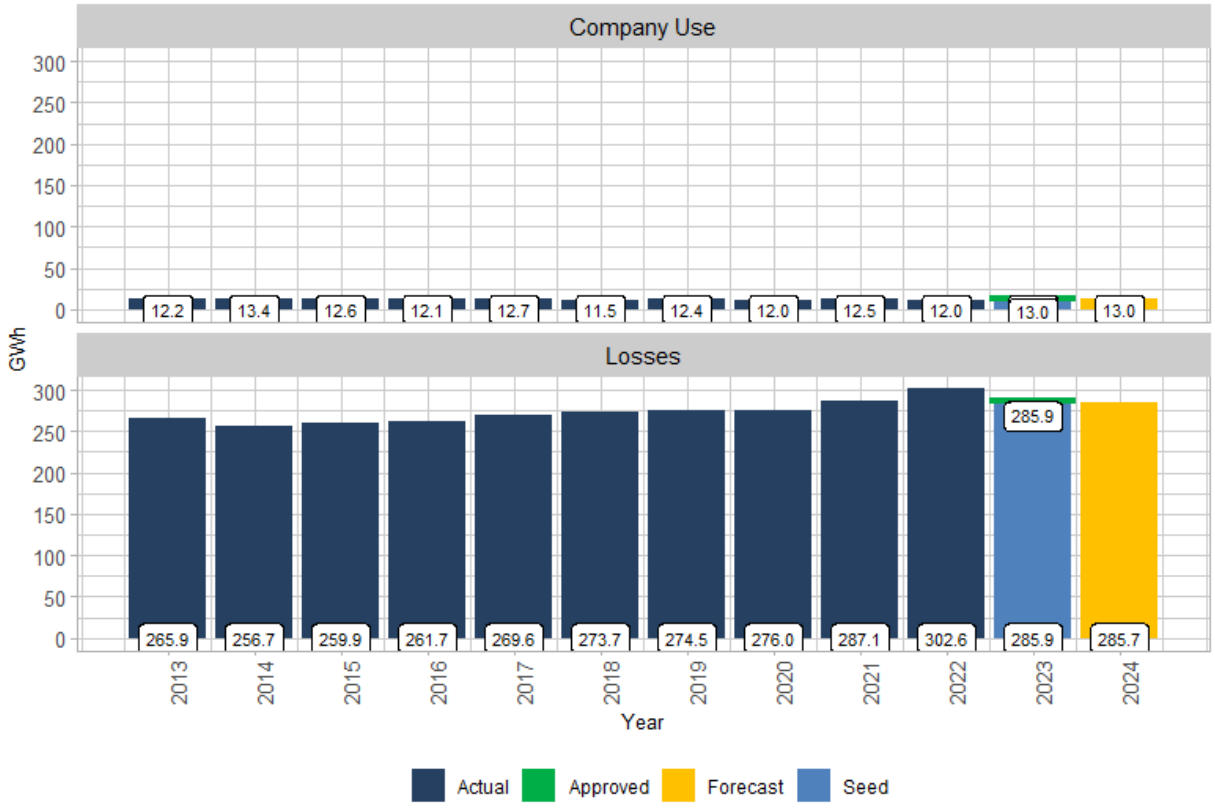
FBC conducted a Losses Study in 2019[10] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-10 below, after-savings load losses are forecast to remain constant in 2024F because the gross load is forecast to be relatively stable when compared to 2023S. When compared to 2023 Approved, the 2024F after-savings load losses are forecast to decrease by 0.2 GWh due to decreased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2024F, consistent with 2023S.

[10] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 "heat dome" event. 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.

Figures 3-11 and 3-12 below provide the historical winter peaks and summer peaks, respectively, from 2013 to 2022, as well as the estimates for 2023S and 2024F. To illustrate the non-weather-related growth in both winter and summer peaks over the last 10 years, the historical winter and summer peaks shown between 2013 and 2022 in Figures 3-11 and 3-12 below are weather-normalized and after-savings.

Furthermore, the peaks shown in both figures below are seasonal, i.e., the winter peak can fall in any month between November of the current year and February of the following year, and the summer peak can fall in any month between June and August.

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

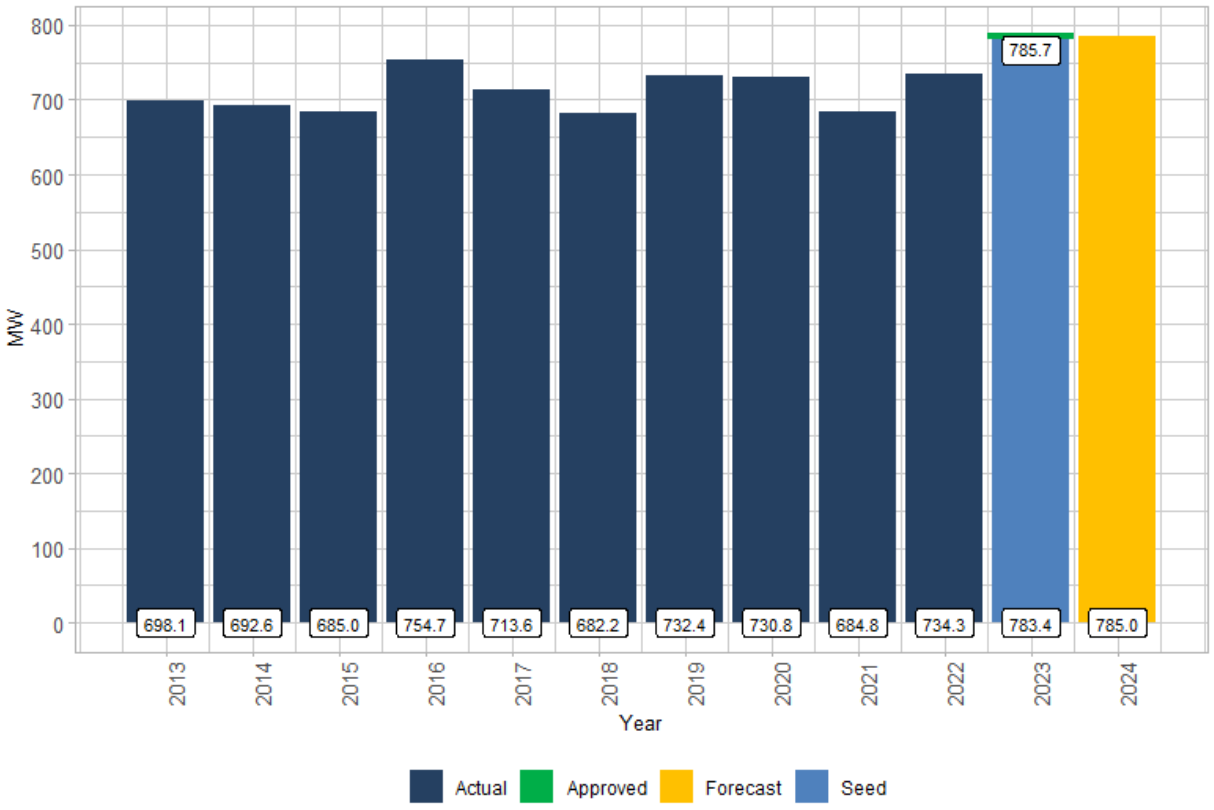
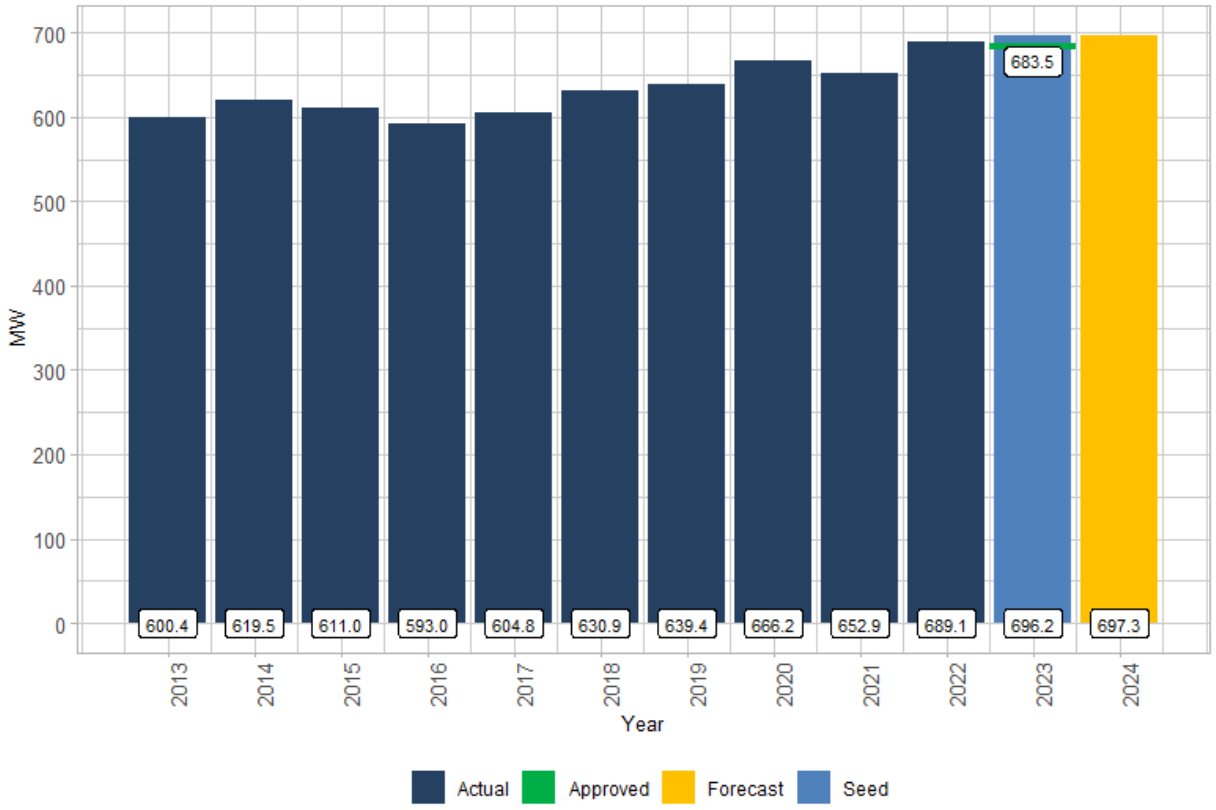


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 CUSTOMER FORECAST

Table 3-3 shows the actual and forecast year-end customer counts by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a five-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2022 levels.

Overall, for 2024F, FBC is forecasting customer growth of 1.5 percent compared to 2023S and growth of 0.7 percent compared to 2023 Approved.

Table 3-3: Customer Forecast[11]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
1	Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
2	Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
3	Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	47	49	50	50	50	52	51	43	42	42	42	42
5	Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
6	Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
7	**Total**	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.6 RATE SCHEDULE 96 EV DCFC SERVICE FORECAST

On July 14, 2021, the BCUC issued Order G-215-21, which concluded that FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR and approved flow-through treatment for the cost of service associated with the charging stations. By Order G-341-21 dated November 24, 2021, the BCUC approved the depreciation rate for the EV charging stations, and the inclusion of related revenues and expenses in FBC's regulated accounts. Following FBC's clarification on November 29, 2021 for the electricity input cost as directed in Decision and Order G-341-21, the BCUC approved the RS 96 rates on a permanent basis, by Order G-350-21 dated November 30, 2021, which include a time-based levelized rate[12] of $0.26 per minute and $0.54 per minute for FBC's 50 kW and 100 kW EV DCFC stations, respectively. FBC currently has a total of 42 EV DCFC stations in service across 22 sites and no additional stations are planned for 2023 or 2024.

As part of the Annual Review for 2022 Rates Decision and Order G-347-21[13], FBC was directed to:

- Provide an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period in future Annual Review filings.

Table 3-4 below provides the 2018 to 2022 Actual (i.e., previous fiscal years), 2023 Projected, and 2024 Forecast charging minutes and the resulting RS 96 revenues. Consistent with the approach presented in FBC's Revised and Updated EV DCFC Service Application dated September 30, 2020, the 2023 Projected and 2024 Forecast of charging minutes were determined based on the growth rates for ZEV sales targeted in the *BC ZEV Act*. These targets are 10 percent of ZEV sales by 2025, 30 percent by 2030, and 100 percent by 2040.[14]

[11] Direct customers only, i.e., excludes indirect wholesales customer counts.
[12] Including 15 percent transaction fees from FBC's EV DCFC vendor (i.e., AddEnergie, operator of the FLO EV charging network).
[13] Page 32.
[14] FBC's Revised and Updated EV DCFC Application, BCUC IR1 8.4 and CEC IR1 8.2. Additionally, as discussed in the RS 96 Assessment Report dated December 29, 2022, for forecasting purposes, FBC assumed the growth rates remain the same but are delayed by one year due to the COVID-19 pandemic.

It can be seen from Table 3-4 below that since the inception of FBC's charging stations (i.e., 50 kW in 2018 and 100 kW in 2021), the utilization rate has continued to grow, including in 2020 and 2021 when travel restrictions were in place due to the COVID-19 pandemic. Table 3-4 below also shows that there was a material increase in charging minutes from 2021 to 2022, which coincides with the ending of the aforementioned travel restrictions. FBC is expecting the upward trend will continue into 2024 with the growing number of electric vehicles available in the market. The upward trend that FBC is seeing with its EV DCFC service is consistent with the growth rates developed based on the ZEV sales targets used for the purpose of forecasting the charging minutes.

Table 3-4: FBC RS 96 EV DCFC Forecast

Line No.	Description	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024
1	RS 96 Charging Minutes							
2	50 kW	15,309	94,386	110,504	229,342	410,783	584,194	782,820
3	100 kW	-	-	-	16,539	54,933	111,234	149,053
4	Total (Minutes)	15,309	94,386	110,504	245,881	465,716	695,428	931,874
5								
6	RS 96 Revenue, excl. 15% fee ($ millions)	$ 0.004	$ 0.024	$ 0.028	$ 0.058	$ 0.116	$ 0.180	$ 0.241

Table 3-5 below provides the cost of FBC's EV DCFC service for 2022 Actual, 2023 Projected and 2024 Forecast, including the RS 96 revenues shown in Table 3-4 above, and the prior years' surplus from 2018 to 2021.

FBC is currently forecasting a cumulative deficiency of $0.932 million from 2018 to 2024, including the 2024 forecast costs and revenue. FBC notes that the current RS 96 rates are set on a levelized basis which are designed to fully recover the forecast cost of service of the charging stations over the life of the stations, as such, deficiencies are expected in the early years of the service offering. Also contributing to the cumulative deficiency to date is the impact of the COVID-19 pandemic from 2019 to 2021 on the utilization of FBC's charging stations. As mentioned above, there has been a significant increase in the utilization of FBC's charging stations since 2022 and FBC expects the growth will continue. Furthermore, consistent with the approach in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of carbon credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. Please refer to Section 5.8 for further discussion of the carbon credits associated with FBC's EV DCFC stations which are recorded as Other Revenue. FBC expects the monetization of carbon credits will continue, which should help to reduce the overall deficiency in the future.

Table 3-5: EV DCFC Stations Costs and Revenues for 2022 Actual, 2023 Projected, and 2024 Forecast ($ millions)

Line No.	Description	Actual 2022	Projected 2023	Forecast 2024	Cumulative
1	Cost of Energy	0.136	0.177	0.197	
2	O&M	0.213	0.181	0.310	
3	Depreciation	0.456	0.551	0.593	
4	Amortization of CIAC	(0.190)	(0.236)	(0.249)	
5	Other Revenue - Carbon Credits	(0.744)	(0.544)	-	
6	Income Tax	(0.007)	0.048	0.132	
7	Earned Return	0.170	0.192	0.200	
8	Total Cost of Service	0.035	0.370	1.183	
9	RS 96 Revenue	(0.116)	(0.180)	(0.241)	
10	(Surplus) / Deficiency	(0.081)	0.190	0.942	1.050
11	Prior Year 2018-2021 (Surplus)/Deficiency				(0.119)
12	Cumulative (Surplus) / Deficiency				0.932

The RS 96 revenue (i.e., Line 9 of Table 3-5 above) is part of FBC's commercial sales revenue as presented in Section 3.7 below. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 3-5 above.

As directed by Order G-341-21, FBC filed a detailed assessment of the EV DCFC service on December 29, 2022 (RS 96 Assessment Report), which was accepted by the BCUC on June 19, 2023 by Letter L-33-23. As part of the RS 96 Assessment Report, FBC committed to providing an updated RS 96 Assessment Report by December 31, 2023, if an application for energy-based rates is not filed with the BCUC prior to this date.

3.7 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2023 rates to the forecast billing determinants for each customer class. Table 3-6 below summarizes the 2023 Approved, 2023 Projected and 2024 Forecast sales revenue. The commercial sales revenue shown in Table 3-6 below also includes the revenue from FBC's RS 96 EV DCFC stations discussed in Section 3.6.

Table 3-6: Forecast Sales Revenue at Approved Rates ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Residential	$ 205.734	$ 208.939	$ 206.007
2	Commercial	110.490	111.741	110.808
3	Wholesale	54.100	55.279	55.574
4	Industrial	49.759	49.797	49.800
5	Lighting	2.295	2.298	2.221
6	Irrigation	3.695	3.666	3.967
7	Total	$ 426.073	$ 431.720	$ 428.377

When comparing the 2023 Projected to 2023 Approved, there is an increase in revenue of $5.647 million, primarily due to increases from the residential customer class, followed by increases from the commercial and wholesale customer classes.

For 2024, despite FBC forecasting a small reduction in net load of approximately 1 GWh (reduction in gross load of 2 GWh), FBC is forecasting an increase in revenue of $2.304 million when compared to 2023 Approved. The increase in revenue between 2024 Forecast and 2023 Approved is primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge). These increases are partially offset by reduced revenue from variable charges (i.e., $ per GWh) due to the forecast reduction in load from residential, industrial, and irrigation customers.

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

3.8 SUMMARY

FBC is forecasting a decrease in consumption in 2024 compared to 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is a 2 GWh decrease compared to the 2023 Approved gross load. Although the forecast load is decreasing in 2024, FBC is forecasting 2024 revenue to be $428.377 million, which is an increase of $2.304 million from 2023 Approved. This increase in revenue is primarily due to the forecast increase in load from the wholesale customers as well as an increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge), which is partially offset by reductions in load from residential, industrial, and irrigation customers.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2023 Projected and 2024 Forecast power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the power supply cost.

