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May 15, 2025

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

Dear Commission Secretary:

Re: FortisBC Inc. (FBC)

2025 Cost of Service Allocation (COSA) and Revenue Rebalancing Application (Application)

Updated Application

FBC is filing the attached updated Application (Updated Application) to correct for errors discovered during the course of responding to Information Request (IR) No. 1, to present new rebalancing options in light of the updated revenue-to-cost (R/C) ratios, and to amend its approvals sought to reflect a new preferred rebalancing option and updated transformation discounts. FBC describes these changes below and includes references to each section and page number of the original Application (as well as appendices) where each change has occurred in Table 3 of this cover letter. In addition to the Updated Application, FBC is filing a blacklined version comparing the Updated Application to the original Application under separate cover for reference purposes to assist the BCUC and interveners in identifying the specific revisions.

In the course of responding to IR No. 1, FBC and its third-party expert EES Consulting Inc. (EES Consulting) identified errors in the COSA model as summarized in Table 2 below. As a result of correcting these errors, the R/C ratios of most rate classes have changed. While for most rate classes the adjustments to the R/C ratios are minor, one rate class – Large Commercial Transmission (RS 31) – has now moved outside of the range of reasonableness (RoR), and one rate class – Wholesale Transmission (RS 41) – has moved within the RoR. Given the updated R/C ratios, FBC has developed new rebalancing options and proposed a new preferred rebalancing option. These new options and new rebalancing proposal are reflected in Sections 7.2 and 7.3 of the Updated Application. Additionally, as a result of the changes to the COSA model, FBC has amended its requests related to the transformation discounts for RS 21, RS 30 and RS 40.

In consideration of the substantive changes to the Application regarding the rebalancing options, FBC proposes that the BCUC establish an amended regulatory timetable which includes a second round of IRs. FBC has provided a draft procedural order as Appendix F-3 to the Updated Application and also provides the proposed timetable below.

Table 1: Proposed Regulatory Timetable

Action	Date (2025)
BCUC IR No. 2	Thursday, June 5
Intervener IR No. 2	Thursday, June 12
FBC Responses to IR No. 2	Friday, July 4
FBC Final Argument	Friday, July 18
Intervener Final Arguments	Friday, August 1
FBC Reply Argument	Monday, August 18

Summary of Revisions to the COSA Report and COSA Model

The Updated Application includes a number of changes to the COSA inputs to correct for the errors discovered in responding to IR No. 1. These changes are summarized in Table 2 below and include a reference to the applicable IR where the correction is discussed. FBC has updated Appendix B with the revised COSA model.

Table 2: Summary of COSA Model Changes

IR Reference	Explanation of Correction
BCUC IR1 6.1	FBC inadvertently excluded neutral conductors from the line length data provided to EES Consulting as part of the 2025 Minimum System Study (MSS) analysis. The impact of correcting for this error (i.e., including the neutral conductors) is that the customer-related portion of conductor costs decreases from 71% to 65%.
BCMEU IR1 1.3	A data input error was discovered whereby the historical load information specific to the November load for RS 41 was too high. This has been corrected in the updated COSA model.
BCMEU IR1 1.2, 1.2.1, and 2.1	EES Consulting revised the approach to calculating Billing Demand for rate classes where Billing Demand can be based on a demand ratchet. RS 30, 40 and 41 demand values were revised to use actual monthly ratchet values from the historical year, rather than an annual average. RS 31 demand values use a ratchet value calculated on the forecast year values due to RS 38 adjustments not in the historical year.
BCOAPO IR1 4.2	Offsetting entries for *GST* and *Amortization & Other* line items were included in the original COSA model. These items netted to zero and have no impact on the COSA, but have now been corrected.

The changes summarized in Table 2 above affected the allocation of the approved revenue requirement and rate base amongst the rate classes, but did not impact the functionalization or classification of those costs. Accordingly, there are only limited adjustments required to the tables contained in the EES COSA Report (Appendix A to the Application), and none of the tables in the original Application (excluding the R/C ratio and revenue rebalancing tables) require corrections. Therefore, in addition to the updated COSA model in Appendix B, FBC provides the applicable updated tables from the EES COSA Report (Appendix A) below. For clarity, the Updated Application does not include an amended EES COSA Report.

Updated Table 4-1 to EES COSA Report: Total Rate Base

	2017 COSA	2020 COSA	2024 COSA (millions)
Residential	$733.6	$757.5	$835.4
Other Retail	396.0	457.2	502.9
Wholesale	154.9	169.0	204.1
Total System	**$1,284.5**	**$1,383.7**	$1,542.4

Updated Table 4-2 to EES COSA Report: Total Revenue Requirement

	2017 COSA	2020 COSA	2024 COSA (millions)
Residential	$188.2	$184.9	$224.1
Other Retail	122.1	129.6	161.0
Wholesale	50.4	49.4	66.5
Total System	**$360.7**	**$364.0**	$451.6

Updated Table 4-4 to EES COSA Report: Revenue and Requirements Comparison – 2024 COSA

	2024 Forecasted Rate Revenues	2024 Allocated Revenue Requirement	2024 Adjusted Revenue to Cost Ratio
Residential	$222,911,124	$224,110,800	**99.5%**
Small Commercial	$48,050,546	$44,682,060	**107.5%**
Commercial	$67,579,081	$66,014,202	**102.4%**
Large Commercial Primary	$26,204,954	$26,014,092	**100.7%**
Large Commercial Transmission	$17,457,593	$16,573,430	**105.3%**
Lighting	$2,403,403	$2,407,389	**99.8%**
Irrigation	$4,082,302	$5,279,269	**77.3%**
Wholesale Primary	$54,138,777	$57,599,301	**94.0%**
Wholesale Transmission	$8,746,523	$8,898,758	**98.3%**
Total	**$451,574,302**	**$451,579,302**	**100.0%**

Additionally, and as explained in Table 2 above, the correction to the line length data utilized as part of the MSS analysis has resulted in changes to the customer-related portion of conductor costs. For ease of reference, FBC has provided a corrected description from page 19 of the EES COSA Report below. The descriptions of the classification of the other distribution accounts on page 19 of the EES COSA Report are unchanged.

- ***Conductors & Devices***. The results of the minimum system analysis show 65% customer-related and 35% demand-related. The customer-related costs allocate based on actual customers.

FORTIS BC™

Summary of Changes to the Application and Appendices

FBC submits the attached Updated Application reflecting the changes described above. For ease of identification of the revisions made, FBC provides the following table summarizing the changes contained in the Updated Application.

Table 3: Summary of Application and Appendices Changes

Description
Application:
• **Section 1, Page 1, Revised Lines 31-32**
• **Section 2.1, Revised all Approvals Sought**
• **Section 4.2, Page 10, Removed Lines 6-11**
• **Section 5.1.2.1, Page 13, Revised Lines 22-23**
• **Section 5.3, Revised Table 5-5 and Page 20, Revised Lines 3-5**
• **Section 7.1, Page 26, Revised Lines 23-30**
• **Section 7.2 (revised all)**
• **Section 7.3 (revised all)**
• **Section 8, Page 38 (Revised Lines 32-36) and Page 39 (Revised Lines 1-7)**
• **Section 9, Page 40, Revised Lines 5-13**
Appendices:
• **Appendix B – Updated FBC COSA Model**
• **Appendix D – Updated FBC Electric Tariff – Blacklined**
• **Appendix F** ○ **F-2 – Updated Draft Order** ○ **New F-3 – Draft Procedural Order with Timetable**

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

FORTISBC INC.

2025 Cost of Service Allocation (COSA) and Application for Approval of Revenue Rebalancing

Updated Application

May 15, 2025

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1. INTRODUCTION

FortisBC Inc. (FBC or the Company) files this 2025 Cost of Service Allocation (COSA) and Revenue Rebalancing Application (Application) with the British Columbia Utilities Commission (BCUC) pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA). The Application reviews FBC's existing retail rates in the context of an updated COSA study and proposes a limited number of rebalancing adjustments to better align FBC's rates with its cost to serve.

FBC last rebalanced its rates as part of its 2017 COSA and Rate Design Application (2017 COSA and RDA). In 2020, FBC submitted an updated COSA (2020 COSA) in compliance with the 2017 COSA and RDA Decision and Order G-40-19 (2017 COSA and RDA Decision), but no adjustments to rates were proposed or implemented as a result. Since the 2017 COSA and RDA and 2020 COSA, FBC has completed its Advanced Metering Infrastructure (AMI) project, and AMI data consisting of individual hourly metered load data from all customers by rate class for historical year 2022 is now available. Given the passage of time since the last COSA and the availability of AMI data, FBC considered that an updated COSA was warranted to determine if rate rebalancing was required.

Consistent with past COSAs, FBC retained EES Consulting Inc. (EES Consulting), a third-party expert in public utility rate design matters, to perform a comprehensive COSA study for this Application. As discussed in more detail in its report (EES COSA Report), EES Consulting completed the COSA study following standard utility practice and using inputs and allocation methodologies substantially the same as past practice for the Company. The COSA study considered each of the rate schedules associated with Residential, Commercial, Lighting, Irrigation, and Wholesale customers. The impact of FBC's two market-based rates, Standby and Maintenance Service and the recently approved Large Commercial Interruptible Rate, is also considered. The COSA study results provide the revenue-to-cost (R/C) ratios of each rate schedule (RS), which shows the extent to which each recovers its allocated cost of service. The EES COSA Report is provided as Appendix A to the Application and the COSA model is provided as Appendix B.

The results of the COSA study indicate that the R/C ratios of four rate schedules fall outside the range of reasonableness (RoR) of 95 to 105 percent. FBC is proposing to rebalance rates to bring all rate schedules with the exception of Irrigation (RS 60) to within the RoR, with Small Commercial (RS 20) and Large Commercial Transmission (RS 31) receiving rate decreases, offset by increases to the Irrigation and the Wholesale Primary (RS 40) customer classes.

FBC's approvals sought are set out in Section 2 of the Application and its rebalancing proposals are discussed in detail in Section 7. Based on the analysis and considerations set out in the Application, FBC considers that its rebalancing proposals will result in an appropriate balance of rate design principles and other relevant considerations, are just and reasonable, and should be approved as proposed.

2. APPROVALS SOUGHT, PROPOSED REGULATORY PROCESS AND ORGANIZATION OF THE APPLICATION

2.1 APPROVALS SOUGHT

In this Application, FBC is seeking approval pursuant to sections 58 to 61 of the UCA to implement the following rate changes, effective January 1, 2026, as a result of revenue rebalancing:

- Rebalancing of all billing-determinant-related rate components included in RS 20 and 22 such that revenues are decreased by 2.4 percent;
- Rebalancing of all billing-determinant-related rate components included in RS 31 and 33 such that revenues are decreased by 0.3 percent; and
- Rebalancing of all billing-determinant-related rate components included in RS 40 and 42 such that revenues are increased by 1.1 percent.

With regard to RS 60 and 61, FBC seeks approval to phase-in the rebalancing of all billing-determinant-related rate components included in RS 60 and 61 such that revenues are increased by 3.0 percent each year for five years (with the in-season irrigation rate from April to October increasing by 3.9 percent each year). In order to implement the phase-in of RS 60 and maintain revenue neutrality, FBC seeks approval of a non-rate base deferral account titled the Irrigation Rebalancing Phase-in deferral account, attracting FBC's weighted average cost of capital (WACC). The deferral account will be amortized over the proposed five-year phase-in period and recovered from all customers through FBC's general rate increases.

Additionally, based on the results of the 2025 COSA study, FBC is seeking approval to update the transformation discount offered to customers under RS 21 who choose to take service at the primary distribution voltage, as well as RS 30 and 40 customers who choose to take service at the transmission line voltage level:

- For RS 21, an update to the transformation discount from $0.409 per kW of Billing Demand to $0.4841 per kW (from $0.371 to $0.4357 on a kVA basis) of Billing Demand;
- For RS 30, an update to the transformation discount from $6.727 per kVA of Billing Demand to $5.98 per kVA of Billing Demand; and
- For RS 40, an update to the transformation discount under the Wires Charge from $3.390 per kVA of Billing Demand to $3.78 per kVA of Billing Demand, and a reduction to the Energy Charge from $0.00985 per kWh to $0.00926 per kWh.

Rather than implement these changes mid-year, FBC is requesting that the rebalancing proposals and transformation discount updates be implemented effective January 1, 2026, to align with FBC's general rate changes which are typically effective on January 1st of each year. Implementing the rebalancing and transformation discount changes at the same time as FBC's general rate change is practical and preferrable as it avoids multiple rate changes in the year, thus mitigating the potential for customer confusion and lack of acceptance.

Finally, pursuant to sections 59 to 61 of the UCA, FBC is seeking approval of the establishment of a new rate base deferral account, titled the 2025 COSA deferral account, to record the costs associated with the regulatory review of the Application, and is proposing to amortize the deferral account over one year, commencing January 1, 2026. FBC estimates the total regulatory proceeding costs to be $450 thousand based on the proposed regulatory timetable provided in Table 2-1. The forecast costs include BCUC costs, Participant Cost Award funding, external legal fees, and consulting fees for EES Consulting. FBC considers a one-year amortization period appropriate as the rate impact to customers is relatively small at 0.13 percent, which equates to $1.70 per year for an average residential customer.[1] Please refer to Appendix E which addresses the considerations identified in the BCUC's Regulatory Account Filing Checklist.

2.2 *PROPOSED REGULATORY PROCESS*

FBC proposes a written public hearing process with one round of information requests (IRs) as an appropriate and efficient review process for this Application. Given that FBC is not proposing any changes to its currently approved rate designs and is proposing only limited rebalancing, FBC believes that one round of IRs will be sufficient. Therefore, FBC proposes the following regulatory timetable for the review of the Application. A draft procedural order is provided in Appendix F-1.

Table 2-1: Proposed Regulatory Timeline

Action	Date (2025)
BCUC Issues Procedural Order by	Tuesday, March 11
FBC provides Notice by	Friday, March 21
Intervener Registration Deadline	Tuesday, April 8
BCUC Information Request (IR) No. 1	Wednesday, April 9
Intervener IR No. 1	Wednesday, April 16
FBC Response to IR No. 1	Thursday, May 15
FBC Written Final Argument	Thursday, May 29
Intervener Written Final Arguments	Thursday, June 12
FBC Written Reply Argument	Thursday, June 26

[1] Compared to 2025 rates approved on an interim basis by Order G-314-24 for an average residential customer with annual consumption of 9,900 kWh.

2.3 ORGANIZATION OF THE APPLICATION

The remainder of the Application is organized into the following sections:

- Section 3 provides the history of FBC's rate design and the BCUC's decisions on previous rate design applications (RDAs) and COSA studies;
- Section 4 describes the consultation which FBC undertook prior to filing this Application;
- Section 5 provides an overview of FBC's COSA methodology and cost allocation process, as well as the R/C ratios and results;
- Section 6 provides the BCUC's and other regulators findings regarding the range of reasonableness and appropriate target for revenue rebalancing;
- Section 7 describes the revenue rebalancing options and FBC's proposed rebalancing;
- Section 8 describes the other proposed changes resulting from the 2025 COSA study related to the transformation discount; and
- Section 9 concludes the Application.

3. CONTEXT AND CONSIDERATIONS FOR COSA ANALYSIS

A COSA study is a fundamental component of the design of a utility's rates. A COSA study provides important contextual information in assessing how the current/proposed rates and rate structures perform against the relevant rate design principles, as well as other considerations, such as the effectiveness of the utility's rates to recover the cost of service, the fairness of cost apportionment among each customer class, and the potential of any undue discrimination or revenue instability due to the current/proposed rate design.

FBC's current rate design and structures were developed through a number of COSA and RDA proceedings over the years, most notably, the 2009 COSA and RDA[2] and the 2017 COSA and RDA[3].

In the following sections, FBC outlines the rate design principles used when considering the options and proposals in this Application and provides the regulatory history and relevant findings and directives from previous COSA and RDA decisions.

3.1 *COSA AND RATE DESIGN PRINCIPLES*

As described in Section 5 of the Application, FBC's COSA is conducted in accordance with the widely accepted rate design principles identified by Dr. Bonbright in his seminal work, *Principles of Public Utility Rates*. These principles are the same as those used in the 2017 COSA and RDA and are as summarized by the BCUC in the BC Hydro Residential Inclining Block (RIB) Rate Re-Pricing Application Decision[4]. The rate design principles, in no particular order, are as follows:

- Principle 1: Recovering the Cost of Service; the aggregate of all customer rates and revenues must be sufficient to recover the utility's total cost of service.
- Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates).
- Principle 3: Price signals that encourage efficient use and discourage inefficient use.
- Principle 4: Customer understanding and acceptance.
- Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives).
- Principle 6: Rate stability (customer rate impacts should be managed).
- Principle 7: Revenue stability.

[2] The 2009 COSA and RDA was filed on October 30, 2009, and the BCUC Decision and Order G-156-10 (2009 COSA and RDA Decision) was issued on October 19, 2010.
[3] The 2017 COSA and RDA was filed on December 22, 2017, and the BCUC Decision and Order G-40-19 (2017 COSA and RDA Decision) was issued on February 25, 2019.
[4] Appendix A of Order G-45-11 dated March 14, 2011, p. 5.

- Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

FBC does not always apply all eight principles in a given context and also does not assign any priority or any particular weighting to the eight principles. As discussed in this Application, rate design (or revenue rebalancing in the case of this Application) is a complex balancing process as it frequently requires the application of multiple, and sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. In addition, as different rate design principles may have varying levels of importance in different contexts, FBC applies its experience and judgement to consider and balance the most relevant principles in a given context when evaluating the different rate design (or revenue rebalancing) solutions. Rate design should strive to strike a balance among competing rate design principles based on the specific characteristics of customers in each rate schedule.

In addition to the eight Bonbright rate design principles, FBC considered its regulatory history of COSA and rate design applications, and the BCUC's previous findings and determinations on these applications, as further described below.

3.2 *FBC COSA HISTORY AND PREVIOUS COMMITMENTS*

3.2.1 Regulatory History of FBC's COSA and Rate Design Applications

FBC's most recent COSA and rate design applications include the 2009 COSA and RDA and the 2017 COSA and RDA. Additionally, in 2020 FBC submitted the 2020 COSA as a compliance filing to Order G-40-19; however, no adjustments to rates were proposed or implemented.

The 2009 COSA and RDA and the 2017 COSA and RDA incorporated proposals for changes to the structures of existing rates. In particular, the 2017 COSA and RDA proposed the phased removal of the Residential Conservation Rate, the re-opening of the residential time-of-use (TOU) rate, the flattening of the declining-block Commercial Rate Schedule (RS 21) rate, and multi-class adjustments to the fixed-cost elements of rates to better reflect cost causation. With the exception of the TOU rate proposals, the BCUC approved these changes as part of the 2017 COSA and RDA Decision.

In both the 2009 and 2017 applications, revenue rebalancing occurred as a result of the COSA studies.

3.2.2 Relevant Directives from the 2017 COSA and RDA Decision

In the 2017 COSA and RDA Decision, the BCUC made a number of determinations that are relevant to the current Application. These are outlined below.

With regard to the classification of distribution costs utilizing the Minimum System Study (MSS) approach, including the Peak Load Carrying Capability (PLCC) credit, the Panel made the following findings:

> … the purpose of the 2017 COSA Study is to equitably allocate the costs of operating the utility to FBC's various customer classes. The Panel must therefore assess whether the MSS method with the PLCC adjustment reasonably assigns FBC's distribution costs to the driver of those costs (i.e. demand or customer). The Panel agrees with FBC, the CEC and BCOAPO that the MSS method with the PLCC adjustment reasonably reflects cost causation because most distribution costs, with the exception of substations and services and meters, are driven by a combination of both the size of the load and the number of customers.[5]
>
> …
>
> The Panel is satisfied that the MSS, when combined with the PLCC adjustment to avoid double-counting of demand, is a reasonable approach for classifying distribution costs. There is no evidence that this approach does not provide reasonable results based on FBC's specific circumstances.[6]

FBC has used the MSS method with the PLCC adjustment to classify distribution costs within the 2025 COSA study.

With regard to the treatment of Standby and Maintenance Service rate (RS 37) revenues, the Panel stated the following:

> The Panel accepts FBC's approach of applying the RS 37 revenues as an offset to the overall revenue requirement. We find this approach appropriate because all customers are contributing to the fixed costs of FBC's system which is providing service to RS 37; thus all customers should receive the benefits of the RS 37 revenue.[7]

There have been no changes in circumstances that necessitate a change in the treatment of RS 37 revenues within the 2025 COSA and none have been made.

In addition to the above, a number of COSA study-related matters were raised by interveners and were examined in the 2017 COSA and RDA proceeding. The key findings and determinations from the 2017 COSA and RDA Decision are as follows:

- Generation Related Transmission Assets (GRTA) are to be classified as Transmission rather than Production.[8]
- The functionalization and classification of Demand Side Management (DSM) costs between Transmission and Distribution should remain consistent with previous COSAs, such that the investments in accounts 369 (Services), 370 (Meters/AMI Meters), 371

[5] 2017 COSA and RDA Decision, p. 14.
[6] 2017 COSA and RDA Decision, p. 14.
[7] 2017 COSA and RDA Decision, p. 17.
[8] 2017 COSA and RDA Decision, p. 18.

(Installation at Customer Premises) and 373 (Street Lights and Signal Systems) are not excluded from the value used for the distribution rate base.[9]

- The use of the two Coincident Peak (CP) allocator is the most appropriate allocator for production and transmission rate base.[10]

The inputs to the 2025 COSA study are consistent with the above findings from the 2017 COSA and RDA Decision.

[9] 2017 COSA and RDA Decision, p. 19.
[10] 2017 COSA and RDA Decision, p. 19.

4. STAKEHOLDER CONSULTATION

Before filing the Application, FBC conducted stakeholder consultation consisting of a virtual technical COSA workshop. The aim of the workshop was to present a high-level overview of the inputs and methodologies employed in the 2025 COSA study, provide the outcomes of the study, and gather feedback on potential rebalancing options.

Please refer to Appendix C of the Application for FBC's workshop presentation.

4.1 *PARTICIPATION*

An invitation to the workshop was sent to BCUC staff and all interveners in the FBC 2017 COSA and RDA proceeding, the FBC Large Commercial Industrial Rate proceeding, and the FBC Annual Review for 2024 Rates.

Representatives from the following stakeholder groups attended the virtual workshop, which was held on December 17, 2024:

- BC Hydro;
- British Columbia Municipal Electric Utilities Association (BCMEU);
- BC Sustainable Energy Association (BCSEA);
- Commercial Energy Consumers Association of British Columbia (CEC);
- Industrial Customer Group (ICG); and
- MoveUP.

BCUC staff also attended the workshop.

4.2 *WORKSHOP COMMENTS*

The comments and questions during the workshop were primarily regarding the availability of additional information on the breakdown of load and end-uses, as well as a request for load details from municipal utilities served by FBC.

A question was asked as to whether adjustments to the COSA methodology would be in scope for the regulatory process. FBC responded that it believed that the COSA methodology could be explored as part of the regulatory proceeding. The availability of the 2025 COSA study was queried, and FBC confirmed that the full electronic study would be filed.[11]

Two specific follow-up items were requested during the workshop:

[11] The EES COSA Report is provided as Appendix A to the Application and the COSA model is provided as Appendix B.

- Details behind the calculations of the rebalancing scenarios provided (a request of ICG); and
- Historic R/C ratio information (a request from the CEC).

FBC provided the requested information to all workshop attendees shortly after the workshop and has included the information as part of Appendix C to the Application.

4.3 *WRITTEN SUBMISSIONS*

FBC requested that any written submissions on the material presented during the workshop be submitted on or before January 10, 2025. None were received.

5. 2025 COSA STUDY METHODOLOGY AND RESULTS

A COSA study allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expenditures. This approach is taken to develop a fair and equitable assignment of costs to each customer class so that customers pay for the costs that they cause. The primary output of the study is the cost to be collected by rate class, which can be used to guide the adjustment of existing rates or as a basic input for rate design.

The outcome of the COSA process is revenue neutral and the primary concern for the Company is that the principles of cost-causation and equity are upheld within the cost allocation methodologies and assumptions while considering and balancing Bonbright's rate design principles described in Section 3.1.

As previously stated, FBC retained EES Consulting to develop the COSA study with inputs provided by the Company. FBC last filed a COSA study in 2020 as a compliance filing to the 2017 COSA and RDA Decision. EES also conducted a COSA study in 2009 and has been utilized by FBC to perform COSA and rate design work since 1982. As discussed in more detail in the EES COSA Report, EES Consulting completed the COSA study for this Application following standard utility practice and using inputs and allocation methodologies substantially the same as past practice for FBC, including those reviewed and accepted in the 2009 COSA and RDA proceeding and the 2017 COSA and RDA proceeding, as discussed in Section 3.2.2. The results of the COSA study are used to ensure that rates are fair, equitable and not unduly discriminatory. The COSA results show the extent to which each rate schedule recovers its allocated cost of service.

This section is organized as follows:

- Section 5.1 discusses the primary financial and customer-related inputs;
- Section 5.2 describes the key processes of the functionalization, classification and allocation exercises undertaken in order to complete the 2025 COSA study; and
- Section 5.3 provides the 2025 COSA results, including the R/C ratio for each customer class.

5.1 *ASSUMPTIONS AND INPUTS FOR THE 2025 COSA STUDY*

The following section describes the primary financial and customer-related inputs for the 2025 COSA study including:

- The customer classes included in the study;
- The revenue requirement;
- The rate base; and
- The load associated with each customer class.

5.1.1 Customer Classes (Segmentation)

Customers are grouped into classes that reflect common usage characteristics or facility requirements. The main FBC customer classes are provided in the following table.

Table 5-1: FBC Customer Classes

Customer Class	Default Rate Schedule
Residential	RS 01
Small Commercial	RS 20
Commercial	RS 21
Large Commercial Primary	RS 30
Large Commercial Transmission	RS 31
Lighting	RS 50
Irrigation	RS 60
Wholesale Primary	RS 40
Wholesale Transmission	RS 41

Notes to Table:

(1) For the purposes of cost allocation, any load and revenue associated with Time-of-Use (TOU) rate schedules is included in the totals for the default rate that would normally apply to a customer. There are very few TOU customers, and the embedded-cost COSA does not differentiate costs by TOU period.

(2) Large Commercial Primary and Large Commercial Transmission are often grouped and referred to as "Industrial" in FBC regulatory filings, which is reflected in several tables in this Application.

FBC serves six customers at the wholesale level under either the Wholesale Primary or Wholesale Transmission classes.

In the 2025 COSA study, residential customers make up 87 percent of the total number of customers and over 38 percent of energy sales. Wholesale customers make up another 17 percent of energy sales, with the remaining 45 percent composed of commercial, irrigation and lighting class consumption.

Since conducting the 2020 COSA study, FBC has had an additional rate approved by the BCUC. This rate, the Large Commercial Interruptible Rate (RS 38), is a non-firm, market-based rate. For the purposes of the 2025 COSA study, FBC has treated both the revenues and costs of RS 38 in a manner that is consistent with how RS 37 revenues and costs are treated. This aspect of the COSA is discussed in Section 5.1.2.1 below.

5.1.2 Revenue Requirement

For the 2025 COSA study, FBC used the 2024 Approved revenue requirement of $457.2 million, which was approved by the BCUC in Decision and Order G-340-23, as the basis for the cost allocation. Consistent with the COSA study approved in the 2017 COSA and RDA Decision, the

2024 Approved revenue requirement is offset by the RS 37 revenue, as discussed in Section 3.2.2 above, and adjusted to account for known and measurable changes since the approval of the 2024 revenue requirement. In the case of the 2025 COSA study, an adjustment has been made to incorporate the RS 38 revenues, as discussed in Section 5.1.2.1 below.

Table 5-2 below summarizes the revenue requirement used for the 2025 COSA study, which is based on FBC's 2024 Approved revenue requirement with adjustments for the revenues of RS 37 and RS 38. The detailed breakdown of FBC's revenue requirement used for the 2025 COSA is provided in the EES COSA Report in Appendix A, Schedule 3.1.

Table 5-2: Revenue Requirement for 2025 COSA

Cost Category	Value ($ millions)
Cost of Energy	193.4
O&M and A&G Expenses	63.3
Return, Depreciation & Taxes	212.6
Gross Revenue Requirements	469.3
Less Other Revenue	12.1
Net Revenue Requirements (2024 Approved)	**457.2**
Less RS 37 Revenues	2.1
Less RS 38 Revenues	3.6
2025 COSA Revenue Requirements	**451.6**

5.1.2.1 Treatment of RS 38 Revenue

RS 38 is FBC's Large Commercial Interruptible Service. This is a market-based, non-firm rate approved by Order G-136-23. RS 38 rates are calculated based on the hourly Mid-C price in effect when the service is used.

At the time of filing this Application, FBC has a single customer taking service under RS 38. However, there were no RS 38 revenues for the 2024 test year as the customer's load was served under RS 31 at the time. FBC considers it appropriate to reflect the change in the COSA load apportionment as a known and measurable change to the test year.

Revenues for RS 38 are difficult to forecast due to the uncertainty arising from the relationship between Mid-C pricing and the Customer's nominated Price Cap, as well as the likelihood of interruption. The actual hours of service provided to the RS 38 Customer cannot be known in advance. Based on the customer's 2022 total load served under RS 31 and the RS 38 customer's RS 31 Contract Demand as determined in the RS 31 Agreement, FBC has estimated the revenue to be approximately $3,574,198 using the hourly Mid-C pricing during the same period for the purposes of the 2025 COSA study.

Since both the RS 37 and RS 38 rates are calculated based on the hourly Mid-C price in effect when the service is used, FBC applied the same treatment approved for RS 37 as part of the 2017 COSA and RDA Decision to the revenues of RS 38, which is allocated to all customers as an offset to the revenue requirement for compensating for the use of the system paid by all customers.

5.1.3 Rate Base

Consistent with the approach used in previous COSA studies (2009 and 2017), FBC used the average of the 2021 and 2022 actual rate base, which is $1,542.4 million for the purposes of cost allocations in the 2025 COSA study. The use of a two-year average is intended to smooth out the impact of large capital expenditures.

Table 5-3 below provides a summary of the rate base used for the 2025 COSA study which reflects a gross plant of $2,316.1 million plus working capital and unamortized deferrals of $127.1 million, offset by accumulated depreciation of $669.2 million and customer contributions of $231.7 million. Distribution plant makes up approximately 53.2 percent of the gross plant, followed by 22.5 percent for transmission plant, 14.4 percent for power production, and 9.9 percent for general plant. FBC's detailed rate base by account used for the 2025 COSA is provided in the EES COSA Report in Appendix A, Schedule 4.1.

Table 5-3: Rate Base for 2025 COSA

Cost Category	Amount ($ millions)
Total Gross Plant	2,316.1
Less Accumulated Depreciation	(669.2)
Less Customer Contributions	(231.7)
Working Capital, Deferrals & Other	127.1
Total Rate Base	**1,542.4**

5.1.4 Load and Average Customer Count

The gross load and average customer count used for the 2025 COSA study is based on the 2024 Approved forecasts. Table 5-4 below provides the summary of the gross load and average customer count used for the 2025 COSA study, which are 3,396 GWh and 152,006 customers, respectively. FBC notes that the gross load of 3,396 GWh excludes the projected load in RS 37 as well as the projected load in RS 31 that would be served through RS 38. The peak demand forecast used for the 2025 COSA cost allocations is 777 MW in the winter months and 629 MW in the summer months. The detailed gross load and average customer count used for the 2025 COSA are provided in the EES COSA Report in Appendix A, Schedule 8.4.

For comparison, in 2017 the total system energy was 3,282 GWh forecast for the year. The system energy change from 2017 to 2024 reflects an average annual increase of 0.6 percent per year. The number of customers, however, has increased by an average of 1.9 percent per year. The difference in the customer growth and energy sales growth is due in part to a change in the mix of customer types and the average use per customer.

Table 5-4: Load Forecast

Customer Class	Load (GWh)	% Load	Count
Residential	1,299	38.3	132,389
Commercial	974	28.7	17,125
Industrial	486	14.3	42
Wholesale	590	17.4	6
Lighting & Irrigation	47	1.3	2,444
Total	**3,396**	**100.0**	**152,006**

As shown in Table 5-4 above, residential customers make up 87.1 percent of the total number of customers and over 38.3 percent of energy sales. Wholesale customers make up another 17.4 percent of energy, with the remaining 44.3 percent related to commercial, industrial, and other retail classes.

5.1.5 Load Analysis

A notable change in the 2025 COSA study compared to the 2017 COSA study is the availability of AMI data for detailed hourly load and consumption history in all customer classes. The load summary above relies on detailed load and consumption data for all customer classes. Using the actual 2022 hourly AMI data, parameters such as load and coincidence factors can be calculated more accurately. This is an improvement from the 2017 COSA study where only aggregate or sample data was used.

The availability of AMI data also validated the reasonableness of the data that had been used in previous years. EES found that the use of AMI data did not cause any significant swings as compared to previous COSA results.

More details on the load analysis are contained in Section 3.5.1 of the EES COSA Report.

5.2 THE KEY COSA PROCESSES – FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION

This section describes the key processes of the functionalization, classification and allocation exercises undertaken to complete the 2025 COSA study. A detailed discussion of how the costs included in the COSA are functionalized, classified and allocated is contained in Section 3 of the EES COSA Report.

The COSA analysis allocates FBC's rate base and revenue requirement to the various customer classes of service to determine each class's level of revenue responsibility. Costs are allocated to the various customer classes of service based upon a fair and equitable method that reflects the cost-causal relationships for the production and delivery of the services.

The first step of the COSA is to functionalize FBC's rate base and revenue requirement as production, transmission, and distribution. The second step is to classify the functionalized costs to demand, energy, and customer-related component costs:

- Demand-related costs are those that FBC incurs to meet a customer's maximum instantaneous usage requirement and is usually measured in kilowatts (kW).
- Energy-related costs are those that vary directly with longer periods of consumption and are usually measured in kilowatt-hours (kWh).
- Customer-related costs are those that vary with the number and type of customers served.

In the third step, these three component costs are allocated to each class of service based upon the most equitable method for each specific cost. At that point, the revenue requirement has been allocated to each class of service and a determination of the necessary revenue adjustments between classes of service can be made.

The following sections provide a summary of how the main steps of functionalization, classification and allocation are applied for FBC. The results of each process can be found in the EES COSA Report (Appendix A to the Application).

5.2.1 Functionalization

The first step in the COSA process is to functionalize the rate base and revenue requirement. Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e. production, transmission, and distribution) using FBC's system of accounts for both the rate base and revenue requirement.

The Production function includes both rate base and expense items associated with generation owned by FBC and power purchase expenses.

The Transmission function includes those costs for operating and maintaining the transmission lines, poles, towers, substations, etc., used to deliver power to the distribution network's load centres. Transmission is generally lines measured at 35,000 volts and above.

The Distribution function includes all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power.

Functionalization of the rate base and revenue requirement is discussed in detail in Sections 3.3.1 and 3.3.2 of the EES COSA Report, respectively.

5.2.2 Classification

The second step in developing the COSA is to classify the functionalized expenses to traditional cost-causation categories. Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related.

Production costs are related to supplying power to customers on the system. Production facilities are designed and operated to meet system peak demands and total energy requirements. Transmission costs are related to the bulk transfer of power to load centres on the system. These transmission facilities are typically designed and operated to meet system peak demand requirements. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer.

The classification for each of FBC's functionalized expenses is summarized below, with the detail, rationale and results contained in the referenced sections of the EES COSA Report.

5.2.2.1 Generation and Transmission Rate Base

For Generation, consistent with the 2017 COSA, the output from the Kootenay River plants was priced as if it were at the BC Hydro 3808 Tariff rate to determine the equivalent split in costs between demand and energy, with this split applied to the actual costs of these projects for the purposes of classification.

For Transmission, the cost of providing transmission service to a customer is directly proportional to the contribution to system peak demand that customers impose on the system. As such, transmission assets in FBC's rate base are classified as 100 percent demand-related, consistent with previous COSA studies.

Please refer to Section 3.4.1 of the EES COSA Report for further details.

5.2.2.2 Distribution Rate Base

For the classification of distribution plant, a minimum system study (MSS) was performed to determine the split between customer- and demand-related costs. A similar approach was taken in the 2017 COSA. The MSS assumes a certain size of the distribution plant such as the number of poles, conductions, and transformers is required to serve the minimum load requirements of customers, thus the costs associated with such minimum system are dependent on the number of customers, i.e., customer-related regardless of their level of load demand. The remaining costs of the distribution plant are then classified as demand-related since any cost associated with the distribution plant beyond the minimum system requirement is considered to be due to the customers' level of load demand being greater than the level that a minimum system can serve.

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are capable of carrying an amount of load beyond the theoretical level, therefore overstating the level of the customer-related component. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the analysis.

Please refer to Section 3.4.2 of the EES COSA Report for further details.

5.2.2.3 Other Rate Base

Functionalized general plant, after being functionalized to Production, Transmission and Distribution, was classified using the resulting percentage of total rate base for each function. For example, general plant assigned to generation was split between demand and energy in the same manner as the generation rate base. Accumulated depreciation accounts and working capital accounts were classified in the same fashion as the corresponding gross plant accounts. Customer contributions were assigned to classes based on poles, conductors and transformers.

Please refer to Section 3.4.4 of the EES COSA Report for further details.

5.2.2.4 Production/Power Supply Expenses

FBC power supply resources include FortisBC-owned generation, long-term power purchase contracts including a tariff-based purchase from BC Hydro, and market purchases. Because power supply sources vary by month, power supply costs were classified to demand and energy for each month and then allocate to customer classes based on each class's contribution to system peak and energy loads for each month. Each of the resources are considered separately as it relates to the split between demand-related and energy-related costs in the 2025 COSA. On a combined basis, the total purchased power expenses were classified 35 percent demand-related and 65 percent energy-related on an annual basis.

Please refer to Section 3.4.5 of the EES COSA Report for further details.

5.2.2.5 Other Expenses

There are other expenses and revenues, such as for some Customer Service costs, depreciation, and administrative and general expenses that are considered separately within the 2025 COSA. Some revenues, such as those for pole attachments, are treated as an offset to the revenue requirement.

Please refer to Section 3.4.6 of the EES COSA Report for further details.

5.2.3 Allocation

The third step in performing a COSA is the allocation of the utility's total functionalized and classified revenue requirement to the customer classes of service. This is performed through the application of a proper allocation methodology.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak (CP), non-coincident peak (NCP) or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records and detailed studies of customer load data.

Allocation reflects the extent to whether the components of the functionalized and classified revenue requirement are driven by demand-related, energy-related, or customer-related factors.

Section 3.5 of the EES COSA Report describes the allocation factors used in the COSA for the revenue requirement and rate base. Notable among these is the continued use of the 2 CP allocator for generation and transmission rate base accounts.

5.3 2025 COSA STUDY RESULTS

The R/C ratio for each customer class is calculated by dividing the revenue at current rates by the total allocated costs. The approved 2024 revenue requirement includes revenues calculated using an average rate for each class, consistent with the method used in past years. For the purposes of the 2025 COSA, revenues were calculated under each tariff based on the billing determinants for each class.

Using the revenues at approved rates for 2024[12] results in projected rate revenues of $451.6 million, after the adjustments for RS 37 and RS 38 revenues. The calculated revenue from rates in the 2025 COSA using the actual billing determinants, multiplied by the various rate components, is $442.8 million, which is 1.99 percent lower than the revenue forecast provided in the Evidentiary Update to the FBC Annual Review for 2024 Rates.

Since the expected revenues derived from billing components and forecast load differ slightly from the 2024 Approved revenues, an adjustment is made on a pro-rated basis to ensure that total allocated revenue divided by total allocated costs is equal to unity or 100 percent. The resulting R/C ratios help inform the need for revenue rebalancing without consideration of overall rate increases considered in separate proceedings. Revenue rebalancing is the method by which the utility shifts revenue responsibility from one customer group to another.

The R/C ratios in the 2025 COSA study are shown in the following table.

Table 5-5: 2025 COSA Study Revenue to Cost Ratios

Customer Class	Default Rate Schedule	Revenue to Cost Ratio
Residential	RS 01	99.5%
Small Commercial	RS 20	107.5%

[12] Evidentiary Update to the FBC Annual Review for 2024 Rates, Appendix A.

Customer Class	Default Rate Schedule	Revenue to Cost Ratio
Commercial	RS 21	102.4%
Large Commercial Primary	RS 30	100.7%
Large Commercial Transmission	RS 31	105.3%
Lighting	RS 50	99.8%
Irrigation	RS 60	77.3%
Wholesale Primary	RS 40	94.0%
Wholesale Transmission	RS 41	98.3%

As shown in the table above, the R/C ratios of five of the nine customer classes are within the range of 95 percent to 105 percent. The Small Commercial and Large Commercial Transmission customer classes are above this range, while the Irrigation and Wholesale Primary classes are below the range.

In the following section, FBC discusses the range of reasonableness (RoR) and its proposal for rebalancing.

6. RANGE OF REASONABLENESS AND TARGET FOR REVENUE REBALANCING

It is industry standard practice to assess R/C ratios based on whether they fall within an established RoR. As cost allocations in a COSA necessarily involve assumptions, estimates, simplifications, judgements and generalizations, the use of an RoR is warranted and is a widely accepted practice used to evaluate the appropriateness of the R/C ratios and whether revenue rebalancing may be needed.

Consistent with this practice, FBC has considered the results of the 2025 COSA for each rate schedule in light of the accepted RoR and considers that each rate schedule that falls within the RoR is recovering its fair cost. If a rate schedule falls outside of the RoR, this indicates that revenues are either insufficient to cover the cost of service or exceed the cost of service, which suggests that rate rebalancing may be in order. The RoR is therefore used as an indication of the rate schedules that may require rebalancing.

As discussed in the subsections below, FBC considers that an RoR of 95 percent to 105 percent remains appropriate and that rebalancing to within the RoR, rather than to unity, is the most reasonable approach and reflective of industry standard practice.

6.1 *RANGE OF REASONABLENESS OF 95% TO 105% REMAINS APPLICABLE*

Consistent with past BCUC determinations, FBC has continued to utilize an RoR of 95 percent to 105 percent in this Application.

In the 2009 COSA and RDA Decision, the BCUC approved FBC's proposed RoR of 95 percent to 105 percent.[13] The appropriateness of the 95 percent to 105 percent RoR was reaffirmed by the BCUC Panel in the 2017 COSA and RDA Decision, where the Panel found that this RoR for FBC continued to be appropriate, noting that the range is consistent with past BCUC decisions on FBC's RoR and there have been no changes in circumstance which indicated that a widening (or narrowing) of the range was required at the time.[14]

The availability of data from AMI has validated the load assumptions made in the previous COSA study. This factor alone does not significantly reduce the uncertainty inherent in the various assumptions and judgement that are part of the COSA study process. FBC considers that there is no change in circumstances sufficient to require a change to the RoR of 95 percent to 105 percent.

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[13] Page 78.
[14] 2017 COSA and RDA Decision, p. 26.

6.2 REBALANCING TO WITHIN THE ROR IS MOST REASONABLE APPROACH AND CONSISTENT WITH MOST RECENT BCUC DECISIONS

In assessing the appropriate target for rebalancing, FBC considered the BCUC's previous decisions. FBC considered the 2009 and 2017 COSA and RDA Decisions, as well the BCUC's more recent findings in Decision and Order G-135-18 regarding FEI's 2016 Rate Design Application (RDA) and its most recent decision on rebalancing in the FEI 2023 COSA and Revenue Rebalancing Application.[15] As discussed below, in the BCUC's more recent decisions, it has endorsed the approach of rebalancing to within the RoR, as opposed to rebalancing to unity. FBC agrees with this approach.

In the 2009 COSA and RDA Decision, the BCUC found that the appropriate target for revenue-to-cost ratios in each class is unity or one, and the BCUC directed FBC to adjust its rates with the goal of achieving R/C ratios of one for each class. The BCUC also found that future rebalancing should only be required when a customer class falls outside of the RoR.[16]

In the 2017 COSA and RDA Decision, the BCUC directed that rebalancing be limited to those customer classes that were outside the RoR (the Lighting customer class (RS 50) and the Large Commercial Transmission customer class (RS 31)), and specifically directed that the Lighting customer class be rebalanced to achieve an R/C ratio of 100 percent, with the resulting revenues allocated to the Large Commercial Transmission class.[17] The BCUC further found the following:[18]

> … where a customer class has an R/C ratio within the range of reasonableness, there is insufficient evidence to conclude that the rate needs to be rebalanced. This is not to say that such a customer class is proven to be fully covering its costs, but rather, there is insufficient evidence it is not doing so. In the interests of another Bonbright principle, rate stability, where there is insufficient justification to rebalance rates, the Panel chooses not to rebalance them. Thus, the Panel agrees with FBC and most interveners, and finds that customer classes with R/C ratios inside the range of reasonableness do not require their rates to be rebalanced.

The BCUC's rationale for directing RS 50 to be rebalanced to unity was as follows:[19]

> The Panel agrees with the CEC that an R/C ratio of unity provides the best evidence that a customer class is fully recovering its costs and no more. Rates set to achieve R/C ratios of 95 percent or 105 percent, the endpoints of the range of reasonableness, are inherently less likely to cover only the allocated costs of their respective customer classes.

15 FEI 2023 COSA and Revenue Rebalancing Application, Decision and Order G-144-24.
16 2009 COSA and RDA Decision, pp. 78-79.
17 2017 COSA and RDA Decision, p. 26.
18 2017 COSA and RDA Decision, p. 27.
19 2017 COSA and RDA Decision, p. 28.

The effect of these previous decisions has been that FBC's rates have only been rebalanced when the R/C ratio of a portion of a customer class taking service under the same rate schedule falls outside of the RoR, and only then to rebalance to a revenue-to-cost ratio of unity where sufficient revenues are available, and to as close to unity as possible if they are not.

However, subsequent to the filing of the 2017 COSA and RDA, as part of the regulatory process to review FEI's 2016 Rate Design Application (FEI 2016 RDA), BCUC staff submitted an independent consultant report from Elenchus Research Associates Inc. (Elenchus Report)[20].

As expressed in its report, Elenchus was of the view that any R/C ratio that is within the defined RoR can be considered to be full cost recovery. An R/C ratio that is below the range is considered to indicate under-recovery of costs and any R/C ratio that is above the range indicates over-recovery of costs.

The BCUC Panel in the FEI 2016 RDA Decision stated that it places weight on the evidence provided by Elenchus that:

- Any R/C ratio that is within the defined RoR can be considered to be full cost recovery;
- Rebalancing should be undertaken to move all classes that are outside the approved range to the nearest boundary;
- It is not appropriate to periodically rebalance to R/C ratios of 1.00; and
- Elenchus is not aware of any jurisdiction that periodically rebalances rates so that all R/C ratios are 1.00.[21]

The BCUC further found the following:[22]

> While the BCUC, in its COSA and R/C Ratios Decision, accepted that in theory an R/C ratio of 100 percent for each rate schedule would indicate that the revenues recovered from each rate schedule are equal to the cost to serve them, the assumptions, estimates and judgements involved in a COSA study, make it appropriate to use a range of reasonableness. In the Panel's view, the range of reasonableness should be used as a guideline to inform rate design and rebalancing. However, in some circumstances it is appropriate not to rebalance to within the accepted range of reasonableness when considering other rate design principles.
>
> …
>
> Accordingly, the Panel finds there is insufficient evidence for the position that FEI should rebalance to unity. The Panel finds that FEI's approach reflects a reasonable balance of rate design principles and appropriately considers the rate

[20] FEI 2016 RDA proceeding, Exhibit A2-10.
[21] FEI 2016 RDA Decision and Order G-135-18, p. 42.
[22] FEI 2016 RDA Decision and Order G-135-18, pp. 41-42.

> impacts to the residential class which is within the range of reasonableness prior to any rebalancing.

In the BCUC's decision on FEI's 2023 COSA and Revenue Rebalancing Application, the BCUC directed that the rate classes outside of the RoR be brought within the RoR of 95 to 105 percent (but not rebalanced to unity).[23] The Panel also explicitly rejected a proposal that FEI aim to achieve unity in its R/C ratios, stating:[24]

> FEI's approach to assess the need for rebalancing a rate class is to rely on a range of reasonableness of 95 percent to 105 percent within which a rate schedule's revenue is considered to be recovering its costs. The CEC has raised no concern with this methodology in the current proceeding but has recommended the BCUC direct FEI in the next COSA proceeding to prepare rebalancing proposals that aim towards unity and ultimately do away with the range of reasonableness. The Panel disagrees. The evidence in this proceeding suggests that an R:C ratio calculation is derived from forecast revenues and costs for the test year and the COSA is reliant upon numerous assumptions and judgements. Thus, an R:C ratio has inherent uncertainty and it follows that R:C ratios are best interpreted as a range on either side of a theoretical mid-point of unity. Therefore, the Panel agrees with FEI's approach to use an R:C range within which a rate schedule's revenue is considered to be recovering its costs to assess the need to rebalance a rate class. Because of this, the Panel is not persuaded by the CEC that there is a need to achieve unity and rejects the CEC's recommendation to depart from the use of a range of reasonableness to assess the need for and the degree of rebalancing required, in this or the next COSA study.

The BCUC's approach to rebalancing in the 2016 and 2023 FEI proceedings is consistent with other recent rebalancing decisions made by Canadian regulators.

On December 16, 2021, the Ontario Energy Board (OEB) issued Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities, chapter 2A of which discussed Cost of Service standards, including rebalancing.[25] The OEB guide includes instructions on rebalancing that specifies:

> Results flowing from the updated cost allocation model may show some ratios being outside of the OEB-approved ranges. In these cases, distributors must ensure that their cost allocation proposals include **adjustments to bring them within the OEB-approved ranges** within a reasonable period of time.

The OEB also specified that rebalancing is to be within the RoR (not to unity):

[23] FEI 2023 COSA and Revenue Rebalancing Decision and Order G-144-24, pp. 25-26.
[24] FEI 2023 COSA and Revenue Rebalancing Decision and Order G-144-24, pp. 20-21.
[25] https://www.oeb.ca/sites/default/files/Chapter-2A-Filing-Requirements-2023-20211216.pdf.

> In particular, if the proposed ratios are outside the OEB's policy range in the test year, the distributor must show the proposed ratios in subsequent years that would **move the ratios to within the policy range**. [Emphasis added]

In addition to the OEB, applications including rebalancing proposals have also been before the Nova Scotia Utility and Review Board (NSURB). In a recent Decision, in addition to confirming that its typical RoR is 95 percent to 105 percent, the NSURB stated:

> The Board recognizes that the allocation of costs in a cost-of-service study is not an exact science. **That is the reason why the Board strives to keep revenue-to-cost ratios within a range as opposed to requiring them to be set precisely at 100%.**[26]

Consistent with the Elenchus Report, recent decisions of the BCUC, and the decisions of the OEB and NSURB, FBC agrees that a rate schedule with an R/C ratio that falls within the RoR is recovering its fair cost and indicates that no rebalancing is required. FBC further considers that any R/C ratio that is within the defined RoR can be considered to be full cost recovery; therefore, rebalancing should be undertaken to move classes that are outside the approved range to the nearest boundary, not to unity. As FBC considers this to reflect industry standard practice, FBC has followed this approach in its rebalancing proposals set out below.

[26] IN THE MATTER OF AN APPLICATION of the RIVERPORT ELECTRIC LIGHT COMMISSION for Approval of Amendments to its Schedule of Rates and Charges for the provision of electric supply and services to its customers and its Schedule of Rules and Regulations 2023 NSUARB 56 M10810.

7. REVENUE REBALANCING PROPOSALS

In this section, FBC discusses its revenue rebalancing considerations, assesses and compares five rebalancing options and sets out why its preferred revenue rebalancing option reflects the best balancing of rate design principles.

7.1 *REVENUE REBALANCING CONSIDERATIONS*

In evaluating revenue rebalancing options, FBC applied the rate design principles identified by Dr. Bonbright, which FBC summarized in Section 3.1 above. FBC uses these principles to identify the issues related to each rebalancing option and to select its preferred option.

FBC does not apply the eight Bonbright principles in any priority or with any particular weighting. In addition, different principles may have varying levels of importance in different contexts. For example, all rebalancing options presented in Section 7.2 below will have either no impact or minimal impact to Bonbright rate design principle 1 – Recovering the Cost of Service, principle 3 – Price signals that encourage efficient use and discourage inefficient use, principle 5 – Practical and cost-effective to implement, principle 7 – revenue stability, and principle 8 – Avoidance of undue discrimination.

As illustrated in the section below, rate design (or revenue rebalancing in the case of this Application) is a complex balancing process as it frequently requires the application of multiple, sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. FBC applies it experience and judgement to consider and balance the most relevant principles when evaluating the different revenue rebalancing solutions. The rebalancing should strive to strike a balance among competing principles based on the specific characteristics of customers in each rate schedule.

The results of the 2025 COSA study show that RS 20 and RS 31 are above 105 percent, while RS 40 and RS 60 are below 95 percent. In accordance with the preceding discussion, FBC has sought to rebalance each rate class with an R/C ratio outside of the RoR to the nearest boundary, subject to other rate design considerations. However, a simple shift of the revenue between RS 20, RS 31, RS 40, and RS 60 is not feasible because the total decrease in revenues resulting from bringing RS 20 and RS 31 down to 105 percent is less than the revenue required to bring RS 40 and RS 60 up to 95 percent. As such, the rebalancing of these four rate schedules to the nearest RoR boundary would lead to the rebalancing not being revenue neutral. Additionally, such a rebalancing approach would result in a significant rate impact to RS 60 customers.

In considering the options for rebalancing in this context, FBC was primarily guided by Bonbright principles 2, 4 and 6. In particular:

- **Principle 2 – Fair apportionment of costs among customers**

  FBC considered the extent to which all R/C ratios fall within the RoR of 95 percent to 105 percent, such that the cost recovery through each rate schedule closely reflects the fair apportionment of costs from each customer group.

- **Principle 4 – Customer understanding and acceptance**

  FBC considered the number of rate schedules that would be adjusted and, in particular, whether any customer group would be adjusted even though their R/C ratio is already within the RoR.

- **Principle 6 – Rate Stability (Customer rate impact should be managed)**

  FBC considered whether any customer group would experience significant rate increases or rate shock (an increase greater than 10 percent in any year).

FBC developed five rebalancing options and assessed each option in Section 7.2 below against the rate design principles outlined above.[27] The proposed rebalancing approach is presented in Section 7.3.

7.2 *REVENUE REBALANCING OPTIONS*

This section discusses the different revenue rebalancing options which FBC developed based on the results of the 2025 COSA study. In all options, rebalancing would be accomplished by adjusting all rate components (Customer Charge, Energy Charge and Demand Charge where present) by the same percentage.

In the subsections below, FBC assesses each revenue rebalancing option against Bonbright's rate design principles and identifies the preferred rebalancing option.

7.2.1 Option 1: Rebalance All Out-of-Range Rate Schedules to the Boundary of the RoR, With Additional Credit from Rebalancing Allocated to Other Rate Schedules Currently with R/C Ratios Above 100%

Option 1 involves rebalancing RS 20 and RS 31 down to an R/C ratio of 105 percent, and rebalancing RS 40 and RS 60 up to 95 percent. This requires a reduction to the revenue recovered (at 2024 Approved rates) from RS 20 of approximately $1.134 million and from RS 31 of approximately $0.055 million, while increasing the revenue to be recovered from RS 40 and RS 60 by approximately $0.581 million and $0.933 million, respectively. However, in order to ensure revenue neutrality after the rebalancing, the credit variance of approximately $0.324 million (i.e., the sum of $0.581 million and $0.933 million, less the sum of $1.134 million and $0.055 million)

[27] As part of the stakeholder consultation workshop held on December 17, 2024, FBC presented five potential revenue rebalancing options. One of the options presented during the workshop involved no rebalancing to RS 60 (i.e., "Rebalancing Option 5" in the workshop presentation). After further consideration, FBC has removed the Option 5 included in the workshop presentation. The result of this change is that all options in the Application contemplate at least some rebalancing of RS 60.

will be distributed to other rate schedules that currently have R/C ratios over 100 percent (i.e., RS 21 and RS 30) proportionally based on their revenue at 2024 Approved rates.

Table 7-1 below provides the initial 2025 COSA R/C ratios (as presented in Table 5-5 above) before any rebalancing, the revenue shifts for rebalancing under Option 1, the approximate bill impact per month in percentage and in dollars, and the final R/C ratios after the revenue shift.

Table 7-1: Option 1 – 2025 COSA R/C Ratio Results after Revenue Rebalancing

Rate Schedule	Initial COSA R/C	Revenue Shift ($000s)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	COSA after Rebalancing R/C
RS 01 Residential	99.5%	-	-	-	99.5%
RS 20 Small Commerical	107.5%	(1,134)	(2.4%)	(6.2)	105.0%
RS 21 Commerical	102.4%	(233)	(0.3%)	(10.9)	102.0%
RS 30 Large Commercial Primary	100.7%	(90)	(0.3%)	(198.3)	100.4%
RS 31 Large Commerical Transmission	105.3%	(55)	(0.3%)	(1,156.1)	105.0%
RS 40 Wholesale Primary	94.0%	581	1.1%	4,838.0	95.0%
RS 41 Wholesale Transmission	98.3%	-	-	-	98.3%
RS 50 Lighting	99.8%	-	-	-	99.8%
RS 60 Irrigation	77.3%	933	22.9%	70.5	95.0%

Under Option 1, as shown in Table 7-1 above, an average RS 20 and RS 31 customer will see a rate reduction of approximately 2.4 percent and 0.3 percent, respectively, while an average RS 40 and RS 60 customer will see a rate increase of approximately 1.1 percent and 22.9 percent, respectively. The rate impacts to the other rate schedules (RS 21 and RS 30) are approximately 0.3 percent (credit). FBC notes that the rate impact under Option 1 of 22.9 percent for RS 60 (equivalent to approximately $70.50 per month for the average RS 60 customer) would be considered rate shock.

When assessed against the Bonbright rate design principles, Option 1 aligns with principle 2 by bringing all R/C ratios within the RoR:

- **Principle 2 – Fair apportionment of costs among customers**

  All R/C ratios of the applicable rate schedules would fall within the RoR of 95 percent to 105 percent. Therefore, the cost recovery through each rate schedule closely reflects the fair apportionment of costs from each customer group.

However, Option 1 does not align with principles 4 and 6:

- **Principle 4 – Customer understanding and acceptance**

  Option 1 results in adjustments to the revenues of RS 21 and RS 30 even though their R/C ratios are already within the RoR. Although the rate impacts (credit) to these customer groups are small at around 0.3 percent, the change in rates affects the majority of rate schedules and is therefore considered to have a greater impact on customer understanding and acceptance.

- **<u>Principle 6 – Rate Stability (Customer rate impact should be managed)</u>**

  The rate impact of approximately 22.9 percent to RS 60 customers would be significant under Option 1. This level of rate increase would be considered rate shock.

7.2.2 Option 2: Rebalance RS 20, RS 31 and RS 40 to the RoR Boundary, and Rebalance RS 60 to Achieve Revenue Neutrality

Option 2 involves rebalancing RS 20 and RS 31 down to an R/C ratio of 105 percent, and rebalancing RS 40 up to 95 percent. This requires a reduction to the revenue recovered (at 2024 Approved rates) from RS 20 of approximately $1.134 million and from RS 31 of approximately $0.055 million, while increasing the revenue to be recovered from RS 40 by approximately $0.581 million. In order to achieve revenue neutrality, the debit variance of approximately $0.609 million will be fully assigned to RS 60 based on its revenue at 2024 Approved rates. This results in RS 60's R/C ratio moving from 77.3 percent to 88.9 percent.

Table 7-2 below provides the initial 2025 COSA R/C ratios (as presented in Table 5-5 above) before any rebalancing, the revenue shifts for rebalancing under Option 2, the approximate bill impact per month in percentage and in dollars, and the final R/C ratios after the revenue shifts.

Table 7-2: Option 2 – 2025 COSA R/C Ratio Results after Revenue Rebalancing

Rate Schedule	Initial COSA R/C	Revenue Shift ($000s)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	COSA after Rebalancing R/C
RS 01 Residential	99.5%	-	-	-	99.5%
RS 20 Small Commerical	107.5%	(1,134)	(2.4%)	(6.2)	105.0%
RS 21 Commerical	102.4%	-	-	-	102.4%
RS 30 Large Commercial Primary	100.7%	-	-	-	100.7%
RS 31 Large Commerical Transmission	105.3%	(55)	(0.3%)	(1,156.1)	105.0%
RS 40 Wholesale Primary	94.0%	581	1.1%	4,838.0	95.0%
RS 41 Wholesale Transmission	98.3%	-	-	-	98.3%
RS 50 Lighting	99.8%	-	-	-	99.8%
RS 60 Irrigation	77.3%	609	14.9%	46.0	88.9%

Under Option 2, an average RS 20 customer and RS 31 customer will see a rate reduction of approximately 2.4 percent and 0.3 percent, respectively, while an average RS 40 and RS 60 customer will see a rate increase of approximately 1.1 percent and 14.9 percent, respectively. FBC notes that the rate impact under Option 2 of 14.9 percent for RS 60 (equivalent to approximately $46 per month for the average RS 60 customer) would be considered rate shock.

When assessed against the Bonbright rate design principles, Option 2 partially aligns with principle 2 and aligns with principle 4:

- **<u>Principle 2 – Fair apportionment of costs among customers (partially)</u>**

  Except for RS 60, all R/C ratios of the applicable rate schedules fall within the RoR. RS 60 will move closer to the RoR, but will still be below 95 percent.

- **<u>Principle 4 – Customer understanding and acceptance</u>**

  Option 2 results in adjustments to only the rate schedules that fall outside of the RoR, which would likely result in a higher level of customer understanding and acceptance compared to options where rate schedules that are already within the RoR are rebalanced.

However, Option 2 does not fully align with principle 6:

- **<u>Principle 6 – Rate Stability (Customer rate impact should be managed)</u>**

  The rate impact of approximately 14.9 percent to RS 60 customers would be significant under Option 2. This level of rate increase would be considered rate shock. FBC discusses how to mitigate this rate impact in Section 7.3.

7.2.3 Option 3: Revenue Rebalancing Between RS 01, 20, 31, 40, 41, 50 and 60, With the R/C Ratio of RS 60 Capped at 85 Percent

Option 3 involves rebalancing all rate schedules except for RS 21 and RS 30. Under Option 3, the revenue to be recovered (at 2024 Approved rates) from RS 20 and RS 31 customers will be reduced by approximately $1.134 million and $0.055 million, respectively, which will bring the R/C ratios of RS 20 and RS 31 down to 105 percent. The revenue to be recovered (at 2024 Approved rates) from RS 40 customers increases by approximately $0.581 million, which will bring the R/C ratio of RS 40 up to 95 percent. RS 20, 31 and 40 will therefore be rebalanced to the RoR boundaries.

In order to somewhat mitigate the rate impact to RS 60 customers, the RS 60 R/C ratio will be capped at 85 percent, which will result in an increased revenue recovery from RS 60 customers of approximately $0.405 million. However, in order to ensure revenue neutrality after the rebalancing, the debit variance of approximately $0.203 million (i.e., the sum of $0.581 million and $0.405 million, less the sum of $1.134 million and $0.055 million) will be distributed to other rate schedules that currently have R/C ratios under 100 percent (i.e., RS 01, RS 41 and RS 50) proportionally based on their revenue at 2024 Approved rates.

Table 7-3 below provides the initial 2025 COSA R/C ratios (as presented in Table 5-5 above) before any rebalancing, the revenue shifts for rebalancing under Option 3, the approximate bill impact per month in percentage and in dollars, and the final R/C ratios after the revenue shifts.

Table 7-3: Option 3 – 2025 COSA R/C Ratio Results after Revenue Rebalancing

Rate Schedule	Initial COSA R/C	Revenue Shift ($000s)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	COSA after Rebalancing R/C
RS 01 Residential	99.5%	195	0.1%	0.1	99.6%
RS 20 Small Commerical	107.5%	(1,134)	(2.4%)	(6.2)	105.0%
RS 21 Commerical	102.4%	-	-	-	102.4%
RS 30 Large Commercial Primary	100.7%	-	-	-	100.7%
RS 31 Large Commerical Transmission	105.3%	(55)	(0.3%)	(1,156.1)	105.0%
RS 40 Wholesale Primary	94.0%	581	1.1%	4,838.0	95.0%
RS 41 Wholesale Transmission	98.3%	8	0.1%	636.0	98.4%
RS 50 Lighting	99.8%	2	0.1%	0.1	99.9%
RS 60 Irrigation	77.3%	405	9.9%	30.6	85.0%

Under Option 3, an average RS 20 customer and RS 31 customer will see a rate reduction of approximately 2.4 percent and 0.3 percent, respectively, while an average RS 40 and RS 60 customer will see a rate increase of approximately 1.1 percent and 9.9 percent, respectively. The rate increases to the other rate schedules (RS 01, RS 41 and RS 50) are approximately 0.1 percent. FBC notes that the rate impact under Option 3 of 9.9 percent for RS 60 (equivalent to approximately $30.6 per month for the average RS 60 customer) would still be close to rate shock (and would likely be considered rate shock when combined with FBC's annual general rate increase).

When assessed against the Bonbright rate design principles, Option 3 does not fully align with principles 2, 4 or 6:

- **Principle 2 – Fair apportionment of costs among customers**

  Except for RS 60, all R/C ratios of the applicable rate schedules fall within the RoR. However, RS 60 will only be rebalanced to an R/C ratio of 85 percent to moderately mitigate the rate impact to RS 60 customers.

- **Principle 4 – Customer understanding and acceptance**

  Option 3 results in adjustments to the revenues of RS 01, RS 41 and RS 50 even though their R/C ratios are already within the RoR. Although the rate increases to these customer groups are minor at around 0.1 percent, the change in rates affects the majority of rate schedules and is therefore considered to have a greater impact on customer understanding and acceptance.

- **Principle 6 – Rate Stability (Customer rate impact should be managed)**

  The rate impact of approximately 9.9 percent to RS 60 customers would be significant under Option 3. When combined with FBC's annual general rate increase, this level of rate increase would likely be considered rate shock.

7.2.4 Option 4: Rebalance RS 20 and RS 31 to the Boundary of the RoR, Cap RS 60 at a 5% Rate Increase, and Rebalance RS 40 to Achieve Revenue Neutrality

Under Option 4, RS 20 and RS 31 would be rebalanced down to an R/C ratio of 105 percent. RS 60 would be rebalanced to a maximum 5 percent rate increase, and RS 40 would be used to maintain revenue neutrality. This requires a reduction to the revenue recovered (at 2024 Approved rates) from RS 20 of approximately $1.134 million and from RS 31 of approximately $0.055 million, while increasing the revenue to be recovered from RS 60 by approximately $0.204 million. In order to achieve revenue neutrality, the debit variance of approximately $0.986 million will be fully allocated to RS 40 based on its revenue at 2024 Approved rates. This results in RS 40's R/C ratio moving from 94.0 percent to 95.7 percent.

Table 7-4 below provides the initial 2025 COSA R/C ratios (as presented in Table 5-5 above) before any rebalancing, the revenue shifts for rebalancing under Option 4, the approximate bill impact per month in percentage and in dollars, and the final R/C ratios after the revenue shifts.

Table 7-4: Option 4 – 2025 COSA R/C Ratio Results after Revenue Rebalancing

Rate Schedule	Initial COSA R/C	Revenue Shift ($000s)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	COSA after Rebalancing R/C
RS 01 Residential	99.5%	-	-	-	99.5%
RS 20 Small Commerical	107.5%	(1,134)	(2.4%)	(6.2)	105.0%
RS 21 Commerical	102.4%	-	-	-	102.4%
RS 30 Large Commercial Primary	100.7%	-	-	-	100.7%
RS 31 Large Commerical Transmission	105.3%	(55)	(0.3%)	(1,156.1)	105.0%
RS 40 Wholesale Primary	94.0%	986	1.8%	8,214.7	95.7%
RS 41 Wholesale Transmission	98.3%	-	-	-	98.3%
RS 50 Lighting	99.8%	-	-	-	99.8%
RS 60 Irrigation	77.3%	204	5.0%	15.4	81.2%

Under Option 4, an average RS 20 and RS 31 customer will see a rate reduction of approximately 2.4 percent and 0.3 percent, respectively, while an average RS 40 and RS 60 customer will see a rate increase of approximately 1.8 percent and 5.0 percent, respectively.

When assessed against the Bonbright rate design principles, Option 4 aligns with principle 6:

- **Principle 6 – Rate Stability (Customer rate impact should be managed)**

  The rate impacts to all impacted rate classes are well below 10 percent, with the impacts ranging from a decrease of 2.4 percent to an increase of 5.0 percent.

However, Option 4 does not fully align with principles 2 and 4:

- **Principle 2 – Fair apportionment of costs among customers**

  Under Option 4, all rate schedules except for RS 60 will be within the RoR; however, RS 60, with an R/C ratio of 81.2 percent after rebalancing, will still be well below the lower bound of the RoR.

- **Principle 4 – Customer understanding and acceptance**

  Only customers in RS 20, 31, 40 and 60, whose R/C ratios are outside the RoR, will be impacted by the revenue rebalancing. This minimizes the number of customers that will be impacted by the revenue rebalancing. However, in order to achieve revenue neutrality under this option, RS 40 will be rebalanced beyond the lower bound of the RoR (i.e., 95.7 percent), which could erode the level of understanding and acceptance in that rate class.

7.2.5 Option 5: Rebalance RS 31 and RS 40 to the Boundary of the RoR, Cap RS 60 at an R/C Ratio of 80%, and Rebalance RS 20 to Achieve Revenue Neutrality

Under Option 5, RS 31 would be rebalanced down to an R/C ratio of 105 percent and RS 40 would be rebalanced up to an R/C ratio of 95 percent. RS 60 would be rebalanced but would be capped at an R/C ratio of 80 percent, and RS 20 would be used to maintain revenue neutrality. This requires a reduction to the revenue recovered (at 2024 Approved rates) from RS 31 by approximately $0.055 million, while increasing the revenue to be recovered from RS 40 by approximately $0.581 million and from RS 60 by approximately $0.141 million. In order to achieve revenue neutrality, the credit variance of approximately $0.666 million will be fully distributed to RS 20 based on its revenue at 2024 Approved rates. This results in RS 20's R/C ratio moving from 107.5 percent to 106.0 percent.

Table 7-5 below provides the initial 2025 COSA R/C ratios (as presented in Table 5-5 above) before any rebalancing, the revenue shifts for rebalancing under Option 5, the approximate bill impact per month in percentage and in dollars, and the final R/C ratios after the revenue shifts.

Table 7-5: Option 5 – 2025 COSA R/C Ratio Results after Revenue Rebalancing

Rate Schedule	Initial COSA R/C	Revenue Shift ($000s)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	COSA after Rebalancing R/C
RS 01 Residential	99.5%	-	-	-	99.5%
RS 20 Small Commerical	107.5%	(666)	(1.4%)	(3.6)	106.0%
RS 21 Commerical	102.4%	-	-	-	102.4%
RS 30 Large Commercial Primary	100.7%	-	-	-	100.7%
RS 31 Large Commerical Transmission	105.3%	(55)	(0.3%)	(1,156.1)	105.0%
RS 40 Wholesale Primary	94.0%	581	1.1%	4,838.0	95.0%
RS 41 Wholesale Transmission	98.3%	-	-	-	98.3%
RS 50 Lighting	99.8%	-	-	-	99.8%
RS 60 Irrigation	77.3%	141	3.5%	10.7	80.0%

Under Option 5, an average RS 20 and RS 31 customer will see a rate reduction of approximately 1.4 percent and 0.3 percent, respectively, while an average RS 40 and RS 60 customer will see a rate increase of approximately 1.1 percent and 3.5 percent, respectively.

When assessed against the Bonbright rate design principles, Option 5 aligns with principle 6:

- **Principle 6 – Rate Stability (Customer rate impact should be managed)**

  The rate impacts to all impacted rate classes are well below 10 percent, with the impacts ranging from a decrease of 1.4 percent to an increase of 3.5 percent.

However, Option 5 does not align with principles 2 and 4:

- **Principle 2 – Fair apportionment of costs among customers**

  Under Option 4, two rate schedules (RS 20 and RS 60) will still be outside of the RoR, which is the most out of any of the options evaluated.

- **Principle 4 – Customer understanding and acceptance**

  This option ranks poorly for customer understanding and acceptance, as RS 20 will still be above the RoR, while RS 60 will still be significantly below the RoR.

7.2.6 Summary of Revenue Rebalancing Options

Table 7-6 below summarizes the revenue shifts as well as the resulting R/C ratios of each rate schedule, and Table 7-7 below summarizes the estimated bill impact in both percentage and in dollars for the average customer by rate schedule for each rebalancing option.

Table 7-6: Summary of Revenue Shifts and Resulting R/C Ratios Between Rate Schedules for All Rebalancing Options

	Option 1: Rebalance All Out-of-Range Rate Schedules to the RoR Boundary, With Additional Credit from Rebalancing Allocated to Other Rate Schedules Currently with R/C Ratios Above 100%		Option 2: Rebalance RS 20, RS 31 and RS 40 to the RoR Boundary, and Rebalance RS 60 to Achieve Revenue Neutrality		Option 3: Revenue Rebalancing Between RS 01, 20, 31, 40, 41, 50 and 60, With the R/C Ratio of RS 60 Capped at 85 Percent		Option 4: Rebalance RS 20 and RS 31 to the RoR Boundary, Cap RS 60 at a 5% Rate Increase, and Rebalance RS 40 to Achieve Revenue Neutrality		Option 5: Rebalance RS 31 and RS 40 to the RoR Boundary, Cap RS 60 at an R/C Ratio of 80%, and Rebalance RS 20 to Achieve Revenue Neutrality	
	Revenue Shift ($000s)	R:C Ratio	Revenue Shift ($000s)	R:C Ratio	Revenue Shift ($000s)	R:C Ratio	Revenue Shift ($000s)	R:C Ratio	Revenue Shift ($000s)	R:C Ratio
RS 01	-	99.5%	-	99.5%	195	99.6%	-	99.5%	-	99.5%
RS 20	(1,134)	105.0%	(1,134)	105.0%	(1,134)	105.0%	(1,134)	105.0%	(666)	106.0%
RS 21	(233)	102.0%	-	102.4%	-	102.4%	-	102.4%	-	102.4%
RS 30	(90)	100.4%	-	100.7%	-	100.7%	-	100.7%	-	100.7%
RS 31	(55)	105.0%	(55)	105.0%	(55)	105.0%	(55)	105.0%	(55)	105.0%
RS 40	581	95.0%	581	95.0%	581	95.0%	986	95.7%	581	95.0%
RS 41	-	98.3%	-	98.3%	8	98.4%	-	98.3%	-	98.3%
RS 50	-	99.8%	-	99.8%	2	99.9%	-	99.8%	-	99.8%
RS 60	933	95.0%	609	88.9%	405	85.0%	204	81.2%	141	80.0%

Table 7-7: Summary of Monthly Bill Impact in % and $ for an Average Customer in Each Rate Schedule for All Rebalancing Options

	Option 1		Option 2		Option 3		Option 4		Option 5	
	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)
RS 01	-	-	-	-	0.1%	0.1	-	-	-	-
RS 20	(2.4%)	(6.2)	(2.4%)	(6.2)	(2.4%)	(6.2)	(2.4%)	(6.2)	(1.4%)	(3.6)
RS 21	(0.3%)	(10.9)	-	-	-	-	-	-	-	-
RS 30	(0.3%)	(198.3)	-	-	-	-	-	-	-	-
RS 31	(0.3%)	(1,156.1)	(0.3%)	(1,156.1)	(0.3%)	(1,156.1)	(0.3%)	(1,156.1)	(0.3%)	(1,156.1)
RS 40	1.1%	4,838.0	1.1%	4,838.0	1.1%	4,838.0	1.8%	8,214.7	1.1%	4,838.0
RS 41	-	-	-	-	0.1%	636.0	-	-	-	-
RS 50	-	-	-	-	0.1%	0.1	-	-	-	-
RS 60	22.9%	70.5	14.9%	46.0	9.9%	30.6	5.0%	15.4	3.5%	10.7

When comparing amongst the different revenue rebalancing options, as shown in Tables 7-6 and 7-7 above, Options 2 and 4 strike the best balance between achieving rebalancing amongst the applicable rate schedules, limiting the rebalancing to rate schedules that are currently outside of the RoR, and minimizing the rate impact to RS 60 customers. FBC notes the following regarding the options:

- Only Option 1 will rebalance all rate schedules to within the RoR. However, this option will lead to a significant rate impact for RS 60 customers at approximately 22.9 percent.
- Option 2 results in all rate schedules moving to within the RoR except for RS 60, and it results in no impacts to the rate schedules that are already within the RoR prior to rebalancing, thus minimizing rate impacts to the majority of customer classes. While not fully moving to the lower bound of the RoR, RS 60 moves much closer to the lower bound (from 77.3 percent to 88.9 percent). However, the rate impact to RS 60 is significant, at 14.9 percent.
- Option 3 better mitigates the rate impact to RS 60 compared to Options 1 and 2 by capping the R/C ratio of RS 60 at 85 percent. However, the resulting rate impact to RS 60 is still 9.9 percent, which when combined with FBC's annual general rate increase, would likely still be considered rate shock. Further, Option 3 affects the most rate schedules out of all of the options, as all rate schedules will be rebalanced except for RS 21 and RS 30 (albeit the impact of the rebalancing on most rate schedules is minor at 0.1 percent).
- Option 4 limits the rebalancing to the rate schedules outside of the RoR (RS 20, RS 31, RS 40 and RS 60). Further, by capping the rate increase at 5 percent for RS 60, the rate impacts for all rate classes subject to rebalancing are reasonably mitigated. However, RS 60 will still be well below the lower bound of the RoR (the RS 60 R/C ratio will be 81.2 percent after rebalancing), and, in order to achieve revenue neutrality, RS 40 will be rebalanced slightly higher than the lower bound of the RoR (i.e., RS 40 will move from 94.0 percent to 95.7 percent).
- Similar to Option 4, Option 5 limits the rebalancing to the rate schedules outside of the RoR (RS 20, RS 31, RS 40 and RS 60). Under Option 5, the rate impact to RS 60 is further

mitigated by capping RS 60's R/C ratio at 80 percent. However, in order to achieve revenue neutrality, RS 20 is only moved from an R/C ratio of 107.5 percent to 106.0 percent and is thus still outside of the upper bound of the RoR. Given that RS 60 is still well outside the RoR, and RS 20 would still be above the upper bound of the RoR, FBC considers this option to rank poorly in terms of Bonbright principles 2 and 4.

7.3 OPTION 2 IS THE PREFERRED REBALANCING OPTION

Based on the evaluation of the revenue rebalancing options against Bonbright's rate design principles, Option 2 is FBC's preferred and proposed option. Option 2 reflects the best balance between the above-discussed rate design principles when compared to other revenue rebalancing options. In order to mitigate the rate impact to RS 60 customers from rebalancing, FBC proposes to phase-in the impact over five years, as further discussed below.

Table 7-8 below presents the final 2025 COSA results after the proposed revenue rebalancing under Option 2.

Table 7-8: Final 2025 COSA Results with Proposed Revenue Rebalancing

Rate Schedule	Initial COSA R/C	Revenue Shift ($000s)	Approx. Monthly Bill Impact (%)	Approx. Monthly Bill Impact ($)	COSA after Rebalancing R/C
RS 01 Residential	99.5%	-	-	-	99.5%
RS 20 Small Commerical	107.5%	(1,134)	(2.4%)	(6.2)	105.0%
RS 21 Commerical	102.4%	-	-	-	102.4%
RS 30 Large Commercial Primary	100.7%	-	-	-	100.7%
RS 31 Large Commerical Transmission	105.3%	(55)	(0.3%)	(1,156.1)	105.0%
RS 40 Wholesale Primary	94.0%	581	1.1%	4,838.0	95.0%
RS 41 Wholesale Transmission	98.3%	-	-	-	98.3%
RS 50 Lighting	99.8%	-	-	-	99.8%
RS 60 Irrigation	77.3%	609	14.9%	46.0	88.9%

FBC proposes to phase-in the rate increase due to revenue rebalancing to RS 60 customers over a 5-year period. As shown in Table 7-9 below, a 5-year phase-in period will reduce the immediate impact to RS 60 customers from 14.9 percent to 3.0 percent. FBC considers a 5-year phase-in period the most appropriate as it avoids rate shock (even when considering the combined impact of the rebalancing and FBC's annual general rate increases).

Table 7-9: Comparison of Bill Impact to RS 60 Customers due to Revenue Rebalancing over a Phase-in Period from One to Five Years

Phase-in Period	1 year	2 Years	3 Years	4 Years	5 Years
Revenue Shift per year ($000s)	$ 609	$ 305	$ 203	$ 152	$ 122
Effective Increase due to rebalancing each year (%)	14.9%	7.5%	5.0%	3.7%	3.0%
Appox. Monthly Bill Impact to RS 60 Customers - Year 1 ($)	$ 46.0	$ 23.0	$ 15.3	$ 11.5	$ 9.2

In accordance with the approved rate design for RS 60, Irrigation customers are charged at RS 20 or RS 21 rates during the off-season (i.e., from November to March). As shown in Table 7-8 above, under the preferred Option 2, the rates for RS 20 will be reduced by 2.4 percent due to revenue rebalancing. In order for the overall revenue from RS 60 to increase by 3.0 percent (or a revenue shift of approximately $122 thousand) based on a 5-year phase-in as shown in Table 7-9 above, the irrigation in-season rates from April to October will need to increase by approximately 3.9 percent each year to offset the off-season reduction from RS 20 rates as illustrated in Table 7-10 below.

Table 7-10: Final 2025 COSA Results with Proposed Revenue Rebalancing

	Revenue before Rebalancing ($000s)	Revenue after Rebalancing - Preferred Option 2 w/ 5-yr Phase-in ($000s)	% Change
RS 60 In-season (Apr to Oct)	$ 3,316.8	$ 3,447.3	3.9%
RS 60 Off-season (Nov to Mar) @ RS 20 Rates	339.8	331.8	-2.4%
RS 60 Off-season (Nov to Mar) @ RS 21 Rates	425.7	425.7	0.0%
Total RS 60 Revenue ($000s)	**$ 4,082.3**	**$ 4,204.8**	**3.0%**

In order to facilitate the phase-in of the impact to RS 60 customers and maintain overall revenue neutrality, FBC is seeking BCUC approval pursuant to sections 59 to 61 of the UCA for a non-rate base deferral account, titled the Irrigation Rebalancing Phase-in deferral account, attracting FBC's WACC, to capture the revenue deficiency resulting from the phase-in for RS 60 customers. The deferral account will be amortized over the same 5-year phase-in period for RS 60 customers and will be recovered from all customers through FBC's general rate increases.

8. PROPOSED CHANGES TO TRANSFORMATION DISCOUNTS

For customers under RS 21, 30, and 40, delivery voltage discounts are available in consideration of the variations from the typical service connection. As a result of the 2025 COSA study, these discounts need to be updated to reflect the updated cost allocations for each of these rate schedules. This approach is consistent with the 2017 COSA and RDA.

For RS 21, the rate is designed on the basis that customers receive service at the secondary voltage. However, some customers might choose to own the transformation equipment required to convert their service voltage from the primary level to the secondary level. In these cases, the customer is taking service at the primary voltage available at the location of the interconnection, and the customer is entitled to a discount from the demand charge under the rate schedule as transformation and secondary costs would normally be included in the rate.

Similarly, the rates of RS 30 and RS 40 are designed on the basis that customers are normally taking service at the primary voltage. However, if the customers choose to take service at the transmission voltage with their own associated transformation equipment, a discount on the delivery is available.

FBC currently has 27 customers under RS 21, two customers under RS 30, and one customer under RS 40 that are taking service at the higher voltage with the transformation discount.