As shown in Table 4-1 below, the 2024 Forecast power supply cost of $193.532 million represents an increase of 6.3 percent or $11.427 million compared to the 2023 Approved cost of $182.105 million. The increase in 2024 Forecast power supply cost is driven primarily by the increase in PPE, although wheeling and water fee expenses have increased as well. The increase in the 2024 Forecast PPE is primarily the result of increased purchase rates for power. The 2024 Forecast wheeling expense has increased as a result of rates, partially offset by lower use. The 2024 Forecast water fee expense has increased compared to 2023 Approved as a result of rates and use.

Any variances between forecast and actual power supply costs 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 2023	Projected 2023	Forecast 2024
1	Power Purchase Expense	$ 163.575	$ 170.873	$ 173.694
2	Wheeling Expense	$ 6.987	$ 7.294	$ 7.324
3	Water Fees	$ 11.543	$ 12.433	$ 12.513
4	Total Power Supply Cost	$ 182.105	$ 190.600	$ 193.532
5				
6	Gross Load (GWh)	3,775	3,813	3,773

4.2 SUMMARY OF POWER SUPPLY RESOURCES

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

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year-to-year timing differences in the entitlement energy storage under the CPA;
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro RS 3808 (Order G-60-14);

4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);

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

6. A number of market purchase arrangements.

4.3 PORTFOLIO OPTIMIZATION

The primary objectives of FBC's power supply portfolio planning are:

1. to ensure that the Company has sufficient firm resources to meet expected load requirements;

2. to ensure the availability of cost-effective reliable power for FBC's customers;

3. to prudently manage exposure to the cost and availability of market power supplies; and

4. 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 most of its forecast annual energy and capacity requirements. FBC's long-term, firm resources are capable of meeting FBC's forecast capacity requirements with the exception of June and a small number of hours during July. Consistent with the capacity self-sufficiency policy in FBC's 2021 Long Term Electric Resource Plan (LTERP), FBC will procure forward market blocks to cover these shortfalls on a planning basis. In addition, FBC is now forecasting small energy shortfalls emerging in November and December starting in 2024. Consistent with the accepted 2023/24 Annual Electric Contracting Plan (AECP), FBC will purchase winter energy blocks to address tightening winter energy supply and mitigate exposure to potential extreme spot market prices, should load exceed expected levels.

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 these firm resources. However, over the past several years, the regional electricity market has been in a state of consistently higher prices compared to recent historical levels. This is due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace Tranche 1, nominated PPA purchases on a forward basis.

Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's 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 Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 FBC 2023/24 ANNUAL ELECTRIC CONTRACTING PLAN

On April 28, 2023, FBC filed its 2023/24 AECP with the BCUC. 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, 2023 and ending September 30, 2024, 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 manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy, but could be more or less, depending on system conditions.[15] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2023 and for 2024 are based on the plan detailed in the 2023/24 AECP, which was accepted by the BCUC on June 1, 2023, by Letter L-24-23.[16]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2023/24 contract year equal to 929 GWh, less any firm market contracts that FBC could enter, as described in Section 5 of the 2023/24 AECP. Prior to the June 30, 2023 nomination deadline, FBC updated its forecast load and resource balance for the 2023/24 contract year and submitted a nomination of 929 GWh.

4.5 2023 PROJECTED POWER PURCHASE EXPENSE

As shown in Table 4-2 below, FBC's 2023 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 38 GWh above the 2023 Approved value, and PPE is projected to be above the 2023 Approved value by $7.298 million. The rise in 2023 Projected PPE is primarily due to increased Market and Contracted Purchase expense as a result of increased volumes and rates.

[15] 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.

[16] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-24-23.

A majority of the increase in volume and cost was due to FBC purchasing wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year to reduce required purchases above the BC Hydro PPA Nomination. In contrast, there was a relatively small amount of wholesale market contracts included in the 2023 Approved figures, as forward market contract prices resulted in little opportunity to displace PPA on a forward basis. In addition, FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 AECP.

While forecast market savings included in the 2023 Approved[17] did materialize during the first six months of the year, FBC has not included any forecast savings for the remainder of 2023 within the Projected PPE. This is due to the current forward market price premium compared to rates for PPA purchases for the remainder of 2023.

Partially offsetting the increase in PPE is a reduction to the Waneta Expansion Expense due to increased forecast surplus sales revenue under the RCA and CEPSA.

Table 4-2: 2023 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Difference
1	Brilliant	$ 44.050	$ 44.048	$ (0.002)
2	BC Hydro PPA	71.302	70.702	(0.600)
3	Waneta Expansion	41.834	38.351	(3.483)
4	Market and Contracted Purchases	6.326	18.624	12.297
6	Independent Power Producers	0.062	0.195	0.133
7	Self-Generators	-	0.044	0.044
8	CPA Balancing Pool	(0.000)	(1.570)	(1.570)
9	Transmission Service Loss Recoveries	-	-	-
10	Special and Accounting Adjustments	-	0.479	0.479
11	Total	$ 163.575	$ 170.873	$ 7.298
12				
13	Gross Load (GWh)	3,775	3,813	38

4.6 2024 FORECAST POWER PURCHASE EXPENSE

As shown in Table 4-3 below, the 2024 Forecast PPE is $2.821 million above the 2023 Projected. The forecast increase from $170.873 million in 2023 to $173.694 million in 2024 is primarily a result of an increase in BC Hydro PPA expenses and escalation of Waneta Expansion rates. This is partially offset by a decrease in Market and Contracted Purchases due to volume. FBC is increasingly reliant on energy supplied by BC Hydro as it is generally more cost effective than the market during most times of the year. However, FBC also requires wholesale market purchases

[17] 2023 Approved included $7.000 million in potential real-time opportunities, including $3.500 million forecast for the first six months. FBC was able to exceed the $3.500 million during the first six months of 2023 but does not expect any further savings for the remainder of 2023.

to address supply gaps and reduce exposure to potentially extreme market prices, beyond what can be supplied by the PPA. Escalations to the Brilliant contract rates are also contributing to increased costs.

Table 4-3 below shows a comparison of the 2023 Projected and 2024 Forecast PPE. Reasons for significant variances from the 2023 Projected PPE are discussed below.

Table 4-3: 2024 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2023	Forecast 2024	Difference
1	Brilliant	$ 44.048	$ 44.433	$ 0.385
2	BC Hydro PPA	$ 70.702	71.680	0.978
3	Waneta Expansion	$ 38.351	40.365	2.014
4	Market and Contracted Purchases	$ 18.624	16.972	(1.652)
5	Independent Power Producers	$ 0.195	0.245	0.050
6	Self-Generators	$ 0.044	-	(0.044)
7	CPA Balancing Pool	$ (1.570)	0.000	1.570
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	$ 0.479	-	(0.479)
10	Total	$ 170.873	$ 173.694	$ 2.821
11				
12	Gross Load (GWh)	3,813	3,773	(40)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2024 by $0.385 million compared to 2023 Projected due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2024 by $0.978 million compared to the 2023 Projected expense. The drivers of the variance are a higher purchased volume (62 GWh), which increases the expense by $4.046 million, offset by a lower average purchase rate for BC Hydro PPA,[18] which accounts for a decrease of $0.068 million, for a total increase of $3.978 million. FBC has decreased its 2024 Forecast of PPA expense by $3.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2023 Projected BC Hydro expense does not include any adjustment for potential real-time opportunities for the remainder of 2023. This results in a variance between 2023 Projected and 2024 Forecast of $0.978 million[19], as shown in Table 4-3. Actual market savings for the remainder of 2023 and 2024 may be higher or lower and will depend on system and market conditions at

[18] A higher PPA nomination for the 2023/24 contract year results in less penalty charges from energy taken over and above the PPA nomination and a lower average BC Hydro PPA purchase rate.

[19] $0.978 million is calculated as follows: Total increase of $3.978 million less the $3.000 million 2024 Forecast real-time opportunities.

the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

4.6.3 Waneta Expansion

The $2.014 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, and a $0.549 million decrease in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of capacity FBC releases to Powerex and 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. CEPSA revenue is forecast using the average monthly sales revenue from the past three years. The forecast of surplus capacity sales revenue in 2024, which is included in Line 3 of Table 4-3, is approximately $13.636 million.

4.6.4 Market and Contracted Purchases

The $1.652 million decrease in Market and Contracted Purchases forecast for 2024 is a result of reduced volume when compared to 2023 Projected. Market and Contracted Purchases for 2023 Projected include fixed price contracted purchases, year to date real-time market purchases and forecast purchases in November and December 2023 at forward market rates. Market purchases included in the 2024 Forecast include fixed price contracted purchases, as well as forecast wholesale market purchases at current forward market rates to cover energy requirements in January, February, November and December, and capacity shortfalls in June and July 2024. Forecast real-time market purchases for Rate Schedule 37[20] load are also included. As discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.6.5 CPA Balancing Pool

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 2023 Projected PPE, FBC has stored a net total of 31 GWh of entitlement energy, valued at $1.570 million. For the 2024 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 TRANSMISSION SERVICE LOSS RECOVERIES

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load

[20] RS 37 is large commercial stand-by service, which is an on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2024 is 15 GWh or 0.4 percent of total gross load.

forecast (included in Tables 4-2 and 4-3, Line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2023 and 2024 loss recoveries.

Table 4-4: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Loss Recoveries	12	12	12

4.8 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 RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2023 Rates.[21] Table 4-5 below shows FBC's Wheeling Expense for 2023 and 2024.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description		Approved 2023	Projected 2023	Forecast 2024
1	Wheeling Nomination (MW Months)				
2	Okanagan Point of Interconnection		2,670	2,670	2,595
3	Creston		420	420	450
4					
5	Wheeling Expense				
6	Okanagan Point of Interconnection	$	5.555	5.786	5.813
7	Creston		0.570	0.593	0.658
8	Other		0.863	0.914	0.854
9	Total Wheeling Expense	$	6.987	7.294	7.324

Total 2023 Projected wheeling expense is $0.307 million greater than 2023 Approved. The 2023 Projected ARWA costs are $6.380 million (Lines 6 and 7 in the table above), a $0.255 million increase when compared to 2023 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2023 Projected Teck and OATT wheeling costs are $0.914 million (Line 8 above), which is $0.051 greater than 2023 Approved. This is mainly due to increased use of OATT wheeling.

[21] ARWA expense is forecast using known volumes and prior year's rates escalated by estimated BC-CPI. Teck wheeling is forecast based on the previous year's costs and escalated by 2 percent annually per contract. OATT wheeling costs are estimated using an average of prior years' expenses.

2024 Forecast wheeling expense is $0.030 million higher than 2023 Projected. This is a result of increased rates. FBC decreased the ARWA Okanagan wheeling nomination to 2,595 MW months in 2024 from 2,670 MW months in 2023. ARWA rates are forecast to increase on October 1 of both 2023 and 2024 based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

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

As shown in Table 4-6 below, the 2024 Forecast water fees are increasing by $0.080 million from the 2023 Projected due to increased rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Plant Entitlement in Previous Year (GWh)	1,571	1,585	1,561
2				
3	Water Fees	$ 11.543	$ 12.433	$ 12.513

4.10 SUMMARY

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing, as well as forecast market purchases, and is consistent with the 2023/24 AECP. Any variances in the power supply cost, including any decreases in PPE due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.[22]

FBC is forecasting Other Revenue for 2024 to be $0.149 million lower than 2023 Approved, primarily due to lower Contract Revenue and Transmission Access Revenue.

2023 Projected Other Revenue is $0.622 million higher than 2023 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Apparatus and Facilities Rental	$ 6.108	$ 6.108	$ 6.199
2	Contract Revenue	2.367	2.591	2.260
3	Transmission Access Revenue	1.834	1.716	1.723
4	Interest Income	0.030	0.035	0.037
5	Late Payment Charges	0.994	0.961	0.962
6	Connection Charges	0.553	0.553	0.561
7	EV Stations Carbon Credits	-	0.544	-
8	Other Recoveries	0.355	0.355	0.351
9	Total Other Revenue	$ 12.241	$ 12.863	$ 12.092

In the following sections, FBC summarizes its projections and 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. There are no variances projected in 2023 compared to 2023 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2024 Forecast is higher than 2023 Approved due to expected escalations in unit rental rates for continuing contracts.

[22] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

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 Company also operates and maintains a number of other facilities for third-party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[23] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2023 Projected revenue is higher than 2023 Approved due to higher expected transfer price profit revenue on facilities operated and maintained by FPHI, based on amounts earned so far in 2023. The 2024 Forecast is slightly lower than 2023 Approved due to less customer requirements expected as a result of a higher level of work performed in the last few years for one customer, which is expected to decrease the need for non-routine work.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2023 Projected revenue is lower than 2023 Approved due to a lower nomination than originally forecast for one customer. The 2024 Forecast is also lower than 2023 Approved due to lower nominations expected.

5.5 INTEREST INCOME

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans outstanding or cash balances on hand attracting interest; as a result, although higher interest rates are available, no significant changes in interest income are expected in 2023 Projected or the 2024 Forecast.

5.6 LATE PAYMENT CHARGES

As explained in the Annual Review for 2023 Rates, Late Payment Charges were historically forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to a number of factors in the most recent years, including the COVID-19 pandemic and FBC's implementation of customer relief measures, the actual amounts collected have fluctuated significantly from year to year. As these fluctuations would still be present in the most recent three years of actual results (i.e., 2020, 2021 and 2022), FBC has utilized the same

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

approach used to calculate the 2023 Approved Late Payment Charges in the 2023 Annual Review. Accordingly, the 2024 Forecast for Late Payment Charges is calculated based on the average of 2022 Actual Late Payment Charges of $0.962 million and 2023 Projected of $0.961 million. This results in a forecast decrease in Late Payment Charges of $0.032 million compared to 2023 Approved and is generally consistent with the 2023 Projected amount.

5.7 CONNECTION CHARGES

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2023 Projected is expected to be consistent with 2023 Approved based on amounts charged so far in 2023. The 2024 Forecast is expected to be slightly higher than 2023 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under Section 5 of the GGRR[24] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 for a summary of EV DCFC station costs and revenues from 2022 Actual to 2024 Forecast.

The sale of the carbon credits related to EV DCFC stations[25] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR) is recorded as Other Revenue in FBC's regulated accounts, which is embedded in the rate design of the EV DCFC stations.

FBC anticipates that 1,210 credits from the 2021 compliance period, with an approximate value of $0.544 million,[26] will be monetized prior to the end of 2023 and has therefore included this amount in 2023 Projected Other Revenue. Since FBC did not forecast any monetization of carbon credits in the 2023 Approved amount as part of the Annual Review for 2023 Rates, the variance between the 2023 Projected amount of $0.544 million and the 2023 Approved amount of zero will be captured in the Flow-through deferral account and returned to customers in 2024 rates. Consistent with the approach described in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. As noted above, the cost of service associated with EV DCFC stations is subject to flow-through treatment. Therefore, any variances between actual and forecast sales

[24] Order G-215-21 dated July 14, 2021.

[25] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's Annual Review for 2022 Rates, BCSEA IR1 4.3. Beginning in 2022, FBC is only permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.

[26] 1,210 credits x $449.20 average Q1-2023 sales price (source: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/credits-market)

of carbon credits will be captured in the Flow-through deferral account and returned to customers in the subsequent year.

5.9 OTHER RECOVERIES

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and AMI radio-off meter read fees. There are no variances expected in 2023 Projected compared to 2023 Approved based on amounts recognized to date. The 2024 Forecast is expected to be slightly lower than 2023 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 SUMMARY

FBC has forecast the Other Revenue components for 2024 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, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FBC's O&M expense is primarily determined by formula, with the addition of a certain items that are forecast outside the formula on an annual basis.

In 2024, the formula O&M is $72.823 million, representing a 3.6 percent increase from the 2023 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2024 are $1.499 million, representing a 36.2 percent decrease from the amount approved for 2023. Overall, the 2024 Forecast gross O&M expense is $74.322 million, which is an increase of approximately 2.3 percent from the 2023 Approved level.

The components of 2024 O&M expense are shown in Table 6-1 below.

Table 6-1: 2024 O&M Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula O&M	$ 70.318	$ 70.318	$ 72.823	Section 11, Schedule 20, Line 8
2	Forecast O&M	2.349	2.361	1.499	Section 11, Schedule 20, Line 20
3	Total Gross O&M	72.667	72.679	74.322	Line 1 + Line 2
4	Capitalized Overhead	(10.900)	(10.900)	(11.148)	Section 11, Schedule 20, Line 23
5	Net O&M	$ 61.767	$ 61.779	$ 63.174	Line 3 + Line 4

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2024. Additionally, in compliance with the BCUC's directive in the MRP Decision,[27] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2024 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 3.580 percent.

For 2024, the annual operating and maintenance expense under the formula is calculated as:

[27] MRP Decision, p. 118.

2023 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2022 Formula O&M True-up

Table 6-2 below shows the calculation of the 2024 Formula O&M, including the calculation of the 2022 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2022.

Table 6-2: Calculation of 2024 Formula O&M ($ millions)

Line No.	Description		Forecast 2024	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	472	G-382-22 FBC 2023 Annual Review
2	I-Factor		3.580%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	489	
4	Average Customer Forecast		148,984	Section 2, Table 2-3, Line 13
5	2024 Inflation-Indexed O&M before 2022 True-up	$	72.853	Line 3 x Line 4 / 1,000,000
6	2022 True-up O&M		(0.030)	Line 16
7	Inflation-Indexed O&M	$	72.823	Line 5 + Line 6
8				
9	2022 O&M True-up			
10	2022 Actual 12 month Average Customers		147,112	FBC 2022 Annual Report
11	2022 Forecast 12 month Average Customers		147,199	G-374-21 FBC 2022 Annual Review
12	Difference		(87)	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		(65)	Line 12 x Line 13
15	2022 Unit Costs	$	455	G-374-21 FBC 2022 Annual Review
16	O&M True-up for 2024	$	(0.030)	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2022 Formula O&M, 2022 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first three years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2022 Formula O&M	Actual 2022 O&M	2022 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.083	$ 0.434	$ 0.352	$ 0.787
2	Generation Dam Safety	$ 0.256	$ 0.111	$ (0.145)	$ (0.007)
3	Network Operations Apprentice Program	$ 0.217	$ 0.245	$ 0.027	$ (0.140)
4	Cyber Security	$ 0.088	$ 0.264	$ 0.176	$ 0.426
5	Data Analytics	$ 0.109	$ -	$ (0.109)	$ (0.316)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.754	$ 1.054	$ 0.301	$ 0.750

Notes to Table:

[1] 2022 Formula O&M is the approved 2021 formula for incremental funding with Net Inflation factor applied (4.041%).
[2] Cumulative Forecast/Actual variance is the 2020, 2021 and 2022 Actual variance.

Overall, total actual spending in 2022 was $1.054 million, which is $0.301 million higher than the 2022 Formula O&M amount. Areas with notable variances include tree management, generation dam safety, cyber security and data analytics.