Consistent with past COSA Studies, the 2025 COSA results were used to establish the difference in costs in order to set the appropriate discount for taking service at a higher voltage level. The COSA is set up to account for the voltage level associated with each customer class. This allows the allocation of costs for the specific facilities used by customers within the class. To determine the difference in costs solely based on a change in voltage level, the COSA was recalculated assuming a higher voltage level for the class in question. The difference was calculated independently for each class where such a discount is offered but assumed the entire class rather than specific customers were served at the higher voltage level. None of the load data or allocation factors were changed for the various classes when completing the calculation. The only difference is that certain costs were no longer assigned to the class. The resulting difference in the unit costs for each class was then taken from the 2025 COSA to determine the appropriate discount level on a per kVA basis.

The updated transformation discounts for RS 21, 30, and 40 based on the results of the 2025 COSA study are presented below:

- For RS 21, the transformation discount will be increased from the current level of $0.409 per kW to $0.4841 per kW (from $0.371 to $0.4357 on a kVA basis) of Billing Demand. The discount is applied to the Demand Charge portion of the eligible customer's bill. The transformation discount is listed as the Delivery and Metering Voltage Discounts under FBC's electric tariff for RS 21.

- For RS 30, the transformation discount will be reduced from the current level of $6.727 per kVA to $5.98 per kVA of Billing Demand. The discount is applied to the Demand Charge portion of the eligible customer's bill. The transformation discount is listed as the Delivery and Metering Voltage Discounts under FBC's electric tariff for RS 30.
- For RS 40, the transformation discount will be increased from the current level of $3.390 per kVA to $3.78 per kVA of Billing Demand applied to the Wires Charge portion of the eligible customer's bill, and reduced from $0.00985 per kWh to $0.00926 per kWh applied to the Energy Charge of the eligible customer's bill. The transformation discount is listed as the Delivery Voltage Discount under FBC's electric tariff for RS 40.

9. CONCLUSION

The results of the 2025 COSA show that the R/C ratios of five of the nine customer classes are within the range of 95 percent to 105 percent which, as explained in Section 6 of the Application, is the accepted range for R/C ratios for evaluating the adequacy of each rate schedule to recover its allocated cost of service. The Small Commercial and Large Commercial Transmission customer classes are above this range, while the Irrigation and Wholesale Primary classes are below the range.

Based on the results of the 2025 COSA and the considerations set out in Section 7, FBC seeks approval of its preferred revenue rebalancing proposal (Option 2). In order to mitigate the rate impact for RS 60 customers of rebalancing, FBC proposes to phase-in the impact over five years and seeks approval of a deferral account to implement the phase-in approach. The proposed revenue rebalancing option, when combined with the phasing in of the increased recovery from RS 60 customers, results in a reasonable balance of rate design principles, and just and reasonable rates for customers.

FBC is also proposing to update the transformation discount offered to customers under RS 21, 30, and 40 who choose to take service at a higher voltage level based on the result of the 2025 COSA study. The updated transformation discounts are presented in Section 8 of the Application.

A blacklined version of the tariff changes based on the proposals in the Application is provided in Appendix D. A Draft Order setting out the approvals sought is provided in Appendix F-2 of the Application.

Appendix A

EES CONSULTING COSA REPORT

PREPARED BY EES CONSULTING

FORTISBC

Electric Cost of Service Study

February 2025

EES Consulting
a GDS Associates Company

Updated Application dated May 15, 2025

EES Consulting
a GDS Associates Company

Russ Schneider, Senior Project Manager
russ.schneider@gdsassociates.com
direct 406-471-8015

February 4, 2025

Corey Sinclair
FortisBC
1975 Springfield Road, Suite 100
Kelowna, BC V1Y 7V7

SUBJECT: 2024 Electric Cost of Service Study

Dear Corey:

Attached please find the revised report for the 2024 FortisBC Electric Cost of Service Study prepared by EES Consulting (EES), a GDS Associates company. This revision includes minor refinements to the report for consistency.

EES based the conclusions and recommendations contained within this report upon industry practice and accepted rate setting principles. The assumptions are consistent with the earlier studies provided by EES, except as noted, and include updated revenue requirement, customer, interval, and system load data.

EES developed the study with mutual aid of FortisBC staff and appreciate the internal effort to refine the study. The findings, conclusions and recommendations of this report supply the basis for the development of fair and equitable rates for FortisBC.

Thank you for the opportunity to aid FortisBC in this rate setting process. Please let us know if there are any questions about the subject analysis or added areas of inquiry going forward.

Very truly yours,

Russ Schneider
Senior Project Manager

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Georgia ▪ Texas ▪ Alabama ▪ New Hampshire ▪ Wisconsin ▪ Florida ▪ Maine ▪ Washington ▪ California

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1 Executive Summary

FortisBC retained EES Consulting (EES), a GDS Associates company, to perform an update to the comprehensive electric cost of service analysis (COSA). The COSA is one of the major inputs used in developing proposed rates for FortisBC. The COSA takes the revenue requirements for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed overall rates are fair, equitable and not unduly discriminatory.

FortisBC last filed a comprehensive COSA as part of its 2017 rate application, with the final COSA accepted in February of 2019, the Commission included a requirement to file an updated COSA study in 2020. EES largely maintained consistent methods from the 2017 COSA while updating data inputs and making appropriate adjustment due to changes over time. FortisBC made a compliance filing with the 2020 results and did not propose any rate design changes or rebalancing at the time.

To support consistency with the earlier study and the approved method in the Commission's 2019 Order, modeling changes primarily include new inputs from the most recent filed revenue requirement and load forecasts for 2024, with a detailed examination of actual operating and financial data from the historical year 2022. The primary focus of this study was improving the load inputs with detailed interval data from all metering points and comparing the allocation results with updated revenue requirements and rate base. In addition, rebalancing[1] and rate design changes are recommended for some classes.

Because the utility's revenue requirement is determined annually on an aggregate basis, with all rate classes receiving the same approved adjustment, the alignment between rate components and unit costs on an individual rate basis can diverge. Periodic COSA studies are intended to provide information that can be used to re-establish this alignment.

1.1 OVERVIEW OF THE COSA

The COSA takes the revenue requirement for the utility and seeks to equitably allocate those costs to the various customer classes of service (i.e., residential, commercial, etc.). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

[1] Rebalancing is the process whereby the total amount of revenue collected from each rate class adjusts compared to other rate classes to better reflect recovery of cost-to-serve.

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission and distribution related.

Classification determines the portion of the Revenue Requirement that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Production costs are related to supplying power to customers on the system. Production facilities are designed and operated to meet system peak demands and total energy requirements. Transmission costs are related to the bulk transfer of power to load centers on the system. These transmission facilities are typically designed and operated to meet the system's peak demand requirements. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the cost item. An analysis of customer requirement, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records and detailed studies of customer load data.

1.2 FORTISBC REVENUE REQUIREMENT AND RATE BASE

A revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the indicated overall adjustment to rate levels. The revenue requirement is the starting point of the COSA, with all items in the revenue requirement allocated across the various customer classes. The allowed return on rate base is a major part of the revenue requirement. The rate base for the utility is net plant in service plus working capital, approved deferrals, and adjustments. It represents the approved capital expenditure in rates.

For purposes of this COSA revenue requirement, EES used a recent filing setting out FBC's forecast for 2024 in its Evidentiary Update to the Annual Review for 2024 Rates Application dated October 10, 2023 (Evidentiary Update) and for load used the final results and metering from historical year 2022.[2] The total approved revenue requirement is $451.6 million, which includes an offset of $17.8 million in revenues from sources other than electric rates. This is after adjustments for Rate Schedule RS37 and RS38 revenues between rate and other revenues.[3]

The accompanying historical rate base associated with the revenue requirement is $1.54 billion. The function of rate base in the COSA is primarily for allocation purposes (not the calculation of return or

[2] EES received both billed and metered data for consumption in 2022 and relied on audited 2022 Annual Report filings for revenue requirement detail not found in the Evidentiary Update.

[3] Revenue requirement is the net of approved amounts less other revenues with RS 37 and RS 38 revenue treated as other revenue instead of rate revenue per previous studies.

other) and EES relied on audited financial results for the 2021-2022 timeframe to match the period of the historical loads. The rate base is an average of two years, 2021 and 2022 year-end results.[4] The rate base reflects gross plant of $2.32 billion, offset by accumulated depreciation and customer contributions. Distribution makes up 53.2% of gross plant, followed by 14.4% for power production and 9.9% general, and 22.5% for transmission plant.

FortisBC projected total customers of 152 thousand on average for 2024 and gross energy consumption of 3,396 GWh, after accounting for reductions in RS 31 projected load served at RS 37 and 38.[5]

Residential customers make up 87.1% of the total number of customers and over 38.2% of energy sales. Wholesale customers make up another 17.4% of energy, with the remaining 44.4% related to commercial, industrial, and other retail classes.

The peak is expected to occur in the winter at a level of 777 MW. The summer peak is expected to be 629 MW which is approximately 81% of the winter peak.

1.3 MAJOR ASSUMPTIONS OF THE COSA

The following provides some of the major assumptions and underlying data used in conducting the COSA for FortisBC.

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirements.

The classes of service analyzed in the study were as follows:[6]

- Residential
- Small Commercial
- Commercial
- Large Commercial Primary
- Large Commercial Transmission[7]
- Lighting
- Irrigation
- Wholesale Primary
- Wholesale Transmission

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[4] Basis for Rate Base is Tab 2 – Utility Rate Base from Source for both 2021 and 2022: 2022 Annual Report to the British Columbia Utilities Commission (BCUC).

[5] 3,396 GWH is net of 15 GWh of RS 37 and 63 GWH of RS 38 compared to the filed total of 3474 GWH.

[6] Appendix C – Load Summary details the aggregation of individual rate schedule numbers included in each rate class, but generally includes optional rates for the appropriate class.

[7] During the study period, FortisBC negotiated with the largest RS 31 customer to include only load below 15 MW and to pass through power supply costs above 15 MW based on RS 38. This reduces energy for RS31 compared to previous filings but provided a better perspective for other RS 31 cost of service.

The major assumptions and methods used in the current study are generally consistent with previously filed and approved COSA studies. Key assumptions include:

- Forecast year 2024 is the test period for the allocation of costs.
- Hourly aggregate load data by rate class for all meters in each rate class from the historical year 2022 provided the basis for energy and demand allocation factors for the 2024 forecast year.
  - Loads adjusted to remove RS 31 over 15 MW contracted for service at RS 38.
  - RS 38 is a new rate schedule affecting forecasted loads. FBC has one Customer participating in the rate that was previously included in RS 31 metered loads.
- The 2024 forecast revenue requirement and sales as contained in the Evidentiary Update, using actual results for 2022 for detailed items.[8]
- Monthly production costs are classified as demand and energy based on wholesale RS 3808 from BC Hydro and allocated on a monthly basis. Power costs are from the October 2023 filing.
- Distribution plant is classified based on an updated minimum system study with a peak load carrying capability (PLCC) credit.[9]
- Demand-related transmission costs are allocated using the 2 CP (coincident peak) method (sum of 2 winter and 2 summer peaks).

These assumptions are discussed in greater detail throughout this report.

1.4 SUMMARY OF RESULTS

Given the above assumptions of the COSA, the operating costs and other revenue requirements are classified and allocated to the individual customer or rate classes of service.

This section supplies the results of the COSA in summary form. The body of the report includes added details on the analysis and Appendix A includes all the final schedules from the study.

The total rate base of $1.54 billion classifies into various components and allocates to customer classes as found in Schedule 4.3 of Appendix A. Table 1-1 shows the split by customer class.

[8] Forecast revenues in the Evidentiary Update include RS37 revenues, but the COSA includes RS 37 revenues as a pass through in Other Revenues for purposes of cost allocation. In addition, EES builds up forecasted revenues based on individual Rate components rather than averaging methods in the filings and spreads the overall variance across classes. Forecasted revenues also exclude over 15 MW revenues from the largest RS31 customer contracted for service at RS38.

[9] Reasons for Decision, Commission Order G-40-19, Page 14 "The Panel is satisfied that the MSS, when combined with the PLCC adjustment to avoid double-counting of demand, is a reasonable approach for classifying distribution costs. There is no evidence that this approach does not provide reasonable results based on FBC's specific circumstances."

TABLE 1-1: TOTAL RATE BASE

	2017 COSA	2020 COSA	2024 COSA (millions)
Residential	$733.6	$757.5	$841.4
Other Retail	396.0	457.2	498.4
Wholesale	154.9	169.0	202.6
Total System	**$1,284.5**	**$1,383.7**	**$1,542.4**

The total revenue requirement of $451.6 million (after other revenues) has been classified into various components and allocated to customer classes as found in Schedule 3.3 of Appendix A. Table 1-2 summarizes the results.

TABLE 1-2: TOTAL REVENUE REQUIREMENT

	2017 COSA	2020 COSA	2024 COSA (millions)
Residential	$188.2	$184.9	$225.2
Other Retail	122.1	129.6	160.1
Wholesale	50.4	49.4	66.3
Total System	**$360.7**	**$364.0**	**$451.6**

A summary comparison of the revenues at present rates, allocated cost of service and resulting revenue to cost ratios can be found in Schedule 1.1 of Appendix A. Table 1-3 shows the resulting revenue to cost ratios.

TABLE 1-3: COSA REVENUE TO COST RATIO

	2017 Revenue to Cost Ratio	2020 Revenue to Cost Ratio	2024 Revenue to Cost Ratio
Residential	98.4%	99.7%	99.6%
Small Commercial	102.2%	101.5%	108.3%
Commercial	104.7%	99.5%	103.9%
Large Commercial Primary	104.0%	105.7%	99.3%
Large Commercial Transmission	107.0%	110.4%	104.7%
Lighting	92.2%	84.9%	100.3%
Irrigation	97.2%	96.5%	82.9%
Wholesale Primary	96.7%	96.7%	92.1%
Wholesale Transmission	103.9%	95.8%	94.6%
Total	**100.0%**	**100.0%**	**100.0%**

Based on the approved range of reasonableness of 95 to 105%,[10] most rate classes fall within the range of reasonableness. The only class with a ratio higher than 105% for 2024 is small commercial (RS 20). Classes with ratios below 95% in 2024 include irrigation and the wholesale classes. Classes outside the range of reasonableness are discussed later in this report.

It is informative for developing future rate designs to compare the revenue to cost ratios and unit costs resulting from the current and previous COSA studies. In particular, it is important to determine if these ratios moved further from the range of reasonableness or if classes still are in a reasonable range.

[10] Order G-40-19 | FBC 2017 COSA & RDA Decision at p. 26.

2 Overview and Basis for the COSA

The COSA is one of the major inputs used in developing rates for FortisBC. COSA takes the revenue requirements established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory.

FortisBC last filed a comprehensive COSA in 2017, with that proceeding resulting in rates implemented in 2019. In between detailed rate studies, rates have increased across the board to reflect approved revenue requirements increases. EES also provided FBC with a COSA update in December of 2020, but there were no recommended rate changes at the time.

EES maintained the methods from the 2017 and 2020 COSA studies for the 2024 COSA and Rate Design studies. EES considered changes over the years in terms of the FortisBC system, the overall electric industry, and trends in utility ratemaking when developing this COSA. For the 2020 update revisions focused on updated load, revenue requirements and rate base inputs. For the 2024 update, EES is doing a complete update based on a full set of new inputs.

EES organized this report such that it follows the steps taken in analyzing and developing FortisBC's COSA. Contained in this section is a discussion of the theory and financial principles behind setting rates. Also included is a summary of the underlying financial results used as the basis for the COSA. The next section discusses the COSA and the results of that process, including the method used to allocate costs between customer classes. The final section provides a summary of the COSA results.

Appendix A includes the selected schedules from the EES COSA Excel model (included as Appendix B of FortisBC's Application) used for the study. Other appendices detail supporting analysis used in the update.

2.1 OVERVIEW OF THE COSA

The setting of electric utility rates that are *fair and equitable* is a complex process. But the process follows generally accepted methodologies as a guide for assessing cost recovery in FortisBC's electric rates. At the same time, there are often several financial principles or guidelines that must be taken into consideration during this process. Therefore, the setting of electric rates that are *fair and equitable* is an integration of these generally accepted methodologies and any related financial policies or specific policy considerations from FortisBC.

The COSA analysis takes the revenue requirement for the utility and seeks to equitably allocate those costs to the various customer classes of service (e.g., residential, commercial). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

Costs allocated to the various customer classes of service are based upon the cost-causal relationships with the production and delivery of the services. COSA begins by *functionalizing* a utility's revenue requirement such as production, transmission and distribution. Next, the functionalized costs *classify* demand-, energy-, and customer-related component costs. Demand-related costs are those that the utility incurs to meet a customer's maximum usage requirement and is usually measured in kilowatts (kW). Energy-related costs are those that vary directly with longer periods of consumption, usually measured in kilowatt-hours (kWh). Customer-related costs are those that vary with the number and type of customers served.

These three component costs *are allocated* to each class of service based upon the most equitable method for each specific cost. At that point, the revenue requirement becomes fully allocated to each class of service for a determination of the necessary revenue adjustments between classes of service. The final step is the calculation of demand, energy and customer unit costs for each class of customer or rate schedule. These unit costs provide valuable input into the rate design process.

2.2 FORTISBC REVENUE REQUIREMENT

A revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the required overall adjustment to rate levels. The revenue requirement is the starting point for overall costs in the COSA, with all items in the revenue requirement allocating across the various customer classes. The rate base for the utility is also an important component when developing allocation factors for the revenue requirement. EES included only historical expenditures in the rate base for allocating related revenue requirement expenses, but also uses a mid-point between two years to account for the *lumpiness* of plant investments.[11] However, for the revenue requirement EES relies on the allowed return on rate base for 2024 to match expected rate revenues for the same period.

For purposes of this COSA, EES used Evidentiary Update with individual account details from the 2022 Annual Report. The total revenue requirement before other revenues for 2024 is $469.3 million. Table 2-1 summarizes the forecast revenue requirements for cost allocation for 2024 and a comparison to revenue requirements from previous studies.

TABLE 2-1: REVENUE REQUIREMENT COMPARISON

Millions	2017	2020	2024[12]
Cost of Energy	$152.2	$155.9	$193.4
O&M and A&G Expenses	48.2	52.5	$63.3
Return, Depreciation and Taxes	169.8	168.3	$212.6
Gross Revenue Requirements	370.2	376.6	$469.3
Less Other Revenue	-8.1	-10.6	-$12.1
Net Revenue Requirements	362.1	366.0	$457.2
Less RS 37 and 38 Revenues	-1.4	-2.0	-$5.7
COSA Revenue Requirements	**$360.7**	**$364.0**	**$451.6**

Gross revenue requirements (before netting out other revenues and RS 37 and 38 revenues) are $469.3 million, 45.3% of which is related to return on rate base, taxes and depreciation. The cost of energy is the next largest component of gross revenue requirements, accounting for 41.2% of the total. The final 13.5%

[11] In most cases, expenses related to a rate base category allocate based on the related plant investment, tracked by general ledger account.

[12] Annual review of rates Section 11, Schedule 14 does not present just a revenue requirement from rates view, but rather an income statement view. However, total approved revenues of $469.3 million less other revenues of $17.8 million results in revenues required from retail rates of $451.6 million, with the adjustment for Rate 37 and 38 this is consistent with Table 2-1 here, within rounding of filed numbers.

is for O&M and A&G expenses of the utility. The revenue requirement is the basis for the rates that are currently in place for FortisBC for the year 2024. Schedule 3.1 in Appendix A provides a summary of the approved revenue requirement.

For comparison, gross revenue requirements in the 2017 COSA were $370.2 million, including 41.1% purchased power costs, 13.0% O&M and A&G costs and 45.9% for return, depreciation, and taxes. The cost of energy and O&M both changed slightly for FortisBC on a percentage basis of the total, but overall proportions remain consistent over time.

Note that for the purposes of the COSA, the study deducts an additional $5.7 million in revenues from RS 37 and RS 38 from the revenue requirement.[13] This offset reflects the fact that the RS 37 and 38 sales are for standby and interruptible power sold directly to one of FortisBC's RS 31 customers. One customer takes 3 MW of standard firm power, and another customer takes 15 MW under RS31. Those sales are part of the RS 31 rate class but amounts otherwise are a direct purchase. Because the standby sales are below the full embedded cost resulting from the COSA, the previous COSA filing process determined that the revenues should be an offset to the revenue requirements and allocated to all customers to compensate for the use of the system paid for by all customers, including those within RS 31. Here, RS 38 revenues have a similar characteristic and are treated the same. The energy and demand associated with the RS 37 and 38 sales are also left out of the RS 31 class amounts and the total system amounts. This treatment is consistent with similarly discounted products for the gas utility.

This COSA includes a revenue requirement from a forecast test year but reflects the account detail of actual costs from a historic year 2022 escalated to the approved revenue requirement for 2024 rates. It does not include actual costs, sales, or revenues for 2024 year-to-date.

The use of a forecast year allows for a more standardized basis as it assumes normal weather conditions and stable economic conditions and excludes the impact of any extraordinary costs for the previous year.

2.3 RATE BASE

The accompanying rate base associated with the 2024 revenue requirement is $1.54 billion. This is an average of the 2021 and 2022 actuals. The use of a 2-year average is consistent with previous COSA and is intended to smooth out the impact of large capital expenditures. The rate base reflects gross plant of $2.32 billion, offset by accumulated depreciation and customer contributions and increased to reflect working capital. Distribution plant makes up 53.2% of gross plant, followed by 14.4% for power production and 9.9% general, and 22.5% for transmission. Table 2-2 summarizes the Rate Base.

[13] In G-40-19 the panel found at page 17, "The Panel accepts FBC's approach of applying the RS 37 revenues as an offset to the overall revenue requirement. We find this approach appropriate because all customers are contributing to the fixed costs of FBC's system which is providing service to RS 37; thus, all customers should receive the benefits of the RS 37 revenue. Further, RS 37 rates are calculated based on the hourly Mid-C price in effect when stand-by service is used and are therefore outside of the embedded COSA framework."

TABLE 2-2: RATE BASE COMPARISON

Millions	2017 COSA	2020 COSA	2024 COSA
Total Gross Plant	$1,943.2	$2,150.5	$2,316.1
Less Accumulated Depreciation	-577.3	-653.6	-669.2
Less Customer Contributions	-112.9	-215.3	-231.7
Working Capital, Deferred and Other	31.5	102.0	127.1
Total Rate Base	**$1,284.5**	**$1,383.7**	**$1,542.4**

Schedule 4.1 of Appendix A provides the detailed rate base for FortisBC by account used for the COSA, decimal variances due to rounding.

2.4 PROJECTED LOAD FORECAST

Schedule 8.4 of Appendix A details FortisBC's projected total customers and sales per class, as provided in the 2020 forecast. FortisBC projected total customers of 152 thousand on average for 2024 and gross energy consumption of 3,396 GWh which is 3.1% higher than the forecasted energy from the 2020 COSA. Residential customers make up 87.1% of the total number of customers and 38.2% of energy sales. Wholesale customers make up another 17.4% of energy, with the remaining 44.4% related to commercial, industrial and other retail classes, as shown in Table 2-3 below.

TABLE 2-3: FORECASTED LOADS COMPARISON

Forecasted Loads (GWh)	2017 COSA	2020 COSA	2024 COSA
Residential	1,354	1,326	**1,299**
Other Retail	1,341	1,401	**1,507**
Wholesale	587	567	**590**
Total System	**3,282**	**3,294**	**3,396**

The peak is expected to occur in the winter at a level of 777 MW. A peak of 629 MW is expected during the summer months. The difference in energy sales growth shows a decrease per customer consumption in the residential class overall, but an increase in both load and customers in other commercial classes. This is, in part, due to a significant increase in RS 31 load due to a new high consumption industrial customer.

2.5 PROJECTED REVENUES

For the purposes of the revenue requirements filing, FortisBC calculates revenues by class based on forecasts and loads multiplied by an average rate for each class, consistent with the method used in past years. For purposes of the COSA, EES calculates revenues under each tariff based on the billing determinants times the various rate components for each class, with the following results shown in Table 2-4. For purposes of consistency with the filing EES adjusted overall revenues to match the filed forecast less RS 37 and RS 38 being in other revenue categories.

TABLE 2-4: PROJECTED REVENUES COMPARISON

Projected Revenues (millions)	2017 COSA	2020 COSA	2024 COSA[14]
Residential	$185.1	$184.8	$224.3
Other Retail	126.3	132.1	$166.0
Wholesale	49.2	47.8	$61.2
Total Revenues	**$360.5**	**$364.8**	**$451.6**

The calculated revenue from current rates in the COSA is $442.8 million without considering separate forecast methods used for the revenue forecast in the annual review of rates. However, to preserve both the approved rate revenues and the COSA basis of actual rates times forecasted loads based on the interval data analysis, there is an even spread adjustment of 1.99% across all classes to produce a consistent overall revenue forecast from rates for 2024 $451.6 million. This preserves the revenue from rates build-up on overall cost recovery.[15]

As noted previously, this does not include RS 37 or RS 38 revenues, but instead treats those as other revenues according to the previous method. Schedule 7.1 of Appendix A provides the revenues projected for each class.

[14] Total revenues exclude RS 37 and 38 revenues and within classes estimates include an overall percentage adjustment spread evenly across classes to match approved rate revenues without changing the revenues at current rates buildup in the COSA.

[15] This is the same adjustment as the traditional true-up to 100% recovery for overall adjusted revenue to cost ratio results, just earlier in the analysis for matching filings. Taking this adjustment out will just move it to the final step on the Summary Schedule 1.1 but does not affect the results.

3 Cost of Service Analysis

The goal of COSA is to analyze costs and equitably assign those costs to customers. The founding principle of cost allocation is the concept of cost-causation. Following the principle of cost-causation, the COSA evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers. This section of the report will discuss the general approach used to perform the FortisBC COSA and supply a summary of the results.

3.1 COSA OVERVIEW AND GENERAL PRINCIPLES

A COSA allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship between specific expenditures and customer classes. This approach is taken to develop a fair and equitable assignment of costs to each customer class so that customers pay for the costs that they cause. Because most costs are not directly incurred for any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various classes using factors appropriate to each type of expense. COSA is the second step in a traditional three-step process for developing service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. COSA spreads the revenue requirement across the various customer classes, creating per unit costs by class. In the third step, unit costs provide initial rate designs for each customer class, with consideration of the proper rate levels.

A COSA can either be based on embedded or marginal costs. Embedded costs reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer and are based on costs of facilities and services if incurred at the present time. While marginal costs can be valuable for designing rates in certain instances, marginal costs are higher than embedded costs. Therefore, the use of a marginal COSA usually requires that all costs be scaled back to a level equal to the embedded cost revenue requirement established using actual or projected costs from an *accounting* perspective.

EES maintained an embedded cost basis for this COSA as its standard method. Therefore, the COSA reflects FortisBC's embedded cost revenue requirement and existing rate base investment.

There are three basic steps to a COSA, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, and distribution.

Classification determines the part of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Production costs relate to supplying power to customers on the system. Production facilities operate to meet system peak demands and total energy requirements. Transmission costs relate to the bulk transfer of power to load centers on the system. These transmission facilities operate to meet the system's peak demand requirement. The distribution system extends service to all customers attached to the system and to meet the peak load capacity requirement of each customer.

Allocation assigns costs to specific customer classes based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the measurement of system demand, whether coincident peak, non-coincident peak or some variation appropriate for the cost item.

To conduct the allocation step, EES completed an analysis of customer requirements, loads, and usage characteristics to develop allocation factors reflecting each of the classifiers employed within the COSA. This analysis maintained the allocation steps and modeling from the previous COSA with updated actual hourly aggregate data for all rate classes from 2022. Appendix C provides a detailed summary of the hourly aggregation by rate classes and the resulting load and coincidence factors used in the study.

The allocation analysis primarily maintained the 2017 COSA approach regarding system design and operations, its accounting and physical asset records, and special studies.

EES based demand and energy allocation factors on actual hourly load data for 2022 with some adjustments to account for monthly billing results. Schedule 8 in Appendix A details load and demand data results for the study. Appendix C – Load Summary provides detailed hourly data by rate class.

3.2 MAJOR ASSUMPTIONS OF THE COST-OF-SERVICE ANALYSIS

In the 2024 COSA, EES maintained the methods consistently with the approved 2017 COSA approach. Changes included the use of updated financial and operational data and no longer having certain special assignments of certain elements of revenue requirements.

The following provides some of the major assumptions and underlying data used in conducting the 2024 COSA for FortisBC.

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirement. The classes of service used within this study were as follows: [16]

- Residential
- Small Commercial
- Commercial
- Large Commercial Primary
- Large Commercial Transmission
- Irrigation
- Lighting
- Wholesale Primary
- Wholesale Transmission

[16] Appendix C – Load Summary details the aggregation of individual rate schedules included in each rate class, but generally includes optional rates for the appropriate class.

Note that while some of the rate classes also have separate time of use (TOU) rates, this study combines those customers with the underlying class for the rate, but accounts for expected revenues. Current TOU rate revenues are minor compared to standard rate revenues.

Key assumptions include:

- Forecast year 2024 is the test period for the allocation of costs.
- Hourly aggregate load data by rate class for all meters in each rate class from the historical year 2022 provided the basis for energy and demand allocation factors for the 2024 forecast year.
  - Loads adjusted to remove RS 31 over 15 MW contracted for service at RS 38
  - RS 38 is a new rate schedule affecting forecasted loads. FBC has one Customer participating in the rate that was previously included in RS 31 metered loads.
- The 2024 forecast revenue requirement and sales as contained in the Evidentiary Update, using actual results for 2022 for detailed items.
- Monthly production costs are classified as demand and energy based on wholesale RS 3808 from BC Hydro and allocated monthly. Power costs are from the October 2023 filing.
- Distribution plant is classified based on an updated minimum system study with a peak load carrying capability (PLCC) credit.
- Demand-related transmission costs are allocated using the 2 CP (coincident peak) method (sum of 2 winter and 2 summer peaks).

The following sections provide the specific treatment of items within the COSA, along with the results of the COSA.

3.3 FUNCTIONALIZATION OF COSTS

The first step in the COSA process is to functionalize the Rate base and revenue requirement. Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., production, transmission and distribution). Functionalization uses FortisBC's system of accounts for both the Rate base and revenue requirement, which largely segregates costs in this manner. Revenue requirement items associated with certain types of plant were generally treated in the same manner as the corresponding plant account.

The bullet list below specifies functions used for FortisBC's COSA. The functions generally follow standard cost of service approaches.

- ***Production***. The production function includes both Rate base and expense items associated with generation owned by the utility and power purchase expenses.

- ***Transmission***. The transmission function includes those costs for operating and maintaining the transmission lines, poles, towers, substations, etc., used to deliver power to the distribution network's load centers. Transmission is generally those lines measured at 35,000 volts and above.

- ***Distribution***. Distribution services include all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power. These include substations, poles, primary and secondary poles and conductors, line transformers, services and meters as well as customer costs and any direct assignment items. The distribution function includes customer-related services, even for those customers served at the transmission voltage level. These services include meter reading, billing, collections, advertising, etc. Primary distribution is at voltages of 750 to 35,000 volts, while secondary distribution has voltages of 750 volts or less.

The two areas where there generally are differences in functionalization among utilities are in the treatment of general plant and administrative and general (A&G) expenses. Typically, general plant is a separate category in the rate base. Functionalization spreads the general plant rate base across the three other functions. On the expense side, A&G costs spread in much the same way. Generally, each is a separate expense category that can be spread across the primary functions.

3.3.1 Functionalization of Rate Base

FortisBC has $333.7 million in hydraulic production plant (accounts 330 to 336). These items are related to the Kootenay River Plants owned by FortisBC. All these accounts are functionalized to production.

FortisBC has $520.6 million in transmission plant (accounts 350 to 359) which is all functionalized as transmission.

Distribution rate base is the biggest functional component of the FortisBC system and includes $1,233.1 million in gross plant (accounts 360 to 373). These costs are all functionalized as distribution, as shown in Table 3-1.

General plant for FortisBC is $228.8 million and includes computer and office equipment, transportation equipment and other items that are used by employees serving all three functional areas. To split general plant costs into the various functions, EES updated labour ratios for the 2024 COSA. The 2024 study reflects the number of full-time equivalents assigned to each of the three functions, with a result of 25.3% generation, 20.3% transmission and 54.4% distribution.

TABLE 3-1: FUNCTIONALIZATION OF PLANT ACCOUNTS

Description	Cost Account(s)	Amount ($ millions)	Functionalized to:
Production	330-336	$333.7	Production
Transmission	350-359	$520.6	Transmission
Distribution	360-373	$1,233.1	Distribution
General Plant	389-397.1	$228.8	25.3% Production 20.3% Transmission 54.4% Distribution
Total Gross Plant		**$2,316.1**	

Gross plant for FortisBC is $2.32 billion. Accumulated depreciation is equal to $0.67 billion, resulting in a net plant amount of $1.65 billion. Accumulated depreciation splits into production, transmission, distribution and general plant based on FortisBC's accounting ledger. Each of the accumulated depreciation accounts was treated in the same fashion as the corresponding gross plant accounts.

There are several adjustments to rate base from working capital, timing adjustments, and amortization. These amounts in total reduce rate base to $1.54 billion. Each of these items was functionalized based on all O&M costs or gross plant or on the same basis as the earlier study as shown in Table 3-2.

TABLE 3-2: FUNCTIONALIZATION OF RATE BASE

Rate Base Category ($millions)	Total	Production	Transmission	Distribution
Hydraulic Production	$333.7	$333.7		
Transmission	520.6		520.6	
Distribution	1,233.1			1,233.1
General Plant	228.8	57.9	46.4	124.5
Accumulated Depreciation	-669.2	-84.6	-185.6	-398.9
Customer Contributions	-231.7			-231.7
Working Capital, Deferrals & Other	127.1	86.1	15.8	25.3
Total	**$1,542.4**	**$393.0**	**$397.2**	**$752.2**
Percent of Total		**25.5%**	**25.8%**	**48.8%**

3.3.2 Functionalization of Revenue Requirement

FortisBC has a net revenue requirement from rates of $451.6 million for the 2024 forecast year, representing gross revenue requirements, net of other revenues and revenues from RS 37 and RS 38. In allocating the revenue requirements, expense items often follow the treatment of the corresponding rate base items. For example, total production costs are projected at $193.4 million for 2024 are all functionalized to production. This includes accounts 535 to 556. FortisBC has $27.5 million in transmission expenses for 2024 (accounts 560 to 567) which all functionalize as transmission (Table 3-3).

Total distribution expenses project at $13.9 million for 2024 (accounts 580-598) and are annual expenses associated with the distribution rate base accounts. All these items functionalize to distribution.

FortisBC has $7.3 million in customer service expenses (accounts 901 to 911). These costs all functionalize to the distribution function.

A&G costs for FortisBC forecast at $14.6 million for 2024 (accounts 920 to 933). Like general plant, these costs relate to all functions of the utility and often associate with the number of employees of the utility. The study relies on labour ratios to functionalize these costs to production, transmission and distribution.

Depreciation and amortization expenses in account 403 are $64.8 million for 2024 and split by functional areas. Generation depreciation follows generation and so on. Depreciation and amortization for general plant and deferred charges respectively follow the gross plant before general plant.

Return on rate base for 2024 is projected at $116.1 million, with another $12.5 million in projected income tax. These accounts are all functionalized on the same basis as the total rate base. Property taxes of $19.3 million are related to the value of FortisBC's assets and are therefore treated in the same manner as the total system net plant.

In addition to revenues from retail and wholesale sales to customers, FortisBC receives revenues from activities not directly related to the sale of electricity, such as pole attachment fees. Because the COSA is concerned with collecting revenues from rates by customer class, the other revenues of the utility are treated as an offset to the revenue requirement. Other revenues are therefore credited back to customer classes in a manner that fits the specific revenue item. Other revenues are $12.1 million not including RS 37 and RS 38 revenues of $5.7 million.

Electric apparatus rental is primarily for pole attachment and credits on the basis on the rate base account for poles, towers and fixtures. Waneta and Brilliant contract revenue credit on the same basis as the generation rate base. Connection charges credit based on retail customers. Sundry revenue and investment income credit on the same basis as gross plant before general plant.

TABLE 3-3. FUNCTIONALIZATION OF REVENUE REQUIREMENT

Revenue Requirement Category ($ millions)	Total	Production	Transmission	Distribution
Production/Purchased Power	$193.4	$193.4		
Transmission O&M	27.5		27.5	
Distribution O&M	13.9			13.9
Customer Service/Accounts	7.3			7.3
Admin & General	14.6	3.9	3.2	7.5
Depreciation	-64.8	-3.9	-15.7	-45.2
Property Taxes	19.3	3.6	4.5	11.2
Return & Income Taxes	128.6	32.8	33.1	62.7
Other Revenues	17.8	3.8	3.3	10.7
Total	**$451.6**	**$233.9**	**$80.6**	**$137.1**
Percent of Total		**51.8%**	**17.9%**	**30.4%**

3.4 CLASSIFICATION OF COSTS

The second step in performing COSA is to classify the functionalized expenses to traditional cost-causation categories. These cost-causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the proper customer classes during the allocation phase of the analysis.

The three primary classifiers are:

- Demand
- Energy
- Customer

Functionalized production costs are split between demand and energy. Transmission system costs are classified as demand related. Distribution costs are split between demand-related and customer-related components, or directly assigned to a specific customer class of service.

Within the three categories, there are varying ways to split costs between two or more classifiers. For example, demand- and energy-related costs can separate by seasonal distinctions as well as to reflect peak/off peak consumption periods. Customer categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where costs are not specifically classified to a category but in the same manner as an individual cost account or subtotal of specific cost accounts.

3.4.1 Classification of Generation and Transmission Rate Base

Generation classification can follow several different methods, most of which rely on looking at the use of various types of plants and their purpose within the system. EES continued to use the specific classification methods from the 2017 and 2020 COSAs for power supply in production. This includes calculating appropriate ratios for energy and capacity for both owned and contracted resources.

For a utility with multiple generating plants, it is common to look at the function of each plant in serving energy and demand needs, with some plants considered peaking units and others more related to supplying energy. Sometimes the capital costs of a plant are considered demand-related and operating costs are considered energy-related, particularly for plants having significant fuel costs. Another approach is a peak credit method where the demand portion follows the cost of building a plant designed primarily to meet peak loads and any additional plant costs are energy related. Other times the market-based pricing of demand and energy components develop the classification split.

In the case of FortisBC, the Kootenay River Plants are the only utility-owned generation, and costs associated with the plants are a small percentage of total production costs. This makes it difficult to use many of the standard classification methodologies and the small level of costs involved does not warrant a time-consuming or expensive study of the issue. On the other hand, BC Hydro does have a great deal of utility-owned generation and has had their classification of generation costs reviewed and approved through the regulatory process.

To develop the classification split for FortisBC, the output from the Kootenay River plants was priced as if as if the energy and capacity of the plant were priced the same as BC Hydro's RS 3808 to determine the equivalent split in costs between demand and energy. This split then applies to actual costs of these assets for purposes of classification. The resulting split is roughly 20% demand-related and 80% energy-related. This is the same approach used in the 2017 COSA and previously approved by the Commission.

The transmission rate base includes the utility's own transmission assets associated with supplying power to FortisBC's distribution system. In addition, FortisBC purchases wheeling from BC Hydro in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is directly proportional to the contribution to system peak demand that customers impose on the system. All transmission rate base accounts are classified as 100 percent demand-related, as was the case for earlier studies.

3.4.2 Classification of Distribution Rate Base

Generally, there are two methods for classifying distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak (NCP). Therefore, distribution costs classify as 100% demand related. EES did not use the 100% demand approach because previous studies used the minimum system approach that reflects that the system is built in part to connect customers to the system, regardless of load level. In addition, EES reviewed methodologies from other jurisdictions and that review supported maintaining the current approach.

In addition, in issuing its Decision in FBC's 2017 COSA, the Panel stated that it was satisfied that the MSS, when combined with the PLCC adjustment to avoid double-counting of demand, was a reasonable approach for classifying distribution costs.

Distribution costs can also split between demand and customer according to a minimum system approach. This approach reflects the fact that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimum size are because customers demand a delivery quantity greater than the minimum unit of electricity and therefore, those costs should be treated as demand related. Because the residential class tends to have a higher share of the number of customers as compared to the share of non-coincident peak, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100% demand methodology.

The process of cost classification is the area within the COSA that can create considerable cost variability between customer classes due to differences in system configurations, demand measurements and system planning criteria. The complexity of the entire COSA process compounds when the classification category is clear, but the specific allocator is not. For example, a particular cost item may clearly be peak demand-related but that demand can be measured as either a single coincident peak (1 CP) for the year, a combined winter and summer coincident peak (2 CP) approach to reflect seasonal considerations, the sum of 12 monthly coincident peaks (12 CP), or through some other approach.

Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility's load centers to the end user of the power. Classifying distribution costs requires a special analysis of the nature of the costs. Most distribution costs appropriately split between demand and customer components. The demand portion is the cost of facilities built to serve a load, such as distribution substations. The customer portion is the cost of facilities that varies with the number of customers, such as meters. Different accounts within the distribution function require separate treatment. For purposes of the previous COSA, FortisBC conducted a specialized *minimum system analysis* which is a theoretical analysis using both engineering and accounting inputs to develop a split of the distribution costs between demand and customer components.

The minimum system analysis provides a study assumption to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system is part of the analysis. The following section discusses the PLCC adjustment.

The minimum system approach reflects the philosophy that the system is in place, in part because there are customers to serve throughout the service territory, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to customers who use a delivery quantity greater than the minimum unit up to the level of their peak demand; therefore, that portion of the costs should be treated as demand related.

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system is built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the number of poles, conductors, and transformers in place at the utility is determined and separated by size. The cost associated with these facilities are then determined. Next, it is assumed that the actual numbers by size could be replaced by the minimum sized pole, conductor and transformer. Then, the analysis produces the cost associated with the minimum size.

The total costs of the minimum sized system are then compared to the cost of the as-built system to reflect the percentage of costs attributed to the system that would be in place if all customers used a minimum amount of power. The remaining percentage of costs are demand-related.

FortisBC provided updated data for the inputs to the EES minimum system analysis including the PLCC Adjustment for the 2024 COSA. The following summarize the resulting classification for the distribution accounts.

- ***Substations, including Land and Station Equipment***. These costs classify as demand related as they are sized based on the peak load for the area served.
- ***Poles, Towers & Fixtures***. The results of the minimum system analysis are 86% customer-related and 14% demand-related. The customer-related costs allocate based on actual customers.
- ***Conductors & Devices***. The results of the minimum system analysis show 71% customer-related and 29% demand-related. The customer-related costs allocate based on actual customers.
- ***Line Transformers***. The results of the minimum system analysis are 43% customer-related and 57% demand-related. The customer-related costs allocate based on actual customers.
- ***Services, Meters and Installation on Customer Premises***. These costs relate to the customer component as they are installed for each customer served.
- ***Streetlights & Signal Systems***. These costs directly relate to the lighting class of customers and directly assign to that class.

3.4.3 Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities chosen as the minimal size can carry some amount of demand, therefore the minimum system without adjustment, overstates the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus demand costs allocate based on the total customer class's non-coincident peaks. As such, it has been argued that a customer class's non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over-allocation demand can be achieved by the application of a PLCC adjustment. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FortisBC case, it was determined that the average PLCC for the FortisBC system is 0.97 kW per customer. This update reflects the same PLCC adjustment methodology as previous studies.

3.4.4 Other Rate Base Items

Functionalized general plant is classified using the percentage of total Rate Base for each function. For example, general plant assigned to generation is split between demand and energy in the same manner as the generation Rate Base. Accumulated depreciation accounts and working capital accounts were classified in the same fashion as the corresponding gross plant accounts. Customer contributions were assigned to classes based on poles, conductors and transformers. Schedule 6.1 in the Appendix A details Classification and Allocation by Function.

3.4.5 Classification of Production Expenses

Classifying production-related power supply costs to demand and energy components depends on the use of the generation and the pricing for power supply purchases. When a utility has numerous generating facilities, the use of the various units to supply baseload versus peaking power should be considered. In the case of FortisBC, the power supply resources include FortisBC-owned generation, long term power purchase contracts including a tariff-based purchase from BC Hydro, and market purchases, which can include monthly blocks purchased to ensure available capacity. Most resources used by FortisBC have both an energy and peaking component.

The average monthly energy forecast is 317 GWh. The peak is expected to occur in the winter at a level of 777 MW. A peak of 629 MW is expected during the summer months. Total production costs for 2024 include purchased power expenses of $173.7 million and direct costs associated with FortisBC-owned generation for water of $12.5 million, with the remaining $7.2 million related to generation operations and maintenance.

FortisBC owns four hydroelectric generating units collectively referred to as the Kootenay River Plants. Output from these plants depends on a water coordination contract with BC Hydro and other parties on the Kootenay River, which predefines the amount of power that can be used at various times. The O&M expenses associated with the Kootenay River Plants are all classified and allocated based on the generation rate base.

The next resource is a contract for power from the Brilliant hydro plant, owned by the Columbia Power Corporation. Under the contract, FortisBC is allocated a share of the output from the project in exchange for paying a share of the costs of the project. The costs associated with the purchase from the Brilliant plants are based on the actual capital and operating costs of the plant. Brilliant exchange purchase power contracts include both energy and capacity components.

FortisBC also has a capacity contract for power from the Waneta Expansion project. In this case, the costs are all capacity related. While this is a pure capacity contract, it really serves to support the other purchases made by FortisBC.

FortisBC also purchases power from BC Hydro under a contract for up to 200 MW of power, with prices set under the BC Hydro Rate 3808. Because there are separate demand and energy charges associated with this purchase, those respective charges are classified as demand-related and energy-related in the COSA.

To reflect the fact that the FortisBC owned generation and Brilliant purchases work together to provide the power needed to FortisBC, it was determined that the 3808 breakdown of demand and energy prices could be used as a proxy for the split between demand and energy components, for these resources. The output from these resources were priced at the 3808 tariffs on a monthly basis to determine the equivalent split in costs between demand and energy for classification. The remaining power requirements for FortisBC are met using various market purchases, and in some cases, there are surplus quantities sold as well to match the hourly needs of the utility.

Because production sources vary by month, production costs were classified to demand and energy for each month and then allocate to customer classes based on each class's contribution to system peak and energy loads for each month. As discussed above, purchases from BC Hydro already have a demand and energy component.

On a combined basis, the total purchased power expenses were classified 35% demand-related and 65% energy-related on an annual basis, as shown in Table 3-4.

TABLE 3-4: POWER SUPPLY CLASSIFICATION

	Classification	Notes
Kootenay River Plants	18% Demand 82% Energy	Based on Generation Rate Base
Columbia Power Corporation (Brilliant) and Waneta Expansion	36% Demand 64% Energy	Using BC Hydro 3808 as a Proxy Each Month
BCH 3808 Purchases	18% Demand 82% Energy	As Charged
Net Market Purchases	100% Energy	All Energy Purchases
Total System	**35% Demand** **65% Energy**	**Sum of All Resources**

3.4.6 Classification of Other Expenses

The transmission function includes FortisBC's own transmission assets associated with supplying power to FortisBC's distribution system. In addition, FortisBC purchases wheeling services from BC Hydro in the Okanagan and Creston areas to supplement its own transmission. The cost of providing transmission service to a customer is directly proportional to the demand that customer imposes on the system. All transmission expense accounts classify on the same basis as transmission rate base.

Many of the distribution expense accounts correspond to a rate base account and follow the treatment of the rate base item. For example, account 583.10 is for distribution line maintenance, corresponding to rate base account 365-conductors and devices. Since the distribution rate base uses a minimum system approach, the expenses will also follow the splits resulting from that analysis. Street lighting expenses are directly assigned to the lighting class. Account 598 – other distribution plant classifies based on total distribution rate base.

Customer Service expenses classify as customer related.

A&G are first assigned to each function based on labour ratios. These amounts are then classified on the same basis as the rate base for each of the three functions. The rate base approach is proper because the employees tie more closely to the size of the asset value of the three functions as opposed to the O&M associated with each function.

Depreciation expenses are assigned to each function following the rate base for that function. Depreciation for general plant and deferred charges follow the gross plant before general plant.

Return accounts all classify on the same basis as the total rate base. Property taxes of $19.3 million relate to the value of FortisBC's assets and are classified the same as the total system net plant.

In addition to revenues from retail and wholesale sales to customers FortisBC also receives revenues from other activities, such as pole attachment fees. Because the COSA evaluates the collection of revenues from rates by customer class, the other revenues of the utility become an offset to the revenue requirement. Other revenues, therefore, credit back to customer classes in a manner that fits the specific revenue item.

Electric apparatus rental is primarily for pole attachment and credits based on the rate base accounts for poles, towers and fixtures. Lease revenue gets the same basis as general plant rate base as it covers revenue from general utility assets rather than from generation assets or utility poles. Waneta and Brilliant contract revenues credit on the same basis as generation rate base as these revenues offset the costs associated with FortisBC's production. Connection charge revenues credit based on retail customers. Sundry revenue and investment income are more general in nature and, therefore, assign on the same basis as gross plant before general plant.

Table 3-5 shows the resulting classification of cost functions based on the methods above.

TABLE 3-5: CLASSIFICATION OF COSTS TO FUNCTIONS

Description		Classified to:	Note:
Production		35% Demand 65% Energy	Based on the Demand / Energy Split for Equivalent BC Hydro 3808 Purchases and other factors (see Table 3-4)
Transmission		100% Demand	
Substations		100% Demand	
Distribution	Poles, Towers & Fixtures	14% Demand 86% Customer	Per Minimum System Study with Peak Load Carrying Capability (PLCC) Adjustment
	Conductors & Devices	29% Demand 71% Customer	
	Line Transformers	57% Demand 43% Customer	
	Services, Meters and Related	100% Customer	
	Streetlights and Signals	Direct Assignment	

3.5 ALLOCATION OF COSTS

The third step in performing a COSA is the allocation of the utility's total functionalized and classified.

For each of the primary classifiers discussed above, there are sub-classifiers that are selected based on the how well they reflect cost-causation and maintaining consistency with prior studies. The following are the specific allocation methods used in FortisBC's COSA. The specific method of cost classification and allocation for various rate base and expense items is discussed in further detail below.

3.5.1 Load Analysis

To allocate costs within the COSA, a combination of customer, demand and energy factors are used. The customer and energy allocations are straightforward as both the number of customers and energy per class are easy to track and forecast. Demand per customer class is more difficult as there are several different types of demand that are considered including the maximum demand for the individual meter, the maximum demand for the rate class and the actual demand for the rate class at the time of the overall system peak.

In the past, developing the necessary demand allocators requires piecing together information from various sources and estimating data in some cases. Since FortisBC installed automated metering for all customers, hourly data is now available in a more accurate aggregate summary basis and this provided the basis for peak demands by class.

FortisBC now has the capability to produce coincidence values needed for a COSA study on actual metered data by metered interval by rate class or sub-rate class. This reflects some maturity in the back-office data processing capability to supply business crucial data for study purposes. As more of these types of processes move into full production, FortisBC will have increasing analytical capability on each emerging time of day rate issues and the ability to monitor changes in cost of service on a continuing basis.

A key driver in cost allocation is detailed load and consumption data on all customer classes. For the 2024 COSA, FortisBC supplied individual hourly metered load data from all customers by rate class for historical year 2022 and monthly billing summaries for data validation. This is an improvement from the 2017 study where aggregate or sample data was required.

Having a complete data set for 2022 allowed the calculation of all actual class, group, and coincidence factors. The factors attribute diversity benefits appropriately across classes.

Table 3-6 below shows a comparison of the average load factors which are a major factor in overall cost allocation of energy and demand related costs. See Appendix C – Load Summary for hourly loads by rate class.

TABLE 3-6: COMPARISON OF PREVIOUS AND 2024 INDIVIDUAL LOAD FACTORS BY CUSTOMER CLASS

	2017 COS Average Load Factor	2020 COS Average Load Factor	2024 COS Average Load Factor
Residential	21.4%	20.1%	22.4%
Small Commercial	37.5%	36.4%	35.2%
Commercial	50.3%	52.7%	53.7%
Large Commercial Primary	56.7%	49.6%	57.9%
Large Commercial Transmission	65.1%	63.7%	88.3%
Lighting	50.1%	50.1%	50.1%
Irrigation	59.5%	34.7%	27.1%
Wholesale Primary	68.8%	62.1%	58.8%
Wholesale Transmission	50.4%	47.3%	35.1%

The most notable change in load factors over the course of the studies are the increase in RS 31 load factors due to the addition of one large and steady running service and slight declines in irrigation and wholesale factors. The removal of the above 15 MW from on RS 31 customer also keeps that class load factor high under a reduced overall load scenario.

FortisBC has several customer classes with significant load spread over a relatively small number of customers. Specifically, RS31 – large commercial transmission has four customers, and the wholesale class (RS40 and RS41) has a combined six customers. This results in a situation where year-over-year variation in consumption in the class may result in swings in class load factors. However, with several data points, it appears that commercial load factors are trending higher while wholesale and irrigation factors are trending lower. Lower load factors all else being equal create higher average costs.

EES also used actual billed demand results for larger customers to check against the hourly data, and in a couple instances, adjusted for lagged billing across months. Overall, the data indicates slightly different load factors than previous studies with relative results overall in line with the previous samples except those trending as noted.

Like the overall comparison of revenue to cost ratios, there are some areas where the use of the updated load data by rate class supplies slightly different results. For example, irrigation and wholesale classes show lower load factors than in previous studies. For irrigation, 2020 was the first time that hourly data became available, but the previous study did use detailed interval data for wholesale customers. With both the different historical period and the improvement in data availability, these changes in load factor are a driver of revenue to cost ratios. However, updated system coincidence and the other differences in allocation do have impacts.

3.5.2 Demand Allocation Factors

For purposes of this study, three types of demand allocation factors were developed.

- *Non-Coincident Peak Demand Allocation Factor (NCP).* First, the study develops a non-coincident peak demand allocation factor for each customer class. Expenses classify and allocate by the non-coincident peak demand allocation factor including those predicated on maximum demands such as distribution substations, and a portion of poles and lines, transformers, meters and services. The NCP demand method allocates costs to each class of service based upon their highest non-coincident peak demand regardless of the time of occurrence. These NCP demand allocators are further separate into

NCP at primary (NCPP) and secondary voltages (NCPS). The NCP allocators are used for distribution rate base items, with substations based on NCPP, transformers based on NCPS, and poles and conductors split 80% to NCPP and 20% to NCPS. EES based this split on industry experience.

Given the use of the PLCC adjustment as part of the minimum system treatment of distribution costs, the NCP allocation factors first subtract the PLCC amount times the number of customers in each rate class.

- *Monthly Coincident Peaks (CP).* For each class of service, a contribution to the system coincident peak in each month derives from the non-coincident peak and the use of a coincidence factor. Coincident peaks allocate the demand-related potion of power purchases as they differ in each month based on system usage.

- *2 Critical Coincident Peaks (2 CP).* Coincident peaks typically allocate a portion of production costs and all of transmission costs because of sizing for the system peak. For FortisBC, previous studies determined that the sum of the 2 highest summer and 2 highest winter coincident peaks were the most appropriate to reflect critical period system use and planning for facilities, as explained further below. This is consistent with the peak allocation method used in the 2017 COSA. The 2 CP allocator is for generation and transmission rate base accounts.

The demand allocation method considers past precedent, FERC and OEB tests, comparisons of load shapes and growth of winter and summer peaks. The 2 CP approach was the best approach because FortisBC has a significant summer peak even though the system is winter peaking. While the summer peak is not at the same level as the winter peak, it is growing faster than the winter peak and will increasingly have a larger impact on the system and subsequent system planning.

3.5.3 Energy Allocation Factors

Energy costs vary directly with consumption. Accordingly, energy allocation factors are based on electricity sales for each class. For purposes of monthly production costs, the energy in each month is the allocator.

3.5.4 Customer Allocation Factors

The study uses two basic types of customer costs—actual and weighted.

- *Actual Customers (CUST).* The allocation factor for actual customers derives from the actual number of customers served in each class of service averaged across the 12 months of the 2022 test period. Note that for wholesale customers the number of points of delivery (POD) were included in some cases as each POD contains its own meter.

- *Customers Weighted for Meters and Services (CUSTM).* The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs. The typical cost of a new meter for each rate class is the weighting factor for each class. FortisBC supplied updated costs for metering and services.

- *Customers Weighted for Accounting/Metering (CUSTW).* The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. The weighting factors for CUSTW are the same as the ones developed in the previous study, and updated based on current metering costs.

3.5.5 Other Allocation Factors

Other costs allocate based on specific rate base items, O&M function totals, revenues, labour ratios and other allocation factors.

3.5.6 Allocation of Rate Base

For generation, the 18% demand-related part allocates across classes using the 2 CP factor. The remaining 82% energy-related part allocates based on annual energy by class.

All transmission rate base accounts allocate based on the 2 CP methodology.

For the 100% demand-related components of distribution, the NCPP is the allocation factor. For those distribution accounts the study bases the split between demand and customer components on the NCPP, NCPS and actual number of customers. Those distribution accounts that are 100% customer-related allocate based on customers weighted according to the average cost of meters by class. Streetlights & Signal Systems all directly related to the lighting class of customers and direct assign to that class.

General plant costs allocate to classes on the same basis as was used for each of the classified components.

Each of the accumulated depreciation accounts allocates in the same fashion as the corresponding gross plant accounts. Working capital items allocates on the same basis as all O&M costs. Customer contributions assign to classes on the same basis as poles, conductors and transformers.

3.5.7 Allocation of Revenue Requirements

Because production purchases vary by month, production costs classify to demand and energy for each month and then allocate to customer classes based on the class contribution to system peak and energy loads for each month.

All transmission expense accounts allocate on the same basis as transmission rate base, which is 2 CP.

Distribution expense accounts correspond to a rate base account and follow allocation of the rate base item. Street lighting expenses directly assign to the lighting class. Account 598 – other distribution plant allocates based on total distribution rate base.

For customer service expenses, each account gets individual consideration. Supervision and administration expenses follow all other customer service expenses. Meter reading, customer billing and customer assistance allocate on customers weighting for accounting/metering. Credit and collections expense allocate to retail customers only.

A&G costs functionalize using labour ratios and then classify and allocate on the same basis as the rate base for each of the three functions. This follows the same treatment described for general plant.

Depreciation expenses follow the allocation treatment used by the associated functional accounts. Depreciation for general plant and deferred charges follow the gross plant before general plant.

Return accounts, (interest, earnings, and income taxes) all allocate on the same basis as the total rate base. Property taxes are related to the value of FortisBC's assets and are therefore allocate in the same manner as the total system net plant. Net plant reflects the gross plant for the utility less accumulated depreciation.

FortisBC receives revenues from retail and wholesale sales to customers, as well as for other activities, such as pole attachment fees. Because the COSA studies collecting revenues from rates by customer class, the other revenues of the utility are an offset to the revenue requirement. Other revenues credit back to customer classes in a manner that fits the specific revenue item.

4 COSA Results between Rate Classes

The results of the COSA analysis include both revenues to cost ratios (RC ratios) and computed unit costs for each rate class. This section discusses the indications regarding rebalancing revenues recovered from various rate classes based on the methods and updated data from the study. A key result of any COSA analysis is whether each rate class is appropriately paying total rates that reflect that rate classes share of total rate revenue required, regardless of the rate design of each rate class.

Appendix A includes detailed tables reflecting all the COSA calculations and result details. The total rate base of $1.54 billion classifies into various components and allocates to customer classes as found in Schedule 4.3 of Appendix A. Table 4-1 below shows the split by customer class. The primary purpose of allocated rate base is for spreading related operations and maintenance costs of plant accounts.

TABLE 4-1: TOTAL RATE BASE

	2017 COSA	2020 COSA	2024 COSA (millions)
Residential	$733.6	$757.5	$841.4
Other Retail	396.0	457.2	498.4
Wholesale	154.9	169.0	202.6
Total System	**$1,284.5**	**$1,383.7**	**$1,542.4**

The total revenue requirement of $451.6 million classifies into various components and allocated to customer classes as found in Schedule 3.3 of Appendix A. Table 4-2 should the overall cost allocation for residential and non-residential classes. As noted previously in the report the total revenue requirement relies on 2024 approved financial requirements.[17]

TABLE 4-2: TOTAL REVENUE REQUIREMENT

	2017 COSA	2020 COSA	2024 COSA (millions)
Residential	$188.2	$184.9	$225.2
Other Retail	122.1	129.6	160.1
Wholesale	50.4	49.4	66.3
Total System	**$360.7**	**$364.0**	**$451.6**

Schedule 1.1 of Appendix A shows a summary comparison of the revenues at present rates, allocated cost of service and resulting revenue to cost ratios can be found in. Table 4-3 also shows the resulting ratios.

[17] Total revenue requirement is not a specific number in the 2024 Annual Review of rates, but EES builds up to that amount using the approved components of the income statement with an adjustment for RS 37 and 38 Revenues as noted earlier in the report.

TABLE4-3. COSA REVENUE TO COST RATIOS

	2017 Adjusted Revenue to Cost Ratio	2020 Adjusted Revenue to Cost Ratio	2024 Adjusted Revenue to Cost Ratio
Residential	98.4%	99.7%	**99.6%**
Small Commercial	102.2%	101.5%	**108.3%**
Commercial	104.7%	99.5%	**103.9%**
Large Commercial Primary	104.0%	105.7%	**99.3%**
Large Commercial Transmission	107.0%	110.4%	**104.7%**
Lighting	92.2%	84.9%	**100.3%**
Irrigation	97.2%	96.5%	**82.9%**
Wholesale Primary	96.7%	96.7%	**92.1%**
Wholesale Transmission	103.9%	95.8%	**94.6%**
Total	**100.0%**	**100.0%**	**100.0%**

A given class is considered to be within a reasonable range if the RC ratio falls between 95% and 105%. Based on that range, small commercial, large commercial transmission, irrigation, and wholesale are all candidates for potential rebalancing. Large commercial transmission has been the class most consistently outside the range of reasonableness as shown in Table 4-4. Other classes have moved in and out of the reasonable range across COSA studies.

TABLE 4-4: REVENUE AND REQUIREMENTS COMPARISON – 2024 COSA

	2024 Forecasted Rate Revenues	2024 Allocated Revenue Requirement	2024 Adjusted Revenue to Cost Ratio[18]
Residential	$224,289,548	$225,234,808	**99.6%**
Small Commercial	$48,347,678	$44,634,574	**108.3%**
Commercial	$67,996,972	$65,439,404	**103.9%**
Large Commercial Primary	$25,624,554	$25,807,585	**99.3%**
Large Commercial Transmission	$17,321,123	$16,537,160	**104.7%**
Lighting	$2,418,265	$2,410,019	**100.3%**
Irrigation	$4,333,942	$5,228,499	**82.9%**
Wholesale Primary	$53,105,528	$57,684,950	**92.1%**
Wholesale Transmission	$8,141,693	$8,603,303	**94.6%**
Total	**$451,579,302**	**$451,580,302**	**100.0%**

One of the key factors resulting in changes to the RC ratios is the load factors for the various rate classes (see Table 3-6), but also there are changes in cost mix, growth, and system coincidence that all factor into the new allocations. In the current study, detailed individual load data was available for all classes and all meters.

For commercial classes, there has been both growth and improvement in load factors with a reduction in system coincidence compared to residential class. For the large commercial transmission (RS 31) class, a

[18] Adjusted to reflect 100% cost-of-service overall for comparison between classes as noted earlier in the report.

new large customer led to an increase in revenues and allocated costs, with allocated costs increasing less than revenues due to the high load factor for the new customer without the change to RS 38 treatment.

The lighting class had a major shift to LED bulbs, reducing both revenues and allocated costs. EES examined lighting data in detail, but forecasted revenues are the rates input in the billing system and there is little variance other than the gradual replacement of older lights with newer LED lighting at both a discounted rate and a reduced O&M cost due to longer fixture life. This saving is predictable but not tracked in detail within the accounting system due to its nature as an avoided cost that will accrue over a long lifespan. Using the 2024 forecast revenues and costs, lighting appears to be in the reasonable range.

Irrigation has dropped out of range, but previous results indicate irrigation just above the lower threshold for rebalancing. Irrigation is a candidate for rebalancing given consistent under-collection.

Wholesale Primary 40 and Wholesale Transmission 41 have trended down and are both slightly out of range. Given previous results, these classes are also candidates for rebalancing.

5 COSA Unit Cost Results

Given the above assumptions regarding COSA, the various costs classify and allocate to the customer classes of service. The results of the analysis include both revenues to cost ratios and unit costs for each rate class. This section includes a discussion of the unbundled unit costs compared to current rates and the implications for rate design changes.

These are the COSA rates on a three-part or more unbundled basis from the study. Tables 5-1 through 5-7 include a comparison of the System Average Unit Costs to the Rate Class Unit Cost and also current rates for the same units.

The purpose of this comparison is to show what direction charges need to go to move closer to cost-of-service on a unit cost basis. For example, the fixed monthly charge (actually bi-monthly billing) for residential is $22.64/month, while the fixed per meter customer cost is $38.01/month, and so on.

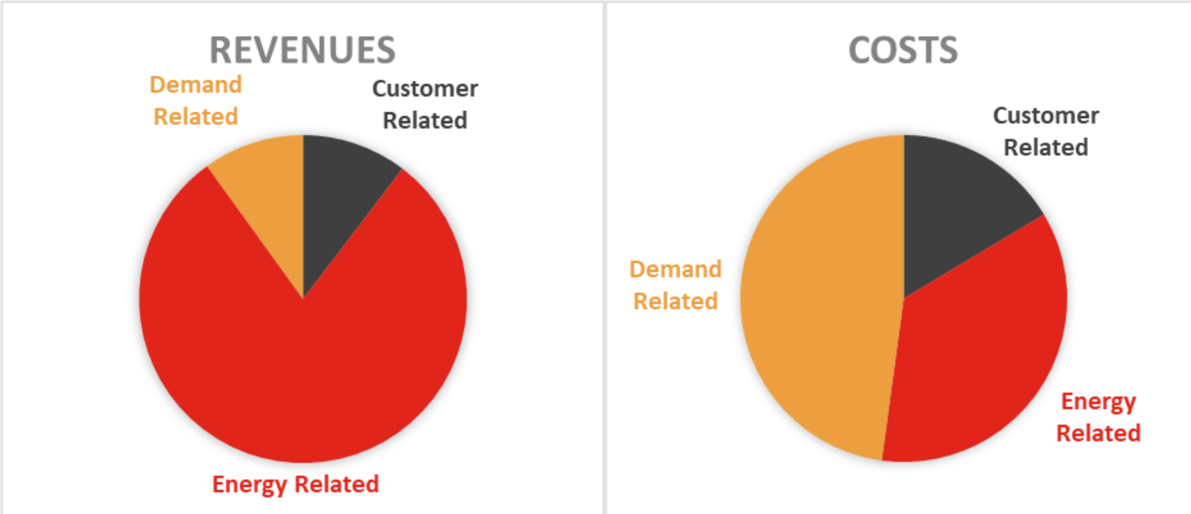
TABLE 5-1: UNBUNDLED UNIT COSTS AND CURRENT RATES – RESIDENTAL AND SMALL COMMERCIAL

Forecast Year: 2024	System Average	Residential	Small Commercial 20
	Functional Unit Cost		
Production Demand $/kW/Month	**$5.45**	**$4.09**	**$4.98**
Production Energy $/kWh	**$0.0473**	**$0.0485**	**$0.0479**
Melded Production $/kWh	**$0.0689**	**$0.0731**	**$0.0671**
Transmission Demand $/kW/Month	**$6.01**	**$4.76**	**$5.31**
Distribution Demand $/kW/Month	**$4.64**	**$4.17**	**$4.82**
$/Service/Month	**$40.12**	**$38.01**	**$40.84**
Total Average Cost per kWh	**$0.1330**	**$0.1734**	**$0.1278**
	Current Rates		
$/Service/Month		$22.64[19]	$27.85[20]
$/kW/Month		$0.00	$0.00
$/kWh		$0.14160	$0.12104
Current Average Rev per kWh		$0.1729	$0.1386

Currently, with no capacity charge for residential and small commercial, there is some disconnect between capacity costs and capacity charge collection. Getting capacity of on-peak demand rate components across all classes would move rate design toward cost-of-service unit costs. For residential, this can be accomplished either through increased demand or capacity charges proportional to other components or through time-of-day energy rates with higher on peak charges, as shown in Figure 5-1. Some large classes have on peak energy charges, and this services a similar rate goal already.

[19] $45.28 for a two-month period, but pro-rated for monthly billing as per the tariff.
[20] $55.69 per two Month period, but pro-rated for monthly billing as per the tariff.

FIGURE 5-1: 2024 RESIDENTIAL DEMAND, CUSTOMER AND ENERGY RELATED REVENUES AND COSTS



Looking at how the rates for residential and small commercial compare to their costs, the biggest variance is the lack of a capacity or demand charge with primary billing being on a two-part rate with a fixed monthly charge and an energy charge. Here, the fixed monthly charge is lower than the fixed monthly cost for both classes, and the energy rate is higher than either the energy only production cost or the melded energy and capacity production cost.

TABLE 5-2: UNIT COSTS AND CURRENT RATES – RESIDENTIAL AND SMALL COMMERCIAL

Residential Component	Existing Tariff Rate	COSA Unit Costs	COSA Unit Cost Percentage
Customer Charge ($/mo.)	$22.64	**$38.01**	168%
$/kWh (Energy Only)	$0.1416	**$0.1269**	90%

Small Commercial Rate Component	Existing Tariff Rate	COSA Unit Costs	COSA Unit Cost Percentage
Customer Charge ($/mo.)	$27.85	**$40.84**	147%
$/kWh (Energy Only)	$0.1210	**$0.1063**	88%

Moving toward COSA unit costs for residential and commercial would involve either a higher fixed charge and a lower energy charge proportionately with or without the addition of a demand or capacity component. Residential demand charges are beginning to be adopted by more utilities, but overall, it is still rare to have a residential demand charge for most jurisdictions, especially for rate-regulated utilities. For small commercial rates, it has been common to have a demand or capacity charge, and a modest rate design step would be to implement a demand charge for small commercial.

TABLE 5-3: UNBUNDLED UNIT COSTS AND CURRENT RATES – LARGE COMMERCIAL

Forecast Year: 2024	System Average	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31
Functional Cost				
Production Demand $/kW/Mo.	**$5.45**	**$7.30**	**$7.24**	**$10.93**
Production Energy $/kWh	**$0.0473**	**$0.0480**	**$0.0452**	**$0.0444**
Melded Production $/kWh	**$0.0689**	**$0.0665**	**$0.0623**	**$0.0614**
Transmission Demand $/kW/Mo.	**$6.01**	**$7.76**	**$6.93**	**$9.28**
Distribution Demand $/kW/Mo.	**$4.64**	**$5.91**	**$5.70**	**-$0.11**
$/Service/Mo.	**$40.12**	**$100.86**	**$2,377.47**	**$680.30**
		$0.00	**$0.00**	**$0.00**
Total Average Cost per kWh	**$0.1330**	**$0.1047**	**$0.0963**	**$0.0758**
Current Rates				
$/Service/Mo.		$65.37	$1,143.93	$3,735.89
Power Rate: $/kW				$4.02
Wires Rate: $/kW			$11.12	$5.76
$/kW/Mo.		$13.75[21]		
$/kWh		$0.08355	$0.06744	$0.06273
Current Average Rev per kWh		$0.1090	$0.0957	$0.0795

For large commercial rates, demand and energy collection reasonably track unit cost for these services. Energy is slightly higher than the melded production for RS 30/32, and slightly lower for RS 31. The monthly fixed charge for RS 31 could be lower.

TABLE 5-4. UNIT COSTS AND CURRENT RATES – COMMERCIAL

Commercial Rate Component	Existing Tariff Rate	COSA Unit Costs	COSA Unit Cost Percentage
Customer Charge ($/mo.)	$65.37	**$100.86**	154%
Energy Rate ($/kWh)	$0.0836	**$0.0480**	57%
Demand Rate (Over 40 kW $/kW)	$13.75	**$20.98**	153%

Looking at how the rates for commercial compare to their costs, the demand rate for RS 21/22 is higher than it would otherwise need to be because it only applies to demand over 40 kW. FortisBC could have a lower rate billed on all demand. In addition, EES looked at whether there should be re-segmentation of commercial rate RS 21/22. In general, analysis suggests that the existing rate classes are at appropriate breakpoints and that the revenue per kWh slope is gradual across the classes. Table 5-5 shows that 97.5% of RS 20 customers have demands no greater than 40 kW.

[21] $13.75 per kW of "Billing Demand" above 40 kW.

Looking more closely at RS 21/22 demands and revenue per kWh, there are some low demand inactive meters in the class but other than those, the rate transitions over 40 kW are relatively smooth with stepwise differences averaging -1.1%. As a rule of thumb on proof of revenue, anything under 2% is well within industry standards of expected revenue compared to the forecasted revenue for a rate change.

TABLE 5-5: COMMERCIAL DEMANDS

Non-Coincident Peak Demand kW	Small Commercial 20 Meters	Rate 20 Cumulative Count %	Commercial 21/22 Meters	Rate 21/22 Cumulative Count %
0-10	8,798	59.3%	16	0.9%
10-20	3,537	83.2%	10	1.5%
20-30	1,416	92.8%	12	2.2%
30-40	709	97.5%	37	4.4%
40-50	238	99.1%	186	15.4%
50-75	77	99.7%	515	45.8%
75-100	16	99.8%	264	61.4%
100-125	16	99.9%	141	69.7%
125-150	7	99.9%	132	77.5%
150-175	1	99.9%	69	81.5%
175-200	2	99.9%	51	84.5%
200-250	4	100.0%	84	89.5%
250-300		100.0%	51	92.5%
300-350	1	100.0%	29	94.2%
350-400		100.0%	25	95.7%
400-450		100.0%	17	96.7%
450-500		100.0%	18	97.8%
500-750	2	100.0%	24	99.2%
750-1,000		100.0%	9	99.7%
1,000+	1	100.0%	5	100.0%

TABLE 5-6: RATE 21/22 REVENUE PER KWH BASED ON DIFFERENT LEVELS OF DEMAND

Customer NCP	Meter Count	Rev/kWh	Rev/kWh % Change
0-10	16	$0.2572	
10-20	10	$0.0961	62.6%
20-30	12	$0.0870	9.5%
30-40	37	$0.0845	2.9%
40-50	186	$0.0823	2.5%
50-75	515	$0.0867	-5.3%
75-100	264	$0.0934	-7.7%
100-125	141	$0.0965	-3.4%
125-150	132	$0.0979	-1.5%
150-175	69	$0.1013	-3.4%
175-200	51	$0.1006	0.7%
200-250	84	$0.1013	-0.7%
250-300	51	$0.1010	0.3%
300-350	29	$0.1050	-3.9%
350-400	25	$0.1050	0.0%
400-450	17	$0.1077	-2.6%
450-500	18	$0.1044	3.1%
500-750	24	$0.1063	-1.8%
750-1,000	9	$0.1017	4.3%
1,000+	5	$0.0993	2.3%
Total	**1,695**	**$0.0981**	

For wholesale and other rates, unit costs and rates have a general alignment.

TABLE 5-7: UNBUNDLED UNIT COSTS FOR RATE DESIGN – WHOLESALE AND OTHER

Forecast Year: 2024	System Average	Lighting	Irrigation	Wholesale Primary 40	Wholesale Trans. 41
			Functional Cost		
Functional Cost					
Production Demand $/kW/Mo.	**$5.45**	**$4.82**	**$3.28**	**$9.66**	**$8.15**
Production Energy $/kWh	**$0.0473**	**$0.0463**	**$0.0479**	**$0.0459**	**$0.0458**
Melded Production $/kWh	**$0.0689**	**$0.0596**	**$0.0627**	**$0.0684**	**$0.0748**
Transmission Demand $/kW/Mo.	**$6.01**	**$2.80**	**$4.67**	**$11.14**	**$8.02**
Distribution Demand $/kW/Mo.	**$4.64**	**$1.67**	**$8.05**	**$7.41**	**-$0.07**
$/Service/Mo.	**$40.12**	**$5.69**	**$49.75**	**$10,291.99**	**$2,576.31**
Direct Assignment	**$0.13**	**$67.25**	**$0.00**	**$0.00**	**$0.00**
Total Average Cost per kWh	**$0.1330**	**$0.2678**	**$0.1376**	**$0.1138**	**$0.1034**
			Current Rates		
$/Service/Mo.		$8.73/fixture $147.34/acct.	$26.74[22]	$5,474.20[23]	$7,231.81[24]
Power Rate: $/kVa				$5.84	$5.77
Wires Rate: $/kVa				$10.88	$7.67
$/kW/Mo.			$13.75		
$/kWh			$0.08730	$0.06522	$0.05448
Current Average Rev per kWh		$0.2691	$0.1142	$0.1049	$0.0980

Overall, considering previous results and approved rates, there is general alignment of rate components with the primary variance being the lack of a capacity charge for some classes and lower collection of fixed costs in the fixed charge which is common for regulated utilities.

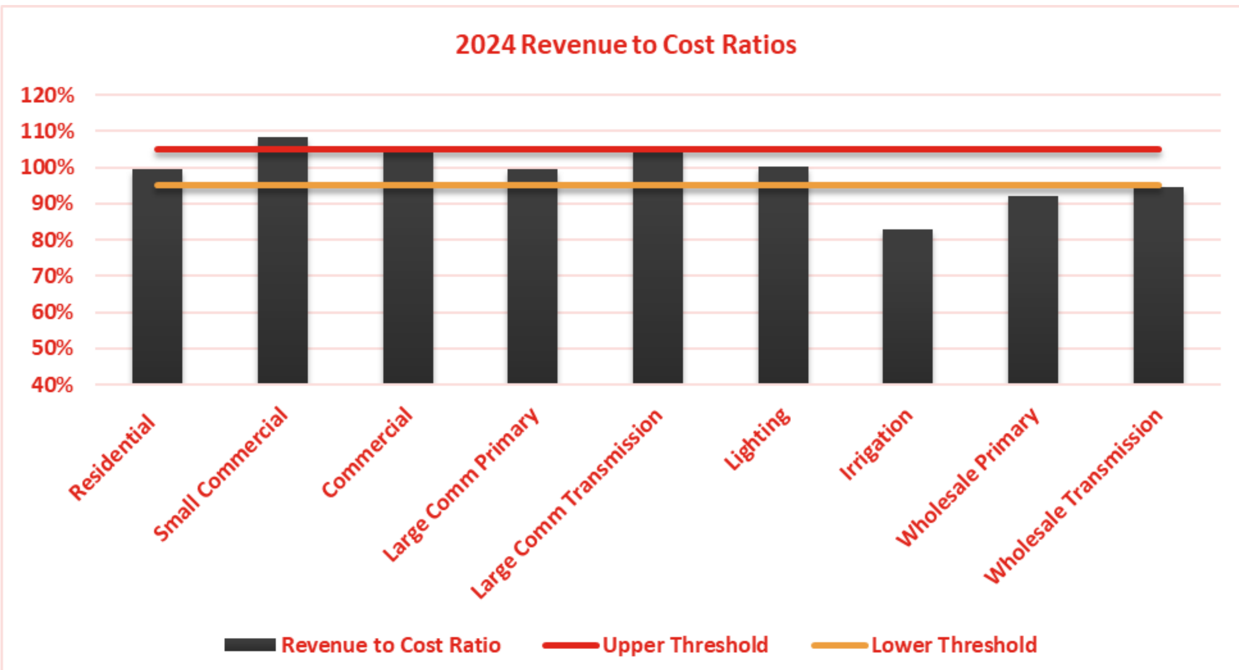
[22] Fixed revenues per meter are slightly higher due to RS 61 customer and off-season commercial rates apply.
[23] Per point of delivery, actual fixed revenues lower due to bypass discounts.
[24] Per customer, only one customer on RS 41 currently.

6 Summary Conclusions

Overall, with more accurate data for all classes and updated revenue requirements, FortisBC rates are largely tracking in the range of reasonableness. There are areas for improvement and some rebalancing warranted. With respect to rate design, looking to the pressures of electrification, there should be a focus on increasing on-peak charges for on-peak costs, whether that be with demand charges or on-peak energy charges. Generally, monthly fixed charges could adjust up and down in some cases, and energy unit costs have increased over time so higher energy charges excluding demand may be appropriate for some rates.

Based on the approved range of reasonableness of 95% to 105% in the ratio of revenues to cost of service, small commercial, irrigation, and wholesale are all candidates for potential rebalancing. Given changes over time, some rebalancing is appropriate and small commercial rates likely deserve some relief from wholesale and other classes, as shown in Figure 6-1.

FIGURE 6-1: 2024 REVENUE TO COST RATIOS



Overall, classes are in a range of reasonableness and there does not seem to be an issue for most classes with moving further out of range over time.

7 Appendix A – EES COSA Model

[PDF of Excel Model, Excel version provided in Appendix B to FBC's Application]

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

COST OF SERVICE SUMMARY
BY CUSTOMER CLASS
Schedule 1.1

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Revenues:												
Customer Charge Revenues	$46,842,274	$35,967,444	$5,127,225	$1,396,663	$521,632	$179,323	$2,371,000	$403,921	$788,285	$86,782	$35,702,388	$265,055
Energy Revenues	$359,999,908	$188,322,104	$43,220,453	$53,525,276	$18,583,373	$14,024,052	$47,265	$3,493,870	$34,092,752	$4,690,764	$186,513,896	$1,809,426
Demand Revenues	$44,737,121			$13,075,034	$6,519,549	$3,117,748		$436,152	$18,224,491	$3,364,148		
	$451,579,302	**$224,289,548**	**$48,347,678**	**$67,996,972**	**$25,624,554**	**$17,321,123**	**$2,418,265**	**$4,333,942**	**$53,105,528**	**$8,141,693**	**$222,216,284**	**$2,074,481**
Production-Related Costs	$233,861,410	$94,961,069	$23,439,417	$41,565,084	$16,717,763	$13,396,696	$536,793	$2,383,265	$34,641,965	$6,219,359	$93,962,274	$1,000,007
Transmission-Related Costs	$80,635,934	$37,254,152	$7,168,389	$12,332,001	$4,393,794	$3,144,821	$69,672	$802,364	$13,096,810	$2,373,931		
Distribution-Related Costs	$137,082,958	$93,019,587	$14,026,769	$11,542,319	$4,696,029	-$4,356	$1,803,554	$2,042,869	$9,946,175	$10,012	$91,970,547	$1,053,269
Total Allocated Revenue Requirements	**$451,580,302**	**$225,234,808**	**$44,634,574**	**$65,439,404**	**$25,807,585**	**$16,537,160**	**$2,410,019**	**$5,228,499**	**$57,684,950**	**$8,603,303**	**$185,932,821**	**$2,053,276**
Difference	-$1,000	-$945,261	$3,713,103	$2,557,568	-$183,031	$783,963	$8,246	-$894,557	-$4,579,422	-$461,609	$36,283,463	$21,205
% Increase to Equal Allocated Cost	0.000%	0.4%	-7.7%	-3.8%	0.7%	-4.5%	-0.3%	20.6%	8.6%	5.7%	-16%	-1%
Revenue To Cost Ratio	**100.0%**	**99.6%**	**108.3%**	**103.9%**	**99.3%**	**104.7%**	**100.3%**	**82.9%**	**92.1%**	**94.6%**	**119.5%**	**101.0%**
Adjusted Revenues at Existing Rates	$451,580,302	$224,290,044	$48,347,785	$67,997,123	$25,624,611	$17,321,162	$2,418,270	$4,333,952	$53,105,645	$8,141,711	$222,216,776	$2,074,486
Adjusted Revenue to Cost Ratio	**100.0%**	**99.6%**	**108.3%**	**103.9%**	**99.3%**	**104.7%**	**100.3%**	**82.9%**	**92.1%**	**94.6%**	**119.5%**	**101.0%**
Average Unit Costs:												
Customer Cost $ / Per Customer / Month	$40.12	$38.01	$40.84	$100.86	$2,377.47	$680.30	$5.69	$49.75	$10,291.99	$2,576.31	$37.96	$44.27
Average Energy Cost $ / kWh	$0.04784	$0.04847	$0.04787	$0.04797	$0.04524	$0.04443	$0.23196	$0.04789	$0.04594	$0.04577	$0.04846	$0.04895
Average Energy + Demand Cost $ / kWh	$0.11141	$0.12691	$0.10627	$0.10130	$0.09221	$0.07565	$0.25761	$0.12026	$0.11138	$0.10306	$0.12661	$0.15738
Demand Charge $ / kW	$16.23	$13.02	$15.11	$20.98	$19.87	$20.10	$76.54	$16.00	$28.21	$16.10	$13.00	$14.44
Combined Average Cost $ / kWh	**$0.1330**	**$0.1734**	**$0.1278**	**$0.1047**	**$0.0963**	**$0.0758**	**$0.2678**	**$0.1376**	**$0.1138**	**$0.1034**	**$0.1731**	**$0.1989**
Current Revenue $ / kWh	**$0.1330**	**$0.1727**	**$0.1384**	**$0.1088**	**$0.0956**	**$0.0794**	**$0.2687**	**$0.1141**	**$0.1048**	**$0.0979**		

Prepared By EES Consulting, Inc.