For tree management, FBC spent $0.352 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.145 million less than the formula amount primarily due to the completion of dam safety review activities in 2021. As explained in Section 6.2.1 of the Annual Review for 2023 Rates, FBC spent $0.199 million more than the formula amount in 2021 due to the continuation of dam safety review activities. The spending overall on these activities has been consistent with the formula amount, as the cumulative variance is only $0.007 million for the first three years of the MRP term (as shown in Table 6-3 above).

For cyber security, FBC spent $0.176 million more than the formula amount. The higher spending was for additional consulting resources in the following areas: an additional consulting resource to augment cybersecurity requirements due to additional threat management needs; emergency management consulting for emergency exercises; physical security threat intelligence services to manage security risk; and the use of consulting services to update the business continuity program.

In data analytics, FBC spent $0.109 million less than the formula amount in 2022 primarily due to labour savings from a delay in hiring. In 2022, the focus was on building solutions in business areas including providing enhanced reporting using dashboards. For further details, please refer to Section 1.4.2 of the Application.

For the first three years of the MRP, FBC spent $0.750 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

In addition to FBC's formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost of service associated with Clean Growth initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. For 2024, FBC continues to include the incremental O&M resulting from the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the Annual Review for 2022 Rates.

The 2024 amounts are shown in Table 6-4 below along with a comparison to 2023.

Table 6-4: 2024 Forecast O&M ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Pension/OPEB (O&M Portion)	$ (1.297)	$ (1.297)	$ (2.532)
2	Insurance Premiums	2.457	2.507	2.678
3	BCUC Levies	0.385	0.385	0.458
4	Clean Growth Initiative - EV DCFC	0.219	0.181	0.310
5	Exogenous Factor - MRS	0.585	0.585	0.585
6	Total Forecast O&M	$ 2.349	$ 2.361	$ 1.499

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2024 is based upon actuarial estimates using a range of assumptions as of December 31, 2022. In addition to O&M, pension and OPEB expense is embedded in capital expenditures, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	O&M	$ (1.297)	$ (1.297)	$ (2.532)
2	Capital	1.888	1.888	1.875
3	Total Pension & OPEB Expense	$ 0.591	$ 0.591	$ (0.657)

The variance between the 2023 Approved/Projected and actual pension and OPEB expense is included in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2024 Forecast pension and OPEB expense is lower than 2023 Approved by $1.248 million. The difference is primarily due to the following factors:

- A decrease of approximately $1.7 million due to an increase in investment returns as a result of a higher balance of pension plan assets; and
- A decrease of approximately $0.3 million due to the US GAAP Pension & OPEB Transition Obligation non-rate base deferral account being fully amortized in 2023.

The above decreases are offset in part by:

- An approximate increase of $0.8 million in interest costs due to an increased discount rate, which is determined with reference to the market rate of interest on high-quality debt instruments at a point in time (a discount rate of 4.50 percent was used to determine the 2023 Approved expense compared to a discount rate of 5.25 percent used to determine the 2024 Forecast expense).

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Insurance Premiums	$ 2.457	$ 2.507	$ 2.678

FBC's annual insurance renewal occurs in July of each year. The 2023 Projected insurance premium expense of $2.507 million is $0.050 million higher than 2023 Approved, as it incorporates the first six months of FBC's actual July 2023 to June 2024 insurance renewals. The 2024 Forecast is $2.678 million, which is an increase of $0.171 million from 2023 Projected. The 2024 Forecast is calculated based on the six months of actual insurance premiums from July 2023 to June 2024 of $1.234 million, plus a 5 percent increase for the remaining six months, and the cost of fire fighting services FBC pays to the Province of $0.148 million.[28]

6.3.3 BCUC Levies

FBC's 2024 Forecast for BCUC levies is $0.458 million. The 2024 Forecast is based on Order G-134-23 for the BCUC's Fiscal 2023/24 year, which represents the best information available at

[28] $2.468 million/2 = $1.234 million. $1.234 million x 1.05 = $1.295 million. $1.234 million + $1.295 million + $0.148 million annual firefighting service fee = $2.678 million.

this time, as the BCUC levy calculation for its Fiscal 2024/25 year will not be available until early or mid 2024.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[29] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 6-7 below provides a breakdown of the 2023 Approved, 2023 Projected and 2024 Forecast O&M expenses for FBC's EV DCFC service. The O&M expenses consist of network management, repairs and maintenance, inspection fees, FBC internal labour, and the electricity costs from third-party utilities (i.e., for stations in Grand Forks, Nelson, and Penticton).

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Network Management	$ 0.047	$ 0.037	$ 0.050
2	Repairs and Maintenance	0.009	0.040	0.050
3	Inspection Fees	0.067	0.042	0.096
4	FBC Labour Costs	0.070	0.030	0.070
5	Third Party Utilities Costs	0.026	0.032	0.044
6	Total	$ 0.219	$ 0.181	$ 0.310

As shown in Table 6-7 above, the 2023 Projected O&M expense for the EV DCFC service is $0.038 million lower than 2023 Approved. This is primarily due to reduced FBC labour costs as a result of a vacancy, and reduced inspection fees as the new inspection agreement did not commence until mid-2023. These decreases are partially offset by the increase in repairs and maintenance costs as well as the increase in third-party utilities costs. The 2023 Projected repairs and maintenance costs are higher than 2023 Approved because the 2023 Approved amount did not account for the regular maintenance costs for stations where the warranty period expired, whereas the 2023 Projected amount includes an estimate of the ongoing regular maintenance costs at stations that are no longer covered by the vendor's warranty period. With regard to the increase in third-party utilities costs, this is primarily due to increased utilization at the stations located in the service areas of third-party utilities (i.e., Grand Forks, Nelson, and Penticton) as well as the rate increases by the third-party utilities.

[29] Order G-215-21 dated July 14, 2021.

The 2024 Forecast is $0.129 million higher than 2023 Projected. This is primarily due to increased inspection fees due to the full year impact of the inspection agreement, and higher FBC labour costs as FBC expects to fill the vacancy for 2024. Other drivers of the increase are higher FLO Global Management Service fees for network management, as well as an increase in third-party utilities costs due to a combination of expected increases in utilization of stations located in the service areas of the third-party utilities and the estimated increase in the rates of the third-party utilities.

6.3.5 MRS Incremental Operating Expenses

In the Annual Review for 2022 Rates Decision,[30] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the Annual Review for 2022 Rates proceeding, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[31].

Table 6-8 below provides the 2023 Approved, 2023 Projected, and 2024 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Labour	$ 0.490	$ 0.490	$ 0.490
2	Non-Labour	0.095	0.095	0.095
3	Total	$ 0.585	$ 0.585	$ 0.585

The 2023 Projected O&M is consistent with 2023 Approved. For 2024, FBC is forecasting the same level of spending as in 2023. The spending is related to the ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. As noted in the Annual Review for 2022 Rates, FBC expects these costs to continue in future years.

6.4 NET O&M EXPENSE

Net O&M expense is gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2023. After capitalized overhead, the net O&M expense is $63.174 million in 2024.

[30] Decision and Order G-374-21, p. 21.
[31] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2023 Approved to 2024 Forecast is 2.3 percent. Formula-driven O&M is increasing at a rate of 3.6 percent while O&M forecast outside the formula is decreasing by approximately 36.2 percent from 2023 Approved.

The capitalized overhead rate for 2024 remains unchanged from 2023.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.714 billion for 2024. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[32]

FBC's 2024 Rate Base includes the full-year impacts of the 2023 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $97.783 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $66.744 million; and
- Capital additions of CPCNs and other Major Projects totalling $5.500 million, as discussed in Section 7.3 below, which include:
    - Full-year impact of $2.769 million for the final capital expenditures and related AFUDC in 2023 for the Kelowna Bulk Transformer Additions (KBTA) Project; and
    - Full-year impact of $2.731 million for the final capital expenditures and related AFUDC in 2023 for the Corra Linn Dam Spillway Gates Replacement Project.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $2.735 million in 2024.

Details of the 2024 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures (i.e., growth, sustainment, and other) for the years 2020 through 2022; and
- Approval of several items to be forecast on an annual basis.

Further, as part of FBC's 2023 Annual Review Decision and Order G-382-22, and Reconsideration Decision and Order G-87-23, FBC received approval of its forecasts of regular capital expenditures for the years 2023 and 2024.

The components of FBC's 2024 regular capital expenditures are shown in Table 7-1 below.

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

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Forecast Capital	$ 92.440	$ 92.440	$ 93.433	Table 7-2, Line 4
2	Flow-Through Capital	0.248	0.580	0.500	Table 7-3, Line 2
3	Total Gross Regular Capital	$ 92.688	$ 93.020	$ 93.933	Sum of Lines 1 & 2
4	Less CIAC	(11.628)	(11.623)	(7.539)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 81.060	$ 81.397	$ 86.394	Sum of Lines 3 & 4

FBC notes that, pursuant to Order G-135-23, FBC is directed to file a CPCN application for the Fruitvale Substation Project prior to the start of construction. This project was included in the approved regular capital expenditure forecasts for 2023 and 2024. As the Fruitvale Substation Project now requires a CPCN, FBC has removed the capital expenditures from the 2023 Approved, 2023 Projected, and 2024 Forecast regular capital amounts shown in Tables 7-1 and 7-2 (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). These expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. Please refer to Section 7.3 for further detail.

In the subsections below, FBC provides further details on its regular capital expenditures for 2024.

7.2.1 Approved Capital Expenditures

The level of forecast capital expenditures approved for 2024 by Orders G-382-22[33] and G-87-23[34] is shown in Table 7-2 below. As discussed above, following Order G-135-23, FBC removed the 2023 Approved, 2023 Projected and 2024 Forecast sustainment capital expenditures related to the Fruitvale Substation Project; therefore, the amounts shown in Table 7-2 exclude the Fruitvale Substation Project expenditures.

Table 7-2: Approved Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Growth Capital	$ 30.072	$ 30.072	$ 24.568	Section 11, Schedule 4, Line 2
2	Sustainment Capital	44.710	44.710	51.652	Section 11, Schedule 4, Line 3
3	Other Capital	17.658	17.658	17.213	Section 11, Schedule 4, Line 4
4	Total	$ 92.440	$ 92.440	$ 93.433	Section 11, Schedule 4, Line 5

[33] FBC Annual Review for 2023 Rates Decision and Order G-382-22.
[34] FBC Reconsideration Decision and Order G-87-23 regarding the FBC Application for Reconsideration and Variance of Decision and Order G-382-22.

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to Clean Growth initiatives, or because of the uncertainty in scope, costs and timing.

The amounts for 2024 are shown in Table 7-3 below along with a comparison to 2023.

Table 7-3: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Clean Growth Initiative - EV DCFC	0.248	0.580	0.500	
2	Total Forecast Capital Expenditures	$ 0.248	$ 0.580	$ 0.500	Section 11, Schedule 4, Line 8

7.2.2.1 EV DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[35], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 3-5 of Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 7-3 above shows the EV DCFC stations capital expenditures for 2023 Approved, 2023 Projected, and 2024 Forecast. The 2023 Projected EV DCFC stations capital expenditures are $0.332 million higher than 2023 Approved, primarily due to unbilled charges from 2022 construction activities, which are related to the planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21.[36] The construction was completed in 2022, but FBC did not receive all invoices for the work until 2023.

The 2024 Forecast capital expenditures are related to the accessibility improvement work at FBC's existing EV DCFC sites that was started in 2023. In 2023, FBC is projecting to complete the improvement work at four sites (which was included as part of the 2023 Approved expenditures), while the remaining sites are expected to complete in 2024. As noted in the Annual Review for 2023 Rates, the scope of the improvements include new or additional lighting, as the stations are available for use 24 hours a day, and paving for wheelchair access to the charger.

FBC is not forecasting the construction of any additional stations in 2024 at this time; however, FBC will continue to monitor the station utilization and customer demand to determine if additional stations are warranted.

[35] Order G-215-21 dated July 14, 2021.
[36] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[37] the BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

For 2024, FBC is not forecasting any capital expenditures related to Major Projects. However, FBC's 2024 Forecast rate base includes the full-year impact of capital additions related to the KBTA Project and the Corra Linn Dam Spillway Gate Replacement Project. FBC also provides a brief discussion on the Fruitvale Substation Project, as FBC is expecting to submit a CPCN application for this project in 2023. Each of these projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The project is expected to complete in 2023 with an estimated final cost of $23.287 million, inclusive of AFUDC and cost of removal. A total of $19.941 million (plus $0.577 million of removal costs) were included in FBC's rate base on January 1, 2023, with the remaining $2.769 million expected to enter FBC's rate base on January 1, 2024.

Corra Linn Dam Spillway Gates Replacement Project

The Corra Linn Dam Spillway Gates Replacement Project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. As explained in FBC's Reconsideration Application to the Decision and Order G-382-22 for the Annual Review for 2023 Rates, which was approved by Order G-87-23, the replacement of all spillway gates was complete in 2022 and the costs were included in FBC's rate base between 2018 and 2023, with the remaining close-out activities delayed to 2023. The close-out activities, including lighting, outstanding claims, and clean-up, are estimated to be approximately $2.731 million and are expected to be complete in 2023; therefore, the costs are forecast to enter FBC's rate base on January 1, 2024. The final project cost is expected to be $80.835 million, inclusive of AFUDC and removal costs.

Fruitvale Substation Project

The Fruitvale Substation Project was included as part of FBC's regular capital forecasts for 2023 and 2024 in the Annual Review for 2023 Rates (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). FBC's 2023 and 2024 regular capital forecasts were approved as part of the BCUC's Decision and Order G-382-22. However, following a complaint regarding the location of the proposed substation in Fruitvale, the BCUC issued Order G-135-23 on June 9, 2023, directing FBC to file an application for a CPCN related to the proposed Fruitvale Substation

[37] MRP Decision and Order G-166-20, pp. 132-133.

Project. As discussed in Section 7.2, FBC has removed the 2023 and 2024 capital expenditures related to the Fruitvale Substation Project from regular capital, as the expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. FBC expects to file an application for a CPCN for the Fruitvale Substation Project before the end of 2023.

7.4 2024 PLANT ADDITIONS

The 2024 Plant Additions are comprised of: (i) FBC's 2024 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-4: Reconciliation of 2024 Capital Expenditures to Plant Additions ($ millions)[38]

Line No.	Description		Forecast 2024	Reference
1	Forecast Capital Expenditures	$	93.433	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.500	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		93.933	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		11.148	Section 11, Schedule 5, Line 16
6	AFUDC		0.241	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.322**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN			
11	Capital Expenditures		-	Section 11, Schedule 5, Line 22
12	AFUDC		0.001	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		5.499	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**5.500**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**110.822**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

[38] Line 11 of Table 7-4 is zero because, as described in Section 7.3, there are no capital expenditures forecast in 2024 for the two approved CPCN Projects (i.e., the KBTA Project and the Corra Linn Dam Spillway Gates Replacement Project). Further, FBC will be filing for a CPCN related to the Fruitvale Substation Project in 2023, as such, FBC has not included the forecast capital expenditures related to this project.

The depreciation rates used for 2024, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, 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 by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2024 depreciation expense is calculated as $66.744 million.[39]

7.6 DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[40] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The 2024 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $51.287 million.

The 2024 debit balance is driven largely by the balance in the Demand Side Management (DSM) deferral account of $44.063 million.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[39] $72.053 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.309 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[40] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on the approved amortization and the opening balances of each deferral account, the amortization expense, including both rate base and non-rate base deferral accounts, is calculated to be a credit of $2.860 million,[41] which will be returned to customers through the proposed 2024 rates. The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FBC is seeking approval to create five new rate base deferral accounts in this Application:

- 2025 Multi-year Rate Plan (MRP) Application;
- 2024 Mandatory Reliability Standards Audit;
- PST Rebate on Select Machinery and Equipment;
- BC Cost of Living Credit; and
- Climate Change Operational Adaptation (CCOA) Plan.

Table 7-5 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to each deferral accounts requested. For a detailed description of each deferral account, please refer to Sections 7.6.1.1 to 7.6.1.5 below.

[41] Section 11, Schedule 21, Column 3, Sum of Lines 5 and 6.