FortisBC 2025 COSA for Electric Service

FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENT SUMMARY
BY CUSTOMER CLASS
Schedule 1.2

Forecast Year: 2024	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Production												
Demand (PD)	$73,069,062	$32,010,492	$6,721,146	$11,596,279	$4,587,239	$3,702,455	$119,832	$563,838	$11,355,820	$2,411,961	$31,622,021	$388,657
Energy (PE)	$160,792,348	$62,950,577	$16,718,270	$29,968,806	$12,130,524	$9,694,240	$416,961	$1,819,428	$23,286,145	$3,807,398	$62,340,253	$611,350
Direct Assignment (PDA)												
Transmission												
Demand (TD)	$80,635,934	$37,254,152	$7,168,389	$12,332,001	$4,393,794	$3,144,821	$69,672	$802,364	$13,096,810	$2,373,931	$36,823,968	$431,016
Energy (TE)												
Direct Assignment (TDA)												
Distribution												
Demand (DD)	$62,216,789	$32,628,734	$6,506,387	$9,388,155	$3,612,271	-$36,018	$41,378	$1,384,181	$8,712,044	-$20,345	$32,094,745	$534,812
Energy (DE)												
Customer (DC)	$73,187,267	$60,380,295	$7,519,332	$2,154,930	$1,084,126	$32,655	$91,526	$658,449	$1,235,039	$30,916	$59,865,343	$518,334
Direct Assignment (DDA)	$1,678,902	$10,558	$1,049	-$767	-$368	-$993	$1,670,651	$239	-$909	-$559	$10,459	$123
Total	**$451,580,302**	**$225,234,808**	**$44,634,574**	**$65,439,404**	**$25,807,585**	**$16,537,160**	**$2,410,019**	**$5,228,499**	**$57,684,950**	**$8,603,303**	**$222,756,789**	**$2,484,292**
Total Cost / Function												
Production	$233,861,410	$94,961,069	$23,439,417	$41,565,084	$16,717,763	$13,396,696	$536,793	$2,383,265	$34,641,965	$6,219,359	$93,962,274	$1,000,007
Transmission	$80,635,934	$37,254,152	$7,168,389	$12,332,001	$4,393,794	$3,144,821	$69,672	$802,364	$13,096,810	$2,373,931		
Distribution	$137,082,958	$93,019,587	$14,026,769	$11,542,319	$4,696,029	-$4,356	$1,803,554	$2,042,869	$9,946,175	$10,012	$91,970,547	$1,053,269
Total Cost / Function	**$451,580,302**	**$225,234,808**	**$44,634,574**	**$65,439,404**	**$25,807,585**	**$16,537,160**	**$2,410,019**	**$5,228,499**	**$57,684,950**	**$8,603,303**	**$185,932,821**	**$2,053,276**
Total Cost / Classifier												
Demand	$215,921,785	$101,893,378	$20,395,923	$33,316,435	$12,593,303	$6,811,259	$230,882	$2,750,383	$33,164,674	$4,765,548	$100,540,734	$1,354,485
Energy	$160,792,348	$62,950,577	$16,718,270	$29,968,806	$12,130,524	$9,694,240	$416,961	$1,819,428	$23,286,145	$3,807,398	$62,340,253	$611,350
Customer	$73,187,267	$60,380,295	$7,519,332	$2,154,930	$1,084,126	$32,655	$91,526	$658,449	$1,235,039	$30,916	$59,865,343	$518,334
Direct Assignment	$1,678,902	$10,558	$1,049	-$767	-$368	-$993	$1,670,651	$239	-$909	-$559	$10,459	$123
Total Cost / Classifier	**$451,580,302**	**$225,234,808**	**$44,634,574**	**$65,439,404**	**$25,807,585**	**$16,537,160**	**$2,410,019**	**$5,228,499**	**$57,684,950**	**$8,603,303**	**$222,756,789**	**$2,484,292**

Prepared By EES Consulting, Inc.

FortisBC 2025 COSA for Electric Service

FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE SUMMARY
BY CUSTOMER CLASS
Schedule 1.3

Mid-year	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Production												
Demand (PD)	$78,902,289	$32,730,513	$7,779,392	$13,691,119	$5,447,157	$4,327,180	$169,620	$788,737	$11,821,157	$2,147,414	$32,378,034	$352,595
Energy (PE)	$314,048,271	$125,711,726	$32,168,930	$57,252,450	$22,919,210	$18,136,376	$770,601	$3,514,731	$45,995,329	$7,578,918	$124,461,979	$1,250,414
Direct Assignment (PDA)												
Transmission												
Demand (TD)	$397,233,196	$184,168,264	$35,389,763	$60,572,284	$21,598,157	$15,380,926	$397,004	$3,975,284	$64,175,554	$11,575,960	$182,039,137	$2,129,127
Energy (TE)												
Direct Assignment (TDA)												
Distribution												
Demand (DD)	$377,066,409	$195,122,364	$39,367,319	$57,745,900	$22,373,495	$7	$69,052	$8,419,380	$53,968,889	$3	$191,887,795	$3,234,612
Energy (DE)												
Customer (DC)	$364,103,128	$303,604,354	$38,040,539	$11,152,986	$2,626,804	$46,428	$78,827	$3,263,507	$5,255,282	$34,400	$300,280,918	$2,442,908
Direct Assignment (DDA)	$11,004,207	$39,818	$6,170	$5,478	$1,950	$0	$10,945,170	$931	$4,690	$0	$39,367	$451
Total	**$1,542,357,500**	**$841,377,038**	**$152,752,113**	**$200,420,218**	**$74,966,773**	**$37,890,918**	**$12,430,274**	**$19,962,569**	**$181,220,902**	**$21,336,695**	**$831,087,230**	**$9,410,107**
Total Cost / Function												
Production	$392,950,561	$158,442,239	$39,948,322	$70,943,569	$28,366,367	$22,463,556	$940,221	$4,303,468	$57,816,486	$9,726,332	$156,840,014	$1,603,009
Transmission	$397,233,196	$184,168,264	$35,389,763	$60,572,284	$21,598,157	$15,380,926	$397,004	$3,975,284	$64,175,554	$11,575,960	$182,039,137	$2,129,127
Distribution	$752,173,744	$498,766,535	$77,414,028	$68,904,365	$25,002,249	$46,435	$11,093,049	$11,683,817	$59,228,862	$34,403	$492,208,079	$5,677,971
Total Cost / Function	**$1,542,357,500**	**$841,377,038**	**$152,752,113**	**$200,420,218**	**$74,966,773**	**$37,890,918**	**$12,430,274**	**$19,962,569**	**$181,220,902**	**$21,336,695**	**$831,087,230**	**$9,410,107**
Total Cost / Classifier												
Demand	$853,201,893	$412,021,140	$82,536,475	$132,009,303	$49,418,809	$19,708,113	$635,676	$13,183,401	$129,965,600	$13,723,377	$406,304,966	$5,716,334
Energy	$314,048,271	$125,711,726	$32,168,930	$57,252,450	$22,919,210	$18,136,376	$770,601	$3,514,731	$45,995,329	$7,578,918	$124,461,979	$1,250,414
Customer	$364,103,128	$303,604,354	$38,040,539	$11,152,986	$2,626,804	$46,428	$78,827	$3,263,507	$5,255,282	$34,400	$300,280,918	$2,442,908
Direct Assignment	$11,004,207	$39,818	$6,170	$5,478	$1,950	$0	$10,945,170	$931	$4,690	$0	$39,367	$451
Total Cost / Classifier	**$1,542,357,500**	**$841,377,038**	**$152,752,113**	**$200,420,218**	**$74,966,773**	**$37,890,918**	**$12,430,274**	**$19,962,569**	**$181,220,902**	**$21,336,695**	**$831,087,230**	**$9,410,107**

Prepared By EES Consulting, Inc.

FortisBC 2025 COSA for Electric Service

SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION
Schedule 1.4

Forecast Year: 2024	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Hydraulic Power Generation	$16,698,922	$6,725,164	$1,702,505	$3,024,822	$1,206,639	$952,259	$40,017	$186,165	$2,455,543	$405,808	$6,657,845	$67,353
Purchased Power Supply/Other	$176,747,137	$72,192,527	$17,608,874	$31,133,929	$12,550,136	$10,085,883	$408,036	$1,748,903	$26,202,123	$4,816,726	$71,419,666	$773,128
Total Production	$193,446,058	$78,917,690	$19,311,379	$34,158,751	$13,756,775	$11,038,142	$448,053	$1,935,068	$28,657,666	$5,222,534	$78,077,511	$840,481
Total Transmission	$27,502,319	$12,750,833	$2,450,199	$4,193,704	$1,495,342	$1,064,894	$27,486	$275,228	$4,443,175	$801,458	$12,603,424	$147,409
Total Distribution	$13,861,404	$10,561,196	$1,428,610	$788,999	$246,846	$24	$77,319	$168,207	$590,195	$9	$10,462,385	$98,959
Total Operation & Maintenance	**$234,809,780**	**$102,229,720**	**$23,190,189**	**$39,141,453**	**$15,498,963**	**$12,103,060**	**$552,858**	**$2,378,502**	**$33,691,036**	**$6,024,001**	**$101,143,320**	**$1,086,849**
Total O&M w/o Purchased Power Supply & A&G	**$65,401,172**	**$35,626,031**	**$6,229,088**	**$8,082,686**	**$3,564,546**	**$2,081,989**	**$201,433**	**$676,163**	**$7,683,351**	**$1,255,885**	**$33,979,691**	**$376,915**
Total Customer Service, Accounts & Sales	$7,338,528	$5,588,838	$647,774	$75,163	$615,720	$64,813	$56,611	$46,563	$194,438	$48,609	$4,256,037	$63,194
Total Administrative & General	$14,557,692	$7,987,479	$1,447,647	$1,873,247	$697,755	$346,438	$156,734	$190,889	$1,670,002	$187,502	$7,898,754	$88,798
Total O&M plus A&G	**$256,706,000**	**$115,806,036**	**$25,285,609**	**$41,089,863**	**$16,812,437**	**$12,514,310**	**$766,202**	**$2,615,954**	**$35,555,476**	**$6,260,112**	**$113,298,111**	**$1,238,840**
Total Depreciation	$64,789,000	$39,491,237	$6,470,963	$7,075,100	$2,520,757	$828,686	$539,991	$892,413	$6,434,803	$535,051	$39,073,108	$437,132
Total Property Taxes	$19,276,000	$11,154,040	$1,921,033	$2,302,077	$842,796	$377,704	$139,332	$253,738	$2,067,888	$217,391	$11,031,602	$122,525
Total Return and Income Taxes	$128,569,000	$70,136,142	$12,733,226	$16,706,780	$6,249,137	$3,158,540	$1,036,172	$1,664,055	$15,106,349	$1,778,600	$69,278,396	$784,415
Revenue Requirement Before Other Revenues	**$469,340,000**	**$236,587,455**	**$46,410,831**	**$67,173,820**	**$26,425,127**	**$16,879,240**	**$2,481,697**	**$5,426,160**	**$59,164,515**	**$8,791,155**	**$232,681,217**	**$2,582,913**
Total Other Revenues	$17,759,698	$11,352,647	$1,776,257	$1,734,416	$617,542	$342,080	$71,678	$197,661	$1,479,565	$187,852	$9,924,428	$98,621
REVENUE REQUIREMENT for COST ALLOCATION	**$451,580,302**	**$225,234,808**	**$44,634,574**	**$65,439,404**	**$25,807,585**	**$16,537,160**	**$2,410,019**	**$5,228,499**	**$57,684,950**	**$8,603,303**	**$222,756,789**	**$2,484,292**

Updated Application dated May 15, 2025

Prepared By EES Consulting, Inc.

FortisBC 2025 COSA for Electric Service

SUMMARY OF RATE BASE COST ALLOCATIONS
Schedule 1.5

Mid-year	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Total Production Plant	$333,657,000	$134,373,823	$34,017,333	$60,438,211	$24,109,555	$19,026,846	$799,573	$3,719,720	$49,063,590	$8,108,351	$133,028,751	$1,345,765
Total Transmission Plant	$520,584,500	$241,357,330	$46,379,211	$79,381,564	$28,304,950	$20,157,106	$520,284	$5,209,714	$84,103,743	$15,170,599	$238,567,053	$2,790,277
Total Distribution Plant	$1,233,071,000	$837,504,851	$127,156,420	$107,367,962	$37,716,749	$1,406	$14,012,993	$18,648,939	$90,661,154	$527	$828,260,002	$9,253,552
Total Transmission & Distribution	$1,753,655,500	$1,078,862,181	$173,535,631	$186,749,525	$66,021,699	$20,158,512	$14,533,277	$23,858,652	$174,764,897	$15,171,126	$1,066,827,055	$12,043,829
Total General Plant	$228,778,500	$131,668,314	$22,885,859	$27,569,272	$10,158,340	$5,098,075	$1,434,408	$2,903,309	$24,301,698	$2,759,226	$130,264,795	$1,404,610
Total Plant Before General Plant & Intangible	**$2,087,312,500**	**$1,213,236,004**	**$207,552,964**	**$247,187,736**	**$90,131,253**	**$39,185,358**	**$15,332,849**	**$27,578,372**	**$223,828,486**	**$23,279,477**	**$1,199,855,806**	**$13,389,594**
Total Gross Plant in Service	**$2,316,091,000**	**$1,344,904,318**	**$230,438,822**	**$274,757,008**	**$100,289,593**	**$44,283,433**	**$16,767,257**	**$30,481,681**	**$248,130,184**	**$26,038,703**	**$1,330,120,601**	**$14,794,204**
Total Accumulated Depreciation	$669,158,000	$391,908,017	$66,306,595	$78,068,518	$28,281,433	$12,012,547	$4,862,822	$8,802,423	$71,450,734	$7,464,910	$387,585,361	$4,325,681
Total Net Plant	**$1,646,933,000**	**$952,996,301**	**$164,132,227**	**$196,688,490**	**$72,008,160**	**$32,270,886**	**$11,904,435**	**$21,679,258**	**$176,679,450**	**$18,573,792**	**$942,535,241**	**$10,468,523**
Total Working Capital	-$6,562,000	-$2,846,157	-$646,575	-$1,093,060	-$441,077	-$338,899	-$17,022	-$66,333	-$943,992	-$168,885	-$2,798,745	-$30,555
Total Contributions	-$231,706,000	-$171,587,071	-$23,971,441	-$15,748,469	-$5,096,202			-$3,086,364	-$12,216,454		-$169,884,427	-$1,702,645
SUB-TOTAL RATE BASE	**$1,408,665,000**	**$778,563,073**	**$139,514,212**	**$179,846,961**	**$66,470,881**	**$31,931,987**	**$11,887,414**	**$18,526,561**	**$163,519,005**	**$18,404,908**	**$769,852,069**	**$8,735,324**
Total Other Rate Base Items	$133,692,500	$62,813,965	$13,237,901	$20,573,257	$8,495,893	$5,958,931	$542,860	$1,436,009	$17,701,897	$2,931,788	$61,235,161	$674,783
TOTAL RATE BASE	**$1,542,357,500**	**$841,377,038**	**$152,752,113**	**$200,420,218**	**$74,966,773**	**$37,890,918**	**$12,430,274**	**$19,962,569**	**$181,220,902**	**$21,336,695**	**$831,087,230**	**$9,410,107**

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

SUMMARY OF REVENUE REQUIREMENT UNIT COSTS
BY CUSTOMER CLASS
Schedule 2.1

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Billing Determinants												
Total kVA (with ratchet)	3,133,859			950,912	586,290	304,865		31,720	1,044,052	216,020		
Total Demand (kW)	13,406,433	7,827,798	1,349,694	1,588,285	633,677	338,738	24,842	171,960	1,175,550	295,887	7,733,956	93,841
Total kVA Contract												
Total Energy (kWh)	3,396,293,260	1,299,000,000	349,268,877	624,731,123	268,127,895	218,165,365	9,000,000	38,000,000	506,820,191	83,179,809	1,286,516,337	12,492,095
Average Monthly Customers	152,011	132,389	15,345	1,780	38	4	1,341	1,103	10	1	131,413	976
Average PODs									1.2	3.0		
Average Monthly kWh	1,862	818	1,897	29,240	588,000	4,545,112	559	2,871	4,223,502	6,931,651	9,790	12,804
Functional Cost			88	892	1,390	7,057		34,451			59	96
Production												
Demand (PD)	$73,069,062	$32,010,492	$6,721,146	$11,596,279	$4,587,239	$3,702,455	$119,832	$563,838	$11,355,820	$2,411,961	$31,622,021	$388,657
$/kW	$5.45	$4.09	$4.98	$7.30	$7.24	$10.93	$4.82	$3.28	$9.66	$8.15	$4.09	$4.14
or $/kVa				$12.19	$7.82	$12.14		$17.78	$10.88	$11.17		
Energy (PE)	$160,792,348	$62,950,577	$16,718,270	$29,968,806	$12,130,524	$9,694,240	$416,961	$1,819,428	$23,286,145	$3,807,398	$62,340,253	$611,350
$/kWh	$0.0473	$0.0485	$0.0479	$0.0480	$0.0452	$0.0444	$0.0463	$0.0479	$0.0459	$0.0458	$0.048	$0.049
Melded Production	0.0689	0.0731	0.0671	0.0665	0.0623	0.0614	0.0596	0.0627	0.0684	0.0748	0.0730	0.0801
Transmission												
Demand (TD)	$80,635,934	$37,254,152	$7,168,389	$12,332,001	$4,393,794	$3,144,821	$69,672	$802,364	$13,096,810	$2,373,931	$36,823,968	$431,016
$/kW	$6.01	$4.76	$5.31	$7.76	$6.93	$9.28	$2.80	$4.67	$11.14	$8.02	$4.76	$4.59
or $/kVa				$12.97	$7.49	$10.32		$25.30	$12.54	$10.99		
	$0.093	$0.102	$0.088	$0.086	$0.079	$0.076	$0.067	$0.084	$0.094	$0.103	$0.102	$0.115
Distribution												
Demand (DD)	$62,216,789	$32,628,734	$6,506,387	$9,388,155	$3,612,271	-$36,018	$41,378	$1,384,181	$8,712,044	-$20,345	$32,094,745	$534,812
$/kW	$4.64	$4.17	$4.82	$5.91	$5.70	-$0.11	$1.67	$8.05	$7.41	-$0.07	$4.15	$5.70
or $/kVa				$9.87	$6.16	-$0.12		$43.64	$8.34	-$0.09		
Customer (DC)	$73,187,267	$60,380,295	$7,519,332	$2,154,930	$1,084,126	$32,655	$91,526	$658,449	$1,235,039	$30,916	$59,865,343	$518,334
$/Customer/Month	$40.12	$38.01	$40.84	$100.86	$2,377.47	$680.30	$5.69	$49.75	$10,291.99	$2,576.31	$37.96	$44.27
Direct Assignment (DDA)	$1,678,902	$10,558	$1,049	-$767	-$368	-$993	$1,670,651	$239	-$909	-$559	$10,459	$123
$/kW	$0.13	$0.00	$0.00	$0.00	$0.00	$0.00	$67.25	$0.00	$0.00	$0.00	$0.00	$0.00
$/kVa				$0.00	$0.00	$0.00		$0.01	$0.00	$0.00		
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.186	$0.000	$0.000	$0.000	$0.000	$0.000
Total	**$451,580,302**	**$225,234,808**	**$44,634,574**	**$65,439,404**	**$25,807,585**	**$16,537,160**	**$2,410,019**	**$5,228,499**	**$57,684,950**	**$8,603,303**	**$222,756,789**	**$2,484,292**

Total	**Total**	**Residential**	**Small Commercial 20**	**Commercial 21/22**	**Large Comm Primary 30/32**	**Large Comm Transmission 31**	**Lighting**	**Irrigation**	**Wholesale Primary 40**	**Wholesale Transmission 41**	**Residential w/o Net Metering**	**Net Metering**
$/kW	**$16.23**	**$13.02**	**$15.11**	**$20.98**	**$19.87**	**$20.10**	**$76.54**	**$16.00**	**$28.21**	**$16.10**	**$13.00**	**$14.44**
or $/kVa					**$21.48**	**$22.34**			**$31.76**	**$22.06**		
$/kWh	**$0.0478**	**$0.0485**	**$0.0479**	**$0.0480**	**$0.0452**	**$0.0444**	**$0.2320**	**$0.0479**	**$0.0459**	**$0.0458**	**$0.0485**	**$0.0489**
$/kWh (energy only)	**$0.1114**	**$0.1269**	**$0.1063**	**$0.1013**	**$0.0922**	**$0.0757**	**$0.2576**	**$0.1203**	**$0.1114**	**$0.1031**	**$0.1266**	**$0.1574**
$/Customer/Month	**$40.12**	**$38.01**	**$40.84**	**$100.86**	**$2,377.47**	**$680.30**	**$5.69**	**$49.75**	**$10,291.99**	**$2,576.31**	**$37.96**	**$44.27**
Total Average Cost per kWh	**$0.1330**	**$0.1734**	**$0.1278**	**$0.1047**	**$0.0963**	**$0.0758**	**$0.2678**	**$0.1376**	**$0.1138**	**$0.1034**	**$0.1731**	**$0.1989**

FortisBC 2025 COSA for Electric Service

SUMMARY OF RATE BASE UNIT COST
BY CUSTOMER CLASS
Schedule 2.2

Forecast Year: 2024	**Total**	**Residential**	**Small Commercial 20**	**Commercial 21/22**	**Large Comm Primary 30/32**	**Large Comm Transmission 31**	**Lighting**	**Irrigation**	**Wholesale Primary 40**	**Wholesale Transmission 41**	**Residential w/o Net Metering**	**Net Metering**
Billing Determinants												
Total kVa	3,133,859			950,912	586,290	304,865		31,720	1,044,052	216,020		
Total Demand (kW)	13,406,433	7,827,798	1,349,694	1,588,285	633,677	338,738	24,842	171,960	1,175,550	295,887	7,733,956	93,841
Total Energy (kWh)	3,396,293,260	1,299,000,000	349,268,877	624,731,123	268,127,895	218,165,365	9,000,000	38,000,000	506,820,191	83,179,809	1,286,516,337	12,492,095
Average Monthly Customers	152,011	132,389	15,345	1,780	38	4	1,341	1,103	10	1	131,413	976
Functional Cost												
Production												
Demand (PD)	$78,902,289	$32,730,513	$7,779,392	$13,691,119	$5,447,157	$4,327,180	$169,620	$788,737	$11,821,157	$2,147,414	$32,378,034	$352,595
$/kW		$4.18	$5.76	$8.62	$8.60	$12.77	$6.83	$4.59	$10.06	$7.26	$4.19	$3.76
or $/kVa				$14.40	$9.29	$14.19		$24.87	$11.32	$9.94		
Energy (PE)	$314,048,271	$125,711,726	$32,168,930	$57,252,450	$22,919,210	$18,136,376	$770,601	$3,514,731	$45,995,329	$7,578,918	$124,461,979	$1,250,414
$/kWh	$0.092	$0.097	$0.092	$0.092	$0.085	$0.083	$0.086	$0.092	$0.091	$0.091	$0.097	$0.100
Transmission												
Demand (TD)	$397,233,196	$184,168,264	$35,389,763	$60,572,284	$21,598,157	$15,380,926	$397,004	$3,975,284	$64,175,554	$11,575,960	$182,039,137	$2,129,127
$/kW		$23.53	$26.22	$38.14	$34.08	$45.41	$15.98	$23.12	$54.59	$39.12	$23.54	$22.69
or $/kVa				$63.70	$36.84	$50.45		$125.32	$61.47	$53.59		
Distribution												
Demand (DD)	$377,066,409	$195,122,364	$39,367,319	$57,745,900	$22,373,495	$7	$69,052	$8,419,380	$53,968,889	$3	$191,887,795	$3,234,612
$/kW		$24.93	$29.17	$36.36	$35.31	$0.00	$2.78	$48.96	$45.91	$0.00	$24.81	$34.47
or $/kVa				$60.73	$38.16	$0.00		$265.43	$51.69	$0.00		
Customer (DC)	$364,103,128	$303,604,354	$38,040,539	$11,152,986	$2,626,804	$46,428	$78,827	$3,263,507	$5,255,282	$34,400	$300,280,918	$2,442,908
$/Customer/Month		$191	$207	$522	$5,761	$967	$5	$247	$43,794	$2,867	$190	$209
Direct Assignment (DDA)	$11,004,207	$39,818	$6,170	$5,478	$1,950	$0	$10,945,170	$931	$4,690	$0	$39,367	$451
$/kW		$0.01	$0.00	$0.00	$0.00	$0.00	$440.58	$0.01	$0.00	$0.00	$0.01	$0.00
$/kVa				$0.01	$0.00	$0.00		$0.03	$0.00	$0.00		
$/kWh		$0.000	$0.000	$0.000	$0.000	$0.000	$1.216	$0.000	$0.000	$0.000	$0.000	$0.000
Total	**$1,542,357,500**	**$841,377,038**	**$152,752,113**	**$200,420,218**	**$74,966,773**	**$37,890,918**	**$12,430,274**	**$19,962,569**	**$181,220,902**	**$21,336,695**	**$831,087,230**	**$9,410,107**

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account		2022 Actual Cost, $	2024 Annual Rev Cost, $	2024 Annual Rev Source	2024 Cost, $	Function	Unbundling Factor	Classification Factor	Classification Method
	Operation & Maintenance Expense								
535.00	Op. Supervision & Engineering	**$777,000**			$909,271	P		RBG	On the Basis of Generation Rate Base
536.00	Water for Power	**$11,838,000**	$12,513,000	Sec 11, Sch 14 Line22	$12,513,000	P		RBG	On the Basis of Generation Rate Base
542.00	Structures	**$1,091,000**			$1,276,724	P		RBG	On the Basis of Generation Rate Base
543.00	Dams & Waterways	**$246,000**			$287,877	P		RBG	On the Basis of Generation Rate Base
544.00	Electric Plant	**$952,000**			$1,114,061	P		RBG	On the Basis of Generation Rate Base
545.00	Other Plant	**$511,000**			$597,989	P		RBG	On the Basis of Generation Rate Base
	Purchased Power Supply/Other								
555.00	Purchased Power - Energy Charges	**$153,457,000**	**$113,577,435**	**Power Supply**	$113,577,435	P		PURCHkWh	On the Basis of Energy Purchases Weighted by Month
555.00	Purchased Power - Demand Charges		**$60,116,565**	**Power Supply**	$60,116,565	P		PURCHkW	On the Basis of Demand Purchases Weighted by Month
556.00	System Control	**$2,609,000**			$3,053,137	P		CP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
	Base Power Supply								
	Total Purchased Power	$153,457,000	$173,694,000		$173,694,000				
	Total Production	$171,481,000	$186,207,000		$193,446,058				
	Transmission								
560.10	Op. Supervision & Engineering	**$4,163,000**			$4,871,678	T		RBT	On the Basis of Transmission Rate Base
560.20	System Planning	**$4,849,000**			$5,674,457	T		RBT	On the Basis of Transmission Rate Base
561.00	Load Dispatching	**$1,485,000**			$1,737,795	T		RBT	On the Basis of Transmission Rate Base
562.00	Transmission Station Expense	**$1,208,000**			$1,413,641	T		RBT	On the Basis of Transmission Rate Base
563.10	Transmission Line Maintenance	**$571,000**			$668,203	T		RBT	On the Basis of Transmission Rate Base
563.20	Transmission TROW Maintenance	**$1,389,000**			$1,625,453	T		RBT	On the Basis of Transmission Rate Base
565.00	Wheeling	**$6,898,000**	$7,324,000	Sec 11, Sch 14 Line 21	$7,324,000	T		RBT	On the Basis of Transmission Rate Base
567.00	Rents	**$3,578,000**			$4,187,092	T		RBT	On the Basis of Transmission Rate Base
	Total Transmission	$24,141,000	$27,502,319		$27,502,319				
	Distribution								
583.10	Distribution Line Maintenance	**$4,558,000**			$5,333,920	D			On the Basis of RBD Poles, Towers & Fixtures
583.20	Distribution ROW Maintenance	**$4,525,000**			$5,295,302	D			On the Basis of RBD Poles, Towers & Fixtures
586.00	Meter Expenses	**$637,000**			$745,438	D			On the Basis of RBD Meters
592.00	Distribution Station Expense	**$1,532,000**			$1,792,796	D			On the Basis of RBD Station Equipment
596.00	Street Lighting	**$60,000**			$70,214	D		DA1	On the Basis of RBD Street Lights and Signal Systems
598.00	Other Plant	**$533,000**			$623,734	D		RBD	On the Basis of Distribution Rate Base
	Total Distribution	$11,845,000			$13,861,404				
	Total Operation & Maintenance	$207,467,000	$234,809,780		$234,809,780				
	Customer Service, Accounts, & Sales								
901.00	Supervision & Administration	**$1,767,000**			$2,067,801	D			As All Other Customer Service Expense
902.00	Meter Reading	**$59,000**			$69,044	D		CUSTW	Customers Weighted for Accounting/Metering
903.00	Customer Billing	**$1,380,000**			$1,614,921	D		CUSTW	Customers Weighted for Accounting/Metering
904.00	Credit & Collections	**$917,000**			$1,073,103	D		CUSTR	Retail Customers
910.00	Customer Assistance	**$2,148,000**			$2,513,659	D		CUSTW	Customers Weighted for Accounting/Metering
911.00	Energy Management Promotion					SS		DSM	Classified 72% Energy, 17% Demand & 12% T&D
	Total Customer Service, Accounts & Sales	$6,271,000			$7,338,528				
	Total O&M w/o Purchased Power Supply & A&G	$60,281,000	$68,454,308		$68,454,308				
	Administrative & General								
920.10	Executive & Senior Management	**$436,000**			$510,221	SS		LABOR	On the Basis of Labor Ratios
920.20	Legal & Regulatory	**$445,000**			$520,753	SS		LABOR	On the Basis of Labor Ratios
920.30	Human Resources	**$1,125,000**			$1,316,512	SS		LABOR	On the Basis of Labor Ratios
920.40	Finance & Accounting	**$1,081,000**			$1,265,021	SS		LABOR	On the Basis of Labor Ratios
920.50	Office Services					SS		LABOR	On the Basis of Labor Ratios
920.60	Information Services	**$1,941,000**			$2,271,421	SS		LABOR	On the Basis of Labor Ratios

Updated Application dated May 15, 2025

INPUT REVENUE REQUIREMENT
Schedule 3.1, Cont'd

920.70	Materials Management					SS		LABOR	On the Basis of Labor Ratios
	Other	**-$2,855,000**			-$3,341,014	SS		LABOR	On the Basis of Labor Ratios
921.10	Executive & Senior Management Expenses	**$22,000**			$25,745	SS		LABOR	On the Basis of Labor Ratios
921.20	Legal Expenses	**$550,000**			$643,628	SS		LABOR	On the Basis of Labor Ratios
921.30	Human Resources Expenses	**$68,000**			$79,576	SS		LABOR	On the Basis of Labor Ratios
921.40	Regulatory & Finance Expenses	**$533,000**			$623,734	SS		LABOR	On the Basis of Labor Ratios
921.60	Information Services Expenses	**$1,932,000**			$2,260,889	SS		LABOR	On the Basis of Labor Ratios
921.70	Materials Management	**$348,000**			$407,241	SS		LABOR	On the Basis of Labor Ratios
XXXX	Other Expenses	**$262,000**			$306,601	SS		LABOR	On the Basis of Labor Ratios
XXXX	Special Services, Insurance, General, and Transportation	**$6,552,000**			$7,667,363	SS		LABOR	On the Basis of Labor Ratios
XXXX	Other					SS		LABOR	On the Basis of Labor Ratios
	Total Administrative & General	$12,440,000			$14,557,692				
	Total O&M plus A&G	$226,178,000	$256,706,000		$256,706,000				
	Depreciation								
403.30	Generation Plant	$7,029,000	$7,643,000	Sec 11, Sch 7 Line 8	$7,643,000	P		RBG	On the Basis of Generation Rate Base
403.50	Transmission Plant	$12,199,000	$13,036,000	Sec 11, Sch 7 Line 17	$13,036,000	T		RBT	On the Basis of Transmission Rate Base
403.60	Distribution Plant	$33,660,000	$37,354,000	Sec 11, Sch 7.1 Line 12	$37,354,000	D		RBD	On the Basis of Distribution Rate Base
403.70	General Plant And Deferred Charges	$13,581,000	$14,020,000	Sec 11, Sch 7.1 Line 30	$14,020,000	SS		GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Amortization & Other	-$2,911,000	-$7,264,000	Sec 11, Sch 9 Line 9	-$7,264,000	SS		GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Depreciation	$63,558,000	$64,789,000		$64,789,000				
	Taxes								
408.00	Taxes		$703,000	Sec 11, Sch 14 Line 25		SS		REV	On The Basis of Revenue Req. Before Taxes and Other Revenues
408.05	Property		$18,573,000	Sec 11, Sch 14 Line 24	$19,276,000	SS		NETPLT	On the Basis of Net Plant
	Total Property Taxes		$19,276,000		$19,276,000				
	Return and Income Taxes								
	Incentive Adjustments					SS		RBASE	On the Basis of Total Rate Base
	Income Tax		$12,484,000	Sec 11, Sch 14 Line 26	$12,484,000	SS		RBASE	On the Basis of Total Rate Base
	Return on Rate Base		$116,085,000	Sec 11, Sch 16 Line 20	$116,085,000	SS		RBASE	On the Basis of Total Rate Base
	Interest on Non Rate Base Deferral Account					SS		RBASE	On the Basis of Total Rate Base
	Total Return and Income Taxes		$128,569,000		$128,569,000				
	Revenue Requirement Before Other Revenues	$289,736,000	$469,340,000		$469,340,000				
	Revenue Req. Before Taxes and Other Revenues	$289,736,000	$450,064,000		$450,064,000				
	Other Revenues								
	Electric Apparatus Rental	**$6,293,000**	$6,199,000	Sec 11, Sch 14 Line 11	$6,199,000	SS			On the Basis of RBD Poles, Towers & Fixtures
	Rate 38 Revenue	**$3,574,198**	$3,574,198		**$3,574,198**	SS		RB	On the Basis of All Rate Base
	Rate 37 Revenue	**$2,092,500**	$2,092,500		**$2,092,500**	SS		RB	On the Basis of All Rate Base
	Contract Revenue	**$3,184,000**	**$2,260,000**	Sec 11, Sch 14 Line 12	$2,260,000	SS		RBG	On the Basis of Generation Rate Base
	Transmission Access Revenue	**$1,661,000**	**$1,723,000**	Sec 11, Sch 14 Line 13	$1,723,000	SS		RBT	On the Basis of Transmission Rate Base
	Fortis Pacific Holdings					SS		LABOR	On the Basis of Labor Ratios
	Connection Charges	**$569,000**	$561,000	Sec 11, Sch 14 Line 15	$561,000	SS		CUSTR	Retail Customers
	Late Payment Charges	**$962,000**	$962,000	Sec 11, Sch 14 Line 14	$962,000	SS		CUSTR	Retail Customers
	Sundry Revenue	**$1,071,000**	$388,000	Sec 11, Sch 14 Line 16	$388,000	SS		GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Investment Income					SS		GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Other Revenues	$19,406,698	$17,759,698		$17,759,698				
	REVENUE REQUIREMENT for COST ALLOCATION		$451,580,302		$451,580,302				
					-				
	Net O&M Expense	**$53,985,000**	**$63,175,000**		17.0%				

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2

	Total	Production			Transmission			Distribution			
		Demand	Energy	Direct Assignment	Demand	Energy	Direct Assignment	Demand	Energy	Customer	Direct Assignment
	Expenses	PD	PE	PDA	TD	TE	TDA	DD	DE	DC	DDA
Operation & Maintenance Expense											
Op. Supervision & Engineering	$909,271	$161,856	$747,414								
Water for Power	$12,513,000	$2,227,397	$10,285,603								
Structures	$1,276,724	$227,265	$1,049,458								
Dams & Waterways	$287,877	$51,244	$236,633								
Electric Plant	$1,114,061	$198,310	$915,751								
Other Plant	$597,989	$106,446	$491,543								
Purchased Power Supply/Other											
Purchased Power - Energy Charges	$113,577,435		$113,577,435								
Purchased Power - Demand Charges	$60,116,565	$60,116,565									
System Control	$3,053,137	$3,053,137									
Total Purchased Power	$173,694,000	$60,116,565	$113,577,435								
Total Production	$193,446,058	$66,142,220	$127,303,838								
Transmission											
Op. Supervision & Engineering	$4,871,678				$4,871,678						
System Planning	$5,674,457				$5,674,457						
Load Dispatching	$1,737,795				$1,737,795						
Transmission Station Expense	$1,413,641				$1,413,641						
Transmission Line Maintenance	$668,203				$668,203						
Transmission TROW Maintenance	$1,625,453				$1,625,453						
Wheeling	$7,324,000				$7,324,000						
Rents	$4,187,092				$4,187,092						
Total Transmission	$27,502,319				$27,502,319						
Distribution											
Distribution Line Maintenance	$5,333,920							$746,749		$4,587,171	
Distribution ROW Maintenance	$5,295,302							$741,342		$4,553,960	
Meter Expenses	$745,438									$745,438	
Distribution Station Expense	$1,792,796							$1,792,796			
Street Lighting	$70,214										$70,214
Other Plant	$623,734							$288,331		$328,315	$7,088
Total Distribution	$13,861,404							$3,569,219		$10,214,883	$77,302
Total Operation & Maintenance	$234,809,780	$66,142,220	$127,303,838		$27,502,319			$3,569,219		$10,214,883	$77,302
Customer Service, Accounts, & Sales											
Supervision & Administration	$2,067,801									$2,067,801	
Meter Reading	$69,044									$69,044	
Customer Billing	$1,614,921									$1,614,921	
Credit & Collections	$1,073,103									$1,073,103	
Customer Assistance	$2,513,659									$2,513,659	
Energy Management Promotion											
Total Customer Service, Accounts & Sales	$7,338,528									$7,338,528	
Total O&M w/o Purchased Power Supply & A&G	$65,401,172	$2,972,519	$13,726,403		$27,502,319			$3,569,219		$17,553,411	$77,302
Administrative & General											
Executive & Senior Management	$510,221	$24,541	$113,322		$110,537			$121,031		$137,815	$2,975
Legal & Regulatory	$520,753	$25,047	$115,662		$112,819			$123,530		$140,660	$3,037
Human Resources	$1,316,512	$63,321	$292,403		$285,216			$312,294		$355,600	$7,677
Finance & Accounting	$1,265,021	$60,845	$280,967		$274,061			$300,080		$341,692	$7,377
Office Services											
Information Services	$2,271,421	$109,250	$504,492		$492,093			$538,812		$613,529	$13,245

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service **Prepared By EES Consulting, Inc.**

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.2, Cont'd

Materials Management							
Other	-$3,341,014	-$160,695	-$742,053	-$723,815	-$792,533	-$902,434	-$19,482
Executive & Senior Management Expenses	$25,745	$1,238	$5,718	$5,578	$6,107	$6,954	$150
Legal Expenses	$643,628	$30,957	$142,952	$139,439	$152,677	$173,849	$3,753
Human Resources Expenses	$79,576	$3,827	$17,674	$17,240	$18,876	$21,494	$464
Regulatory & Finance Expenses	$623,734	$30,000	$138,534	$135,129	$147,958	$168,475	$3,637
Information Services Expenses	$2,260,889	$108,744	$502,153	$489,811	$536,313	$610,684	$13,184
Materials Management	$407,241	$19,587	$90,450	$88,227	$96,603	$109,999	$2,375
	$306,601	$14,747	$68,097	$66,424	$72,730	$82,815	$1,788
	$7,667,363	$368,783	$1,702,954	$1,661,099	$1,818,801	$2,071,016	$44,710
Total Administrative & General	$14,557,692	$700,192	$3,233,326	$3,153,858	$3,453,279	$3,932,148	$84,889
Total O&M plus A&G	$256,706,000	$66,842,413	$130,537,163	$30,656,176	$7,022,498	$21,485,559	$162,191
Depreciation							
Generation Plant	$7,643,000	$1,360,505	$6,282,495				
Transmission Plant	$13,036,000			$13,036,000			
Distribution Plant	$37,354,000				$17,267,515	$19,662,013	$424,472
General Plant And Deferred Charges	$14,020,000	$398,930	$1,842,167	$3,496,647	$3,828,612	$4,359,528	$94,115
Amortization & Other	-$7,264,000	-$2,046,154	-$3,938,231	-$850,803	-$110,416	-$316,004	-$2,391
Total Depreciation	$64,789,000	-$286,720	$4,186,432	$15,681,844	$20,985,711	$23,705,536	$516,196
Taxes							
Taxes							
Property	$19,276,000	$639,399	$2,952,596	$4,464,272	$5,135,970	$5,957,510	$126,253
Total Property Taxes	$19,276,000	$639,399	$2,952,596	$4,464,272	$5,135,970	$5,957,510	$126,253
Return and Income Taxes							
Incentive Adjustments							
Income Tax	$12,484,000	$638,643	$2,541,939	$3,215,246	$3,052,014	$2,947,088	$89,069
Return on Rate Base	$116,085,000	$5,938,553	$23,636,734	$29,897,618	$28,379,772	$27,404,095	$828,228
Interest on Non Rate Base Deferral Account							
Total Return and Income Taxes	$128,569,000	$6,577,197	$26,178,673	$33,112,864	$31,431,786	$30,351,183	$917,297
Revenue Requirement Before Other Revenues	$469,340,000	$73,772,288	$163,854,864	$83,915,157	$64,575,965	$81,499,789	$1,721,937
Revenue Req. Before Taxes and Other Revenues	$450,064,000	$73,132,890	$160,902,268	$79,450,885	$59,439,995	$75,542,279	$1,595,684
Other Revenues							
Electric Apparatus Rental	$6,199,000				$867,860	$5,331,140	
Rate 38 Revenue	$3,574,198	$182,845	$727,763	$920,532	$873,799	$843,758	$25,501
Rate 37 Revenue	$2,092,500	$107,046	$426,066	$538,922	$511,562	$493,975	$14,929
Contract Revenue	$2,260,000	$402,295	$1,857,705				
Transmission Access Revenue	$1,723,000			$1,723,000			
Fortis Pacific Holdings							
Connection Charges	$561,000					$561,000	
Late Payment Charges	$962,000					$962,000	
Sundry Revenue	$388,000	$11,040	$50,982	$96,769	$105,956	$120,649	$2,605
Investment Income							
Total Other Revenues	$17,759,698	$703,226	$3,062,515	$3,279,223	$2,359,176	$8,312,522	$43,035
REVENUE REQUIREMENT for COST ALLOCATION	$451,580,302	$73,069,062	$160,792,348	$80,635,934	$62,216,789	$73,187,267	$1,678,902