Table 7-5: Deferral Account Filing Considerations

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The 2025 MRP Application is a new deferral account. Please refer to Section 7.6.1.1 for additional information.	The 2024 MRS Audit is a new deferral account. Please refer to Section 7.6.1.2 for additional information.	The PST Rebate on Select Machinery and Equipment is a new deferral account. Please refer to Section 7.6.1.3 for additional information.	The BC Hydro Cost of Living Credit is a new deferral account. Please refer to Section 7.6.1.4 for additional information.	The Climate Change Operation Adaptation Plan is a new deferral account. Please refer to Section 7.6.1.5 for additional information.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A	N/A	N/A	N/A	N/A

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested account is a regulatory proceeding cost account, which is routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.	The requested account will capture periodic incremental costs of the MRS compliance audit.	The requested account will capture PST Rebates on Select Machinery and Equipment received from the Province of BC.	The requested account will capture the residual balance of the BC Cost of Living Credit.	The requested account will capture costs related to the development of the Climate Change Operational Adaptation Plan.
II.	Propose a term (i.e., length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of the account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.	The term of the account encompasses the required time to conduct the audit.	The term of the account encompasses the required time for the Province of BC to approve the qualified claim filed by FBC and issue the refund payment.	The term of the account encompasses the time required to distribute the credits to all applicable customers.	The term of the account encompasses the time required for the development of the CCOA Plan and subsequent business cases as discussed in the 2021 Long Term Electric Resource Plan (LTERP).
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the MRP index-based O&M as regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the	In the absence of a deferral account, the audit costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome	In the absence of a deferral account, the rebate would be recorded as an offset in the applicable accounts where the original PST costs were recorded, whether those accounts were O&M or capital. FBC considers this to be a less transparent way of recording the rebates as it is the cost-of-	In the absence of a deferral account, the credit would remain in an FBC liability account until the residual balance is distributed through inquiries. FBC does not expect there will be enough inquiries to distribute the total residual balance. Eventually, the residual balance would be recorded as	In the absence of a deferral account, the costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
		Flow-Through deferral account. FBC considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report.	and less efficient means of managing the audit costs. In addition, the use of a deferral account permits multi-year cost recovery, which is consistent with the three-year period between audits, as opposed to recovery in a single year.	service impacts of the amounts credited to capital that would be returned to customers over a longer timeframe, rather than the rebate amount itself over one year as proposed using the deferral account approach.	income, and FBC would need to request a method of returning that income to customers, either via the Flow-Through deferral or by including the amount in its revenue requirements. The use of a deferral account permits the remaining credits to be used to benefit all customers, in a timely and efficient manner, consistent with the purpose of the credit.	and less efficient means of managing these costs.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
IV a)	Address: whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the BCUC and the degree of involvement of interveners.	Compliance audits of MRS are conducted every three years. The scope and complexity of audits varies depending on the standards under review and are not within the control of the Company.	The final amount of PST rebates claimed by FBC are subject to approval by the Province of BC.	The amount of credit available to FBC and the eligibility criteria was determined by the Province of BC.	As a result of the ongoing impacts of global climate change, FBC has determined it is imperative to address the risks of climate change risk on its system. Therefore, although direct costs are within Management's control, the need to incur these costs is considered necessary.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FBC forecasts additions to the deferral account based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on past audit experience. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on the rebates received to date plus those claimed and expected to be received. Actual expected rebates will be recorded in the account so that actual, not forecast, rebates are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on the residual balance of credits remaining to date. The actual residual balance, inclusive of further eligible inquiries, will be recorded in the account so that the actual, not forecast, remaining credits are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on expected incremental resources required to complete the plan. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the MRP. Please refer to Section 7.6.1.1 for additional information.	Audit preparation and participation impacts many individuals and business units and is not manageable within FBC's formula O&M Expense. FBC expects costs related to the MRS Audit of approximately $0.375 million ($0.274 million after-tax). Please refer to Section 7.6.1.2 for additional information.	FBC expects rebates of approximately $0.591 million ($0.431 million after-tax). Please refer to Section 7.6.1.3 for additional information.	FBC expects the remaining credit to be approximately $0.507 million ($0.370 million after-tax). Please refer to Section 7.6.1.4 for additional information.	FBC expects costs related to the CCOA Plan of approximately $0.225 million ($0.164 million after tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. Please refer to Section 7.6.1.5 for additional information.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
d)	any impact on intergenerational equity	Generally, FBC recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.	FBC expects to recover the audit costs over the period of time between audits, which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.	FBC expects to return the rebates over the same period of time as the qualifying period to make the PST rebate claims. There are no intergenerational inequities in this practice.	FBC expects to return the remaining credit over the same period of time as the credit is made available by the Province of BC. There are no intergenerational inequities in this practice.	FBC expects to recover the costs of the CCOA Plan over the period of time required to develop the plan and subsequent business cases as outlined in the 2021 LTERP. There are no intergenerational inequities inherent in this practice.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC generally classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.	The account is classified as a benefit matching account since the costs will be recovered over the period of time between audits, which serves to match the costs and benefits of the audit.	The account is classified as “other”.	The account is classified as “other”.	The account is classified as “other”.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.	The MRS Audit deferral account is a cash account.	The PST Rebate on Select Machinery and Equipment is a cash account.	The BC Cost of Living Credit deferral account is a cash account.	The Climate Change Operational Adaptation Plan deferral account is a cash account.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the BCUC's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M Expense.	Eligible costs are incremental to ongoing MRS expenses and include labour, consulting and miscellaneous expenses not included in formula O&M Expense.	PST Rebates received from the Province of BC for claims filed by FBC for the qualifying period. Please refer to Section 7.6.1.3 for additional information.	The remaining credit is the total funds received by FBC less any credit already applied to customer bills as of June 2023. FBC will continue to capture any credits provided to customers from eligible inquiries for the credit. Please refer to Section 7.6.1.4 for additional information.	Eligible costs include fees for consultants required for the development of the plan.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.	Rebates will be refunded in revenue requirements by way of amortization expense.	Credits will be refunded in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally, FBC proposes to amortize the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. Please refer to Sections 7.6.1.1 for additional information.	FBC proposes to amortize the costs over three years beginning January 1, 2024, to reflect the period until the next audit. Recovery of the costs over the period of time between audits serves to match the costs and benefits of the audit. Please refer to Section 7.6.1.2 for additional information.	FBC proposes to refund the rebates over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases. Please refer to Section 7.6.1.3 for additional information.	FBC proposes to refund the remaining credits over one year beginning January 1, 2024. Please refer to Section 7.6.1.4 for additional information.	FBC proposes to amortize the costs over four years beginning January 1, 2024 to reflect the CCOA Plan timeline discussed in the 2021 LTERP. Please refer to Section 7.6.1.5 for additional information.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and therefore, implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings.				

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7.6.1.1 2025 Multi-Year Rate Plan (MRP) Application

FBC's current Multi-year Rate Plan (MRP) approved by Order G-166-20 will end in 2024. FBC has started developing its next rate plan and expects to file this rate plan with the BCUC in early 2024. FBC will incur regulatory costs related to the development of the application and is requesting approval to establish a rate base deferral account to capture these costs, which will include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs. FBC forecasts costs of $0.350 million ($0.256 million after-tax) in 2023 and $1.200 million ($0.876 million after-tax) in 2024. Actual costs will vary depending on how the application progresses and will be confirmed after the regulatory process is completed.

FBC is only requesting approval to establish this deferral account. FBC will propose an amortization period for the deferral account in a future rate-setting application (i.e., subsequent to the completion of the 2025 MRP application proceeding).

7.6.1.2 2024 Mandatory Reliability Standards (MRS) Audit

FBC's triennial MRS compliance audit is scheduled to occur in 2024. This audit will be performed by the administrator of the BC MRS Program, the Western Electricity Coordinating Council (WECC), and will include a review, at minimum, of all applicable reliability standards identified in the Actively Monitored List. This will include Critical Infrastructure Protection (CIP) and Operations and Planning (O&P) standards. Eligible costs are incremental labour and expenses directly caused by the periodic audit and therefore not included in Formula O&M Expense. Based on previous audits, FBC forecasts costs of $0.375 million before tax ($0.274 after tax) in 2024.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the 2024 MRS Audit. Further, FBC is proposing to amortize these costs over three years beginning January 1, 2024. This amortization period is appropriate as it reflects the period until the next MRS triennial audit.

7.6.1.3 PST Rebate on Select Machinery and Equipment

The BC PST Rebate on Select Machinery and Equipment is a provincial government program to help corporations recover from the financial impacts of the COVID-19 pandemic. Eligible businesses can receive as a rebate the PST paid on purchases of specified equipment and software during the qualifying period between September 17, 2020 and March 31, 2022.

FBC is eligible to claim a BC PST Rebate on Select Machinery and Equipment on capital purchases of software and equipment and has filed for these rebates for the qualifying periods as set out by the Province of BC. To date, FBC has received $0.029 million ($0.021 million after-tax) in rebates and expects additional rebates of approximately $0.562 million ($0.410 million after-tax) to be received by December 31, 2023.

FBC is requesting approval to establish a rate base deferral account to capture the PST Rebates on Select Machinery and Equipment received from the Province of BC. Further, FBC is proposing to amortize these rebates to customers over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases.

7.6.1.4 BC Cost of Living Credit

On November 18, 2022, the Province of BC issued OIC 571/2022[42] for a one-time cost-of-living credit to all eligible residential and commercial electricity customers through a BC Hydro bill credit, including those who receive their electricity service from FBC or a municipal utility.

FBC received funds through BC Hydro for applying the credits to all eligible residential electricity customers in the amount of a one-time $100 cost-of-living credit and to all eligible commercial electricity customers as a one-time bill credit calculated based on their prior year electricity consumption.

FBC received a total of $23.816 million and applied $23.290 million of credits to all eligible customers as of March 10, 2023. In addition to the bill credits applied to eligible customers, FBC has committed to provide credits to customers if/when a customer inquires about such credits to FBC (and if the customer is determined to be eligible)[43]. Between March 10, 2023 and May 31, 2023, FBC received a total of six inquiries (three residential and three commercial customers), resulting in a further $0.019 million of credits applied. The total credits applied to eligible customers as of June 10, 2023 are therefore $23.309 million, with $0.507 million ($0.370 million after-tax) of residual credits which FBC proposes to include as a credit amortization (i.e., return to all customers) in 2024 rates.

FBC requested and received confirmation from the Ministry of Energy, Mines and Low Carbon Innovation (EMLI) that there is no expectation or requirement for FBC to return the residual credits to either BC Hydro or the Province of BC. Furthermore, EMLI agreed that the remaining funds could be used to benefit all FBC customers through rates, which is consistent with the purpose of the bill credits. As such, FBC is requesting approval in this Application to establish a rate base deferral account to capture the residual balance of the BC Cost of Living Credit and to amortize the residual credits to customers through rates over a one-year period beginning January 1, 2024.

As agreed with EMLI, FBC will continue to field inquiries from customers and will provide bill credits to customers that are determined to be eligible. As noted above, FBC only received a total of six inquiries from March to May 2023 and has received no inquiries since then. As such, FBC is expecting a very limited number of inquiries to occur in the remaining months of 2023 and into 2024. However, should any further bill credits be issued to eligible customers in 2023 or 2024, FBC will record these issued amounts in the deferral account. If there is any remaining balance

[42] https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0571_2022.

[43] OIC 571/2022 sets out the eligibility criteria which defined that customers must be a customer and receiving service on October 1, 2022. Due to the timing lapse between October 1, 2022 and when the credits are distributed starting from December 2022 to March 2023 (the credit was announced by the Province of BC on November 18, 2022), customers could be connecting to and/or leaving FBC's system, potentially resulting in eligible customers not receiving the bill credit. As such, FBC agreed to field inquiries and continue to pay out any eligible credits.

(credit or debit) at the end of 2024, FBC will amortize the remaining balance into rates in the subsequent year (i.e., 2025).

7.6.1.5 Climate Change Operational Adaptation (CCOA) Plan

As discussed in FBC's most recent Long Term Electric Resource Plan (2021 LTERP) accepted by Order G-380-22, the threat that climate change presents to FBC infrastructure and operations is a continuing reality that FBC is taking seriously; accordingly, FBC is developing a roadmap for climate change adaptation.[44] FBC's Climate Change Operational Adaptation (CCOA) Plan focuses on addressing the climate change risks associated with five hazards: wildfires, flooding, extreme temperatures, snowstorms, and windstorms. During the initial phase of the CCOA Plan, FBC is working with consultants to identify assets vulnerable to each hazard, define the current and future risk profiles of the vulnerable assets due to these hazards, and propose adaptation strategies. These strategies may consist of, but are not limited to, system hardening, asset replacement, or modification of design standards. Future phases will apply these results and strategies to existing assets to determine whether risk reduction projects will be required.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the CCOA Plan. FBC forecasts costs of $0.225 million ($0.164 million after-tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. The costs are primarily related to the resources required to develop the roadmap for climate change adaptation and, stemming from the roadmap, develop the business cases for the five key hazard areas (i.e., wildfires, flooding, extreme temperatures, snowstorms and windstorms). FBC is proposing to amortize these costs over four years beginning January 1, 2024. This period aligns with the CCOA Plan timeline discussed in the 2021 LTERP, which states that the development of the CCOA Plan and subsequent business cases would occur between now and 2027. FBC will continue to provide updates on the progress of the CCOA Plan and the deferral account in future annual reviews or revenue requirement applications.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on one existing deferral account.

7.6.2.1 Princeton Office Disposition Deferral Account

On January 24, 2023, pursuant to Order G-14-23, FBC was approved to sell the Princeton Office Properties, consisting of the land and buildings located on Bridge Street in Princeton, BC, to the Town of Princeton. FBC was also approved to establish the Princeton Office Disposition non-rate base deferral account to capture the net gain on the sale, and to transfer the balance in the non-rate base deferral account to a rate base deferral account on January 1, 2024 and commence amortization of the deferral account over one year in 2024. FBC was directed to provide details

[44] FBC 2021 LTERP Application, p. 140; Exhibit B-2, BCUC IR1 24.4.

on the final balance in the Princeton Office Disposition deferral account in the Annual Review for 2024 Rates.

FBC received written notification of the removal of the Buyer's Subject Conditions on February 10, 2023, and on March 13, 2023, the sale of the Princeton Office Properties was fully completed. The final projected ending balance of the deferral account (i.e., projected to the end of 2023) is approximately $0.406 million, and this credit amount has been included in the 2024 revenue requirements and rates.

Please refer to Table 7-6 below for a breakdown of the net gain on the sale of the Princeton Office Properties. FBC notes that the estimated net gain on sale at the time of filing the Princeton Office Properties Application was $0.346 million. The difference between the original estimate and the final projected ending balance is solely due to a difference in the net book value of the land and building. When preparing this Application, FBC discovered that it incorrectly calculated the accumulated depreciation on the building at the time of filing the Princeton Office Properties Application. FBC has now corrected this error and, as a result, the net gain on sale to be provided to customers is higher than originally forecast in the Princeton Office Properties Application.

Table 7-6: Breakdown of Final Net Gain on Sale of the Princeton Office Properties

		$ millions
Sales Proceeds		0.474
Less:	Net Book Value of Land and Building	(0.041)
	Disposal Costs	(0.019)
	Taxes Payable	(0.008)
Gain on Sale		**0.406**

7.7 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). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings, and inventory of materials and supplies. 2024 amounts are forecast based on 2022 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its

rate base deferral accounts in the financial schedules included in Section 11. In Section 7.6.1, FBC requested approval of five new deferral accounts; and in Section 7.6.2, FBC discussed one existing deferral account. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN ON EQUITY

8.1 INTRODUCTION AND OVERVIEW

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent, as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which it expects to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

The 2024 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 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent.[45] Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

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 BCUC from time to time. Pursuant to Order G-47-14, FBC used the currently approved capital structure of 60.0 percent debt and 40.0 percent equity, with an equity risk premium of 40 basis point over the benchmark ROE, which was set at 8.75 percent by Order G-129-16, effective January 1, 2016, to calculate rates in this Application.

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- and short-term debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. FBC plans to issue additional long-term debt of approximately $100 million in April 2024 and will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. The 2024 debt issuance is reflected in the financial schedules at a rate of 4.90 percent.[46] The exact timing, amount and rate of the 2024 issuance will depend on future market conditions and capital expenditure

[45] As part of the Evidentiary Update, FBC will update the AFUDC rate for 2024 to reflect any changes resulting from the GCOC decision.
[46] Section 11, Schedule 27, Line 9.

requirements. 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 commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2027.[47] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its 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's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-month T-Bill forecast for 2024 is 4.27 percent, which is an increase from the 3.14 percent approved in 2023. FBC continues to face a rising interest rate environment due to high inflation and the Bank of Canada continuing to raise its policy interest rate in an attempt to slow economic growth and reduce core inflation. While the inflation in Canada eased to 3.40 percent in May 2023 from a high of 8.10 percent from a year ago, the downward movement was driven largely by lower energy prices rather than easing underlying inflation. The Bank of Canada's latest interest rate

[47] On July 14, 2023, FBC filed an application with the BCUC to increase the principal amount of the credit facility from $150 million to $200 million and to extend the maturity date of the credit facility to April 2028. If this application is approved, FBC will include any related impacts in the Evidentiary Update which FBC expects to file subsequent to the GCOC decision being issued.

increase in July 2023 brings the overnight rate to 5.0 percent, which was the tenth interest rate increase since March 2022 when the overnight rate was at 0.25 percent.

For 2024, FBC forecasts higher Other Financing Fees than the 2023 Approved amount due to higher customer deposit interest, resulting from a higher prime rate in 2023. Other Financing Fees include the fees that FBC incurs for its letters of credit under the credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2023	Projected 2023	Forecasted 2024
3-Month T-Bill Rate [1]	3.14%	5.04%	4.27%
Spread to CDOR	0.36%	0.41%	0.41%
CDOR Rate	3.50%	5.45%	4.69%
Spread to CP	-0.36%	-0.47%	-0.47%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**3.24%**	**5.09%**	**4.32%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.24%	0.32%
Renewal Fee on Undrawn Credit	0.12%	0.07%	0.09%
Other Financing Fees	0.44%	0.34%	0.49%
ST Interest Rate on Fixed Financing Fee	**1.00%**	**0.64%**	**0.89%**
FBC Short Term Rate	**4.24%**	**5.73%**	**5.21%**

Notes to Table:

[1] 3-month T-Bill rate for 2024 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2023.

[2] Fixed financing fees represent the costs of maintaining the credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is planning to discontinue using CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[48] The Canadian Alternative Reference Rate Working Group (CARR) was established to coordinate the transition to a new risk-free rate benchmark. In January

[48] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

2023, CARR announced a development of a Term Canadian Overnight Repo Rate Average (Term CORRA), a risk-free interest rate benchmark for one- and three-month terms. Term CORRA is expected to replace CDOR and will become available in the latter half of 2023. As the Term CORRA rate is not yet available, FBC continues to use the CDOR methodology, consistent with its previous Annual Reviews, to forecast the short-term interest rate for 2024.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- 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. 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 2024 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2024

Description	Weight	Pre-Tax Rate	After-Tax Rate	Earned Return
Short Term Debt	5.46%	5.21%	3.80%	5.21%
Long Term Debt	54.54%	4.72%	3.45%	4.72%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.87%	5.75%	6.52%

8.4 SUMMARY

FBC's equity financing and ROE have been forecast for 2024 at the same percentages as by Orders G-47-14 and G-129-16. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to decrease in 2024 compared to 2023 (4.72 percent forecast for 2024 compared to 2023 Approved of 4.78 percent).

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2024, property taxes are forecast to increase by $0.313 million (1.7 percent) from 2023 Approved, while income tax is forecast to increase by $4.002 million (65.9 percent) compared to 2023 Approved.

9.2 PROPERTY TAXES

The 2024 Forecast of property taxes is approximately $18.573 million and is based on the Company's 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 2023	Projected 2023	Forecast 2024
1	Generation Plant	$ 3.253	$ 3.201	$ 3.259
2	Transmission and Distribution	7.189	7.104	7.317
3	Substation Equipment	4.208	4.204	4.328
4	Land and Buildings	1.322	1.438	1.532
5	In Lieu	2.288	2.301	2.137
6	Total Property Taxes	$ 18.260	$ 18.248	$ 18.573
7				
8	2024 Forecast Change from 2023 Approved			1.7%
9	2024 Forecast Change from 2023 Projected			1.8%

As shown in the above table, in 2024 property taxes are forecast to increase by 1.7 percent from 2023 Approved and by 1.8 percent from 2023 Projected. In general, the 2024 increase from 2023 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. ***Changes in Tax Rates.*** Tax Rates are expected to change for 2024 as follows:
    a) Municipal rates are expected to increase by 0.6 percent;
    b) School rates are expected to decrease by 1.2 percent;
    c) Rural rates are expected to decrease by 0.5 percent;
    d) Tax rates on First Nations are expected to increase by 0.8 percent; and
    e) Other rates are expected to decrease by 1.1 percent.

2. ***Changes in Revenues to Calculate Grants In Lieu of Taxes.*** Revenues reported to municipalities are expected to decrease by 7.1 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual decrease in revenues reported to municipalities decreases the grants in-lieu of taxes due.

3. ***Changes in Assessed Values.*** Forecast changes in the assessed values of FBC's property are based on expected inflationary increases. These include:

   a) A 5.2 percent increase in assessed values of distribution lines and a 4.7 percent increase in transmission lines;

   b) A 4.1 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

   c) A 2.1 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

   d) A 7.1 percent increase for offices.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered 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 BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. 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 are updated each year as part of the annual rate setting process.

Income tax for 2024 is forecast to increase by $4.002 million or 65.9 percent compared to 2023 Approved. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA) by approximately $2.849 million. The lower deductibility is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024).[49] Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

[49] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html#AppPhaseOut.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

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

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2024 rates, it is the 2022 formula O&M and 2022 earnings sharing amounts that are calculated and impact rates in 2024.

For 2024, FBC proposes to distribute a $2.396 million pre-tax credit ($1.749 million after-tax) to customers, comprised of:

- The $1.749 million credit difference between the projected 2022 deferral account after-tax addition of zero embedded in 2023 rates, and the actual 2022 deferral account after-tax credit addition of $1.749 million as provided in FBC's 2022 Annual Report to the BCUC. This amount is also shown in the opening 2024 balance[50] in the financial schedules in the Application.

FBC proposes to distribute $2.396 million to customers in 2024 as a reduction in 2024 revenue requirements through amortization of the projected 2024 opening after-tax balance of $1.749 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2023 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2023 ROE variance from approved.

[50] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2024
($millions)

Schedule 1

Line No.	Particulars	2024 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (2.304)		
3	Change in Other Revenue	0.149	(2.155)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	10.119		
7	Wheeling	0.337		
8	Water Fees	0.971	11.427	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	1.655		
12	Capitalized Overhead Change	(0.248)	1.407	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.579	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.242)		
19	Deferrals	0.487	0.245	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	0.346		
23	Financing Ratio Changes	(0.056)		
24	Rate Base Growth	2.566	2.856	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.313		
28	Other Income Taxes Changes	4.002	4.315	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 20.674**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		428.377	Schedule 18, Line 7, Column 3
33	Rate Change		4.83%	

FORTISBC INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 2

Line No.	Particulars	2023 Approved	2024 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,375,297	$ 2,505,386	$ 130,089	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.1, Line 32, Column 4
3	Net Additions	133,903	96,482	(37,421)	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,509,200	2,601,868	92,668	
5					
6	Accumulated Depreciation Beginning	$ (693,759)	$ (741,726)	$ (47,967)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.1, Line 32, Column 6
8	Net Additions	(48,025)	(52,613)	(4,588)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(741,784)	(794,339)	(52,555)	
10					
11	CIAC, Beginning	$ (243,101)	$ (254,724)	$ (11,623)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(11,628)	(7,539)	4,089	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(254,729)	(262,263)	(7,534)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 89,140	$ 94,207	$ 5,067	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	5,067	5,309	242	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	94,207	99,516	5,309	
20					
21	Net Plant in Service, Mid-Year	$ 1,567,236	$ 1,623,963	$ 56,727	
22					
23	Adjustment for timing of Capital additions	$ 22,720	$ 2,750	$ (19,970)	
24	Capital Work in Progress, No AFUDC	34,306	25,574	(8,732)	
25	Unamortized Deferred Charges	40,045	51,287	11,242	Schedule 11, Line 34, Column 8
26	Working Capital	6,099	6,510	411	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,563	4,377	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,674,969	$ 1,714,461	$ 39,492	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2024
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	2024	Total for 2024 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Formula Cost Drivers**								
2	CPI		2.692%	1.596%	1.281%	4.940%	6.031%		
3	AWE		2.881%	5.745%	6.455%	3.944%	2.609%		
4	Labour Split								
5	Non Labour		38.000%	38.000%	37.000%	40.000%	43.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%	57.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.342%	4.080%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	3.842%	3.580%		
10									
11									
12	**Growth in Average Customer Calculation**								
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,112	149,677		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,112	149,677	152,006		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,235	2,565	2,329	12,090	
16									
17	Customer Growth Factor Multiplier	G-166-20						75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17						9,068	
19									
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020						139,916	
21									
22	Average Customer Forecast - 2024 Rate Setting Purposes	Line 18 + Line 20						148,984	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 24,568	
3	Sustainment Capital	51,652	
4	Other Capital	17,213	
5	Total Forecast Capital	$ 93,433	
6			
7	**Flow-Through Capital Expenditures**		
8	EV Charging Stations	$ 500	
9			
10	**Total Regular Capital Expenditures**	$ 93,933	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 5

Line No.	Particulars	2024 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	93,433	
3	Flow-Through Capital		500	
4	Total Regular Capital Expenditures	$	93,933	Schedule 4, Line 10, Column 2
5				
6	**Special Projects and CPCN's**			
7				
8	Total Special Projects and CPCN's	$	-	
9				
10	**Total Capital Expenditures**	$	93,933	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	93,933	Line 4
16	Add - Capitalized Overheads		11,148	Schedule 20, Line 23, Column 4
17	Add - AFUDC		241	
18	Gross Capital Expenditures	$	105,322	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,322	
21				
22	Special Projects and CPCN's Capital Expenditures	$	-	Line 8
23	Add - AFUDC		1	
24	Gross Capital Expenditures		1	
25	Change in Work in Progress		5,499	
26	**Total Special Projects and CPCN Additions to Plant**	$	5,500	
27				
28	**Grand Total Additions to Plant**	$	110,822	Schedule 6.1, Line 32, Columns 5 + 6

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	22,199	-	-	166	(12)	22,353	
4	332	Reservoirs, Dams & Waterways	139,590	-	2,731	7,690	(777)	149,234	
5	333	Water Wheels, Turbines and Gen.	106,005	-	-	694	(141)	106,558	
6	334	Accessory Equipment	51,447	-	-	128	(38)	51,537	
7	335	Other Power Plant Equipment	48,576	-	-	5	(1)	48,580	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 370,066	$ -	$ 2,731	$ 8,683	$ (969)	$ 380,511	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,884	$ -	$ -	$ 118	$ -	$ 11,002	
13	350.1	Land Rights-Clearing	10,109	-	-	118	-	10,227	
14	353	Station Equipment	264,083	-	2,769	3,420	(303)	269,969	
15	355	Poles Towers & Fixtures	134,762	-	-	6,403	(289)	140,876	
16	356	Conductors and Devices	129,994	-	-	6,403	(310)	136,087	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 550,791	$ -	$ 2,769	$ 16,462	$ (902)	$ 569,120	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.1
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,995	$ -	$ -	$ 810	$ -	$ 8,805	
3	360.1	Land Rights-Clearing	12,001	-	-	372	-	12,373	
4	362	Station Equipment	324,416	-	-	12,969	(879)	336,506	
5	364	Poles Towers & Fixtures	271,743	-	-	13,565	(577)	284,731	
6	365	Conductors and Devices	456,680	-	-	20,383	(722)	476,341	
7	368	Line Transformers	205,825	-	-	14,062	(1,803)	218,084	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,986	-	-	528	-	42,514	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,304	-	-	168	(42)	14,430	
12	372	EV Stations Kiosks & Charger Connectors	6,265	-	-	-	-	6,265	
13			$ 1,351,674	$ -	$ -	$ 62,857	$ (4,023)	$ 1,410,508	
14									
15		**General Plant**							
16	389	Land	$ 11,268	$ -	$ -	$ -	$ -	$ 11,268	
17	390.1	Structures - Masonry	50,339	-	-	2,765	(317)	52,787	
18	390.2	Operation Building	20,014	-	-	605	(22)	20,597	
19	390.9	Leasehold Improvements	3,727	-	-	-	-	3,727	
20	391	Office Furniture & Equipment	5,376	-	-	214	(5)	5,585	
21	391.1	Computer Hardware	13,899	-	-	3,305	(1,278)	15,926	
22	391.2	Computer Software	44,861	-	-	6,982	(4,254)	47,589	
23	391.2	AMI Software	13,436	-	-	(3)	-	13,433	
24	392.1	Light Duty Vehicles	6,031	-	-	545	(481)	6,095	
25	392.1	Heavy Duty Vehciles	29,840	-	-	1,512	(348)	31,004	
26	394	Tools and Work Equipment	8,637	-	-	719	(658)	8,698	
27	397	Communication Structures & Equipment	14,926	-	-	676	(836)	14,766	
28	397.1	Fibre	5,531	-	-	-	(247)	5,284	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 232,855	$ -	$ -	$ 17,320	$ (8,446)	$ 241,729	
31									
32		**Total Plant in Service**	$ 2,505,386	$ -	$ 5,500	$ 105,322	$ (14,340)	$ 2,601,868	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (372)	$ -	$ 10	$ -	$ -	$ -	$ (362)	
3	331	Structures and Improvements	22,199	1.68%	6,076	-	373	(12)	-	-	6,437	
4	332	Reservoirs, Dams & Waterways	142,321	1.90%	7,167	-	2,704	(777)	(1,894)	-	7,200	
5	333	Water Wheels, Turbines and Gen.	106,005	1.79%	22,308	-	1,897	(141)	(3)	-	24,061	
6	334	Accessory Equipment	51,447	3.13%	16,560	-	1,610	(38)	(133)	-	17,999	
7	335	Other Power Plant Equipment	48,576	2.12%	21,200	-	1,030	(1)	-	-	22,229	
8	336	Roads, Railroads and Bridges	1,287	1.44%	495	-	19	-	-	-	514	
9			$ 372,797		$ 73,434	$ -	$ 7,643	$ (969)	$ (2,030)	$ -	$ 78,078	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,884	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	10,109	1.27%	2,612	-	128	-	-	-	2,740	
14	353	Station Equipment	266,852	2.33%	107,657	-	6,218	(303)	(162)	-	113,410	
15	355	Poles Towers & Fixtures	134,762	2.52%	41,827	-	3,396	(289)	(479)	-	44,455	
16	356	Conductors and Devices	129,994	2.52%	26,379	-	3,275	(310)	(479)	-	28,865	
17	359	Roads and Trails	959	1.96%	451	-	19	-	-	-	470	
18			$ 553,560		$ 178,926	$ -	$ 13,036	$ (902)	$ (1,120)	$ -	$ 189,940	

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,995	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	12,001	1.25%	3,080	-	150	-	-	-	3,230	
4	362	Station Equipment	324,416	2.61%	100,441	-	8,467	(879)	(159)	-	107,870	
5	364	Poles Towers & Fixtures	271,743	2.73%	86,032	-	7,419	(577)	(578)	-	92,296	
6	365	Conductors and Devices	456,680	2.38%	138,391	-	10,868	(722)	(933)	-	147,604	
7	368	Line Transformers	205,825	3.13%	49,872	-	6,442	(1,803)	(354)	-	54,157	
8	369	Services	9,521	0.51%	6,856	-	49	-	-	-	6,905	
9	370.1	AMI Meters	41,986	6.25%	15,488	-	2,624	-	-	-	18,112	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,304	4.95%	6,919	-	708	(42)	-	-	7,585	
12	372	EV Stations Kiosks & Charger Connectors	6,265	10.00%	1,422	-	627	-	-	-	2,049	
13			$ 1,351,674		$ 409,438	$ -	$ 37,354	$ (4,023)	$ (2,024)	$ -	$ 440,745	
14												
15		**General Plant**										
16	389	Land	$ 11,268	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	50,339	2.53%	14,019	-	1,274	(317)	-	-	14,976	
18	390.2	Operation Building	20,014	1.63%	7,376	-	326	(22)	-	-	7,680	
19	390.9	Leasehold Improvements	3,727	1.63%	2,747	-	61	-	-	-	2,808	
20	391	Office Furniture & Equipment	5,376	4.42%	1,503	-	238	(5)	-	-	1,736	
21	391.1	Computer Hardware	13,899	21.60%	4,422	-	3,002	(1,278)	-	-	6,146	
22	391.2	Computer Software	44,861	8.96%	16,106	-	4,020	(4,254)	-	-	15,872	
23	391.2	AMI Software	13,436	10.00%	8,971	-	1,344	-	-	-	10,315	
24	392.1	Light Duty Vehicles	6,031	3.81%	2,352	-	230	(481)	79	-	2,180	
25	392.1	Heavy Duty Vehciles	29,840	6.50%	9,582	-	1,940	(348)	-	-	11,174	
26	394	Tools and Work Equipment	8,637	4.11%	3,262	-	355	(658)	-	-	2,959	
27	397	Communication Structures & Equipment	14,926	3.44%	4,145	-	513	(836)	(5)	-	3,817	
28	397.1	Fibre	5,531	6.97%	2,687	-	386	(247)	-	-	2,826	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,722	-	331	-	-	-	3,053	
30			$ 232,855		$ 79,928	$ -	$ 14,020	$ (8,446)	$ 74	$ -	$ 85,576	
31												
32		**Total**	$ 2,510,886		$ 741,726	$ -	$ 72,053	$ (14,340)	$ (5,100)	$ -	$ 794,339	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
3	**Total**	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
4								
5	**Amortization**							
6	Amortization	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
7	**Total**	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
8								
9	**Net CIAC**	$ 160,517	$ -	$ -	$ 2,230	$ -	$ 162,747	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 36	$ -	$ -	$ -	$ (36)	$ -	$ 18	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges '	$ 2,923	$ -	$ 328	$ -	$ -	$ 3,251	$ 3,087	Note 1
8	Demand Side Management	41,573	-	15,436	(4,168)	(6,287)	46,554	44,063	
9	Deferred Debt Issue Costs	4,391	-	-	(110)	(196)	4,084	4,237	
10	2025 Multi-year Rate Plan Application	256	-	1,200	(324)	-	1,132	694	
11	2023 - 2027 DSM Expenditure Schedule	62	-	-	-	(16)	47	55	
12	Mandatory Reliability Standards 2024 Audit	-	-	375	(101)	(91)	183	91	
13	Joint Pole Use Audit 2023	356	-	-	-	(89)	267	312	
14	2021 Generic Cost of Capital Proceeding	770	-	-	-	-	770	770	
15	Annual Reviews for 2020-2024 Rates	49	-	90	(25)	(49)	66	58	
16	2021 Long Term Electric Resource Plan	329	-	-	-	(174)	155	242	
17	BCUC Initiated Inquiry Costs	(57)	-	-	-	57	-	(28)	
18	EV Fleet & Workplace Charging Funding Account	-	169	576	(155)	(17)	572	371	
19	Mandatory Reliability Standards 2021 Audit	78	-	-	-	(78)	-	39	
20		$ 50,730	$ 169	$ 18,005	$ (4,883)	$ (6,940)	$ 57,080	$ 53,991	
21									
22	**4. Retroactive Expense Accounts**								
23									
24	**5.Other Accounts**								
25	Pension and OPEB Liability	$ (5,046)	$ -	$ 5,220	$ -	$ -	$ 174	$ (2,436)	
26	COVID-19 Customer Recovery Fund	139	-	-	-	(70)	68	104	
27	Climate Change Operational Adaptation (CCOA)	164	-	192	(52)	(41)	263	214	
28	BC Cost of Living Credit	(370)	-	-	-	370	-	(185)	
29	Princeton Office Disposition	-	(406)	-	-	406	-	(203)	
30	PST Rebate on Select Machinery and Equipment	(431)	-	-	-	431	-	(216)	
31	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
32		$ (5,545)	$ (406)	$ 5,412	$ (52)	$ 1,096	$ 506	$ (2,722)	
33									
34	**Total Rate Base Deferral Accounts**	$ 45,221	$ (237)	$ 23,417	$ (4,935)	$ (5,880)	$ 57,586	$ 51,287	
35									

36 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $1.60 million - transfer of $1.272 million = $0.328 million.

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 12

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	**1. Forecasting Variance Accounts**								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ (169)	$ -	$ -	$ -	$ (246)	$ (415)	$ (292)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	86	-	75	(20)	(86)	54	70	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14									
15	**Total NRB Deferral Accounts at Short Term Interest**	$ (83)	$ -	$ 75	$ (20)	$ (332)	$ (361)	$ (222)	
16									
17	Financing Costs at STI	$ 27	$ -	$ (7)	$ -	$ (27)	$ (7)	$ 10	

FORTISBC INC.

Schedule 12.1

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	**1. Forecasting Variance Accounts**								
4									
5	**2. Rate Smoothing Accounts**								
6									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 2,666	$ -	$ (255)	$ -	$ -	$ 2,411	$ 2,538	Note 1
9	2017 Rate Design Application	118	-	-	-	(118)	-	59	
10	2020 - 2024 Multi-Year Rate Plan Application	145	-	-	-	(145)	-	72	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	68	-	-	-	(59)	9	38	
12		$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17									
18	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
19									
20	Financing Costs at WACD	$ 76	$ -	$ 95	$ -	$ (76)	$ 95	$ 86	

21 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	**1. Forecasting Variance Accounts**								
4	2020 - 2024 Flow-Through Deferral Account	$ (6,520)	$ -	$ -	$ -	$ 6,520	$ -	$ (3,260)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	EV Fleet & Workplace Charging Funding Account	$ 169	$ (169)	$ -	$ -	$ -	$ -	$ -	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (1,749)	$ -	$ -	$ -	$ 1,749	$ -	$ (875)	
15	Princeton Office Disposition	(406)	406	-	-	-	-	-	
16									
17	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (8,506)	$ 237	$ -	$ -	$ 8,269	$ -	$ (4,135)	
18									
19	Financing Costs at AFUDC	$ (1,228)	$ -	$ (272)	$ -	$ 1,228	(272)	(750)	
20									
21	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
22									
23									
24	**Total Non Rate Base Deferral Accounts (including financing)**	$ (6,668)	$ 237	$ (364)	$ (20)	$ 8,740	$ 1,924	$ (2,254)	

FORTISBC INC.

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 6,849	$ 7,367	$ 518	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	353	306	(47)	
6	Employee Loans	570	509	(61)	
7	Inventories - Materials and Supplies	649	783	134	
8	Employee Withholdings	(2,322)	(2,455)	(133)	
9	Total	$ 6,099	$ 6,510	$ 411	

FORTISBC INC.