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

CLASSIFICATION BY CUSTOMER
Schedule 3.3

	Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Operation & Maintenance Expense												
Op. Supervision & Engineering	$909,271	$366,191	$92,703	$164,704	$65,703	$51,851	$2,179	$10,137	$133,706	$22,097	$362,525	$3,667
Water for Power	$12,513,000	$5,039,366	$1,275,738	$2,266,589	$904,171	$713,556	$29,986	$139,499	$1,840,011	$304,084	$4,988,922	$50,470
Structures	$1,276,724	$514,175	$130,166	$231,264	$92,254	$72,805	$3,060	$14,233	$187,740	$31,026	$509,029	$5,150
Dams & Waterways	$287,877	$115,937	$29,350	$52,146	$20,802	$16,416	$690	$3,209	$42,332	$6,996	$114,776	$1,161
Electric Plant	$1,114,061	$448,666	$113,582	$201,800	$80,500	$63,530	$2,670	$12,420	$163,820	$27,073	$444,175	$4,493
Other Plant	$597,989	$240,828	$60,967	$108,319	$43,210	$34,100	$1,433	$6,667	$87,933	$14,532	$238,418	$2,412
Purchased Power Supply/Other												
Purchased Power - Energy Charges	$113,577,435	$44,124,548	$11,898,120	$21,346,907	$8,685,628	$6,957,934	$310,248	$1,294,969	$16,310,784	$2,648,296	$43,701,075	$423,740
Purchased Power - Demand Charges	$60,116,565	$26,652,460	$5,438,749	$9,321,463	$3,698,505	$3,009,731	$94,736	$423,380	$9,398,085	$2,079,456	$26,319,437	$333,023
System Control	$3,053,137	$1,415,518	$272,006	$465,559	$166,004	$118,218	$3,051	$30,554	$493,254	$88,973	$1,399,154	$16,364
Base Power Supply												
Total Purchased Power	$113,577,435	$44,124,548	$11,898,120	$21,346,907	$8,685,628	$6,957,934	$310,248	$1,294,969	$16,310,784	$2,648,296	$43,701,075	$423,740
Total Production	$193,446,058	$78,917,690	$19,311,379	$34,158,751	$13,756,775	$11,038,142	$448,053	$1,935,068	$28,657,666	$5,222,534	$78,077,511	$840,481
Transmission												
Op. Supervision & Engineering	$4,871,678	$2,258,644	$434,021	$742,860	$264,880	$188,632	$4,869	$48,753	$787,051	$141,968	$2,232,532	$26,112
System Planning	$5,674,457	$2,630,835	$505,541	$865,272	$308,529	$219,716	$5,671	$56,787	$916,745	$165,362	$2,600,420	$30,414
Load Dispatching	$1,737,795	$805,690	$154,821	$264,988	$94,486	$67,288	$1,737	$17,391	$280,752	$50,642	$796,375	$9,314
Transmission Station Expense	$1,413,641	$655,403	$125,942	$215,560	$76,862	$54,736	$1,413	$14,147	$228,383	$41,196	$647,826	$7,577
Transmission Line Maintenance	$668,203	$309,797	$59,531	$101,891	$36,331	$25,873	$668	$6,687	$107,952	$19,472	$306,216	$3,581
Transmission TROW Maintenance	$1,625,453	$753,605	$144,813	$247,858	$88,378	$62,938	$1,625	$16,267	$262,602	$47,368	$744,893	$8,712
Wheeling	$7,324,000	$3,395,608	$652,500	$1,116,803	$398,217	$283,586	$7,320	$73,294	$1,183,239	$213,432	$3,356,353	$39,256
Rents	$4,187,092	$1,941,251	$373,031	$638,471	$227,658	$162,125	$4,185	$41,902	$676,451	$122,018	$1,918,809	$22,442
Total Transmission	$27,502,319	$12,750,833	$2,450,199	$4,193,704	$1,495,342	$1,064,894	$27,486	$275,228	$4,443,175	$801,458	$12,603,424	$147,409
Distribution												
Distribution Line Maintenance	$5,333,920	$4,303,967	$549,883	$225,849	$58,598			$56,563	$139,060		$4,266,774	$37,193
Distribution ROW Maintenance	$5,295,302	$4,272,806	$545,902	$224,214	$58,174			$56,153	$138,053		$4,235,882	$36,924
Meter Expenses	$745,438	$644,847	$82,974	$11,076	$232	$23	$16	$6,225	$35	$9	$640,095	$4,896
Distribution Station Expense	$1,792,796	$915,935	$185,530	$273,549	$110,763			$39,832	$267,187		$900,669	$15,266
Street Lighting	$70,214						$70,214					
Other Plant	$623,734	$423,642	$64,321	$54,311	$19,079	$1	$7,088	$9,433	$45,860	$0	$418,965	$4,681
Total Distribution	$13,861,404	$10,561,196	$1,428,610	$788,999	$246,846	$24	$77,319	$168,207	$590,195	$9	$10,462,385	$98,959
Total Operation & Maintenance	$234,809,780	$102,229,720	$23,190,189	$39,141,453	$15,498,963	$12,103,060	$552,858	$2,378,502	$33,691,036	$6,024,001	$101,143,320	$1,086,849
Customer Service, Accounts, & Sales												
Supervision & Administration	$2,067,801	$1,574,785	$182,525	$21,179	$173,493	$18,262	$15,951	$13,120	$54,787	$13,697	$1,199,237	$17,806
Meter Reading	$69,044	$50,652	$5,871	$681	$7,269	$765	$513	$422	$2,296	$574	$50,279	$747
Customer Billing	$1,614,921	$1,184,751	$137,318	$15,933	$170,031	$17,898	$12,001	$9,871	$53,694	$13,424	$1,176,020	$17,462
Credit & Collections	$1,073,103	$934,559	$108,320	$12,569	$268	$28	$9,466	$7,786	$85	$21		
Customer Assistance	$2,513,659	$1,844,090	$213,739	$24,801	$264,657	$27,859	$18,679	$15,364	$83,576	$20,894	$1,830,501	$27,179
Energy Management Promotion												
Total Customer Service, Accounts & Sales	$7,338,528	$5,588,838	$647,774	$75,163	$615,720	$64,813	$56,611	$46,563	$194,438	$48,609	$4,256,037	$63,194
Total O&M w/o Purchased Power Supply & A&G	$65,401,172	$35,626,031	$6,229,088	$8,082,686	$3,564,546	$2,081,989	$201,433	$676,163	$7,683,351	$1,255,885	$33,979,691	$376,915
Administrative & General												
Executive & Senior Management	$510,221	$278,905	$50,576	$65,511	$24,404	$12,142	$7,038	$6,666	$58,408	$6,572	$275,807	$3,100
Legal & Regulatory	$520,753	$284,662	$51,620	$66,863	$24,908	$12,393	$7,184	$6,804	$59,614	$6,707	$281,500	$3,164
Human Resources	$1,316,512	$719,651	$130,500	$169,035	$62,969	$31,330	$18,161	$17,200	$150,708	$16,957	$711,658	$8,000
Finance & Accounting	$1,265,021	$691,505	$125,396	$162,424	$60,506	$30,104	$17,451	$16,527	$144,814	$16,293	$683,824	$7,687
Office Services												
Information Services	$2,271,421	$1,241,639	$225,156	$291,643	$108,643	$54,054	$31,333	$29,676	$260,022	$29,256	$1,227,848	$13,802

FortisBC 2025 COSA for Electric Service **Prepared By EES Consulting, Inc.**

REVENUE REQUIREMENT COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 3.3, Cont'd

Materials Management												
Other	-$3,341,014	-$1,826,316	-$331,180	-$428,974	-$159,802	-$79,508	-$46,088	-$43,650	-$382,464	-$43,032	-$1,806,030	-$20,302
Executive & Senior Management Expenses	$25,745	$14,073	$2,552	$3,306	$1,231	$613	$355	$336	$2,947	$332	$13,917	$156
Legal Expenses	$643,628	$351,830	$63,800	$82,640	$30,785	$15,317	$8,879	$8,409	$73,680	$8,290	$347,922	$3,911
Human Resources Expenses	$79,576	$43,499	$7,888	$10,217	$3,806	$1,894	$1,098	$1,040	$9,109	$1,025	$43,016	$484
Regulatory & Finance Expenses	$623,734	$340,955	$61,828	$80,085	$29,833	$14,843	$8,604	$8,149	$71,402	$8,034	$337,168	$3,790
Information Services Expenses	$2,260,889	$1,235,881	$224,112	$290,290	$108,139	$53,804	$31,188	$29,538	$258,816	$29,120	$1,222,154	$13,738
Materials Management	$407,241	$222,612	$40,368	$52,288	$19,478	$9,691	$5,618	$5,321	$46,619	$5,245	$220,140	$2,475
Other Expenses	$306,601	$167,599	$30,392	$39,366	$14,665	$7,296	$4,229	$4,006	$35,098	$3,949	$165,737	$1,863
Special Services, Insurance, General, and Transportati	$7,667,363	$4,220,983	$764,639	$988,553	$368,189	$182,465	$61,684	$100,868	$881,228	$98,755	$4,174,093	$46,928
Other												
Total Administrative & General	$14,557,692	$7,987,479	$1,447,647	$1,873,247	$697,755	$346,438	$156,734	$190,889	$1,670,002	$187,502	$7,898,754	$88,798
Total O&M plus A&G	$256,706,000	$115,806,036	$25,285,609	$41,089,863	$16,812,437	$12,514,310	$766,202	$2,615,954	$35,555,476	$6,260,112	$113,298,111	$1,238,840
Depreciation												
Generation Plant	$7,643,000	$3,078,069	$779,227	$1,384,443	$552,272	$435,843	$18,316	$85,207	$1,123,888	$185,736	$3,047,257	$30,827
Transmission Plant	$13,036,000	$6,043,849	$1,161,386	$1,987,800	$708,787	$504,756	$13,028	$130,457	$2,106,049	$379,888	$5,973,978	$69,872
Distribution Plant	$37,354,000	$25,370,929	$3,852,009	$3,252,548	$1,142,571	$43	$424,502	$564,941	$2,746,441	$16	$25,090,870	$280,322
General Plant And Deferred Charges	$14,020,000	$8,149,028	$1,394,086	$1,660,303	$605,391	$263,199	$102,987	$185,238	$1,503,405	$156,363	$8,059,157	$89,935
Amortization & Other	-$7,264,000	-$3,150,638	-$715,745	-$1,209,996	-$488,264	-$375,154	-$18,843	-$73,430	-$1,044,980	-$186,952	-$3,098,154	-$33,824
Total Depreciation	$64,789,000	$39,491,237	$6,470,963	$7,075,100	$2,520,757	$828,686	$539,991	$892,413	$6,434,803	$535,051	$39,073,108	$437,132
Taxes												
Taxes												
Property	$19,276,000	$11,154,040	$1,921,033	$2,302,077	$842,796	$377,704	$139,332	$253,738	$2,067,888	$217,391	$11,031,602	$122,525
Total Property Taxes	$19,276,000	$11,154,040	$1,921,033	$2,302,077	$842,796	$377,704	$139,332	$253,738	$2,067,888	$217,391	$11,031,602	$122,525
Return and Income Taxes												
Incentive Adjustments												
Income Tax	$12,484,000	$6,810,192	$1,236,391	$1,622,222	$606,789	$306,693	$100,612	$161,579	$1,466,821	$172,701	$6,726,905	$76,166
Return on Rate Base	$116,085,000	$63,325,950	$11,496,835	$15,084,558	$5,642,348	$2,851,847	$935,560	$1,502,476	$13,639,528	$1,605,899	$62,551,491	$708,248
Interest on Non Rate Base Deferral Account												
Total Return and Income Taxes	$128,569,000	$70,136,142	$12,733,226	$16,706,780	$6,249,137	$3,158,540	$1,036,172	$1,664,055	$15,106,349	$1,778,600	$69,278,396	$784,415
Revenue Requirement Before Other Revenues	$469,340,000	$236,587,455	$46,410,831	$67,173,820	$26,425,127	$16,879,240	$2,481,697	$5,426,160	$59,164,515	$8,791,155	$232,681,217	$2,582,913
Revenue Req. Before Taxes and Other Revenues	$450,064,000	$225,433,415	$44,489,798	$64,871,742	$25,582,331	$16,501,536	$2,342,365	$5,172,422	$57,096,627	$8,573,764	$221,649,615	$2,460,387
Other Revenues												
Electric Apparatus Rental	$6,199,000	$5,002,004	$639,066	$262,478	$68,102			$65,737	$161,613		$4,958,779	$43,225
Rate 38 Revenue	$3,574,198	$1,949,773	$353,982	$464,446	$173,725	$87,807	$28,805	$46,260	$419,954	$49,445	$1,925,928	$21,807
Rate 37 Revenue	$2,092,500	$1,141,487	$207,237	$271,908	$101,707	$51,406	$16,864	$27,083	$245,860	$28,947	$1,127,527	$12,767
Contract Revenue	$2,260,000	$910,171	$230,414	$409,374	$163,304	$128,877	$5,416	$25,195	$332,328	$54,921	$901,060	$9,115
Transmission Access Revenue	$1,723,000	$798,830	$153,503	$262,732	$93,682	$66,715	$1,722	$17,243	$278,362	$50,211	$789,595	$9,235
Fortis Pacific Holdings												
Connection Charges	$561,000	$488,572	$56,628	$6,571	$140	$15	$4,949	$4,071	$44	$11		
Late Payment Charges	$962,000	$837,800	$97,105	$11,267	$240	$25	$8,486	$6,980	$76	$19		
Sundry Revenue	$388,000	$224,008	$38,322	$45,640	$16,642	$7,235	$5,436	$5,092	$41,327	$4,298	$221,538	$2,472
Investment Income												
Total Other Revenues	$17,759,698	$11,352,647	$1,776,257	$1,734,416	$617,542	$342,080	$71,678	$197,661	$1,479,565	$187,852	$9,924,428	$98,621
REVENUE REQUIREMENT for COST ALLOCATION	$451,580,302	$225,234,808	$44,634,574	$65,439,404	$25,807,585	$16,537,160	$2,410,019	$5,228,499	$57,684,950	$8,603,303	$222,756,789	$2,484,292

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4

	Total Expenses	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Operation & Maintenance Expense												
Op. Supervision & Engineering												
Water for Power												
Structures												
Dams & Waterways												
Electric Plant												
Other Plant												
Purchased Power Supply/Other												
Purchased Power - Energy Charges												
Purchased Power - Demand Charges												
System Control												
Base Power Supply												
Total Purchased Power												
Total Production												
Transmission												
Op. Supervision & Engineering												
System Planning												
Load Dispatching												
Transmission Station Expense												
Transmission Line Maintenance												
Transmission TROW Maintenance												
Wheeling												
Rents												
Total Transmission												
Distribution												
Distribution Line Maintenance												
Distribution ROW Maintenance												
Meter Expenses												
Distribution Station Expense												
Street Lighting	$70,214						$70,214					
Other Plant	$7,088						$7,088					
Total Distribution	$77,302						$77,302					
Total Operation & Maintenance	$77,302						$77,302					
Customer Service, Accounts, & Sales												
Supervision & Administration												
Meter Reading												
Customer Billing												
Credit & Collections												
Customer Assistance												
Energy Management Promotion												
Total Customer Service, Accounts & Sales												
Total O&M w/o Purchased Power Supply & A&G	$77,302						$77,302					
Administrative & General												
Executive & Senior Management	$2,975						$2,975					
Legal & Regulatory	$3,037						$3,037					
Human Resources	$7,677						$7,677					
Finance & Accounting	$7,377						$7,377					
Office Services												
Information Services	$13,245						$13,245					

FortisBC 2025 COSA for Electric Service — **Prepared By EES Consulting, Inc.**

REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.4, Cont'd

Materials Management												
Other	-$19,482						-$19,482					
Executive & Senior Management Expenses	$150						$150					
Legal Expenses	$3,753						$3,753					
Human Resources Expenses	$464						$464					
Regulatory & Finance Expenses	$3,637						$3,637					
Information Services Expenses	$13,184						$13,184					
Materials Management	$2,375						$2,375					
Other Expenses	$1,788						$1,788					
Special Services, Insurance, General, and Transportation	$44,710	$29,733	$4,607	$4,091	$1,456	$0	$626	$695	$3,502	$0	$29,396	$337
Other												
Total Administrative & General	$84,889	$29,733	$4,607	$4,091	$1,456	$0	$40,805	$695	$3,502	$0	$29,396	$337
Total O&M plus A&G	$162,191	$29,733	$4,607	$4,091	$1,456	$0	$118,106	$695	$3,502	$0	$29,396	$337
Depreciation												
Generation Plant												
Transmission Plant												
Distribution Plant	$424,472						$424,472					
General Plant And Deferred Charges	$94,115						$94,115					
Amortization & Other	-$2,391	-$438	-$68	-$60	-$21	$0	-$1,741	-$10	-$52	$0	-$433	-$5
Total Depreciation	$516,196	-$438	-$68	-$60	-$21	$0	$516,846	-$10	-$52	$0	-$433	-$5
Taxes												
Taxes												
Property	$126,253						$126,253					
Total Property Taxes	$126,253						$126,253					
Return and Income Taxes												
Incentive Adjustments												
Income Tax	$89,069	$322	$50	$44	$16	$0	$88,591	$8	$38	$0	$319	$4
Return on Rate Base	$828,228	$2,997	$464	$412	$147	$0	$823,784	$70	$353	$0	$2,963	$34
Interest on Non Rate Base Deferral Account												
Total Return and Income Taxes	$917,297	$3,319	$514	$457	$163	$0	$912,376	$78	$391	$0	$3,282	$38
Revenue Requirement Before Other Revenues	$1,721,937	$32,613	$5,053	$4,487	$1,598	$0	$1,673,581	$762	$3,842	$0	$32,244	$370
Revenue Req. Before Taxes and Other Revenues	$1,595,684	$32,613	$5,053	$4,487	$1,598	$0	$1,547,328	$762	$3,842	$0	$32,244	$370
Other Revenues												
Electric Apparatus Rental												
Rate 38 Revenue	$25,501	$13,911	$2,526	$3,314	$1,239	$626	$206	$330	$2,996	$353	$13,741	$156
Rate 37 Revenue	$14,929	$8,144	$1,479	$1,940	$726	$367	$120	$193	$1,754	$207	$8,045	$91
Contract Revenue												
Transmission Access Revenue												
Fortis Pacific Holdings												
Connection Charges												
Late Payment Charges												
Sundry Revenue	$2,605						$2,605					
Investment Income												
Total Other Revenues	$43,035	$22,055	$4,004	$5,254	$1,965	$993	$2,930	$523	$4,750	$559	$21,785	$247
REVENUE REQUIREMENT for COST ALLOCATION	$1,678,902	$10,558	$1,049	-$767	-$368	-$993	$1,670,651	$239	-$909	-$559	$10,459	$123

FortisBC 2025 COSA for Electric Service

INPUT RATE BASE
Schedule 4.1

FERC Account		2021 Cost, $	2022 Cost, $	Mid-year Cost, $	Function	Classification Factor	Classification Method
	Hydraulic Production						
330.00	Land & Rights	**$962,000**	**$962,000**	$962,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
331.00	Structures & Improvements	**$20,134,000**	**$21,008,000**	$20,571,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
332.00	Reservoirs, Dams, & Waterways	**$81,385,000**	**$102,672,000**	$92,028,500	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
333.00	Water Wheels, Turbines, & Generators	**$121,049,000**	**$122,271,000**	$121,660,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
334.00	Accessory Electric Equipment	**$50,585,000**	**$51,724,000**	$51,154,500	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
335.00	Misc. Power Plant Equipment	**$45,994,000**	**$45,994,000**	$45,994,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
336.00	Roads, RR, & Bridges	**$1,287,000**	**$1,287,000**	$1,287,000	P	20D/80E	20% Demand & 80% Energy (per Equivalent BCH Purchase)
	Total Hydraulic Production	$321,396,000	$345,918,000	$333,657,000			
	Total Production Plant	$321,396,000	$345,918,000	$333,657,000	14%		
	Transmission Plant						
350.10	Land & Rights - R/W	**$9,191,000**	**$9,219,000**	$9,205,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
350.10	Land & Rights - Clearing	**$8,417,000**	**$8,449,000**	$8,433,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
353.00	Station Equipment	**$245,873,000**	**$254,432,000**	$250,152,500	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
355.00	Poles Towers & Fixtures	**$124,586,000**	**$129,294,000**	$126,940,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
356.00	Conductors & Devices	**$122,392,000**	**$127,074,000**	$124,733,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
359.00	Roads, Railroads & Bridges	**$1,121,000**	**$1,121,000**	$1,121,000	T	TCP2	2 Coincident Utility Peak (Sum 2 Winter & 2 Summer)
	Total Transmission Plant	$511,580,000	$529,589,000	$520,584,500	22%		
	Distribution Plant						
360.10	Land & Rights - R/W	**$8,448,000**	**$8,889,000**	$8,668,500	D	NCPP	Non-Coincident Peak - Primary
360.10	Land & Rights - Clearing	**$12,094,000**	**$12,557,000**	$12,325,500	D	NCPP	Non-Coincident Peak - Primary
362.00	Station Equipment	**$275,607,000**	**$282,640,000**	$279,123,500	D	NCPP	Non-Coincident Peak - Primary
363.00					D	NCPP	Non-Coincident Peak - Primary
364.00	Poles, Towers, & Fixtures	**$249,149,000**	**$262,448,000**	$255,798,500	D	MINSYSP	Minimum System - Poles, Towers & Fixtures
365.00	Conductors & Devices	**$401,333,000**	**$421,941,000**	$411,637,000	D	MINSYSC	Minimum System - Overhead and Underground Conduit
366.00					D	MINSYSC	Minimum System - Overhead and Underground Conduit
367.00					D	MINSYSC	Minimum System - Overhead and Underground Conduit
368.00	Line Transformers	**$197,758,000**	**$209,706,000**	$203,732,000	D	MINSYST	Minimum System - Transformers
369.00	Services	**$3,431,000**	**$3,431,000**	$3,431,000	D	CUSTM	Customers Weighted for Meters and Services
370.00	Meters/AMI Meters	**$41,431,000**	**$41,972,000**	$41,701,500	D	CUSTM	Customers Weighted for Meters and Services
371.00	Installation on Customer Premises	**$1,000**	**$1,000**	$1,000	D	CUSTM	Customers Weighted for Meters and Services
372.00	EV Stations Kiosks & Charger Connectors		**$5,281,000**	$2,640,500	D	DA2	Direct Assignment to Commercial
373.00	Street Lights and Signal Systems	**$14,003,000**	**$14,021,000**	$14,012,000	D	DA1	Direct Assignment for Streetlights
	Total Distribution Plant	$1,203,255,000	$1,262,887,000	$1,233,071,000	53%		
	Total Transmission & Distribution	$1,714,835,000	$1,792,476,000	$1,753,655,500			

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FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

INPUT RATE BASE
Schedule 4.1, Cont'd

	General Plant						
389.00	Land & Rights	**$11,105,000**	**$11,105,000**	$11,105,000	SS	LABOR	On the Basis of Labor Ratios
390.00	Structures - Frame & Iron				SS	LABOR	On the Basis of Labor Ratios
390.10	Structures - Masonry	**$66,563,000**	**$51,641,000**	$59,102,000	SS	LABOR	On the Basis of Labor Ratios
391.00	Operation Building, Furniture & Equipment	**$8,268,000**	**$26,849,000**	$17,558,500	SS	LABOR	On the Basis of Labor Ratios
391.10	Computer Equipment & Software	**$60,520,000**	**$63,704,000**	$62,112,000	SS	LABOR	On the Basis of Labor Ratios
391.20	AMI Software	**$9,583,000**	**$9,581,000**	$9,582,000	SS	CUSTM	Customers Weighted for Meters and Services
392.00	Transportation Equipment	**$32,639,000**	**$35,025,000**	$33,832,000	SS	LABOR	On the Basis of Labor Ratios
394.00	Tool and Work Environment	**$8,869,000**	**$8,434,000**	$8,651,500	SS	LABOR	On the Basis of Labor Ratios
397.00	Communication Structures & Equipment	**$20,025,000**	**$23,706,000**	$21,865,500	SS	LABOR	On the Basis of Labor Ratios
397.10	AMI Communications & Equipment	**$4,970,000**	**$4,970,000**	$4,970,000	SS	CUSTM	Customers Weighted for Meters and Services
						LABOR	On the Basis of Labor Ratios
	Total General Plant	$222,542,000	$235,015,000	$228,778,500	10%		
	Total Plant Before General Plant & Intangible	$2,036,231,000	$2,138,394,000	$2,087,312,500			
	Total Gross Plant in Service	**$2,258,773,000**	$2,373,409,000	$2,316,091,000			
	Less: Accumulated Depreciation						
	Hydraulic Production Plant	**$61,101,000**	$66,731,000	$63,916,000	P		On the Basis of Hydraulic Production Plant
	Transmission Plant	**$163,758,000**	$174,145,000	$168,951,500	T	RBT	On the Basis of Transmission Rate Base
	Distribution Plant	**$342,183,000**	$366,558,000	$354,370,500	D	RBD	On the Basis of Distribution Rate Base
	General Plant	**$80,529,000**	$83,311,000	$81,920,000	SS	RBGP	On the Basis of General Plant Rate Base
	CWIP				SS		On the Basis of CWIP
	Total Accumulated Depreciation	$647,571,000	$690,745,000	$669,158,000			
	Total Net Plant	$1,611,202,000	$1,682,664,000	$1,646,933,000			
	Working Capital						
	Allowance for Working Capital	-$6,800,000	-$6,324,000	-$6,562,000	SS	OM	On the Basis of All O&M
	Adjustment for Capital Additions				SS	OM	On the Basis of All O&M
	Total Working Capital	-$6,800,000	-$6,324,000	-$6,562,000			
	Distribution Plant CIAC	**-$232,300,000**	-$231,112,000	-$231,706,000	D		On the Basis of Poles, Conductors and Transformers
	Total Contributions	-$232,300,000	-$231,112,000	-$231,706,000			
	SUB-TOTAL RATE BASE	$1,372,102,000	$1,445,228,000	$1,408,665,000			
	Other Rate Base Items						
	Accumulated Amortization Ending - CIAC	$82,745,000	$87,051,000	$84,898,000	SS	OM	On the Basis of All O&M
	Adjustment for timing of Capital additions	$99,000	$7,438,000	$3,768,500	SS	OM	On the Basis of All O&M
	Capital Work in Progress, No AFUDC	$34,306,000	$25,574,000	$29,940,000	D	RBGP	On the Basis of General Plant Rate Base
	Unamortized Deferred Charges	$25,132,000	$30,658,000	$27,895,000	SS	DSM	Classified 72% Energy, 17% Demand & 12% T&D
	CPCNs/Other	-$13,581,000	-$21,721,000	-$17,651,000	SS	OM	On the Basis of All O&M
	Utility Plant Acquistion Adjustment	$4,935,000	$4,749,000	$4,842,000	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total Other Rate Base Items	$133,636,000	$133,749,000	$133,692,500			
	TOTAL RATE BASE	$1,505,738,000	$1,578,977,000	$1,542,357,500			

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FortisBC 2025 COSA for Electric Service

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

		Production			Transmission			Distribution			
Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Hydraulic Production											
Land & Rights	$962,000	$171,242	$790,758								
Structures & Improvements	$20,571,000	$3,661,775	$16,909,225								
Reservoirs, Dams, & Waterways	$92,028,500	$16,381,684	$75,646,816								
Water Wheels, Turbines, & Generators	$121,660,000	$21,656,287	$100,003,713								
Accessory Electric Equipment	$51,154,500	$9,105,841	$42,048,659								
Misc. Power Plant Equipment	$45,994,000	$8,187,237	$37,806,763								
Roads, RR, & Bridges	$1,287,000	$229,095	$1,057,905								
Total Hydraulic Production	$333,657,000	$59,393,160	$274,263,840								
Total Production Plant	$333,657,000	$59,393,160	$274,263,840								
Transmission Plant											
Land & Rights - R/W	$9,205,000				$9,205,000						
Land & Rights - Clearing	$8,433,000				$8,433,000						
Station Equipment	$250,152,500				$250,152,500						
Poles Towers & Fixtures	$126,940,000				$126,940,000						
Conductors & Devices	$124,733,000				$124,733,000						
Roads, Railroads & Bridges	$1,121,000				$1,121,000						
Total Transmission Plant	$520,584,500				$520,584,500						
Distribution Plant											
Land & Rights - R/W	$8,668,500							$8,668,500			
Land & Rights - Clearing	$12,325,500							$12,325,500			
Station Equipment	$279,123,500							$279,123,500			
Poles, Towers, & Fixtures	$255,798,500							$35,811,790		$219,986,710	
Conductors & Devices	$411,637,000							$117,951,294		$293,685,706	
Line Transformers	$203,732,000							$116,127,240		$87,604,760	
Services	$3,431,000									$3,431,000	
Meters/AMI Meters	$41,701,500									$41,701,500	
Installation on Customer Premises	$1,000									$1,000	
EV Stations Kiosks & Charger Connectors	$2,640,500									$2,640,500	
Street Lights and Signal Systems	$14,012,000										$14,012,000
Total Distribution Plant	$1,233,071,000							$570,007,824		$649,051,176	$14,012,000
Total Transmission & Distribution	$1,753,655,500				$520,584,500			$570,007,824		$649,051,176	$14,012,000

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FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2, Cont'd

General Plant							
Land & Rights	$11,105,000	$534,126	$2,466,468	$2,405,848	$2,634,255	$2,999,548	$64,756
Structures - Frame & Iron							
Structures - Masonry	$59,102,000	$2,842,673	$13,126,806	$12,804,180	$14,019,786	$15,963,918	$344,636
Operation Building, Furniture & Equipment	$17,558,500	$844,524	$3,899,818	$3,803,969	$4,165,111	$4,742,690	$102,387
Computer Equipment & Software	$62,112,000	$2,987,448	$13,795,340	$13,456,283	$14,733,798	$16,776,943	$362,188
AMI Software	$9,582,000					$9,582,000	
Transportation Equipment	$33,832,000	$1,627,243	$7,514,232	$7,329,549	$8,025,403	$9,138,291	$197,281
Tool and Work Environment	$8,651,500	$416,118	$1,921,535	$1,874,308	$2,052,252	$2,336,839	$50,449
Communication Structures & Equipment	$21,865,500	$1,051,681	$4,856,421	$4,737,061	$5,186,789	$5,906,045	$127,502
AMI Communications & Equipment	$4,970,000					$4,970,000	
Total General Plant	$228,778,500	$10,303,813	$47,580,620	$46,411,200	$50,817,393	$72,416,274	$1,249,199
Total Plant Before General Plant & Intangible	$2,087,312,500	$59,393,160	$274,263,840	$520,584,500	$570,007,824	$649,051,176	$14,012,000
Total Gross Plant in Service	$2,316,091,000	$69,696,974	$321,844,459	$566,995,700	$620,825,217	$721,467,450	$15,261,199
Less: Accumulated Depreciation							
Hydraulic Production Plant	$63,916,000	$11,377,472	$52,538,528				
Transmission Plant	$168,951,500			$168,951,500			
Distribution Plant	$354,370,500				$163,813,728	$186,529,883	$4,026,889
General Plant	$81,920,000	$3,689,544	$17,037,459	$16,618,719	$18,196,469	$25,930,501	$447,308
CWIP							
Total Accumulated Depreciation	$669,158,000	$15,067,016	$69,575,987	$185,570,219	$182,010,197	$212,460,385	$4,474,196
Total Net Plant	$1,646,933,000	$54,629,957	$252,268,472	$381,425,482	$438,815,020	$509,007,066	$10,787,003
Working Capital							
Allowance for Working Capital	-$6,562,000	-$1,848,412	-$3,557,636	-$768,580	-$99,745	-$285,465	-$2,160
Adjustment for Capital Additions							
Total Working Capital	-$6,562,000	-$1,848,412	-$3,557,636	-$768,580	-$99,745	-$285,465	-$2,160
Distribution Plant CIAC	-$231,706,000				-$71,783,219	-$159,922,781	
Total Contributions	-$231,706,000				-$71,783,219	-$159,922,781	
SUB-TOTAL RATE BASE	$1,408,665,000	$52,781,545	$248,710,836	$380,656,901	$366,932,056	$348,798,819	$10,784,843
Other Rate Base Items							
Accumulated Amortization Ending - CIAC	$84,898,000	$23,914,431	$46,028,071	$9,943,759	$1,290,489	$3,693,301	$27,949
Adjustment for timing of Capital additions	$3,768,500	$1,061,527	$2,043,120	$441,389	$57,283	$163,940	$1,241
Capital Work in Progress, No AFUDC	$29,940,000	$1,348,449	$6,226,825	$6,073,785	$6,650,418	$9,477,041	$163,481
Unamortized Deferred Charges	$27,895,000	$4,630,570	$19,972,820	$977,137	$1,082,202	$1,232,271	
CPCNs/Other	-$17,651,000	-$4,972,009	-$9,569,619	-$2,067,390	-$268,303	-$767,868	-$5,811
Utility Plant Acquistion Adjustment	$4,842,000	$137,776	$636,218	$1,207,615	$1,322,264	$1,505,623	$32,504
Total Other Rate Base Items	$133,692,500	$26,120,744	$65,337,435	$16,576,294	$10,134,353	$15,304,309	$219,364
TOTAL RATE BASE	$1,542,357,500	$78,902,289	$314,048,271	$397,233,196	$377,066,409	$364,103,128	$11,004,207

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FortisBC 2025 COSA for Electric Service

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Account Description	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Hydraulic Production												
Land & Rights	$962,000	$387,427	$98,079	$174,255	$69,513	$54,858	$2,305	$10,725	$141,460	$23,378	$383,549	$3,880
Structures & Improvements	$20,571,000	$8,284,567	$2,097,275	$3,726,205	$1,486,430	$1,173,065	$49,296	$229,332	$3,024,924	$499,905	$8,201,640	$82,971
Reservoirs, Dams, & Waterways	$92,028,500	$37,062,676	$9,382,582	$16,669,927	$6,649,841	$5,247,941	$220,536	$1,025,965	$13,532,605	$2,236,427	$36,691,682	$371,186
Water Wheels, Turbines, & Generators	$121,660,000	$48,996,183	$12,403,602	$22,037,340	$8,790,969	$6,937,682	$291,545	$1,356,306	$17,889,858	$2,956,515	$48,505,734	$490,701
Accessory Electric Equipment	$51,154,500	$20,601,473	$5,215,355	$9,266,062	$3,696,348	$2,917,094	$122,586	$570,287	$7,522,166	$1,243,129	$20,395,254	$206,326
Misc. Power Plant Equipment	$45,994,000	$18,523,183	$4,689,226	$8,331,295	$3,323,458	$2,622,816	$110,220	$512,756	$6,763,325	$1,117,721	$18,337,767	$185,511
Roads, RR, & Bridges	$1,287,000	$518,314	$131,214	$233,126	$92,997	$73,391	$3,084	$14,348	$189,251	$31,276	$513,126	$5,191
Total Hydraulic Production	$333,657,000	$134,373,823	$34,017,333	$60,438,211	$24,109,555	$19,026,846	$799,573	$3,719,720	$49,063,590	$8,108,351	$133,028,751	$1,345,765
Total Production Plant	$333,657,000	$134,373,823	$34,017,333	$60,438,211	$24,109,555	$19,026,846	$799,573	$3,719,720	$49,063,590	$8,108,351	$133,028,751	$1,345,765
Transmission Plant												
Land & Rights - R/W	$9,205,000	$4,267,692	$820,079	$1,403,629	$500,489	$356,419	$9,200	$92,118	$1,487,126	$268,247	$4,218,354	$49,338
Land & Rights - Clearing	$8,433,000	$3,909,771	$751,301	$1,285,910	$458,515	$326,527	$8,428	$84,393	$1,362,405	$245,750	$3,864,571	$45,200
Station Equipment	$250,152,500	$115,977,597	$22,286,248	$38,144,617	$13,601,162	$9,685,941	$250,008	$2,503,384	$40,413,730	$7,289,812	$114,636,807	$1,340,790
Poles Towers & Fixtures	$126,940,000	$58,852,885	$11,309,167	$19,356,503	$6,901,916	$4,915,135	$126,867	$1,270,343	$20,507,966	$3,699,218	$58,172,500	$680,385
Conductors & Devices	$124,733,000	$57,829,659	$11,112,544	$19,019,968	$6,781,918	$4,829,680	$124,661	$1,248,257	$20,151,411	$3,634,903	$57,161,103	$668,555
Roads, Railroads & Bridges	$1,121,000	$519,727	$99,871	$170,936	$60,950	$43,405	$1,120	$11,218	$181,105	$32,668	$513,718	$6,008
Total Transmission Plant	$520,584,500	$241,357,330	$46,379,211	$79,381,564	$28,304,950	$20,157,106	$520,284	$5,209,714	$84,103,743	$15,170,599	$238,567,053	$2,790,277
Distribution Plant												
Land & Rights - R/W	$8,668,500	$4,428,713	$897,070	$1,322,662	$535,562			$192,594	$1,291,900		$4,354,900	$73,813
Land & Rights - Clearing	$12,325,500	$6,297,065	$1,275,519	$1,880,656	$761,500			$273,844	$1,836,916		$6,192,112	$104,953
Station Equipment	$279,123,500	$142,603,442	$28,885,425	$42,589,366	$17,244,950			$6,201,475	$41,598,843		$140,226,677	$2,376,765
Poles, Towers, & Fixtures	$255,798,500	$209,126,361	$26,323,477	$9,674,006	$2,403,321			$2,588,124	$5,683,212		$207,361,561	$1,764,800
Conductors & Devices	$411,637,000	$310,181,342	$42,817,801	$26,770,970	$7,807,013			$5,369,996	$18,689,879		$307,158,787	$3,022,555
Line Transformers	$203,732,000	$125,824,835	$20,986,471	$22,766,069	$8,950,349			$3,645,982	$21,558,295		$124,210,592	$1,614,242
Services	$3,431,000	$2,968,014	$381,903	$50,978	$1,068	$107	$75	$28,653	$160	$40	$2,946,142	$22,534
Meters/AMI Meters	$41,701,500	$36,074,214	$4,641,780	$619,605	$12,985	$1,299	$918	$348,263	$1,949	$487	$35,808,372	$273,883
Installation on Customer Premises	$1,000	$865	$111	$15	$0	$0	$0	$8	$0	$0	$859	$7
EV Stations Kiosks & Charger Connectors	$2,640,500		$946,863	$1,693,637								
Street Lights and Signal Systems	$14,012,000						$14,012,000					
Total Distribution Plant	$1,233,071,000	$837,504,851	$127,156,420	$107,367,962	$37,716,749	$1,406	$14,012,993	$18,648,939	$90,661,154	$527	$828,260,002	$9,253,552
Total Transmission & Distribution	$1,753,655,500	$1,078,862,181	$173,535,631	$186,749,525	$66,021,699	$20,158,512	$14,533,277	$23,858,652	$174,764,897	$15,171,126	$1,066,827,055	$12,043,829

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3, Cont'd

General Plant												
Land & Rights	$11,105,000	$6,194,323	$1,107,903	$1,406,575	$521,933	$264,271	$74,355	$143,713	$1,248,896	$143,031	$6,126,607	$67,762
Structures - Frame & Iron												
Structures - Masonry	$59,102,000	$32,966,849	$5,896,380	$7,485,941	$2,777,786	$1,406,477	$395,726	$764,855	$6,646,758	$761,227	$32,606,458	$360,638
Operation Building, Furniture & Equipment	$17,558,500	$9,794,058	$1,751,744	$2,223,984	$825,247	$417,847	$117,566	$227,229	$1,974,673	$226,152	$9,686,990	$107,141
Computer Equipment & Software	$62,112,000	$34,645,815	$6,196,676	$7,867,192	$2,919,255	$1,478,107	$415,880	$803,808	$6,985,270	$799,996	$34,267,069	$379,005
AMI Software	$9,582,000	$8,015,947	$996,458	$286,464	$59,080	$21	$15	$86,223	$137,785	$8	$7,951,936	$64,140
Transportation Equipment	$33,832,000	$18,871,349	$3,375,289	$4,285,208	$1,590,099	$805,115	$226,527	$437,829	$3,804,831	$435,752	$18,665,048	$206,442
Tool and Work Environment	$8,651,500	$4,825,771	$863,127	$1,095,811	$406,619	$205,884	$57,927	$111,961	$972,969	$111,430	$4,773,016	$52,791
Communication Structures & Equipment	$21,865,500	$12,196,485	$2,181,437	$2,769,515	$1,027,675	$520,343	$146,404	$282,967	$2,459,049	$281,625	$12,063,154	$133,423
AMI Communications & Equipment	$4,970,000	$4,157,718	$516,844	$148,583	$30,644	$11	$8	$44,722	$71,467	$4	$4,124,517	$33,268
Total General Plant	$228,778,500	$131,668,314	$22,885,859	$27,569,272	$10,158,340	$5,098,075	$1,434,408	$2,903,309	$24,301,698	$2,759,226	$130,264,795	$1,404,610
Total Plant Before General Plant & Intangible	$2,087,312,500	$1,213,236,004	$207,552,964	$247,187,736	$90,131,253	$39,185,358	$15,332,849	$27,578,372	$223,828,486	$23,279,477	$1,199,855,806	$13,389,594
Total Gross Plant in Service	$2,316,091,000	$1,344,904,318	$230,438,822	$274,757,008	$100,289,593	$44,283,433	$16,767,257	$30,481,681	$248,130,184	$26,038,703	$1,330,120,601	$14,794,204
Less: Accumulated Depreciation												
Hydraulic Production Plant	$63,916,000	$25,740,917	$6,516,428	$11,577,664	$4,618,474	$3,644,821	$153,168	$712,557	$9,398,719	$1,553,252	$25,483,253	$257,798
Transmission Plant	$168,951,500	$78,330,575	$15,051,999	$25,762,646	$9,186,143	$6,541,826	$168,854	$1,690,771	$27,295,191	$4,923,495	$77,425,013	$905,562
Distribution Plant	$354,370,500	$240,689,314	$36,543,301	$30,856,324	$10,839,362	$404	$4,027,174	$5,359,492	$26,054,978	$152	$238,032,450	$2,659,365
General Plant	$81,920,000	$47,147,211	$8,194,868	$9,871,884	$3,637,454	$1,825,496	$513,627	$1,039,604	$8,701,845	$988,011	$46,644,645	$502,957
CWIP												
Total Accumulated Depreciation	$669,158,000	$391,908,017	$66,306,595	$78,068,518	$28,281,433	$12,012,547	$4,862,822	$8,802,423	$71,450,734	$7,464,910	$387,585,361	$4,325,681
Total Net Plant	$1,646,933,000	$952,996,301	$164,132,227	$196,688,490	$72,008,160	$32,270,886	$11,904,435	$21,679,258	$176,679,450	$18,573,792	$942,535,241	$10,468,523
Working Capital												
Allowance for Working Capital	-$6,562,000	-$2,846,157	-$646,575	-$1,093,060	-$441,077	-$338,899	-$17,022	-$66,333	-$943,992	-$168,885	-$2,798,745	-$30,555
Adjustment for Capital Additions												
Total Working Capital	-$6,562,000	-$2,846,157	-$646,575	-$1,093,060	-$441,077	-$338,899	-$17,022	-$66,333	-$943,992	-$168,885	-$2,798,745	-$30,555
Distribution Plant CIAC	-$231,706,000	-$171,587,071	-$23,971,441	-$15,748,469	-$5,096,202			-$3,086,364	-$12,216,454		-$169,884,427	-$1,702,645
Total Contributions	-$231,706,000	-$171,587,071	-$23,971,441	-$15,748,469	-$5,096,202			-$3,086,364	-$12,216,454		-$169,884,427	-$1,702,645
SUB-TOTAL RATE BASE	$1,408,665,000	$778,563,073	$139,514,212	$179,846,961	$66,470,881	$31,931,987	$11,887,414	$18,526,561	$163,519,005	$18,404,908	$769,852,069	$8,735,324
Other Rate Base Items												
Accumulated Amortization Ending - CIAC	$84,898,000	$36,823,078	$8,365,267	$14,141,824	$5,706,582	$4,384,617	$220,224	$858,210	$12,213,199	$2,185,000	$36,209,670	$395,313
Adjustment for timing of Capital additions	$3,768,500	$1,634,523	$371,322	$627,735	$253,307	$194,627	$9,775	$38,095	$542,126	$96,989	$1,607,295	$17,547
Capital Work in Progress, No AFUDC	$29,940,000	$17,264,086	$2,940,474	$3,425,681	$1,535,129	$709,148	$239,018	$355,634	$3,080,850	$389,980	$16,515,559	$188,642
Unamortized Deferred Charges	$27,895,000	$11,906,080	$2,827,204	$4,781,867	$1,949,688	$1,485,329	$75,899	$303,035	$3,909,968	$655,930	$11,709,549	$123,777
CPCNs/Other	-$17,651,000	-$7,655,824	-$1,739,209	-$2,940,203	-$1,186,446	-$911,598	-$45,786	-$178,429	-$2,539,226	-$454,280	-$7,528,291	-$82,189
Utility Plant Acquistion Adjustment	$4,842,000	$2,842,021	$472,843	$536,354	$237,633	$96,808	$43,729	$59,463	$494,980	$58,169	$2,721,379	$31,693
Total Other Rate Base Items	$133,692,500	$62,813,965	$13,237,901	$20,573,257	$8,495,893	$5,958,931	$542,860	$1,436,009	$17,701,897	$2,931,788	$61,235,161	$674,783
TOTAL RATE BASE	$1,542,357,500	$841,377,038	$152,752,113	$200,420,218	$74,966,773	$37,890,918	$12,430,274	$19,962,569	$181,220,902	$21,336,695	$831,087,230	$9,410,107

FortisBC 2025 COSA for Electric Service

ANALYSIS OF FORECAST POWER PURCHASE EXPENSE
FOR THE YEAR ENDING DECEMBER 31
Schedule 5.1

Purchased Power Supply Summary	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	Totals
Energy Charges	$11,723,354	$10,665,932	$9,427,579	$8,248,848	$7,776,406	$6,257,398	$8,457,461	$10,243,253	$8,979,803	$9,618,233	$10,862,039	$11,317,215	$113,577,522
Total System kWh	399,481,415	339,584,568	320,707,171	282,862,781	268,287,597	247,531,246	311,167,142	328,542,669	263,085,931	256,652,045	356,959,835	424,766,979	3,799,629,380
	$0.0293	$0.0314	$0.0294	$0.0292	$0.0290	$0.0253	$0.0272	$0.0312	$0.0341	$0.0375	$0.0304	$0.0266	$0.0299
Capacity Charges	$7,916,079	$7,295,904	$6,852,319	$1,267,540	$334,616	$3,826,631	$7,429,226	$3,495,724	$911,353	$4,477,879	$7,552,582	$8,756,759	$60,116,611
Total System CP kW	666,217	607,841	511,860	481,918	403,607	496,711	629,312	599,578	575,116	425,358	625,443	776,480	6,799,441
	$11.88	$12.00	$13.39	$2.63	$0.83	$7.70	$11.81	$5.83	$1.58	$10.53	$12.08	$11.28	$8.84

Total Annual		Net Cost	
Combined Costs	$173,694,133	**$173,694,000**	$133
Energy %	113,577,522	$113,577,435	65%
Demand %	60,116,611	$60,116,565	35%

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Energy Amount (GWh)													
Brilliant/Waneta	94	82	64	87	93	85	93	99	68	65	76	80	988
FortisBC	146	118	132	112	112	122	166	170	150	101	112	151	1,594
Demand Amount (MW)													
Brilliant/Waneta	395	395	316	241	176	150	280	375	363	244	360	398	4,687
FortisBC	201	202	196	172	183	175	185	198	186	189	192	208	2,287
Total System Demand (MW)	270	242	204	236	241	231	242	199	199	128	212	281	2,686
System	740	622	573	480	432	503	651	648	521	501	625	738	7,034
% of Total	37%	39%	36%	49%	56%	46%	37%	31%	38%	26%	34%	38%	**38.2%**
Total System Energy (GWh)	366	305	309	263	254	235	295	302	265	284	309	354	3,541
System	394	346	324	278	268	280	314	309	272	292	345	393	3,815
% of Total	93%	88%	95%	95%	95%	84%	94%	98%	97%	97%	90%	90%	93%
Purchased Power Expense ($000)													
Brilliant/Waneta	$9,914	$9,308	$8,111	$5,876	$5,187	$4,462	$7,211	$8,702	$4,176	$7,978	$8,965	$8,131	$88,022
Energy Costs if Using 3808 ($000)													
Brilliant/Waneta	$4,809	$4,192	$3,273	$4,555	$4,878	$4,460	$6,232	$7,784	$5,347	$3,398	$3,974	$4,202	$57,105
FortisBC	$7,448	$6,030	$6,707	$5,878	$5,855	$6,368	$11,142	$13,362	$11,796	$5,262	$5,872	$7,919	$93,639
Demand Costs if Using 3808 ($000)													
Brilliant/Waneta	$3,433	$3,431	$2,749	$2,155	$1,573	$1,342	$2,501	$3,348	$3,241	$2,177	$3,212	$3,557	$32,719
FortisBC	$1,747	$1,756	$1,700	$1,534	$1,637	$1,561	$1,647	$1,770	$1,665	$1,688	$1,715	$1,858	$20,278
Combined Costs if Using 3808 ($000)	$9,194	$7,786	$8,406	$7,412	$7,492	$7,930	$12,789	$15,132	$13,461	$6,950	$7,587	$9,777	$113,917

Resulting Classification Factor	
Energy Component	82%
Demand Component	18%

Adjustment Factor Calculation	Combined 3808 Cost	Actual Cost vs 3808 Cost
Brilliant/Waneta	$89,824	98%

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	TOTAL
Adjusted Energy Costs if Using 3808 ($000)													
Brilliant/Waneta	$4,713	$4,107	$3,207	$4,464	$4,780	$4,371	$6,107	$7,628	$5,240	$3,330	$3,895	$4,117	$55,959
Adjusted Demand Costs if Using 3808 ($000)													
Brilliant/Waneta	$3,364	$3,362	$2,693	$2,112	$1,541	$1,316	$2,451	$3,281	$3,176	$2,134	$3,148	$3,486	$32,063

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3, Cont'd

Analysis of Forecast Power Purchase Expense for Year Ending December 31, 2024

2022	Jan Forecast	Feb Forecast	Mar Forecast	Apr Forecast	May Forecast	Jun Forecast	Jul Forecast	Aug Forecast	Sep Forecast	Oct Forecast	Nov Forecast	Dec Forecast	Total
Energy (GWh)													
FortisBC Resources Energy	**146.215**	**118.392**	**131.673**	**112.373**	**111.930**	**121.746**	**166.403**	**170.291**	**150.336**	**100.600**	**112.255**	**151.384**	**1,594**
													-
Brilliant Base Plant Energy	**81.914**	**58.434**	**55.895**	**75.895**	**79.066**	**72.124**	**79.183**	**85.861**	**66.083**	**62.144**	**62.980**	**64.996**	**845**
Brilliant Upgrade Energy	**0.702**	**-0.642**	**-0.443**	**9.792**	**13.896**	**12.939**	**13.892**	**12.751**	**0.968**	**0.612**	**0.297**	**0.330**	**65**
Total BCH 3808 Energy	137.640	128.760	122.126	64.718	49.033	28.033	35.099	33.328	47.663	120.221	133.200	137.640	**1,037**
BRX Energy	11.800	24.500	8.800	1.400	0.300	0.200		0.600	1.100	2.200	12.700	15.000	**79**
Market Energy	9.491	9.662									17.115	17.015	**53**
Market Capacity - Energy													-
Market Energy Block Purchase				7.600	8.200	8.000							**24**
Market Capacity Block Purchase						31.200	13.728						**45**
Purchase From Self-Generators													-
IPP Generation	0.388	0.367	0.377	0.372	0.358	0.359	0.351	0.351	0.348	0.360	0.371	0.382	**4**
Operating Reserve													-
DSM and Other Customer Savings - Energ	4.787	4.733	4.602	4.436	4.262	4.148	4.093	4.131	4.213	4.367	4.489	4.553	**53**
DSM and Other Loss Reduction	0.394	0.389	0.378	0.365	0.351	0.341	0.337	0.340	0.347	0.359	0.369	0.374	**4**
													-
Loss Recovery	1.138	0.944	0.937	0.973	0.753	0.771	1.010	1.163	0.893	1.047	1.107	1.244	**12**
WEPAS Adjustments													-
FBC Surplus Energy Sales													-
													-
													-
													-
Total Gross Load (GWh)	**394**	**346**	**324**	**278**	**268**	**280**	**314**	**309**	**272**	**292**	**345**	**393**	**3,815**
Surplus Energy													

Capacity (MW)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Peak
FortisBC Resources Capacity	200.98	202.00	195.52	171.85	183.41	174.90	184.52	198.30	186.49	189.10	192.10	208.19	**2,287**	**208**
Waneta Expansion	296.99	296.16	266.60	95.08	63.20	45.79	161.02	302.81	316.14	278.20	302.66	265.36	**2,690**	**316**
WAX RCA	-50.00	-50.00	-50.00	-50.00	-50.00	-45.79	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	**(596)**	**-46**
WAX Firm Energy Sales		-22.77	-40.88					-64.13	-53.01	-126.44	-51.33		**(359)**	
Brilliant Base Plant Capacity	118.10	109.55	98.21	112.15	101.92	95.93	102.02	110.87	114.51	114.60	118.17	118.09	**1,314**	**118**
Brilliant Upgrade Capacity	19.80	19.90	19.90	20.00	19.80	19.50	19.70	20.10	19.60	19.70	20.10	20.00	**238**	**20**
Brilliant Tailrace	1.14	3.00	1.00	2.50	6.00	6.00	5.70	3.60	0.90	0.90	3.40	4.80	**39**	**6**
BCH Billing Capacity	185.00	185.00	164.37	150.00	150.00	200.00	199.79	150.00	150.00	161.59	184.74	185.00	**2,065**	**200**
BCH Peak Usage	132.32	100.00	100.00	101.36	130.20	200.00	199.79	100.00	100.00	100.00	100.00	178.12	**1,542**	**200**
Powerex Capacity Blocks													-	
BRX Capacity	8.92	38.90	21.38	61.69	35.25	28.96	41.75	51.80	14.92	6.97	16.86	40.24	**368**	**62**
Market Purchases - Real Time						77.81	33.00						**111**	**78**
													-	
DSM and Other Customer Savings - Capa	8.39	8.97	7.87	8.13	7.56	7.79	7.54	7.70	7.82	7.84	8.13	8.08	**96**	**9**
FBC Peak Load (MW)	**740**	**622**	**573**	**480**	**432**	**503**	**651**	**648**	**521**	**501**	**625**	**738**	**7,034**	**740**
Planning Reserve Margin													-	
Total Capacity Planning Load (MW)	**740**	**622**	**573**	**480**	**432**	**503**	**651**	**648**	**521**	**501**	**625**	**738**	**7,034**	**740**

Energy Rates (CDN$/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Brilliant Base Plant Rate	48.09	48.09	48.09	48.09	48.09	48.09	48.09	48.09	48.09	48.09	48.09	48.09	**48.09**
Brilliant Upgrade Rate	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	**44.75**
BCH 3808 Energy Rate	50.94	50.94	50.94	52.31	52.31	52.31	66.96	78.46	78.46	52.31	52.31	52.31	**57.55**
BRX Energy Rate	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	**25.00**
Market Energy Rate	123.10	110.33	64.66	74.47	51.57	51.50	82.01	122.52	80.85	68.21	96.40	135.35	**88.41**

Updated Application dated May 15, 2025

Februrary 3rd, 2025

FortisBC 2025 COSA for Electric Service — Prepared By EES Consulting, Inc.

POWER SUPPLY CALCULATIONS IF PURCHASED AT BC HDYRO 3808 RATES
USED FOR CLASSIFICATION OF HYDRO PLANT
Schedule 5.3, Cont'd

Market Capacity - Energy Rate	153.38	130.10	77.92	78.37	68.44	72.63	201.31	257.94	188.02	87.98	115.46	157.45	**132.41**
Market Energy Block Rate				52.57	52.57	52.57							**13.14**
Market Capacity Block Rate	153.38	130.10	77.92	78.37	68.44	72.63	201.31	257.94	188.02	87.98	115.46	157.45	**132.41**
Self-Generator Rate	48.12	48.12	48.12	48.12	48.12	48.12	48.12	48.12	48.12	48.12	48.12	48.12	**48.12**
IPP Rate	55.87	55.87	55.87	55.87	55.87	55.87	55.87	55.87	55.87	55.87	55.87	55.87	**55.87**
Surplus Energy Rate	107.79	96.29	55.20	64.02	43.41	43.35	70.81	107.27	69.77	58.39	83.76	118.82	**76.57**
Operating Reserve Rate	153.38	130.10	77.92	78.37	68.44	72.63	201.31	257.94	188.02	87.98	115.46	157.45	**132.41**
Capacity Rates (CDN$/MW/month)													
BRD Tailrace Capacity Rate	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	**5026**
BCH 3808 Capacity Rate	8,692	8,692	8,692	8,927	8,927	8,927	8,927	8,927	8,927	8,927	8,927	8,927	**8868**
BRX Capacity Rate	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	**3400**
Waneta Expansion Rate	20,066	20,066	20,066	20,066	20,066	20,066	20,066	20,066	20,066	20,066	20,066	20,066	**20066**
Powerex Capacity Rate	-	-	-	-	-	-	-	-	-	-	-	-	
WAX Sales Rates													
WAX Capacity Block ($/MW/Month)													
Exchange Rate (CDN$/USD$)	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	**1.29**
Energy Expense ($000)													
Brilliant Base Plant Expense	3,940.317	3,032.800	2,836.371	3,935.076	3,813.804	3,474.321	3,815.343	4,141.747	3,179.701	2,995.005	3,029.001	3,130.173	**41,324**
Brilliant Upgrade	31.417	(28.732)	(19.826)	438.225	621.894	579.064	621.714	570.651	43.321	27.389	13.292	14.769	**2,913**
BCH 3808 Expense	7,010.762	6,558.455	6,220.558	3,385.341	2,564.859	1,466.353	2,350.222	2,615.000	3,739.793	6,288.633	6,967.526	7,199.777	**56,367**
BRX Energy Expense	295.000	612.500	220.000	35.000	7.500	5.000	-	15.000	27.500	55.000	317.500	375.000	**1,965**
Market Energy Expense	1,168.308	1,065.986	-	-	-	-	-	-	-	-	1,649.849	2,303.033	**6,187**
Market Capacity - Energy Expense	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Market Energy Block Purchase Expense	-	-	-	399.513	431.054	420.540	-	-	-	-	-	-	**1,251**
Market Capacity Block Purchase Expense	-	-	-	-	-	2,265.978	2,763.515	-	-	-	-	-	**5,029**
Market for RS 37 Expense	115.405	6.966	34.999	0.808	74.772	71.177	596.528	240.749	3.727	29.664	40.159	64.838	**1,280**
IPP Costs	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Operating Reserve Expense	21.702	20.522	21.085	20.786	19.995	20.053	19.613	19.592	19.435	20.117	20.740	21.320	
Total Energy Expense ($000)	**12,583**	**11,268**	**9,313**	**8,215**	**7,534**	**8,302**	**10,167**	**7,603**	**7,013**	**9,416**	**12,038**	**13,109**	**116,562**
Capacity Expense ($000)													
Waneta Expansion Expense	6,308.614	6,290.643	5,649.286	1,928.106	1,236.469	865.653	3,358.722	6,434.844	3,973.906	5,900.878	6,431.593	5,622.448	**54,001**
BCH 3808 Capacity Expense	1,608.057	1,608.057	1,428.728	1,338.982	1,338.982	1,785.309	1,783.476	1,338.982	1,338.982	1,442.422	1,649.121	1,651.411	**18,313**
BRD Tailrace Capacity Expense	5.707	15.078	5.026	12.565	30.155	30.155	28.648	18.093	4.523	4.523	17.088	24.124	**196**
BRX Capacity Expense	-	138.720	75.480	224.740	124.440	99.620	143.480	182.580	48.280	20.434	59.840	141.780	**1,259**
Total Capacity Expense ($000)	**7,922**	**8,052**	**7,159**	**3,504**	**2,730**	**2,781**	**5,314**	**7,974**	**5,366**	**7,368**	**8,158**	**7,440**	**73,769**
Other Expenses ($000)													
Surplus Energy Revenue	-	-	-	-	-	-	-	-	-	-	-	-	**-**
WAX RCA Revenue	(443)	(414)	(443)	(440)	(455)	(403)	(455)	(455)	(440)	(455)	(440)	(455)	**(5,298)**
WAX CEPSA Sales	(224)	(338)	(212)	(257)	(193)	(189)	(302)	(2,206)	(2,661)	(571)	(463)	(722)	**(8,338)**
Market Savings	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	(250)	**(3,000)**
Special & Accounting Adjustments													**-**
Balancing Pool Adjustments	51	(357)	713	(1,255)	(1,255)	(157)	1,412	1,072	863	(1,412)	(628)	953	**0**
Total Other Expense ($000)	(866)	(1,359)	(192)	(2,203)	(2,153)	(999)	405	(1,838)	(2,488)	(2,688)	(1,781)	(475)	**(16,636)**
Total Power Purchase Expense	**19,639**	**17,962**	**16,280**	**9,516**	**8,111**	**10,084**	**15,887**	**13,739**	**9,891**	**14,096**	**18,415**	**20,074**	**173,694**
Average Power Purchase Cost	80.86	81.22	86.92	59.56	53.26	65.38	106.25	101.88	85.12	75.80	81.09	85.12	
Cummulative Balancing Pool	50.94	-305.61	407.48	-847.93	-2103.34	-2260.26	-847.93	224.40	1087.50	-324.84	-952.54	0.01	

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

CLASSIFICATION and ALLOCATION BY FUNCTION
Schedule 6.1

INPUT RATE BASE	**Production**			**Transmission**			**Distribution**				Total % Allocated
Demand	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
CP1	100.00%			100.00%			100.00%				100%
CP2	100.00%			100.00%			100.00%				100%
CP4	100.00%			100.00%			100.00%				100%
CP12	100.00%			100.00%			100.00%				100%
TCP1				100.00%							100%
TCP2				100.00%							100%
TCP4				100.00%							100%
TCP12				100.00%							100%
NCP	100.00%			100.00%			100.00%				100%
NCPP	100.00%			100.00%			100.00%				100%
NCPS	100.00%			100.00%			100.00%				100%
kWh		100.00%			100.00%			100.00%			100%
CUST									100.00%		100%
CUSTW									100.00%		100%
CUSTM									100.00%		100%
CUSTR									100.00%		100%
MINSYSP							14.00%		86.00%		100%
MINSYSC							28.65%		71.35%		100%
MINSYST							57.00%		43.00%		100%
20D/80E	17.80%	82.20%									
DA1			100.00%			100.00%				100.00%	100%
REV	16.25%	35.75%		17.65%			13.21%		16.78%	0.35%	100%
RB	5.12%	20.36%		25.75%			24.45%		23.61%	0.71%	100%
RBG	17.80%	82.20%									100%
RBT				100.00%							100%
RBD							46.23%		52.64%	1.14%	100%
RBGP	4.50%	20.80%		20.29%			22.21%		31.65%	0.55%	100%
OM	28.17%	54.22%		11.71%			1.52%		4.35%	0.03%	100%
OMAG	4.55%	20.99%		42.05%			5.46%		26.84%	0.12%	100%
GPLT	2.85%	13.14%		24.94%			27.31%		31.10%	0.67%	100%
NETPLT	3.32%	15.32%		23.16%			26.64%		30.91%	0.65%	100%
LABOR	4.81%	22.21%		21.66%			23.72%		27.01%	0.58%	100%
PURCHkWh		100.00%									
PURCHkW	100.00%										
DSM	16.60%	71.60%		3.50%			3.88%		4.42%		100%
DA2									100.00%		
RBASE	5.12%	20.36%		25.75%			24.45%		23.61%	0.71%	100%
	P % of Total	52%		**T % of Total**	18%		**D % of Total**	30%			
	Total	100%									

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER
Schedule 6.2

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
CP1	100%	47.820%	8.614%	13.101%	3.831%	5.588%	0.176%	0.181%	16.348%	4.339%	47.037%	0.784%
CP2	100%	46.363%	8.909%	15.249%	5.437%	3.872%	0.100%	1.001%	16.156%	2.914%	45.827%	0.536%
CP4	100%	45.730%	8.783%	13.862%	4.863%	5.464%	0.198%	0.180%	16.627%	4.293%	45.055%	0.676%
CP12	100%	43.266%	9.155%	16.089%	6.485%	5.240%	0.132%	0.893%	15.653%	3.088%	42.774%	0.491%
TCP1	100%	47.820%	8.614%	13.101%	3.831%	5.588%	0.176%	0.181%	16.348%	4.339%	47.037%	0.784%
TCP2	100%	46.363%	8.909%	15.249%	5.437%	3.872%	0.100%	1.001%	16.156%	2.914%	45.827%	0.536%
TCP4	100%	45.730%	8.783%	13.862%	4.863%	5.464%	0.198%	0.180%	16.627%	4.293%	45.055%	0.676%
TCP12	100%	43.266%	9.155%	16.089%	6.485%	5.240%	0.132%	0.893%	15.653%	3.088%	42.774%	0.491%
NCP	100%	46.911%	9.502%	14.010%	5.673%	3.980%	0.187%	2.040%	13.684%	4.013%	46.129%	0.782%
NCPP	100%	51.090%	10.349%	15.258%	6.178%			2.222%	14.903%		50.238%	0.852%
NCPS	100%	64.737%	13.113%	19.334%				2.815%			63.658%	1.079%
kWh	100%	38.954%	10.474%	18.734%	7.613%	6.099%	0.270%	1.140%	14.391%	2.325%	38.58%	0.375%
CUST	100%	87.089%	10.094%	1.171%	0.025%	0.003%	0.882%	0.726%	0.008%	0.002%	86.448%	0.642%
CUSTW	100%	73.363%	8.503%	0.987%	10.529%	1.108%	0.743%	0.611%	3.325%	0.831%	72.82%	1.08%
CUSTM	100%	86.506%	11.131%	1.486%	0.031%	0.003%	0.002%	0.835%	0.005%	0.001%	85.87%	0.66%
CUSTR	100%	87.089%	10.094%	1.171%	0.025%	0.003%	0.882%	0.726%	0.008%	0.002%		
MINSYSP	100%	82.432%	10.207%	3.258%	0.713%	0.002%	0.759%	0.952%	1.676%	0.002%	81.75%	0.68%
MINSYSC	100%	77.556%	10.325%	5.441%	1.434%	0.002%	0.629%	1.188%	3.422%	0.001%	76.84%	0.71%
MINSYST	100%	74.349%	11.815%	11.524%	0.011%	0.001%	0.379%	1.917%	0.003%	0.001%	73.46%	0.89%
20D/80E	100%	40.273%	10.195%	18.114%	7.226%	5.703%	0.240%	1.115%	14.705%	2.430%	39.870%	0.403%
DA1	100%						100.000%					
REV	100%	50.089%	9.885%	14.414%	5.684%	3.666%	0.520%	1.149%	12.686%	1.905%	49.25%	0.55%
RB	100%	54.551%	9.904%	12.994%	4.861%	2.457%	0.806%	1.294%	11.750%	1.383%	53.88%	0.61%
RBG	100%	40.273%	10.195%	18.114%	7.226%	5.703%	0.240%	1.115%	14.705%	2.430%	39.870%	0.403%
RBT	100%	46.363%	8.909%	15.249%	5.437%	3.872%	0.100%	1.001%	16.156%	2.914%	45.83%	0.54%
RBT-D	100%	46.363%	8.909%	15.249%	5.437%	3.872%	0.100%	1.001%	16.156%	2.914%	45.827%	0.536%
RBT-E												
RBT-DA												
RBD	100%	66.501%	10.304%	9.149%	3.258%	0.000%	1.399%	1.554%	7.834%	0.000%	65.748%	0.754%
RBGP	100%	57.553%	10.004%	12.051%	4.440%	2.228%	0.627%	1.269%	10.622%	1.206%	56.94%	0.614%
OM	100%	43.537%	9.876%	16.669%	6.601%	5.154%	0.235%	1.013%	14.348%	2.565%	43.07%	0.463%
OMAG	100%	54.473%	9.524%	12.359%	5.450%	3.183%	0.308%	1.034%	11.748%	1.920%	51.96%	0.576%
GPLT	100%	58.124%	9.944%	11.842%	4.318%	1.877%	0.735%	1.321%	10.723%	1.115%	57.48%	0.641%
NETPLT	100%	57.865%	9.966%	11.943%	4.372%	1.959%	0.723%	1.316%	10.728%	1.128%	57.23%	0.636%
LABOR	100%	55.05%	9.97%	12.89%	4.80%	2.38%	0.80%	1.32%	11.49%	1.29%	54.44%	0.612%
PURCHkWh	100%	38.85%	10.48%	18.80%	7.65%	6.13%	0.27%	1.14%	14.36%	2.33%	38.48%	0.373%
PURCHkW	100%	44.33%	9.05%	15.51%	6.15%	5.01%	0.16%	0.70%	15.63%	3.46%	43.78%	0.554%
DA2			35.86%	64.14%								
DSM												

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

COINCIDENT PEAK DEMAND ALLOCATION - PRODUCTION
Schedule 6.3

Calculation of 1 CP Allocation - Production

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-24												
Feb-24												
Mar-24												
Apr-24												
May-24												
Jun-24												
Jul-24												
Aug-24												
Sep-24												
Oct-24												
Nov-24												
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	353,925	5,897
Total Annual 1CP	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	353,925	5,897
% of Total	100%	47.82%	8.61%	13.10%	3.83%	5.59%	0.18%	0.18%	16.35%	4.34%	47.04%	0.78%

Calculation of 2 CP & 4 CP Allocation - Production

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
2 CP - Production												
Jan-24	645,119	312,052	54,776	85,068	29,222	23,248	1,256	1,175	109,720	28,602	308,122	3,930
Feb-24												
Mar-24												
Apr-24												
May-24												
Jun-24												
Jul-24	605,849	274,532	57,374	107,654	45,471	11,717		12,064	84,560	12,477	272,337	2,195
Aug-24	579,954	251,313	53,191	102,623	36,941	23,015		11,250	100,066	1,557	249,488	1,825
Sep-24												
Oct-24												
Nov-24												
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	353,925	5,897
2 Winter + 2 Summer	2,583,365	1,197,719	230,154	393,926	140,461	100,028	2,582	25,853	417,359	75,283	1,183,873	13,847
% of Total	100%	46.36%	8.91%	15.25%	5.44%	3.87%	0.10%	1.00%	16.16%	2.91%	45.83%	0.54%

FortisBC 2025 COSA for Electric Service — **Prepared By EES Consulting, Inc.**

COINCIDENT PEAK DEMAND ALLOCATION - PRODUCTION
Schedule 6.3, Cont'd

4 CP - Production

Jan-24	645,119	312,052	54,776	85,068	29,222	23,248	1,256	1,175	109,720	28,602	308,122	3,930
Feb-24	590,440	248,525	55,978	89,809	35,239	34,130	1,359	925	98,706	25,769	245,134	3,391
Mar-24												
Apr-24												
May-24												
Jun-24												
Jul-24												
Aug-24												
Sep-24												
Oct-24												
Nov-24	606,965	266,290	52,352	86,268	32,895	42,356	1,189	1,208	100,016	24,392	261,978	4,312
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	353,925	5,897
4 Winter	2,594,968	1,186,689	227,919	359,726	126,184	141,784	5,129	4,672	431,456	111,410	1,169,160	17,529
% of Total	100%	45.73%	8.78%	13.86%	4.86%	5.46%	0.20%	0.18%	16.63%	4.29%	45.05%	0.68%

Calculation of 12 CP Allocation - Production

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Power Supply												
Winter	2,605,856	1,197,577	227,919	359,726	126,184	141,784	5,129	4,672	431,456	111,410	1,169,160	28,417
% of Total	100%	45.96%	8.75%	13.80%	4.84%	5.44%	0.20%	0.18%	16.56%	4.28%	44.87%	1.09%
Summer	3,976,839	1,650,471	374,699	699,359	300,730	203,133	3,539	54,088	598,938	91,882	1,646,541	3,930
% of Total	100%	41.50%	9.42%	17.59%	7.56%	5.11%	0.09%	1.36%	15.06%	2.31%	41.40%	0.10%
Annual	6,582,694	2,848,048	602,618	1,059,085	426,913	344,917	8,668	58,759	1,030,393	203,293	2,815,701	32,347
% of Total	100%	43.27%	9.15%	16.09%	6.49%	5.24%	0.13%	0.89%	15.65%	3.09%	42.77%	0.49%
Utility Owned Transmission												
Annual	6,582,694	2,848,048	602,618	1,059,085	426,913	344,917	8,668	58,759	1,030,393	203,293	2,815,701	32,347
% of Total	100%	43.27%	9.15%	16.09%	6.49%	5.24%	0.13%	0.89%	15.65%	3.09%	42.77%	0.49%

Prepared By EES Consulting, Inc.

FortisBC 2025 COSA for Electric Service

COINCIDENT PEAK DEMAND ALLOCATION - TRANSMISSION
Schedule 6.4

Calculation of 1 CP Allocation - Transmission

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-24												
Feb-24												
Mar-24												
Apr-24												
May-24												
Jun-24												
Jul-24												
Aug-24												
Sep-24												
Oct-24												
Nov-24												
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	353,925	5,897
% of Total	100%	47.82%	8.61%	13.10%	3.83%	5.59%	0.18%	0.18%	16.35%	4.34%	47.04%	0.78%

Calculation of 2 CP & 4 CP Allocation - Transmission

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
2 CP - Transmission												
Jan-24	645,119	312,052	54,776	85,068	29,222	23,248	1,256	1,175	109,720	28,602	308,122	3,930
Feb-24												
Mar-24												
Apr-24												
May-24												
Jun-24												
Jul-24	605,849	274,532	57,374	107,654	45,471	11,717		12,064	84,560	12,477	272,337	2,195
Aug-24	579,954	251,313	53,191	102,623	36,941	23,015		11,250	100,066	1,557	249,488	1,825
Sep-24												
Oct-24												
Nov-24												
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	353,925	5,897
2 Winter + 2 Summer	2,583,365	1,197,719	230,154	393,926	140,461	100,028	2,582	25,853	417,359	75,283	1,183,873	13,847
% of Total	100%	46.36%	8.91%	15.25%	5.44%	3.87%	0.10%	1.00%	16.16%	2.91%	45.83%	0.54%

FortisBC 2025 COSA for Electric Service Prepared By EES Consulting, Inc.

COINCIDENT PEAK DEMAND ALLOCATION - TRANSMISSION
Schedule 6.4, Cont'd

4 CP - Transmission	1											
Jan-24	645,119	312,052	54,776	85,068	29,222	23,248	1,256	1,175	109,720	28,602	308,122	3,930
Feb-24	590,440	248,525	55,978	89,809	35,239	34,130	1,359	925	98,706	25,769	245,134	3,391
Mar-24												
Apr-24												
May-24												
Jun-24												
Jul-24												
Aug-24												
Sep-24												
Nov-24	606,965	266,290	52,352	86,268	32,895	42,356	1,189	1,208	100,016	24,392	261,978	4,312
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	353,925	5,897
4 Winter	2,594,968	1,186,689	227,919	359,726	126,184	141,784	5,129	4,672	431,456	111,410	1,169,160	17,529
% of Total	100%	45.73%	8.78%	13.86%	4.86%	5.46%	0.20%	0.18%	16.63%	4.29%	45.05%	0.68%

Calculation of 12 CP Allocation - Transmission

Utility Owned Transmission

Annual	6,582,694	2,848,048	602,618	1,059,085	426,913	344,917	8,668	58,759	1,030,393	203,293	2,815,701	32,347
% of Total	100%	43.27%	9.15%	16.09%	6.49%	5.24%	0.13%	0.89%	15.65%	3.09%	42.77%	0.49%

Prepared By EES Consulting, Inc.

FortisBC 2025 COSA for Electric Service

NON-COINCIDENT PEAK DEMAND ALLOCATION
Schedule 6.5

NCP Distribution Allocation

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Winter												
NCP at Input (NCP)	820,531	394,694	79,948	114,780	44,883	33,485	1,359	2,485	115,136	33,761	388,116	6,578
% of Total	100%	48.10%	9.74%	13.99%	5.47%	4.08%	0.17%	0.30%	14.03%	4.11%	47.30%	0.80%
NCP Primary (NCPP)	720,547	378,223	76,612	109,990	43,010			2,381	110,331		371,919	6,304
% of Total	100%	52.49%	10.63%	15.26%	5.97%			0.33%	15.31%		51.62%	0.87%
NCP Secondary (NCPS)	539,663	359,822	72,905	104,669				2,266			353,925	5,999
% of Total	100%	66.68%	13.51%	19.40%				0.42%			65.58%	1.11%
Summer												
NCP at Input (NCP)	713,793	302,509	75,284	117,878	47,730	27,909	1,572	17,164	101,127	22,620	298,646	3,863
% of Total	100%	42.38%	10.55%	16.51%	6.69%	3.91%	0.22%	2.40%	14.17%	3.17%	41.84%	0.54%
NCP Primary (NCPP)	634,078	289,884	72,142	112,958	45,738			16,448	96,907		286,183	3,702
% of Total	100%	45.72%	11.38%	17.81%	7.21%			2.59%	15.28%		45.13%	0.58%
NCP Secondary (NCPS)	467,657	275,860	68,652	107,494				15,652			272,337	3,522
% of Total	100%	58.99%	14.68%	22.99%				3.35%			58.23%	0.75%
Annual												
NCP at Input (NCP)	841,369	394,694	79,948	117,878	47,730	33,485	1,572	17,164	115,136	33,761	388,116	6,578
% of Total	100%	46.91%	9.50%	14.01%	5.67%	3.98%	0.19%	2.04%	13.68%	4.01%	46.13%	0.78%
NCP Primary (NCPP)	740,310	378,223	76,612	112,958	45,738			16,448	110,331		371,919	6,304
% of Total	100%	51.09%	10.35%	15.26%	6.18%			2.22%	14.90%		50.24%	0.85%
NCP Secondary (NCPS)	555,975	359,924	72,905	107,494				15,652			353,925	5,999
% of Total	100%	64.74%	13.11%	19.33%				2.82%			63.66%	1.08%

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

NON-COINCIDENT PEAK DEMAND ALLOCATION
Schedule 6.5, Cont'd

NCP Distribution Allocation for Minimum System (including PLCC adjustment)

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Max NCP	841,369	394,694	79,948	117,878	47,730	33,485	1,572	17,164	115,136	33,761	388,116	6,578
NCP Weighting	-	-	-	-	-	-	-	-	-	-	-	-
Max NCPP	740,310	378,223	76,612	112,958	45,738	-	-	16,448	110,331	-	371,919	6,304
NCPP Weighting	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Max NCPS	555,975	359,924	72,905	107,494	-	-	-	15,652	-	-	353,925	5,999
NCPS Weighting	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Weighted NCP (P+ S)	703,443	374,563	75,871	111,865	36,591	-	-	16,289	88,265	-	368,320	6,243
		53.2%	10.8%	15.9%	5.2%			2.3%	12.5%		52.4%	0.9%
Transformers	740,310	51%	10%	15%	6%			2%	15%		50%	1%
Distribution Customers (Primary + Secondary)	150,665	132,389	15,345	1,780	38			1,103	10		131,413	976
	100%	87.9%	10.2%	1.2%	0.0%			0.7%	0.0%		87.2%	0.6%
Distribution Customers (Secondary)	150,617	132,389	15,345	1,780				1,103			131,413	976
	100%	87.9%	10.2%	1.2%				0.7%			87.3%	0.6%
Distribution Customers (Transformers)	150,665	132,389	15,345	1,780	38	-	-	1,103	10	-	131,413	976
	100%	87.9%	10.2%	1.2%	0.0%			0.7%	0.0%		87.2%	0.6%
PLCC Amount		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
NCP After PLCC (P+S)	557,559	246,374	61,013	110,141	36,554			15,221	88,255		241,076	5,298
	100%	44.2%	10.9%	19.8%	6.6%			2.7%	15.8%		43.2%	1.0%
NCP After PLCC (S)	410,137	231,736	58,048	105,770				14,584			226,681	5,054
	100%	56.5%	14.2%	25.8%				3.6%			55.3%	1.2%
NCP After PLCC (Transformers)	594,425	250,034	61,754	111,234	45,701			15,380	110,322		244,675	5,359
	100%	42.1%	10.4%	18.7%	7.7%			2.6%	18.6%		41.2%	0.9%
Rate Base Items												
Poles, Towers, & Fixtures	255,798,500											
Customer	219,986,710	$193,301,832	$22,404,640	$2,599,657	$55,484			$1,610,496	$14,601		$191,877,331	$1,424,501
Demand (before PLCC)	35,811,790	$19,068,725	$3,862,517	$5,694,988	$1,862,800			$829,252	$4,493,508		$18,750,907	$317,817
Demand (after PLCC)	35,811,790	$15,824,528	$3,918,837	$7,074,349	$2,347,837			$977,628	$5,668,610		$15,484,230	$340,299
Adjusted Customer	219,986,710	$190,057,636	$22,460,960	$3,979,018	$540,521			$1,758,872	$1,189,703		$188,610,653	$1,446,983
Adjusted Demand	35,811,790	$19,068,725	$3,862,517	$5,694,988	$1,862,800			$829,252	$4,493,508		$18,750,907	$317,817
Conductors & Devices	411,637,000											
Customer	293,685,706	$258,060,976	$29,910,546	$3,470,583	$74,072			$2,150,037	$19,493		$256,159,245	$1,901,731
Demand (before PLCC)	117,951,294	$62,805,594	$12,721,757	$18,757,264	$6,135,400			$2,731,262	$14,800,017		$61,758,816	$1,046,778
Demand (after PLCC)	117,951,294	$52,120,366	$12,907,255	$23,300,387	$7,732,941			$3,219,959	$18,670,386		$50,999,542	$1,120,824
Adjusted Customer	293,685,706	$247,375,749	$30,096,044	$8,013,706	$1,671,613			$2,638,734	$3,889,861		$245,399,971	$1,975,777
Adjusted Demand	117,951,294	$62,805,594	$12,721,757	$18,757,264	$6,135,400			$2,731,262	$14,800,017		$61,758,816	$1,046,778
Line Transformers	203,732,000											
Customer	87,604,760	$76,978,108	$8,922,144	$1,035,255	$22,095			$641,344	$5,815		$76,410,832	$567,276
Demand (before PLCC)	116,127,240	$59,329,093	$12,017,565	$17,718,986	$7,174,632			$2,580,077	$17,306,887		$58,340,258	$988,835
Demand (after PLCC)	116,127,240	$48,846,727	$12,064,327	$21,730,814	$8,928,254			$3,004,638	$21,552,480		$47,799,760	$1,046,967
Adjusted Customer	87,604,760	$66,495,742	$8,968,906	$5,047,082	$1,775,717			$1,065,905	$4,251,408		$65,870,334	$625,407
Adjusted Demand	116,127,240	$59,329,093	$12,017,565	$17,718,986	$7,174,632			$2,580,077	$17,306,887		$58,340,258	$988,835

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

POWER SUPPLY COST ALLOCATION
Schedule 6.6

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Monthly Power Costs-kWh												
Jan-22	$11,723,354	42.67%	10.17%	16.41%	6.02%	5.19%	0.28%	0.21%	15.62%	3.44%	42.11%	0.55%
Feb-22	$10,665,932	41.54%	10.31%	16.91%	6.51%	5.42%	0.30%	0.19%	15.31%	3.51%	41.10%	0.44%
Mar-22	$9,427,579	39.12%	10.55%	18.02%	7.48%	6.25%	0.27%	0.22%	14.89%	3.20%	38.80%	0.31%
Apr-22	$8,248,848	38.06%	10.44%	18.55%	7.86%	6.76%	0.26%	0.48%	14.73%	2.86%	37.87%	0.19%
May-22	$7,776,406	35.25%	10.50%	19.66%	9.11%	7.60%	0.23%	1.40%	14.49%	1.76%	35.09%	0.16%
Jun-22	$6,257,398	35.09%	11.23%	21.62%	9.56%	7.69%	0.23%	2.73%	11.55%	0.31%	34.96%	0.13%
Jul-22	$8,457,461	38.32%	10.96%	20.97%	8.85%	5.68%	0.19%	2.93%	11.88%	0.22%	38.15%	0.16%
Aug-22	$10,243,253	36.04%	10.42%	20.50%	8.43%	5.75%	0.21%	2.82%	15.57%	0.26%	35.81%	0.23%
Sep-22	$8,979,803	33.35%	10.54%	21.02%	9.12%	7.41%	0.32%	2.13%	14.66%	1.45%	33.12%	0.23%
Oct-22	$9,618,233	36.76%	10.89%	21.54%	9.03%	7.10%	0.38%	1.31%	10.65%	2.34%	36.41%	0.35%
Nov-22	$10,862,039	41.35%	10.22%	17.20%	6.55%	5.63%	0.30%	0.29%	15.07%	3.39%	40.69%	0.66%
Dec-22	$11,317,215	43.94%	10.01%	15.98%	5.43%	4.63%	0.27%	0.22%	15.91%	3.61%	43.22%	0.73%
Total	$113,577,522	38.95%	10.47%	18.73%	7.61%	6.10%	0.27%	1.14%	14.39%	2.33%	38.58%	0.37%
Weighted % Allocation	100.00%	38.85%	10.48%	18.80%	7.65%	6.13%	0.27%	1.14%	14.36%	2.33%	38.48%	0.37%
Monthly Power Costs-kW												
Jan-22	$7,916,079	48.4%	8.5%	13.2%	4.5%	3.6%	0.2%	0.2%	17.0%	4.4%	47.8%	0.6%
Feb-22	$7,295,904	42.1%	9.5%	15.2%	6.0%	5.8%	0.2%	0.2%	16.7%	4.4%	41.5%	0.6%
Mar-22	$6,852,319	41.7%	9.6%	16.3%	7.5%	3.9%	0.2%	0.2%	16.0%	4.5%	41.2%	0.6%
Apr-22	$1,267,540	39.1%	9.4%	16.8%	7.7%	7.7%	0.3%	0.4%	15.1%	3.7%	38.7%	0.4%
May-22	$334,616	33.9%	10.5%	19.7%	9.0%	7.6%		1.5%	15.0%	2.8%	33.8%	0.1%
Jun-22	$3,826,631	42.8%	9.7%	18.4%	7.8%	5.5%		2.3%	13.0%	0.5%	42.6%	0.2%
Jul-22	$7,429,226	45.3%	9.5%	17.8%	7.5%	1.9%		2.0%	14.0%	2.1%	45.0%	0.4%
Aug-22	$3,495,724	43.3%	9.2%	17.7%	6.4%	4.0%		1.9%	17.3%	0.3%	43.0%	0.3%
Sep-22	$911,353	42.3%	9.0%	17.2%	6.8%	4.2%		1.6%	17.1%	1.7%	41.9%	0.4%
Oct-22	$4,477,879	41.9%	8.4%	16.8%	8.4%	8.2%	0.3%	0.6%	11.7%	3.7%	41.3%	0.6%
Nov-22	$7,552,582	43.9%	8.6%	14.2%	5.4%	7.0%	0.2%	0.2%	16.5%	4.0%	43.2%	0.7%
Dec-22	$8,756,759	47.8%	8.6%	13.1%	3.8%	5.6%	0.2%	0.2%	16.3%	4.3%	47.0%	0.8%
Total	$60,116,611	43.3%	9.2%	16.1%	6.5%	5.2%	0.1%	0.9%	15.7%	3.1%	42.8%	0.5%
Weighted % Allocation	100.00%	44.33%	9.05%	15.51%	6.15%	5.01%	0.16%	0.70%	15.63%	3.46%	43.78%	0.55%

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service Prepared By EES Consulting, Inc.