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Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2024 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	$ 215,950	56.0	$ 12,093,200		
4	Commercial Tariff Revenue	116,156	45.1	5,238,636		
5	Wholesale Tariff Revenue	58,256	37.5	2,184,600		
6	Industrial Tariff Revenue	52,203	38.0	1,983,714		
7	Lighting Tariff Revenue	2,328	34.6	80,549		
8	Irrigation Tariff Revenue	4,158	47.0	195,426		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,199	90.0	$ 557,894		
12	Contract Revenue	2,260	62.2	140,563		
13	Transmission Access Revenue	1,723	65.2	112,340		
14	Late Payment Charges	962	54.0	51,922		
15	Connection Charges	561	30.5	17,104		
16	Other Utility Income	388	63.4	24,606		
17	Total	$ 461,143		$ 22,680,554		49.2
18						
19	**EXPENSES**					
20	Power Purchases	$ 173,694	(51.5)	$ (8,945,261)		
21	Wheeling	7,324	(46.9)	(343,514)		
22	Water Fees	12,513	(1.4)	(17,518)		
23	Operating and Maintenance	63,174	(28.6)	(1,806,768)		
24	Property Taxes	18,573	(4.9)	(91,008)		
25	GST	703	(45.4)	(31,916)		
26	Income Tax	10,075	(15.2)	(153,140)		
27	Total	$ 286,057		$ (11,389,125)		(39.8)
28						
29	Net Lag (Lead) Days					9.4
30	Total Expenses				$	286,057
31						
32	Cash Working Capital				$	7,367

SCHEDULE NOT APPLICABLE

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UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 16

Line No.	Particulars	2023 Approved	2024 Forecast at 2023 Approved Rates	Revised Revenue	2024 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,475	3,474	-	3,474	(1)	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 426,073	$ 428,377	$ -	$ 428,377	$ 2,304	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	20,674	20,674	20,674	
7	Total	426,073	428,377	20,674	449,051	22,978	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 182,105	$ 193,532	$ -	$ 193,532	$ 11,427	Schedule 19, Line 29, Column 3
11	O&M Expense (net)	61,767	63,174	-	63,174	1,407	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	61,246	64,070	-	64,070	2,824	Schedule 21, Line 11, Column 3
13	Property Taxes	18,260	18,573	-	18,573	313	Schedule 22, Line 6, Column 3
14	Other Revenue	(12,241)	(12,092)	-	(12,092)	149	Schedule 23, Line 8, Column 3
15	Utility Income Before Income Taxes	114,936	101,120	20,674	121,794	6,859	
16							
17	Income Taxes	6,073	4,498	5,577	10,075	4,002	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 108,863	$ 96,622	$ 15,097	$ 111,719	$ 2,857	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,674,969	$ 1,713,933		$ 1,714,461	$ 39,492	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.50%	5.64%		6.52%	0.02%	Schedule 26, Line 5, Column 6

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,300	1,299	(1)	
3	Commercial	973	974	1	
4	Wholesale	579	590	11	
5	Industrial	575	564	(11)	
6	Lighting	9	9	-	
7	Irrigation	39	38	(1)	
8	Total	3,475	3,474	(1)	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 205,734	$ 206,007	$ 273	
12	Commercial	110,490	110,808	318	
13	Wholesale	54,100	55,574	1,474	
14	Industrial	49,759	49,800	41	
15	Lighting	2,295	2,221	(74)	
16	Irrigation	3,695	3,967	272	
17	Total	$ 426,073	$ 428,377	$ 2,304	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 18

Line No.	Particulars	2023 Approved Revenue	2024 Forecast Revenue at 2023 Approved Rates	2024 Forecast Effective Increase	2024 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 205,734	$ 206,007	$ 9,943	$ 215,950	132,389	1,299	
2	Commercial	110,490	110,808	5,348	116,156	17,125	974	
3	Wholesale	54,100	55,574	2,682	58,256	6	590	
4	Industrial	49,759	49,800	2,403	52,203	42	564	
5	Lighting	2,295	2,221	107	2,328	1,341	9	
6	Irrigation	3,695	3,967	191	4,158	1,103	38	
7	Total	$ 426,073	$ 428,377	$ 20,674	$ 449,051	152,006	3,474	
8								
9	**Effective Increase**			4.83%				

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,775	3,773	(2)	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 44,050	$ 44,433	$ 383	
6	BC Hydro PPA	71,302	71,680	378	
7	Waneta Expansion	41,834	40,365	(1,469)	
8	Market and Contracted Producers	6,326	16,972	10,646	
9	Independent Power Producers	62	245	183	
10	CPA Balancing Pool	-	0	0	
11	Total	$ 163,575	$ 173,694	$ 10,119	
12					
13	**WHEELING**				
14	**Wheeling Nomination (MW months)**				
15	Okanagan Point of Interconnection	2,670	2,595	(75)	
16	Creston	420	450	30	
17					
18	**Wheeling Expense**				
19	Okanagan Point of Interconnect	$ 5,555	$ 5,813	$ 258	
20	Creston	570	658	88	
21	Other	863	854	(9)	
22	Total	$ 6,987	$ 7,324	$ 337	
23					
24	**WATER FEES**				
25	Plant Entitlement Use in previous year (GWh)	1,571	1,561	(10)	
26					
27	Water Fees	$ 11,543	$ 12,513	$ 971	
28					
29	Total	$ 182,105	$ 193,532	$ 11,427	

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OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 20

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2023 Base Unit Cost O&M	$ 472			
3	2024 Net Inflation Factor	3.580%			Schedule 3, Line 9, Column 7
4	2024 Base Unit Cost O&M	$ 489			Line 2 x (1 + Line 3)
5					
6	2024 Average Customer Forecast - Rate Setting Purpose	148,984			Schedule 3, Line 22, Column 8
7					
8	2024 Inflation Indexed O&M before prior year True-up	$ 72,853			Line 4 x Line 6 / 1,000
9					
10	2022 Average Customer True-up	(30)			
11					
12	2024 Inflation Indexed O&M	$ 72,823		$ 72,823	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (2,532)		
16	Insurance Premiums		2,678		
17	BCUC Levies		458		
18	MRS		585		
19	EV Charging Stations		310		
20	Sub-total		$ 1,499	1,499	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 74,322	Line 12 + Line 20
23	Capitalized Overhead			(11,148)	-15 % x Line 22
24	**Net O&M Expense**			$ 63,174	Sum of Lines 22 and 23

FORTISBC INC.

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Section 11

Schedule 21

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 69,474	$ 72,053	$ 2,579	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 6,716	$ 5,880	$ (836)	Schedule 11, Line 34, Column 6
6	Non-Rate Base Deferrals	(10,063)	(8,740)	1,323	Schedule 12.2, Line 24, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(5,067)	(5,309)	(242)	Schedule 9, Line 7, Column 5
9		(8,228)	(7,983)	245	
10					
11	Total	$ 61,246	$ 64,070	$ 2,824	

FORTISBC INC.

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Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,253	$ 3,259	$ 6	
2	Transmission and Distribution	7,189	7,317	128	
3	Substation Equipment	4,208	4,328	120	
4	Land and Buildings	1,322	1,532	210	
5	1% In-Lieu of Municipal Taxes	2,288	2,137	(151)	
6	Total	$ 18,260	$ 18,573	$ 313	

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OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,108	$ 6,199	$ 91	
2	Contract Revenue	2,367	2,260	(107)	
3	Transmission Access Revenue	1,834	1,723	(111)	
4	Interest Income	30	37	7	
5	Late Payment Charges	994	962	(32)	
6	Connection Charges	553	561	8	
7	Other Recoveries	355	351	(4)	
8	Total	$ 12,241	$ 12,092	$ (149)	

FORTISBC INC.

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Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 108,863	$ 111,719	$ 2,856	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(47,559)	(48,970)	(1,411)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(44,884)	(35,508)	9,376	Line 32
4	Accounting Income After Tax	$ 16,420	$ 27,241	$ 10,821	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 22,493	$ 37,316	$ 14,823	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 6,073	$ 10,075	$ 4,002	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 6,073	$ 10,075	$ 4,002	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 69,474	$ 72,053	$ 2,579	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	(3,347)	(2,860)	487	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	(528)	(1,501)	(973)	
22	OPEB Expense	1,119	844	(275)	
23					
24	Deductions:				
25	Capital Cost Allowance	(89,602)	(81,899)	7,703	Schedule 25, Line 18, Column 6
26	CIAC Amortization	(5,067)	(5,309)	(242)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,203)	(3,811)	392	
28	OPEB Contributions	(705)	(752)	(47)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,900)	(11,148)	(248)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (44,884)	$ (35,508)	$ 9,376	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Class	CCA Rate	12/31/2023 UCC Balance	2024 Additions & Opening Adjt	Adjustment	2024 CCA	Forecast 12/31/2024 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 147,922	$ -	$ -	$ (5,917)	$ 142,005
2	1(b)	6%	33,070	3,010	-	(2,165)	33,915
3	2	6%	10,719	-	-	(643)	10,076
4	3	5%	616	-	-	(31)	585
5	6	10%	2	-	-	-	2
6	8	20%	3,538	833	-	(874)	3,497
7	10	30%	4,308	1,838	-	(1,844)	4,302
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,441	-	-	(451)	5,990
10	14.1 (post 2016)	5%	4,926	1,266	-	(310)	5,882
11	17	8%	161,210	8,533	-	(13,579)	156,164
12	42	12%	8,987	604	-	(1,151)	8,440
13	43.1	30%	477	-	-	(143)	334
14	46	30%	1,896	-	-	(569)	1,327
15	47	8%	530,216	64,669	-	(47,591)	547,294
16	50	55%	2,869	9,188	-	(6,631)	5,426
17							
18	Total		$ 917,208	$ 89,941	$ -	$ (81,899)	$ 925,250

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	Amount	Ratio	2024 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 43,709	$ 935,137	54.54%	4.72%	2.57%	$ 44,097	$ 388	Schedule 27, Line 11, Column 6
2	Short Term Debt	3,850	93,540	5.46%	5.21%	0.28%	4,873	1,023	
3	Common Equity	61,304	685,784	40.00%	9.15%	3.66%	62,749	1,445	
4									
5	Total	$ 108,863	$ 1,714,461	100.00%		6.52%	$ 111,719	$ 2,856	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

FORTISBC INC.

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Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2024
($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	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	$ 100,000	5.600%	$ 5,600	
2	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
3	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
4	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
5	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
6	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
7	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
8	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
9	2024 Debt Issue - MTN - 24	April 1, 2024	April 1, 2054	75,137	4.900%	3,682	
10							
11	Total			$ 935,137		$ 44,097	
12							
13	Average Embedded Cost				4.72%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

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

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

In 2022 and thus far in 2023, FBC has not identified any items that merit exogenous factor treatment.

12.3 ACCOUNTING MATTERS

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

12.3.1 Emerging Accounting Guidance

In the 2014-2019 PBR Plan Decision and Order G-139-14, the BCUC 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." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2024.

12.4 NON-RATE BASE DEFERRAL ACCOUNTS

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

In the following section, FBC provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, 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 forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

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

	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 Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2023 Projected Flow-through amount of $2.898 million debit is shown in Table 12-2 below. To calculate the overall combined amount to be distributed to customers, FBC has also included the following adjustment:

- The $9.418 million credit difference between the projected ending 2022 deferral account credit balance of $9.693 million[51] embedded in 2023 rates, and the actual ending 2022 deferral credit balance of $19.111 million. A more detailed breakout of the 2022 variance is provided in Table 12-3 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 19.

Table 12-2: 2023 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2023 Approved	2023 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (426.073)	$ (431.720)	$ (5.647)
2				
3	**Total Power Purchase Expense**	163.575	170.873	7.298
4				
5	**Total Wheeling**	6.987	7.294	0.307
6				
7	**Total Water Fees**	11.543	12.433	0.890
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.297)	(1.297)	-
11	Insurance	2.457	2.507	0.050
12	BCUC Fees	0.385	0.385	-
13	MRS	0.585	0.585	-
14	EV Charging Stations	0.219	0.181	(0.038)
15	Capitalized Overhead	(10.900)	(10.900)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	(3.347)	(3.347)	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	18.260	18.248	(0.012)
23				
24	**Other Revenues**			
25	EV Carbon Credits	-	(0.544)	(0.544)
26				
27	**Interest Expense**			
28	Long-term debt interest expense variance	43.709	41.856	(1.853)
29	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
30	Short-term debt rate variance	-	1.353	1.353
31	Short-term debt volume variance from long-term debt issue variance	-	2.166	2.166
32	Short-term debt timing variance from long-term debt issue timing	-	-	-
33				
34	**Income Tax Expense**			
35	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
36	Income tax/CCA rate changes	-	-	-
37	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	(1.072)	(1.072)
38				
39	**2023 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**2.898**
40				
41	2022 Ending Deferral Account Balance True-up			(9.418)
42				
43	**2024 After-Tax Amortization**			**(6.520)**

[51] FBC Annual Review for 2023 Rates, April 24, 2023 finalized financial schedules supporting 2023 Interim Rates, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2023 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2023 Projected flow-through variances shown in Table 12-2 above:

- The variance in revenue is due to increased sales from residential, commercial, and wholesale customers;
- The variance in power purchase expense is primarily due to increased Market and Contracted Purchases required to address supply gaps and reduce exposure to potentially extreme market prices. FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. FBC also purchased wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year, to reduce required purchases above the BC Hydro PPA Nomination. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 Annual Electric Contracting Plan (AECP);
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC forecasting issuing long-term debt in 2023 in the Annual Review for 2023 Rates, whereas FBC is no longer projecting a debt issuance, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2023 subject to flow-through will be recorded in the deferral account in 2023 and amortized in 2025 rates.

12.4.2.1.2 2022 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

Table 12-3 below provides a breakdown of the 2022 true-up amount of $9.418 million credit.

Table 12-3: 2022 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Projected	2022 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (414.385)	$ (425.782)	$ (11.397)
2				
3	**Total Power Purchase Expense**	153.164	153.457	0.293
4				
5	**Total Wheeling**	6.330	6.898	0.568
6				
7	**Total Water Fees**	11.916	11.838	(0.078)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.291	2.286	(0.005)
12	BCUC Fees	0.373	0.373	-
13	MRS	0.500	0.468	(0.032)
14	EV Charging Stations	0.187	0.213	0.026
15	COVID-19 Pandemic	(1.030)	(1.030)	-
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.027)	(0.027)
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.021	0.021
22				
23	**Total Property Taxes**	17.621	17.385	(0.236)
24				
25	**Other Revenues**			
26	EV Carbon Credits	(0.625)	(0.744)	(0.119)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.794	41.794	(0.000)
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.041)	(0.041)
31	Short-term debt rate variance	2.253	0.964	(1.289)
32	Short-term debt volume variance from long-term debt issue variance	(1.005)	(0.646)	0.359
33	Short-term debt timing variance from long-term debt issue timing	0.793	0.510	(0.283)
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.470)	(0.470)
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.877	5.169	3.292
39				
40	**2022 Ending Deferral Account Balance True-up**			**(9.418)**

FBC provides the following explanations of the 2022 Actual variances shown in Table 12-3 above:

- The favourable variance in revenue of $11.397 million was primarily due to higher than projected residential and wholesale loads resulting largely from weather variations. Favourable variances in residential ($11.641 million), industrial ($0.270 million) and wholesale ($0.201 million) revenue were partially offset by unfavourable variances in commercial ($0.547 million), irrigation ($0.146 million) and lighting ($0.022 million) revenue;

- The increase in power purchase expense of $0.293 million was due to several factors including increased load, increased market purchases, and increased reliance on the BC Hydro PPA. Increased load and PPA purchases were primarily a result of prolonged cold weather at the end of 2022. This increase was partially offset by increased surplus capacity sales under the Capacity and Energy Purchase and Sale Agreement (CEPSA);

- The increase in wheeling costs of $0.568 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;

- The decrease in water fees of $0.078 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.011 million lower than projected, with all items comparable to the projected amounts;

- Actual property tax expense was relatively consistent with the projected amount;

- The flow-through components of other revenue were $0.119 million higher than projected, with the variance in EV Carbon Credit revenue due to approximately 329 carbon credits related to FBC's EV charging stations that were validated by BC-LCFS and monetized in 2022 but were not accounted for in the 2022 Projected amount;

- The variance between the actual (2.58 percent) and projected (4.02 percent) short-term debt interest rates results in an amount to be returned to customers of $1.289 million,[52] shown on Line 31 of the table above. There was no variance in long-term debt interest expense as actuals were as projected. The net variance of $0.076 million to be collected from customers on Lines 32 and 33 of Table 12-3 above is due to the impact of a lower actual short-term interest rate than projected;

- The unfavourable income tax variance of $3.292 million is calculated as 27 percent of the aforementioned variances; and

- The combined favourable variance of $0.517 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 20, 21, 30 and 36, respectively, were derived for 2022 by comparing the actual 2022 cost of service impacts of the EV stations and the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 SUMMARY

FBC is not seeking any exogenous factor treatment in this Application. FBC is also not seeking approval of any new non-rate base deferral accounts but has provided an update on the Flow-through deferral account.

[52] (2.584% - 4.02%) x $89.744 million forecast 2022 short-term debt in Schedule 26 of Annual Review for 2022 Rates Compliance Filing financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 INTRODUCTION AND OVERVIEW

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FBC reports on its 2022 and June 2023 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[53] FBC has provided 2022 and year-to-date 2023 SQI results in this annual review.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2022 and June year-to-date performance for 2023 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2022 and June year-to-date results for 2023 are also provided for the four informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	94%	93%
All Injury Frequency Rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	1.42	1.76

[53] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs."

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	77%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.14	2.20
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	65%	72%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.5
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	98	60
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[54]	4.52	2.42	3.21
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	1.52	1.48
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.50%	0.65%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.94%	99.98%

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2022 and 2023. Discussion is also provided for the informational SQIs.

[54] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.1 Safety Service Quality Indicators

13.2.1.1 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 time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2022 result was 94 percent which was better than the benchmark. The June 2023 year-to-date performance is 93 percent, which meets the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020, 2021, and 2022 results and the June 2023 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage 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	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	94%	93%
Benchmark	93%									
Threshold	90.6%									

13.2.1.2 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 2022 (three-year rolling average) result was 1.42 which was better than the benchmark of 1.64. The 2022 annual AIFR was 2.60 which reflected 4 Medical Treatments and 8 Lost Time Injuries. The increase in AIFR was particularly prevalent in Q4 2022, after a sudden change in winter conditions led to a notable spike in slips, trips, and falls resulting in more serious injuries. FBC responded to this by issuing an immediate safety alert (Safely Navigating Winter Conditions) to all field employees, which was also reviewed at all safety meetings, and providing access to traction aids throughout Operations.

The June 2023 year-to-date performance (three-year rolling average) result is 1.76 which is better than the threshold. The June 2023 year-to-date performance (annual) is 2.54 and reflects 3 Medical Treatments and 3 Lost Time Injuries. Thus far in 2023, FBC continues to see an increase in total minor preventable injuries, predominately those sustained while performing activities involving repetitive work and/or awkward positioning. FBC has responded to this by engaging its Ergonomist and Injury Prevention Specialist to provide more education and treatment throughout the Company. FBC also hired an Injury Management Specialist to provide proactive educational sessions, as well as customized Recover at Work plans for employees. In addition, FBC has implemented customized ergonomics courses for some of the higher risk areas.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve the safety management system through the implementation and sustainment of robust safety defences and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	2.60	2.54
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	1.42	1.76
Benchmark	1.64									
Threshold	2.39									

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact 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 2022 result was 77 percent which was better than the threshold of 74 percent. The reduction in FCR for 2022 as compared to previous years, as shown in Table 13-4 below, is largely attributable to the increased volume of high bill inquiries. Depending on the nature of the high bill, there may be a need for customers to follow up on their bill, resulting in more than one contact to resolve their concerns. As well, high bill calls can require longer-term payment arrangements which at times may require changes, leading to customers connecting with FBC multiple times for the same reason. The June 2023 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	77%	78%
Benchmark	78%									
Threshold	72%						74%			

13.2.2.2 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 2022 result was 0.14 which was better than the benchmark of 3.0. No significant billing issues occurred in 2022. The June 2023 year-to-date result of 2.20 is attributable to a technical issue experienced in February which resulted in a timing delay between the creation of the bills and those bills being sent to the print vendor. This technical issue has been corrected.

The 2022 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2022 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),100*(1.05-PA))	=5000*(1-100%)	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%	99.57%	(100%-PA)*100	=(100%-99.57%)*100	0.43
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.+0+0.43) /3	0.14

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14	2.20
Benchmark	5.0						3.0			
Threshold	5.0									

13.2.2.3 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 2022 result was 99 percent, which was better than the benchmark of 98 percent. The June 2023 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%			
Threshold	94%						96%			

13.2.2.4 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 2022 result was 65 percent, which was lower than the threshold. The June 2023 year-to-date performance is 72 percent, which is better than the benchmark.

FBC experienced several challenging circumstances in 2022 that contributed to the year-end performance being below the threshold. These challenges included higher than expected attrition being experienced in the contact centre, compounded by an increased amount of high bill inquiries in the first and fourth quarters. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 40 percent of its Customer Service Representatives in 2022, compared to 20 percent in 2021.[55] Exits in 2021 occurred during the third and fourth quarters, resulting in fewer and less experienced employees prepared to support call volumes at the start of 2022. Additionally, 2022 exits were spread throughout 2022 with the majority in the first and fourth quarters. To mitigate the impact of this attrition, FBC accelerated the timing of planned new hire

[55] On average, FBC has approximately 20 customer service representatives, and 8 left the organization in 2022 and 4 in 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

classes as well as the size of new hire classes in 2021, 2022 and 2023. While some success was achieved, FBC continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes approximately 12 months for new employees to be proficient and fully trained to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical. This particular call type is often longer in duration and may also result in follow-up work and investigation. Compounded by attrition, there were fewer and less experienced employees prepared to support these types of calls, resulting in overall longer average wait times and a lower percentage of calls answered within 30 seconds or less.

The additional hiring and training classes in 2023 have proven to be successful, with year-to-date performance better than the benchmark. Additionally, the customer service index has remained high throughout 2022 and 2023 year-to-date, indicating that the focus on first contact resolution continues to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by 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 (Non-Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	65%	72%
Benchmark	70%									
Threshold	68%									

13.2.2.5 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is 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 10.

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.

The annual CSI score for 2022 was 8.4, consistent with 2021. There were no statistically significant shifts from 2021 to 2022 in the five measures that make up the overall customer satisfaction score. The score for the accuracy of meter reading metric increased from 8.2 in 2021 to 8.3 in 2022. The score for the satisfaction with energy conservation information metric decreased from 7.5 in 2021 to 7.4 in 2022. In addition, the scores for overall satisfaction, satisfaction with the contact centre and field services metrics remained static at 8.4, 8.4, and 9.0 in 2022, respectively.

The score for 2023 year-to-date is 8.5, slightly higher than the annual score recorded for 2022. Of the five measures that make up the overall customer satisfaction score, the results for June 2023 year-to-date were higher in three areas and static in two when compared to the annual 2022 scores. The scores for the satisfaction with energy conservation, contact centre, and field services metrics increased from 7.4 to 7.5, 8.4 to 8.5, and 9.0 to 9.2, respectively. The scores for the overall satisfaction and satisfaction with the accuracy of meter reading metrics remained static at 8.4 and 8.3, respectively, from results achieved in 2022. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4	8.5
Benchmark	n/a									
Threshold	n/a									

13.2.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2022 result was 98 seconds, and the June 2023 year-to-date performance is 60 seconds.

2022 performance reflects the challenging circumstances described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA commenced in March 2023 with monthly ASA performance returning to typical levels of approximately 1 minute. This is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.[56]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	226	49	48	49	49	49	71	65	98	60
Benchmark	n/a									
Threshold	n/a									

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to 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. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, 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.

13.2.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

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

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

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

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2022 result was 2.42 which was better than the benchmark of 3.22. The June 2023 year-to-date performance is 3.21 which is better than the benchmark. The 2022 results improved

[56] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

compared to 2021 due to the absence of multiple external factors (i.e., fires, storms, collapse of crane incident in Kelowna in 2021)[57] which negatively impacted the 2021 SAIDI results.

There were no Major Event Days that met the threshold for normalization in 2022, and one Major Event Day in 2023 year-to-date. On May 21, 2023, a windstorm impacted the Kootenay region (centered in Salmo) resulting in outages to over 13,500 customers for a total of just under 46,200 customer hours lost.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[58]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.42	3.21
Benchmark	2.22						3.22			
Threshold	2.62						4.52			

13.2.3.2 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 purpose of this SQI, the measurement of performance is based on the annual results.

The 2022 result was 1.52 which was better than the benchmark, and the June 2023 year-to-date performance is 1.48 which is also better than the benchmark. The 2022 SAIFI results improved compared to 2021 due to the absence of the same multiple external factors (i.e., fires, storms and collapse of crane incident in Kelowna in 2021) discussed in the SAIDI section above.

[57] Refer to the FBC Annual Review for 2023 Rates, pages 140-141 for further details.
[58] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[59]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.52	1.48
Benchmark	1.64						1.57			
Threshold	2.50						2.19			

13.2.3.3 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 the CEA as follows:

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

The 2022 result for GFOR was 0.50 percent. The June 2023 year-to-date performance is 0.65 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.2%	0.5%	0.65%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.6%	5.0%	TBD	

[59] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are 12 points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The 2022 result of 99.94 percent and June 2023 year-to-date result of 99.98 percent are generally consistent with prior years' results. There were no notable major events in 2022 that impacted the interconnection utilization performance. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.94%	99.98%
Benchmark	n/a									
Threshold	n/a									

13.3 SUMMARY

In summary, FBC's 2022 and June 2023 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark with one, First Contact Resolution, better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher, performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Reference period	
	2002=100
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5
July 2022	147.6
August 2022	147.0
September 2022	147.8
October 2022	148.6
November 2022	148.1
December 2022	147.1
January 2023	148.1
February 2023	149.1
March 2023	149.7
April 2023	150.4
May 2023	151.0
June 2023	151.6

Table A1-2: Average Weekly Earnings (AWE)

Reference period	
	Dollars
July 2021	1,143.76[B]
August 2021	1,143.96[B]
September 2021	1,142.37[B]
October 2021	1,140.94[B]
November 2021	1,129.51[B]
December 2021	1,132.93[B]
January 2022	1,155.32[B]
February 2022	1,153.57[B]
March 2022	1,161.00[B]
April 2022	1,164.51[B]
May 2022	1,159.89[B]
June 2022	1,167.14[B]
July 2022	1,162.26[B]
August 2022	1,171.52[B]
September 2022	1,171.94[B]
October 2022	1,174.29[B]
November 2022	1,176.97[B]
December 2022	1,153.31[B]
January 2023	1,180.04[B]
February 2023	1,175.83[B]
March 2023	1,191.20[B]
April 2023	1,199.14[B]

Table A1-3: British Columbia Three-Year Outlook 2023

Key Economic Indicators: British Columbia, 2022–25
(forecast completed February 6, 2023)

	2023Q1	2023Q2	2023Q3	2023Q4	2024Q1	2024Q2	2024Q3	2024Q4	2025Q1	2025Q2	2025Q3	2025Q4	2022	2023	2024	2025
GDP at market prices ($ millions)	391,736	395,415	399,177	403,736	406,355	410,776	415,451	420,228	424,501	428,452	432,006	435,380	387,452	397,516	413,202	430,085
	0.8	*0.9*	*1.0*	*1.1*	*0.6*	*1.1*	*1.1*	*1.1*	*1.0*	*0.9*	*0.8*	*0.8*	*10.5*	*2.6*	*3.9*	*4.1*
GDP at market prices (2012 $ millions)	288,445	288,783	289,747	291,630	293,450	295,974	298,578	301,260	303,505	305,509	307,230	308,858	288,561	289,651	297,315	306,276
	-0.4	*0.1*	*0.3*	*0.6*	*0.6*	*0.9*	*0.9*	*0.9*	*0.7*	*0.7*	*0.6*	*0.5*	*2.3*	*0.4*	*2.6*	*3.0*
GDP at basic prices (2012 $ millions)	268,952	269,263	270,150	271,927	273,661	276,038	278,453	280,981	283,105	284,983	286,596	288,138	268,886	270,073	277,283	285,705
	-0.4	*0.1*	*0.3*	*0.7*	*0.6*	*0.9*	*0.9*	*0.9*	*0.8*	*0.7*	*0.6*	*0.5*	*2.4*	*0.4*	*2.7*	*3.0*
Consumer price index (2002 = 1.000)	1.494	1.511	1.518	1.525	1.537	1.547	1.553	1.559	1.567	1.578	1.584	1.590	1.455	1.512	1.549	1.580
	1.0	*1.1*	*0.5*	*0.5*	*0.8*	*0.6*	*0.4*	*0.4*	*0.6*	*0.7*	*0.4*	*0.4*	*6.9*	*3.9*	*2.4*	*2.0*
Implicit price deflator—GDP at market prices	1.358	1.369	1.378	1.384	1.385	1.388	1.391	1.395	1.399	1.402	1.406	1.410	1.343	1.372	1.390	1.404
(2012 = 1.000)	*1.1*	*0.8*	*0.6*	*0.5*	*0.0*	*0.2*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.2*	*8.1*	*2.2*	*1.3*	*1.0*
Wages and salary per employee ($ 000s)	62.6	63.0	63.4	63.9	64.3	64.7	65.2	65.5	65.8	66.2	66.6	66.9	61.3	63.2	64.9	66.4
	1.4	*0.6*	*0.6*	*0.8*	*0.7*	*0.6*	*0.6*	*0.6*	*0.4*	*0.6*	*0.6*	*0.6*	*7.5*	*3.2*	*2.7*	*2.2*
Primary household income ($ millions)	271,333	273,731	277,762	281,397	284,854	288,183	291,553	294,696	297,304	300,218	303,091	306,018	263,680	276,056	289,821	301,658
	1.0	*0.9*	*1.5*	*1.3*	*1.2*	*1.2*	*1.2*	*1.1*	*0.9*	*1.0*	*1.0*	*1.0*	*9.3*	*4.7*	*5.0*	*4.1*
Household disposable income ($ millions)	238,251	238,085	241,327	244,400	246,131	248,862	251,726	254,524	256,290	258,790	261,242	263,730	230,486	240,516	250,311	260,013
	0.8	*-0.1*	*1.4*	*1.3*	*0.7*	*1.1*	*1.2*	*1.1*	*0.7*	*1.0*	*0.9*	*1.0*	*6.4*	*4.4*	*4.1*	*3.9*
Household net savings rate (per cent)	6.5	5.4	5.4	5.3	5.0	4.9	4.8	4.8	4.7	4.6	4.7	4.7	5.1	5.6	4.9	4.7
Population (000s)	5,395	5,422	5,447	5,472	5,496	5,519	5,542	5,564	5,586	5,608	5,631	5,652	5,303	5,434	5,530	5,619
	0.5	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*2.1*	*2.5*	*1.8*	*1.6*
Employment (000s)	2,767	2,766	2,781	2,794	2,804	2,816	2,827	2,837	2,847	2,857	2,866	2,875	2,748	2,777	2,821	2,861
	0.3	*0.0*	*0.6*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*3.1*	*1.0*	*1.6*	*1.4*
Labour force (000s)	2,910	2,916	2,929	2,939	2,949	2,959	2,969	2,979	2,989	2,999	3,008	3,017	2,880	2,923	2,964	3,003
	0.9	*0.2*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.0*	*1.5*	*1.4*	*1.3*
Labour force participation rate (per cent)	64.3	64.1	64.1	64.0	64.0	63.9	63.9	63.8	63.8	63.7	63.7	63.6	64.9	64.1	63.9	63.7
Unemployment rate (per cent)	4.9	5.1	5.0	4.9	4.9	4.8	4.8	4.8	4.8	4.7	4.7	4.7	4.6	5.0	4.8	4.7
Retail sales ($ millions)	100,889	101,567	102,870	104,222	105,539	106,986	108,360	109,565	110,577	111,794	112,829	113,854	101,049	102,387	107,613	112,263
	0.0	*0.7*	*1.3*	*1.3*	*1.3*	*1.4*	*1.3*	*1.1*	*0.9*	*1.1*	*0.9*	*0.9*	*2.5*	*1.3*	*5.1*	*4.3*
Housing starts (units, 000s)	39,451	38,118	38,500	40,000	42,000	43,584	43,850	43,838	43,692	43,528	43,340	43,127	46,721	39,017	43,318	43,422
	-23.3	*-3.4*	*1.0*	*3.9*	*5.0*	*3.8*	*0.6*	*0.0*	*-0.3*	*-0.4*	*-0.4*	*-0.5*	*-1.9*	*-16.5*	*11.0*	*0.2*
Net interprovincial migration (000s)	15.2	17.7	16.3	16.8	17.0	17.3	17.5	17.8	18.0	18.3	18.5	18.8	12	16.5	17.4	18.4
Net international migration (000s)	89.7	85.5	81.8	78.9	76.5	74.6	73.1	72.0	72.3	71.6	71.0	70.5	118.4	84.0	74.1	71.3

Shaded area represents forecast data, *italics indicate percentage change*.
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.

Note: Table above is from the Conference Board of Canada, British Columbia Three-Year Outlook, March 31, 2023.



Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 of this appendix show 10 years of historical data and the before-savings and after-savings forecast for 2023S and 2024F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2024F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2017 to 2022 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2017. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2020 to 2022. Finally, Table 6.6 shows the system load factor from the years 2017 to 2022 and the forecast load factor for 2023S and 2024F.

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 includes Normalized loads to December 2022.
- after-savings – the load after DSM and includes Normalized loads to December 2022.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,245	306,420	303,949	253,146	241,945	242,396	285,626	270,799	229,532	256,624	301,612	380,684	3,435,977
2015	364,636	317,325	299,476	250,366	249,815	247,921	287,307	276,774	233,611	256,959	300,534	361,093	3,445,816
2016	362,417	311,090	292,322	268,567	248,286	243,400	287,329	280,865	234,850	266,011	328,783	352,683	3,476,603
2017	364,284	298,155	307,568	263,749	249,610	251,126	300,242	289,240	246,675	265,495	324,809	356,765	3,517,718
2018	373,759	312,050	306,251	264,157	273,363	256,750	308,108	296,176	231,268	262,444	302,321	372,719	3,559,367
2019	371,601	294,208	316,259	261,193	267,746	257,893	295,882	292,659	260,751	291,966	314,389	370,267	3,594,813
2020	380,978	331,422	304,284	246,809	239,849	247,702	308,135	302,775	260,553	282,819	332,127	373,313	3,610,765
2021	379,923	340,308	320,380	275,424	255,599	264,059	313,426	294,626	255,445	284,819	333,861	374,965	3,692,835
2022	395,393	344,739	328,117	275,896	259,774	274,145	317,727	309,709	265,171	280,605	337,000	396,554	3,784,830
Before-Savings													
2023S	393,099	343,506	322,822	275,878	267,544	279,101	319,086	308,550	269,588	290,246	343,143	391,122	3,803,684
2024F	395,405	345,601	324,885	277,934	269,596	281,241	321,367	310,778	271,994	292,344	345,298	393,394	3,829,838
After-Savings													
2023S	390,501	340,929	320,309	273,448	265,202	276,815	316,824	306,260	267,245	287,810	340,630	388,565	3,774,539
2024F	390,223	340,479	319,905	273,132	264,983	276,752	316,937	306,307	267,435	287,618	340,441	388,467	3,772,679

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	329,517	279,546	279,656	235,365	226,070	226,002	263,980	251,199	214,732	238,897	276,987	343,940	3,165,892
2015	330,474	288,500	275,700	232,842	232,855	230,716	265,292	256,237	218,219	239,080	275,925	327,535	3,173,373
2016	328,972	283,576	269,823	248,799	231,696	226,952	265,539	259,978	219,469	247,136	300,036	320,866	3,202,843
2017	330,163	272,433	282,574	244,425	232,665	233,492	276,339	266,935	229,621	246,479	296,394	323,921	3,235,440
2018	338,459	284,446	281,783	245,037	253,552	238,619	283,364	273,179	216,362	244,085	277,755	337,598	3,274,238
2019	336,960	269,648	290,510	242,633	248,852	239,769	273,123	270,359	242,250	269,764	288,203	335,853	3,307,924
2020	345,128	301,193	280,588	230,312	224,658	231,093	283,880	279,297	242,295	262,137	303,482	338,771	3,322,834
2021	344,200	308,531	294,270	255,141	238,455	245,309	288,355	272,273	237,823	263,831	304,896	340,091	3,393,175
2022	356,904	312,144	300,781	255,512	242,069	254,001	291,969	285,142	246,240	260,155	307,481	357,859	3,470,257
Before-Savings													
2023S	356,862	312,701	297,618	256,528	249,790	259,327	294,420	285,377	251,055	269,568	314,129	355,218	3,502,592
2024F	358,989	314,632	299,533	258,433	251,695	261,304	296,522	287,433	253,266	271,513	316,120	357,317	3,526,758
After-Savings													
2023S	354,461	310,320	295,296	254,283	247,626	257,215	292,330	283,261	248,891	267,317	311,807	352,855	3,475,662
2024F	354,202	309,899	294,931	253,996	247,433	257,156	292,429	283,302	249,053	267,146	311,631	352,765	3,473,943

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
2022	150,247	130,107	119,338	92,786	83,362	90,463	111,776	99,512	80,706	95,008	120,814	146,242	1,320,362
Before-Savings													
2023S	148,630	127,563	116,282	92,342	85,724	88,930	111,180	104,355	74,030	96,625	121,724	144,778	1,312,162
2024F	148,154	127,155	115,910	92,046	85,450	88,645	110,824	104,021	73,793	96,316	121,335	144,314	1,307,962
After-Savings													
2023S	148,150	127,096	115,852	91,964	85,397	88,640	110,904	104,066	73,703	96,247	121,295	144,311	1,307,625
2024F	147,193	126,221	115,051	91,290	84,797	88,068	110,274	103,444	73,140	95,560	120,475	143,379	1,298,891

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,354	73,607	69,309	70,566	73,342	72,255	76,262	75,406	66,710	60,531	66,112	81,292	865,746
2015	80,156	72,259	68,665	64,591	71,392	74,678	72,149	71,980	68,558	62,811	67,227	78,701	853,168
2016	81,888	75,253	71,663	71,537	69,950	67,264	75,224	78,198	68,802	70,075	79,061	92,524	901,438
2017	87,580	76,292	77,390	69,008	70,517	72,425	82,456	81,640	72,344	73,698	77,035	80,003	920,385
2018	85,824	76,573	78,401	70,827	73,372	72,287	81,199	81,422	70,961	73,116	75,837	82,157	921,978
2019	85,718	80,999	80,956	69,682	72,347	72,907	78,731	80,774	73,021	75,361	78,350	85,041	933,887
2020	87,508	79,773	76,660	64,284	65,222	67,351	78,479	81,698	74,157	76,661	80,042	85,339	917,174
2021	87,315	79,792	80,058	71,855	73,925	80,219	85,512	69,286	96,034	76,263	80,232	90,890	971,380
2022	93,663	80,863	81,664	72,557	71,986	71,849	84,690	88,145	74,835	75,357	80,089	93,445	969,143
Before-Savings													
2023S	91,951	82,346	81,646	71,485	72,319	75,155	85,172	81,902	83,920	78,188	82,324	92,357	978,766
2024F	93,611	83,835	83,122	72,779	73,628	76,515	86,710	83,382	85,437	79,602	83,812	94,025	996,458
After-Savings													
2023S	90,995	81,393	80,699	70,545	71,387	74,230	84,248	80,976	82,989	77,249	81,377	91,404	967,494
2024F	91,705	81,937	81,239	70,914	71,779	74,679	84,880	81,551	83,599	77,757	81,960	92,169	974,168

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
2022	64,786	56,887	52,353	41,723	35,185	36,472	44,017	44,848	38,048	41,846	54,139	65,162	575,466
Before-Savings													
2023S	67,256	57,713	51,399	42,651	38,415	37,652	45,051	46,169	40,005	46,783	57,049	64,421	594,563
2024F	67,539	57,947	51,611	42,840	38,640	37,900	45,329	46,428	40,224	47,006	57,281	64,693	597,438
After-Savings													
2023S	66,907	57,368	51,064	42,331	38,109	37,357	44,759	45,873	39,699	46,463	56,714	64,076	590,719
2024F	66,842	57,258	50,944	42,202	38,032	37,313	44,750	45,843	39,618	46,374	56,622	64,014	589,812

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
2022	46,629	42,908	45,937	46,285	47,294	50,460	43,070	43,215	46,443	44,094	50,708	51,418	558,461
Before-Savings													
2023S	47,521	43,708	46,835	47,439	48,308	51,817	43,854	44,015	47,362	44,605	51,508	52,182	569,155
2024F	48,181	44,325	47,433	48,156	48,954	52,472	44,495	44,665	48,074	45,222	52,168	52,806	576,954
After-Savings													
2023S	46,915	43,102	46,233	46,841	47,721	51,233	43,279	43,436	46,785	44,009	50,910	51,595	562,059
2024F	46,977	43,131	46,259	46,998	47,826	51,360	43,409	43,582	47,004	44,123	51,075	51,743	563,488

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
2022	820	724	772	760	790	729	784	762	767	800	766	788	9,262
Before-Savings													
2023S	804	743	797	763	796	743	783	782	751	796	748	756	9,262
2024F	804	743	797	763	796	743	783	782	751	796	748	756	9,262
After-Savings													
2023S	796	735	789	756	790	737	776	775	744	788	740	748	9,173
2024F	787	727	781	749	783	730	770	769	737	781	732	739	9,084

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
2022	760	655	718	1,400	3,452	4,028	7,631	8,660	5,441	3,049	965	804	37,563
Before-Savings													
2023S	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
2024F	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
After-Savings													
2023S	698	627	659	1,846	4,222	5,018	8,364	8,134	4,970	2,561	771	722	38,592
2024F	698	626	657	1,844	4,217	5,007	8,346	8,113	4,954	2,552	767	720	38,500

2.9 SYSTEM PEAK (MW)

System Peak (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
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	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
2022	685	676	572	490	432	615	681	689	629	480	673	734	734	689
Before-Savings														
2023S	723	701	615	519	494	607	682	676	527	537	655	742	788	700
2024F	728	705	619	522	497	611	687	681	531	541	660	747	793	705
After-Savings														
2023S	719	696	611	515	490	603	678	672	523	533	651	738	783	696
2024F	720	696	611	514	490	603	679	673	523	533	652	739	785	697

Note: The peaks shown in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
Industrial	47	49	50	50	50	52	51	43	42	42	42	42
Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
Total Direct	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.2 CUSTOMER ADDITIONS

Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	(433)	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,453	2,192	1,969
Commercial	489	701	613	97	325	280	278	209	429	179	157	360
Wholesale	(1)	-	-	-	-	-	-	-	-	-	-	-
Industrial	(4)	2	1	-	-	2	(1)	(8)	(1)	-	-	-
Lighting	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(27)	(23)	(26)
Irrigation	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-	-
Total Direct	(38)	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	2,605	2,326	2,302

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

MWh/Customer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.57	10.32	10.04	9.82

5. LOAD

5.1 AFTER-SAVINGS LOAD

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak (MW)												
Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
BCH Lardeau	6.3	6.3	6.5	5.9	8.4	7.8	7.1	6.1	5.9	5.0	6.6	6.5
BCH Kingsgate	4.9	4.6	4.8	4.9	4.6	4.7	4.6	5.0	4.1	4.0	4.6	4.6
City of Grand Forks	41.1	39.5	40.7	40.5	38.7	45.8	36.9	37.5	36.3	37.0	37.5	37.5
City of Nelson	82.7	80.9	83.0	79.6	86.1	88.0	83.8	82.0	85.6	86.0	84.5	83.2
City of Penticton	348.4	341.9	348.4	345.2	338.0	340.0	338.4	340.3	337.0	347.0	357.9	357.9
District of Summerland	97.9	94.0	97.1	98.2	98.2	98.5	95.1	98.5	96.9	96.0	99.7	100.1
City of Kelowna	93.9	-	-	-	-	-	-	-	-	-	-	-
Total	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.0	590.7	589.8

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2018	2019	2020	2021	2022	2023S	2024F
Demand Side Management	(31.4)	(25.8)	(26.3)	(30.0)	(35.9)	(26.9)	(52.8)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2017	2018	2019	2020	2021	2022
Actual						
Residential	117,748	120,291	122,465	124,966	126,678	129,131
Commercial	15,398	15,678	15,956	16,165	16,594	16,773
Wholesale	6	6	6	6	6	6
Industrial	50	52	51	43	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103
Total	135,793	138,587	141,027	143,714	145,830	148,435
Forecast						
Residential	116,031	117,774	120,405	124,076	124,603	128,941
Commercial	15,813	16,122	16,405	16,220	16,579	16,975
Wholesale	6	6	6	6	6	6
Industrial	50	50	51	57	59	43
Lighting	1,590	1,559	1,511	1,425	1,393	1,406
Irrigation	1,095	1,090	1,080	1,082	1,082	1,091
Total	134,585	136,602	139,459	142,865	143,721	148,462
Variance (customers)						
Residential	1,717	2,517	2,060	890	2,075	190
Commercial	(415)	(444)	(449)	(55)	15	(202)
Wholesale	0	0	0	0	0	0
Industrial	0	2	0	(14)	(17)	(1)
Lighting	(79)	(77)	(44)	18	14	(26)
Irrigation	(15)	(12)	2	9	21	12
Total	1,208	1,986	1,569	849	2,109	(27)
Variance (%)						
Residential	1.5%	2.1%	1.7%	0.7%	1.6%	0.1%
Commercial	-2.7%	-2.8%	-2.8%	-0.3%	0.1%	-1.2%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	3.8%	0.0%	-32.6%	-40.5%	-2.4%
Lighting	-5.2%	-5.2%	-3.0%	1.3%	1.0%	-1.9%
Irrigation	-1.4%	-1.1%	0.2%	0.8%	1.9%	1.1%
Total	0.9%	1.4%	1.1%	0.6%	1.4%	0.0%

6.2 LOAD VARIANCE, NORMALIZED/HISTORIC ACTUAL TO FORECAST[1]

Energy (GWh)	2017	2018	2019	2020	2021	2022
Historic						
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4
Commercial	920.4	922.0	933.9	917.2	971.4	969.1
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5
Industrial	362.6	402.7	494.9	441.2	472.3	558.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8
Forecast						
Residential	1,353.0	1,280.0	1,349.3	1,325.6	1,255.4	1,283.2
Commercial	879.4	912.0	935.2	901.7	952.3	945.5
Wholesale	587.3	586.0	594.0	567.5	583.5	559.5
Industrial	407.0	379.0	385.0	453.0	536.7	470.4
Lighting	14.4	15.0	13.0	10.6	9.9	10.3
Irrigation	40.3	41.0	42.0	35.3	35.8	37.1
Net	3,282.2	3,213.0	3,318.5	3,293.7	3,373.7	3,306.0
Gross	3,559.0	3,485.0	3,602.0	3,602.0	3,664.0	3,591.0
Variance (GWh)						
Residential	(32.5)	32.6	(83.2)	21.3	74.9	37.1
Commercial	41.0	10.0	(1.3)	15.5	19.1	23.6
Wholesale	(13.2)	(1.3)	(28.0)	2.0	(17.7)	16.0
Industrial	(44.4)	23.7	109.9	(11.8)	(64.3)	88.1
Lighting	1.5	(1.8)	(2.0)	0.2	(0.3)	(1.0)
Irrigation	1.7	(2.0)	(6.0)	2.0	7.8	0.5
Net	(46.8)	61.2	(10.6)	29.2	19.5	164.3
Gross	(41.3)	74.4	(7.2)	8.8	28.9	193.9
Variance (%)						
Residential	-2.5%	2.5%	-6.6%	1.6%	5.6%	2.8%
Commercial	4.4%	1.1%	-0.1%	1.7%	2.0%	2.4%
Wholesale	-2.3%	-0.2%	-5.0%	0.4%	-3.1%	2.8%
Industrial	-12.3%	5.9%	22.2%	-2.7%	-13.6%	15.8%
Lighting	9.4%	-13.4%	-17.8%	2.1%	-2.8%	-10.7%
Irrigation	3.9%	-5.2%	-16.7%	5.3%	17.9%	1.3%
Net	-1.4%	1.9%	-0.3%	0.9%	0.6%	4.7%
Gross	-1.2%	2.1%	-0.2%	0.2%	0.8%	5.1%

[1] Residential and Wholesale historic loads shown are normalized loads. All other rate classes show historic actual loads.

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak								
Winter Peak (MW)	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak (MW)	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.9%	-0.6%	-3.5%	6.4%	-1.2%	-0.7%	-1.0%	-0.7%
Commercial	2.1%	0.2%	1.3%	-1.8%	5.9%	-0.2%	-0.2%	0.7%
Wholesale	-0.1%	1.8%	-3.2%	0.6%	-0.6%	1.7%	2.7%	-0.2%
Industrial	-2.9%	11.1%	22.9%	-10.8%	7.0%	18.2%	0.6%	0.3%
Lighting	0.0%	-17.0%	-16.5%	-1.7%	-10.7%	-4.3%	-1.0%	-1.0%
Irrigation	-0.3%	-7.1%	-7.7%	3.6%	17.1%	-13.9%	2.7%	-0.2%
Net	1.0%	1.2%	1.0%	0.5%	2.1%	2.3%	0.2%	0.0%
Losses & Company Use	3.1%	1.0%	0.6%	0.4%	4.1%	5.0%	-5.0%	0.0%
Gross	1.2%	1.2%	1.0%	0.4%	2.3%	2.5%	-0.3%	0.0%
System Peak								
Winter Peak (MW)	-5.4%	-4.4%	7.4%	-0.2%	-6.3%	7.2%	6.7%	0.2%
Summer Peak (MW)	2.0%	4.3%	1.4%	4.2%	-2.0%	5.5%	1.0%	0.1%

Customer Count	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	52	51	43	42	42	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380	1,103	1,103
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103	1,357	1,330
Total Direct	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.7%	2.2%	1.8%	2.0%	1.4%	1.9%	1.7%	1.5%
Commercial	2.2%	1.8%	1.8%	1.3%	2.7%	1.1%	0.9%	2.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	4.0%	-1.9%	-15.7%	-2.3%	0.0%	0.0%	0.0%
Lighting	-3.1%	-1.9%	-1.0%	-1.6%	-2.5%	-1.9%	-20.1%	0.0%
Irrigation	-0.9%	-0.2%	0.4%	0.8%	1.1%	0.0%	23.0%	-1.9%
Total Direct	1.7%	2.1%	1.8%	1.9%	1.5%	1.8%	1.6%	1.5%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2020	2021	2022
After- Savings Normalized Actual UPC	10.89	10.57	10.32
Forecast	10.75	10.10	10.04
Variance	0.13	0.48	0.29
Variance (%)	1.2%	4.5%	2.8%

6.5 WINTER PEAK, ACTUAL TO FORECAST

Winter Peak (MW)	2020	2021	2022
Actual Peak	725.0	777.0	835.0
Forecast	737.0	748.0	716.5
Variance	(12.0)	29.0	118.5
Variance (%)	-2%	4%	17%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

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

Year	Energy (MWh)	Peak (MW)	Load Factor
2017	3,517,718	714	0.56
2018	3,559,367	682	0.60
2019	3,594,813	732	0.56
2020	3,610,765	731	0.56
2021	3,692,835	684	0.62
2022	3,784,830	733	0.59
2023S	3,774,539	783	0.55
2024F	3,772,679	785	0.55

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.



Appendix A3

Load Forecast Methods

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1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in Section 3 of the Application is based.

In the figures provided in this appendix, 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 2024 Annual Review the latest calendar year for which full actual data exists is the 2022 calendar year.
- 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 filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.
- 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, 2024 is the Forecast Year (2024F).

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load 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[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential and wholesale load classes; therefore these classes are normalized. The commercial class shows a low R^2 value for all seasons and the irrigation class for the winter, summer and fall seasons; therefore, these classes were not normalized.

[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.
[2] Industrial and lighting loads are typically insensitive to the weather.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	35,802	71,302	76,725	70,811
Slope HDD	180	108	-	93
Slope CDD	-	-	250	-
Adjusted R^2	0.77	0.75	0.83	0.78

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	63,808	60,024	33,068	34,997
Slope HDD	60	49	-	32
Slope CDD	-	-	103	-
Adjusted R^2	0.91	0.95	0.85	0.79

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	50,957	49,648	69,253	71,660
Slope HDD	25	18	-	(2)
Slope CDD	-	-	78	-
Adjusted R^2	0.31	0.28	0.36	(0.05)

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,382	5,363	5,017	5,846
Slope HDD	(1)	(12)	-	(11)
Slope CDD	-	-	24	-
Adjusted R^2	0.01	0.78	0.53	0.52

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[3] and Cooling Degree Days (CDD)[4] 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 load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring

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

(March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2022:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2013-2022) 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 load requirements in month t is shown below.

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

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

And

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

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

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings[5]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2022) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

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

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

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

[5] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2022".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2013 to 2022.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2013
End Year	2022
R^2	0.825
Adjusted R^2	0.803
df	9
Intercept	395
Slope UPC	-0.19

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

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

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

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

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-6: Results of Residential Customer Count Regression

Regression	Residential
Start Year	2017
End Year	2022
R^2	0.996
Adjusted R^2	0.995
df	5
Intercept	(3,342)
Slope Population	0.46

The residential class represented 38.0 percent of the net load in 2022.

1.2.2 Commercial

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

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2008 to 2022 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 27.9 percent of the net load in 2022.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2008
End Year	2022
R^2	0.987
Adjusted R^2	0.985
df	14
Intercept	186,072
Slope GDP	2
Slope CoK Event	136,787

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers. 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 load requirements, etc. The wholesale class represented 16.6 percent of the net load in 2022.

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. 76 percent of FBC's industrial customers responded to the surveys, accounting for 91 percent of 2022 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group. The industrial class represented 16.1 percent of the net load in 2022.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2022 are included in the forecast but do not overly influence it. The irrigation class represented 1.1 percent of the net load in 2022.

1.2.6 Lighting

The before-savings lighting load uses the 2022 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2022. The lighting class represented 0.3 percent of the net load in 2022.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019-2022 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the 10-year average (2013-2022) 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. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

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

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-166-20 – FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
1.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2.1
2.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). 4. FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a
3.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
4.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
5.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
6.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Sections 3.6, 5.8, 6.3.4 and 7.2.2.1
G-14-23 – FBC PRINCETON BRIDGE STREET PROPERTIES DISPOSITION						
7.	n/a	4	Princeton Office Disposition Deferral Account	FBC is directed to provide details of the final balance in the Princeton Office Disposition deferral account in the FBC Annual Review for 2024 Rates.	Complete	Section 7.6.2.1

Appendix C
DRAFT ORDER

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British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2024 Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-165-20 for FortisBC Energy Inc. and Order G-166-20 for FortisBC Inc. (FBC) approving a Multi-Year Rate Plan for 2020 through 2024 (MRP Decision). In accordance with the MRP Decision, FBC is to conduct an annual review (Annual Review) process to set rates for each year;

B. By letter dated June 28, 2023, FBC proposed a regulatory timetable for the Annual Review of its 2024 rates;

C. By Order G-191-23, the BCUC established a regulatory timetable for the Annual Review for FBC's 2024 rates, which included FBC filing its Annual Review materials, the deadline for intervener registration, one round of information requests, a workshop, FBC's response to undertakings at the workshop, and written final and reply arguments;

D. On August 4, 2023, FBC submitted its materials for the Annual Review for 2024 Rates Application (Application). In the Application, FBC requests a 4.83 percent rate increase over the 2023 rates, effective January 1, 2024, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.

2. FBC is approved to establish the following rate base deferral accounts:

    a. 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

    b. 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;

    c. PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;

    d. BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and

    e. Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

3. FBC is directed to file as a compliance filing, the finalized financial schedules and updated tariff pages within 10 days from the date of the issuance of this order.

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