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Jan-24	150,713	131,139	15,295	1,790	38	4	1,341	1,094	10	1	130,292	847
Feb-24	150,972	131,392	15,304	1,788	38	4	1,341	1,093	10	1	130,528	865
Mar-24	151,130	131,554	15,309	1,776	38	4	1,341	1,097	10	1	130,675	879
Apr-24	151,473	131,886	15,319	1,775	38	4	1,341	1,099	10	1	130,984	902
May-24	151,788	132,179	15,328	1,778	38	4	1,341	1,108	10	1	131,254	926
Jun-24	152,054	132,435	15,336	1,781	38	4	1,341	1,109	10	1	131,475	960
Jul-24	152,198	132,547	15,368	1,782	38	4	1,341	1,107	10	1	131,552	995
Aug-24	152,322	132,664	15,376	1,780	38	4	1,341	1,108	10	1	131,646	1,019
Sep-24	152,600	132,949	15,375	1,778	38	4	1,341	1,104	10	1	131,896	1,053
Oct-24	152,763	133,126	15,364	1,773	38	4	1,341	1,106	10	1	132,052	1,073
Nov-24	152,951	133,291	15,382	1,778	38	4	1,341	1,106	10	1	132,200	1,091
Dec-24	153,168	133,506	15,378	1,785	38	4	1,341	1,104	10	1	132,407	1,099
Total / Average	152,011	132,389	15,345	1,780	38	4	1,341	1,103	10	1	131,413	976
									Per POD	Per Cust		
Customer Charge Revenues	**Rate: $/Month**	**$22.64**	**$27.85**	**$65.37**	**$1,143.93**	**$3,735.89**	$147.34	**$32.41**	**$5,474.20**	**$7,231.81**	**$22.64**	**$22.64**
	Rate Misc $											
Jan-24	$3,871,309	$2,968,989	$425,893	$117,044	$43,469	$14,944	$197,583	$30,465	$65,690	$7,232	$2,949,814	$19,175
Feb-24	$3,877,118	$2,974,725	$426,137	$116,901	$43,469	$14,944	$197,583	$30,437	$65,690	$7,232	$2,955,152	$19,573
Mar-24	$3,880,247	$2,978,377	$426,289	$116,115	$43,469	$14,944	$197,583	$30,548	$65,690	$7,232	$2,958,476	$19,901
Apr-24	$3,893,042	$2,985,893	$426,563	$116,043	$43,469	$14,944	$197,583	$35,625	$65,690	$7,232	$2,965,477	$20,416
May-24	$3,900,441	$2,992,542	$426,807	$116,258	$43,469	$14,944	$197,583	$35,917	$65,690	$7,232	$2,971,588	$20,954
Jun-24	$3,906,613	$2,998,325	$427,020	$116,401	$43,469	$14,944	$197,583	$35,949	$65,690	$7,232	$2,976,598	$21,727
Jul-24	$3,910,062	$3,000,853	$427,934	$116,472	$43,469	$14,944	$197,583	$35,884	$65,690	$7,232	$2,978,330	$22,523
Aug-24	$3,912,833	$3,003,523	$428,147	$116,329	$43,469	$14,944	$197,583	$35,917	$65,690	$7,232	$2,980,461	$23,062
Sep-24	$3,919,040	$3,009,961	$428,116	$116,258	$43,469	$14,944	$197,583	$35,787	$65,690	$7,232	$2,986,127	$23,834
Oct-24	$3,922,447	$3,013,965	$427,812	$115,900	$43,469	$14,944	$197,583	$35,852	$65,690	$7,232	$2,989,662	$24,302
Nov-24	$3,921,985	$3,017,711	$428,299	$116,258	$43,469	$14,944	$197,583	$30,799	$65,690	$7,232	$2,993,010	$24,700
Dec-24	$3,927,136	$3,022,580	$428,208	$116,687	$43,469	$14,944	$197,583	$30,743	$65,690	$7,232	$2,997,693	$24,888
Total	$46,842,274	$35,967,444	$5,127,225	$1,396,663	$521,632	$179,323	$2,371,000	$403,921	$788,285	$86,782	$35,702,388	$265,055
Forecast kWh												
Jan-24	357,418,804	149,736,603	35,703,323	57,576,212	22,326,950	19,536,738	978,701	723,309	57,879,435	12,957,533	147,792,988	1,947,272
Feb-24	303,992,773	123,967,127	30,760,965	50,451,562	20,512,866	17,350,212	886,049	561,752	48,265,210	11,237,029	122,650,625	1,316,502
Mar-24	287,421,625	110,288,054	29,735,745	50,818,285	22,280,348	18,888,837	771,033	615,962	44,333,279	9,690,082	109,406,845	881,107
Apr-24	253,545,586	94,629,938	25,957,177	46,134,309	20,642,565	18,030,220	651,757	1,191,712	38,681,502	7,626,406	94,167,279	462,659
May-24	240,401,234	83,074,484	24,744,339	46,343,776	22,671,897	19,217,198	547,391	3,297,176	36,065,833	4,439,141	82,704,029	370,455
Jun-24	220,343,067	75,974,409	24,311,619	46,801,881	21,866,745	17,856,788	493,078	5,902,731	26,417,449	718,367	75,687,064	287,346
Jul-24	275,996,182	104,102,606	29,765,480	56,968,379	25,393,821	16,559,374	520,767	7,947,299	34,092,939	645,517	103,654,717	447,889
Aug-24	293,341,339	103,856,928	30,028,201	59,091,304	25,662,034	17,773,766	612,354	8,132,750	47,392,788	791,216	103,206,613	650,315
Sep-24	235,818,592	77,117,237	24,384,285	48,600,141	22,278,230	18,379,106	728,435	4,933,680	35,812,221	3,585,258	76,587,668	529,570
Oct-24	228,747,550	82,617,148	24,476,763	48,403,262	21,420,273	17,106,121	846,645	2,953,644	25,280,165	5,643,530	81,824,209	792,939
Nov-24	319,468,394	129,679,835	32,046,693	53,924,688	21,680,469	18,947,644	953,142	920,678	49,899,650	11,415,596	127,598,622	2,081,213
Dec-24	379,798,113	163,955,629	37,354,287	59,617,326	21,391,697	18,519,363	1,010,650	819,307	62,699,720	14,430,134	161,235,678	2,724,829
Total / Average	3,396,293,260	1,299,000,000	349,268,877	624,731,123	268,127,895	218,165,365	9,000,000	38,000,000	506,820,191	83,179,809	1,286,516,337	12,492,095

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1, Cont'd

Energy Rates	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Residential w/o Net Metering	Net Metering
Flat Rate:	Flat Rate $/kWh	**$0.14160**	**$0.12104**	**$0.08355**	**$0.06744**	**$0.06273**		**$0.08730**	**$0.06522**	**$0.05448**	$0.1416	$0.1416
Seasonal Rate:	Jan $/kWh							$0.12104				
	Feb $/kWh							$0.12104				
	Mar $/kWh							$0.12104				
	Ap $/kWh							$0.08730				
	May $/kWh							$0.08730				
	Jun $/kWh							$0.08730				
	Jul $/kWh							$0.08730				
	Aug $/kWh							$0.08730				
	Sep $/kWh							$0.08730				
	Oct $/kWh							$0.07678				
	Nov $/kWh							$0.12104				
	Dec $/kWh							$0.12104				
Energy Revenues												
Jan-24	$37,634,367	$21,202,703	$4,321,530	$4,810,492	$1,505,730	$1,225,540		$87,549	$3,774,897	$705,926	$20,927,487	$275,734
Feb-24	$31,792,092	$17,553,745	$3,723,307	$4,215,228	$1,383,388	$1,088,379		$67,994	$3,147,857	$612,193	$17,367,329	$186,417
Mar-24	$29,643,242	$15,616,788	$3,599,215	$4,245,868	$1,502,587	$1,184,897		$74,556	$2,891,416	$527,916	$15,492,009	$124,765
Apr-24	$25,961,478	$13,399,599	$3,141,857	$3,854,522	$1,392,135	$1,131,036		$104,036	$2,522,808	$415,487	$13,334,087	$65,513
May-24	$24,246,813	$11,763,347	$2,995,055	$3,872,022	$1,528,993	$1,205,495		$287,843	$2,352,214	$241,844	$11,710,891	$52,456
Jun-24	$22,483,193	$10,757,976	$2,942,678	$3,910,297	$1,474,693	$1,120,156		$515,308	$1,722,946	$39,137	$10,717,288	$40,688
Jul-24	$28,807,288	$14,740,929	$3,602,814	$4,759,708	$1,712,559	$1,038,770		$693,799	$2,223,541	$35,168	$14,677,508	$63,421
Aug-24	$29,967,481	$14,706,141	$3,634,613	$4,937,078	$1,730,648	$1,114,948		$709,989	$3,090,958	$43,105	$14,614,056	$92,085
Sep-24	$23,548,890	$10,919,801	$2,951,474	$4,060,542	$1,502,444	$1,152,921		$430,710	$2,335,673	$195,325	$10,844,814	$74,987
Oct-24	$23,405,999	$11,698,588	$2,962,667	$4,044,093	$1,444,583	$1,073,067		$226,769	$1,648,772	$307,459	$11,586,308	$112,280
Nov-24	$33,385,536	$18,362,665	$3,878,932	$4,505,408	$1,462,131	$1,188,586		$111,439	$3,254,455	$621,922	$18,067,965	$294,700
Dec-24	$40,297,482	$23,216,117	$4,521,363	$4,981,028	$1,442,656	$1,161,720		$99,169	$4,089,276	$786,154	$22,830,972	$385,836
Subtotal	$351,173,861	$183,938,400	$42,275,505	$52,196,285	$18,082,545	$13,685,513		$3,409,163	$33,054,813	$4,531,636	$182,170,713	$1,768,881
Total	$351,173,861	$183,938,400	$42,275,505	$52,196,285	$18,082,545	$13,685,513		$3,409,163	$33,054,813	$4,531,636	$182,170,713	$1,768,881
Metered Demand kVa or kW				All kVA	All kVA	All kVA						
Jan-24	1,207,684	728,145	116,946	132,952	52,390	28,037	1,961	3,674	112,530	31,046	719,973	8,172
Feb-24	1,165,195	696,539	114,928	129,864	57,825	28,474	2,098	3,103	104,262	28,102	688,803	7,736
Mar-24	1,097,301	653,373	109,737	124,757	50,698	28,013	1,981	4,422	101,308	23,011	646,292	7,081
Apr-24	1,076,525	632,473	106,645	121,850	55,161	27,975	2,101	14,262	91,233	24,826	625,729	6,744
May-24	1,004,233	594,891	103,562	119,759	50,667	27,254	2,131	21,680	68,594	15,696	588,397	6,493
Jun-24	1,009,461	585,155	108,050	130,791	49,968	27,370	2,301	23,834	66,613	15,379	578,746	6,409
Jul-24	1,108,572	634,036	117,516	147,424	55,857	27,435	2,177	25,659	83,407	15,061	626,827	7,209
Aug-24	1,123,819	624,893	114,695	144,274	54,955	27,068	2,063	24,142	118,585	13,143	617,583	7,310
Sep-24	1,059,314	594,185	110,078	137,250	52,242	27,074	2,066	22,314	96,707	17,399	586,899	7,286
Oct-24	1,069,029	610,655	107,096	128,162	52,710	26,786	1,969	19,082	100,913	21,655	602,616	8,039
Nov-24	1,201,863	698,258	116,161	130,453	51,355	35,333	2,028	5,678	105,119	57,478	688,306	9,952
Dec-24	1,283,436	775,193	124,280	140,750	49,849	27,918	1,965	4,109	126,278	33,093	763,785	11,408
Total / Average												
Total	13,406,433	7,827,798	1,349,694	1,588,285	633,677	338,738	24,842	171,960	1,175,550	295,887	7,733,956	93,841

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1, Cont'd

Billed Demand kVa or kW												
Jan-24	278,306			79,786	48,472	25,233		2,205	99,943	22,666		
Feb-24	271,012			76,930	53,501	25,627		1,838	92,599	20,516		
Mar-24	253,260			71,821	46,907	25,212		2,546	89,976	16,799		
Apr-24	252,410			68,972	51,036	25,177		8,073	81,027	18,125		
May-24	211,146			67,360	46,878	24,529			60,921	11,459		
Jun-24	219,009			77,755	46,231	24,633			59,162	11,228		
Jun-24	-											
Jul-24	-											
Aug-24	-											
Sep-24	-											
Oct-24	-											
Nov-24	-											
Dec-24	-											
Total / Average												
Total	-	-	-	-	-	-	-	-	-	-	-	-

	Power Rate: $/kVa					**$4.02**			**$5.84**	**$5.77**		
	Wires Rate: $/kVa				**$11.12**	**$5.76**			**$10.88**	**$7.67**		
Demand Revenues	**Rate: $/kW**			**$13.75**				**$13.75**				
Jan-24	$4,021,983			$1,097,061	$539,008	$258,055		$30,319	$1,744,551	$352,989		
Feb-24	$3,875,952			$1,057,789	$594,929	$262,075		$25,278	$1,616,373	$319,508		
Mar-24	$3,634,176			$987,536	$521,602	$257,834		$35,005	$1,570,576	$261,623		
Apr-24	$3,581,003			$948,363	$567,524	$257,481		$110,999	$1,414,376	$282,260		
May-24	$2,940,189			$926,193	$521,280	$250,848			$1,063,407	$178,460		
Jun-24	$3,042,694			$1,069,138	$514,094	$251,912			$1,032,700	$174,850		
Jul-24	$3,584,903			$1,293,412	$574,682	$252,513			$1,293,054	$171,241		
Aug-24	$4,057,154			$1,254,763	$565,404	$249,137			$1,838,422	$149,428		
Sep-24	$3,634,797			$1,151,052	$537,490	$249,189			$1,499,245	$197,820		
Oct-24	$3,783,155			$1,030,249	$542,308	$246,540		$153,395	$1,564,451	$246,212		
Nov-24	$4,242,929			$1,060,064	$528,363	$325,204		$46,136	$1,629,658	$653,504		
Dec-24	$4,338,187			$1,199,412	$512,864	$256,960		$35,019	$1,957,678	$376,253		
Total	$44,737,121			$13,075,034	$6,519,549	$3,117,748		$436,152	$18,224,491	$3,364,148		

Total Revenues	**Total**	**Residential**	**Small Commercial 20**	**Commercial 21/22**	**Large Comm Primary 30/32**	**Large Comm Transmission 31**	**Lighting**	**Irrigation**	**Wholesale Primary 40**	**Wholesale Transmission 41**	**Residential w/o Net Metering**	**Net Metering**
Jan-24	$45,527,659	$24,171,692	$4,747,423	$6,024,598	$2,088,207	$1,498,538	$197,583	$148,333	$5,585,138	$1,066,147	$23,877,301	$294,909
Feb-24	$39,545,162	$20,528,470	$4,149,444	$5,389,918	$2,021,786	$1,365,397	$197,583	$123,709	$4,829,920	$938,933	$20,322,480	$205,990
Mar-24	$37,157,666	$18,595,166	$4,025,504	$5,349,518	$2,067,658	$1,457,674	$197,583	$140,110	$4,527,683	$796,770	$18,450,486	$144,666
Apr-24	$33,435,523	$16,385,492	$3,568,420	$4,918,927	$2,003,127	$1,403,460	$197,583	$250,660	$4,002,874	$704,978	$16,299,564	$85,928
May-24	$31,087,444	$14,755,889	$3,421,862	$4,914,473	$2,093,742	$1,471,287	$197,583	$323,760	$3,481,311	$427,536	$14,682,478	$73,411
Jun-24	$29,432,499	$13,756,301	$3,369,698	$5,095,835	$2,032,256	$1,387,012	$197,583	$551,257	$2,821,336	$221,219	$13,693,886	$62,415
Jul-24	$36,302,253	$17,741,783	$4,030,747	$6,169,592	$2,330,711	$1,306,227	$197,583	$729,683	$3,582,286	$213,640	$17,655,838	$85,944
Aug-24	$37,937,468	$17,709,664	$4,062,760	$6,308,170	$2,339,521	$1,379,029	$197,583	$745,906	$4,995,070	$199,765	$17,594,517	$115,146
Sep-24	$31,102,727	$13,929,762	$3,379,590	$5,327,851	$2,083,404	$1,417,054	$197,583	$466,497	$3,900,608	$400,376	$13,830,941	$98,821
Oct-24	$31,111,601	$14,712,553	$3,390,479	$5,190,242	$2,030,360	$1,334,551	$197,583	$416,016	$3,278,914	$560,903	$14,575,970	$136,582
Nov-24	$41,550,450	$21,380,375	$4,307,231	$5,681,729	$2,033,963	$1,528,733	$197,583	$188,374	$4,949,803	$1,282,658	$21,060,975	$319,400
Dec-24	$48,562,805	$26,238,698	$4,949,571	$6,297,126	$1,998,989	$1,433,623	$197,583	$164,931	$6,112,645	$1,169,639	$25,828,665	$410,724
Subtotal	$442,753,256	$219,905,844	$47,402,730	$66,667,982	$25,123,726	$16,982,585	$2,371,000	$4,249,236	$52,067,589	$7,982,565	$217,873,102	$2,033,936
2024 Revenue Forecast Adjustment	$8,826,047	$4,383,704	$944,948	$1,328,990	$500,828	$338,539	$47,265	$84,706	$1,037,939	$159,128	$4,343,182	$40,545
Total	**$451,579,302**	$224,289,548	$48,347,678	$67,996,972	$25,624,554	$17,321,123	$2,418,265	$4,333,942	$53,105,528	$8,141,693	$222,216,284	$2,074,481

Updated Application dated May 15, 2025

FortisBC 2025 COSA for Electric Service Prepared By EES Consulting, Inc.

HISTORIC CUSTOMERS AND ENERGY SALES
Schedule 8.1

Number of Customers / Services	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22	166,199	**126,811**	**13,984**	**1,637**	**38**	**4**	**22,621**	**1,093**	10	1	819
Feb-22	166,449	**127,056**	**13,992**	**1,635**	**38**	**4**	**22,621**	**1,092**	10	1	836
Mar-22	166,603	**127,212**	**13,997**	**1,624**	**38**	**4**	**22,621**	**1,096**	10	1	850
Apr-22	166,934	**127,533**	**14,006**	**1,623**	**38**	**4**	**22,621**	**1,098**	10	1	872
May-22	167,238	**127,817**	**14,014**	**1,626**	**38**	**4**	**22,621**	**1,107**	10	1	895
Jun-22	167,495	**128,064**	**14,021**	**1,628**	**38**	**4**	**22,621**	**1,108**	10	1	928
Jul-22	167,632	**128,172**	**14,051**	**1,629**	**38**	**4**	**22,621**	**1,106**	10	1	962
Aug-22	167,752	**128,286**	**14,058**	**1,627**	**38**	**4**	**22,621**	**1,107**	10	1	985
Sep-22	168,021	**128,561**	**14,057**	**1,626**	**38**	**4**	**22,621**	**1,103**	10	1	1,018
Oct-22	168,179	**128,732**	**14,047**	**1,621**	**38**	**4**	**22,621**	**1,105**	10	1	1,038
Nov-22	168,360	**128,892**	**14,063**	**1,626**	**38**	**4**	**22,621**	**1,105**	10	1	1,055
Dec-22	168,569	**129,100**	**14,060**	**1,632**	**38**	**4**	**22,621**	**1,103**	10	1	1,063
Total Average	167,453	128,020	14,029	1,628	38	4	22,621	1,102	10	1	943
2022 Actuals in Annual Report Filing	147,112	127,899	16,674		42		1,391	1,100	6		

Historic Energy, Demand And Customer Count
Historic Year

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Input Recorded Data											
Energy Sales (kWh)	3,502,263,865	1,402,953,903	350,577,276	627,071,434	296,765,570	217,729,905	7,809,439	43,355,716	473,695,298	82,305,324	13,491,789
Total Billing Capacity (kVa)	14,317,236	8,454,226	1,354,751	1,771,372	779,286	355,855		196,196	1,109,816	295,734	101,351
Avg. Monthly Billing Capacity (kVa)	1,193,103	704,519	112,896	147,614	64,941	29,655		16,350	92,485	24,645	8,446
Number of Customers	167,453	128,020	14,029	1,628	38	4	22,621	1,102	10	1	943
Ratio of NCP to Avg. Billing Capacity		55%	65%	73%	78%	110%		109%	125%	132%	77%
Rate Classes NCP Demand at Meter	820,074	388,618	73,179	107,896	50,623	32,490	1,244	17,858	115,687	32,479	6,479
Estimated Based on Recorded Data											
Annual NCP Load Factor	49%	41%	55%	66%	67%	76%	72%	28%	47%	29%	24%
Rate Classes CP Demand at Input Voltage	776,480	388,618	65,056	98,950	31,907	41,965	1,150	1,557	114,973	32,304	6,369
Annual CP Load Factor	51%	41%	62%	72%	106%	59%	78%	318%	47%	29%	24%

Customer Information	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Weighting Factors for:											
Points of Delivery per Customer		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.2	3.0	1
Customers Meters & Services		**$398.20**	**$442.06**	**$508.55**	**$499.35**	**$474.57**	**$1.00**	**$461.41**	**$237.39**	**$237.39**	**$410.24**
Customer Retail		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Customer Accounting/Metering		1.000	1.000	1.000	202.500	202.500	1.000	1.400	159.700	159.700	2.00
Weighted Number of Customers											
Customers (PODs)	295,476	128,020	14,029	1,628	38	4	22,621	1,102	12.0	3	943
Customers Meters & Services	109,550,796	50,977,161	6,201,781	827,841	18,975	1,898	22,621	508,434	2,849	712	387,030
Customer Retail	295,476	128,020	14,029	1,628	38	4	22,621	1,102	12	3	943
Customer Accounting/Metering	307,704	128,020	14,029	1,628	7,695	810	22,621	1,543	1,916	479	1,887
Provided Services											
Power Purchased from Utility*		1	1	1	1	1	1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1	1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1	1	1	1	1	1
Uses Primary Distribution*		1	1	1	1			1	1		1
Uses Secondary Distribution*		1	1	1				1			1

* (yes=1,no=0)

Updated Application dated May 15, 2025

HISTORIC CUSTOMERS AND ENERGY SALES

Schedule 8.1,Cont'd

Load Data And Customer Sales by Rate Class

Actuals from AMI Analysis

kWh Sales at the Meter	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22	368,150,085	**161,719,440**	**35,837,072**	**57,791,898**	**24,711,603**	**19,497,742**	**849,234**	**825,253**	**54,096,535**	**12,821,308**	**2,103,104**
Feb-22	313,063,171	**133,887,733**	**30,876,199**	**50,640,559**	**22,703,764**	**17,315,581**	**768,838**	**640,926**	**45,110,679**	**11,118,892**	**1,421,856**
Mar-22	295,876,682	**119,113,977**	**29,847,139**	**51,008,656**	**24,660,023**	**18,851,134**	**669,037**	**702,776**	**41,435,733**	**9,588,208**	**951,618**
Apr-22	261,030,683	**102,202,803**	**26,054,415**	**46,307,133**	**22,847,316**	**17,994,231**	**565,540**	**1,359,671**	**36,153,346**	**7,546,228**	**499,684**
May-22	247,687,224	**89,722,611**	**24,837,034**	**46,517,385**	**25,093,392**	**19,178,840**	**474,980**	**3,761,879**	**33,708,633**	**4,392,471**	**400,101**
Jun-22	228,021,812	**82,054,345**	**24,402,693**	**46,977,206**	**24,202,245**	**17,821,146**	**427,851**	**6,734,662**	**24,690,850**	**710,814**	**310,341**
Jul-22	286,147,342	**112,433,532**	**29,876,985**	**57,181,788**	**28,106,034**	**16,526,321**	**451,877**	**9,067,391**	**31,864,683**	**638,731**	**483,732**
Aug-22	302,651,234	**112,168,193**	**30,140,690**	**59,312,666**	**28,402,894**	**17,738,289**	**531,349**	**9,278,978**	**44,295,277**	**782,898**	**702,357**
Sep-22	242,826,830	**83,288,629**	**24,475,632**	**48,782,202**	**24,657,679**	**18,342,421**	**632,074**	**5,629,032**	**33,471,596**	**3,547,565**	**571,949**
Oct-22	236,478,454	**89,228,676**	**24,568,455**	**48,584,586**	**23,708,087**	**17,071,977**	**734,647**	**3,369,930**	**23,627,897**	**5,584,198**	**856,394**
Nov-22	329,068,314	**140,057,606**	**32,166,743**	**54,126,696**	**23,996,074**	**18,909,824**	**827,056**	**1,050,438**	**46,638,295**	**11,295,582**	**2,247,764**
Dec-22	391,262,033	**177,076,358**	**37,494,220**	**59,840,659**	**23,676,460**	**18,482,398**	**876,956**	**934,779**	**58,601,775**	**14,278,428**	**2,942,887**
Total Sales	3,502,263,865	1,402,953,903	350,577,276	627,071,434	296,765,570	217,729,905	7,809,439	43,355,716	473,695,298	82,305,324	13,491,789

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

HISTORIC CUSTOMER DEMAND
Schedule 8.2

kW in AMI data summary

Measured - kW	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22	1,287,421	**786,416**	**117,385**	**148,278**	**64,428**	**29,454**		**4,192**	**106,238**	**31,030**	8,826
Feb-22	1,243,557	**752,280**	**115,358**	**144,834**	**71,112**	**29,913**		**3,541**	**98,432**	**28,087**	8,355
Mar-22	1,170,410	**705,660**	**110,148**	**139,138**	**62,347**	**29,429**		**5,046**	**95,643**	**22,999**	7,648
Apr-22	1,150,468	**683,087**	**107,045**	**135,896**	**67,836**	**29,389**		**16,272**	**86,131**	**24,813**	7,284
May-22	1,076,134	**642,497**	**103,950**	**133,564**	**62,309**	**28,631**		**24,736**	**64,758**	**15,688**	7,013
Jun-22	1,081,961	**631,983**	**108,455**	**145,868**	**61,450**	**28,753**		**27,193**	**62,888**	**15,371**	6,922
Jul-22	1,187,735	**684,776**	**117,956**	**164,418**	**68,692**	**28,822**		**29,276**	**78,743**	**15,053**	7,786
Aug-22	1,199,585	**674,901**	**115,125**	**160,905**	**67,583**	**28,436**		**27,545**	**111,954**	**13,136**	7,895
Sep-22	1,132,133	**641,736**	**110,490**	**153,071**	**64,247**	**28,442**		**25,459**	**91,299**	**17,390**	7,869
Oct-22	1,141,604	**659,524**	**107,497**	**142,935**	**64,822**	**28,140**		**21,772**	**95,270**	**21,644**	8,683
Nov-22	1,279,665	**754,137**	**116,596**	**145,491**	**63,156**	**37,118**		**6,478**	**99,241**	**57,448**	10,749
Dec-22	1,366,563	**837,229**	**124,745**	**156,975**	**61,303**	**29,329**		**4,689**	**119,217**	**33,076**	12,321
Total	14,317,236	8,454,226	1,354,751	1,771,372	779,286	355,855		196,196	1,109,816	295,734	101,351

Individual Load Factor		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22		27.6%	41.0%	58.2%	57.3%	93.7%	67.1%	26.5%	69.1%	56.1%	32.0%
Feb-22		25.6%	38.5%	55.8%	51.0%	87.5%	60.7%	26.0%	66.5%	57.5%	24.5%
Mar-22		22.7%	36.4%	54.7%	59.1%	90.6%	52.3%	18.7%	58.8%	56.6%	16.7%
Apr-22		20.8%	33.8%	52.6%	52.0%	89.5%	43.1%	11.6%	58.9%	42.7%	9.5%
May-22		18.8%	32.1%	52.0%	60.1%	94.8%	34.5%	20.4%	70.7%	38.0%	7.7%
Jun-22		18.0%	31.3%	49.7%	60.8%	90.6%	29.8%	34.4%	55.1%	6.5%	6.2%
Jul-22		22.1%	34.0%	51.9%	61.1%	81.1%	32.2%	41.6%	54.9%	5.8%	8.4%
Aug-22		22.3%	35.2%	55.1%	62.8%	88.3%	39.9%	45.3%	53.7%	8.1%	12.0%
Sep-22		18.0%	30.8%	49.2%	59.2%	94.3%	49.0%	30.7%	51.4%	28.6%	10.1%
Oct-22		18.2%	30.7%	50.8%	54.6%	85.8%	57.8%	20.8%	33.7%	35.0%	13.3%
Nov-22		25.8%	38.3%	57.4%	58.6%	74.5%	65.3%	22.5%	65.9%	27.6%	29.0%
Dec-22		28.4%	40.4%	56.9%	57.7%	89.2%	69.1%	26.8%	66.7%	58.6%	32.1%
		22.4%	35.2%	53.7%	57.9%	88.3%	50.1%	27.1%	58.8%	35.1%	16.8%

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

HISTORIC CUSTOMER DEMAND

Schedule 8.2, Cont'd

Individual NCP (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
	Power Factor:	100%	100%	90%	90%	95%	100%	100%	99%	99%	100%
Jan-22	1,265,007	786,416	117,385	133,450	57,985	27,981	1,702	4,192	105,175	30,720	8,826
Feb-22	1,221,088	752,280	115,358	130,350	64,001	28,417	1,886	3,541	97,448	27,806	8,355
Mar-22	1,149,323	705,660	110,148	125,225	56,113	27,957	1,719	5,046	94,687	22,769	7,648
Apr-22	1,129,339	683,087	107,045	122,306	61,053	27,919	1,823	16,272	85,270	24,565	7,284
May-22	1,056,159	642,497	103,950	120,207	56,078	27,200	1,849	24,736	64,111	15,531	7,013
Jun-22	1,061,005	631,983	108,455	131,281	55,305	27,315	1,997	27,193	62,259	15,217	6,922
Jul-22	1,163,934	684,776	117,956	147,976	61,823	27,380	1,889	29,276	77,956	14,903	7,786
Aug-22	1,175,854	674,901	115,125	144,814	60,825	27,014	1,790	27,545	110,835	13,004	7,895
Sep-22	1,109,685	641,736	110,490	137,764	57,822	27,020	1,793	25,459	90,386	17,216	7,869
Oct-22	1,119,961	659,524	107,497	128,642	58,340	26,733	1,709	21,772	94,318	21,427	8,683
Nov-22	1,257,138	754,137	116,596	130,941	56,840	35,262	1,760	6,478	98,249	56,874	10,749
Dec-22	1,343,451	837,229	124,745	141,278	55,173	27,863	1,705	4,689	118,024	32,745	12,321
Maximum	1,343,451	837,229	124,745	147,976	64,001	35,262	1,997	29,276	118,024	56,874	12,321
	14,051,943	8,454,226	1,354,751	1,594,235	701,358	338,062	21,621	196,196	1,098,718	292,777	101,351
					91.39%						

Group Coincidence Factor		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22		43.63%	54.26%	67.73%	75.58%	97.55%	58.41%	38.17%	96.53%	91.20%	48.65%
Feb-22		38.60%	54.81%	68.91%	74.38%	96.43%	59.04%	38.14%	93.72%	97.52%	47.45%
Mar-22		33.52%	49.69%	64.67%	82.00%	96.86%	55.89%	27.94%	80.47%	95.58%	39.79%
Apr-22		28.89%	45.68%	60.83%	69.60%	95.85%	51.91%	32.80%	76.66%	86.57%	33.94%
May-22		27.03%	43.49%	62.36%	76.97%	97.22%	55.35%	42.98%	91.60%	80.71%	30.50%
Jun-22		36.06%	51.04%	67.50%	74.84%	96.85%	62.29%	61.18%	92.46%	90.29%	41.00%
Jul-22		43.30%	58.42%	72.91%	80.56%	97.14%	63.59%	61.00%	100.00%	97.78%	48.86%
Aug-22		40.40%	56.07%	70.43%	83.23%	98.33%	63.70%	59.74%	84.65%	86.40%	45.04%
Sep-22		39.67%	57.29%	71.34%	83.04%	97.95%	56.30%	60.00%	99.06%	96.05%	44.25%
Oct-22		28.20%	43.10%	62.73%	73.89%	96.99%	52.30%	37.58%	82.15%	74.09%	32.52%
Nov-22		38.14%	60.10%	80.23%	82.79%	92.14%	53.44%	39.91%	99.42%	43.33%	46.56%
Dec-22		46.42%	58.66%	69.04%	83.23%	97.24%	61.51%	36.92%	98.02%	99.19%	52.58%

Rate Class NCP @ Meter (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22		343,117	63,694	90,382	43,826	27,295	994	1,600	101,524	28,018	4,294
Feb-22		290,411	63,226	89,828	47,603	27,404	1,113	1,350	91,332	27,116	3,964
Mar-22		236,532	54,732	80,981	46,012	27,080	961	1,410	76,195	21,761	3,043
Apr-22		197,318	48,901	74,403	42,491	26,761	946	5,337	65,371	21,265	2,472
May-22		173,651	45,206	74,965	43,164	26,444	1,023	10,632	58,726	12,535	2,139
Jun-22		227,890	55,359	88,616	41,389	26,455	1,244	16,637	57,568	13,739	2,838
Jul-22		296,502	68,909	107,896	49,804	26,596	1,201	17,858	77,956	14,572	3,804
Aug-22		272,646	64,555	101,999	50,623	26,563	1,140	16,455	93,827	11,236	3,555
Sep-22		254,546	63,305	98,286	48,013	26,466	1,009	15,275	89,538	16,536	3,482
Oct-22		186,003	46,331	80,693	43,105	25,929	894	8,182	77,478	15,877	2,824
Nov-22		287,600	70,070	105,061	47,060	32,490	941	2,586	97,680	24,645	5,004
Dec-22		388,618	73,179	97,535	45,923	27,095	1,049	1,731	115,687	32,479	6,479
Maximum		388,618	73,179	107,896	50,623	32,490	1,244	17,858	115,687	32,479	6,479
Winter Peak Month		388,618	73,179	105,061	47,603	32,490	1,113	2,586	115,687	32,479	6,479
Summer Peak Month		296,502	68,909	107,896	50,623	27,080	1,244	17,858	93,827	21,761	3,804

FortisBC 2025 COSA for Electric Service Prepared By EES Consulting, Inc.

HISTORIC CUSTOMER DEMAND

Schedule 8.2, Cont'd

Rate Class NCP @ Primary Voltage (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
	Line Losses:	5.08%	5.08%	5.08%			5.08%	5.08%			5.08%
Jan-22		360,561	66,932	94,977	43,826	27,295	1,045	1,682	101,524	28,018	4,512
Feb-22		305,175	66,440	94,395	47,603	27,404	1,170	1,419	91,332	27,116	4,166
Mar-22		248,557	57,515	85,098	46,012	27,080	1,010	1,482	76,195	21,761	3,198
Apr-22		207,350	51,387	78,186	42,491	26,761	994	5,609	65,371	21,265	2,598
May-22		182,480	47,505	78,776	43,164	26,444	1,075	11,173	58,726	12,535	2,248
Jun-22		239,475	58,173	93,121	41,389	26,455	1,307	17,483	57,568	13,739	2,983
Jul-22		311,576	72,412	113,382	49,804	26,596	1,262	18,766	77,956	14,572	3,998
Aug-22		286,507	67,837	107,184	50,623	26,563	1,198	17,291	93,827	11,236	3,736
Sep-22		267,487	66,523	103,282	48,013	26,466	1,061	16,052	89,538	16,536	3,659
Oct-22		195,459	48,686	84,795	43,105	25,929	939	8,598	77,478	15,877	2,967
Nov-22		302,221	73,632	110,402	47,060	32,490	988	2,717	97,680	24,645	5,259
Dec-22		408,375	76,899	102,494	45,923	27,095	1,102	1,819	115,687	32,479	6,808
Maximum		408,375	76,899	113,382	50,623	32,490	1,307	18,766	115,687	32,479	6,808
Winter Peak Month		408,375	76,899	110,402	47,603	32,490	1,170	2,717	115,687	32,479	6,808
Summer Peak Month		311,576	72,412	113,382	50,623	27,080	1,307	18,766	93,827	21,761	3,998

Rate Class NCP @ Input Voltage (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
	Line Losses:	4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%
Jan-22	756,641	376,263	69,847	99,113	45,735	28,075	1,090	1,755	105,945	28,818	4,709
Feb-22	690,070	318,466	69,334	98,506	49,677	28,186	1,221	1,481	95,310	27,890	4,347
Mar-22	588,570	259,382	60,019	88,804	48,016	27,853	1,053	1,546	79,513	22,382	3,337
Apr-22	520,442	216,380	53,625	81,591	44,341	27,525	1,038	5,853	68,218	21,872	2,711
May-22	481,408	190,427	49,573	82,207	45,044	27,199	1,122	11,659	61,284	12,892	2,346
Jun-22	572,004	249,905	60,706	97,177	43,191	27,211	1,364	18,244	60,075	14,131	3,112
Jul-22	715,598	325,145	75,566	118,319	51,973	27,355	1,317	19,583	81,351	14,988	4,172
Aug-22	690,542	298,985	70,791	111,852	52,828	27,322	1,251	18,044	97,913	11,557	3,899
Sep-22	661,966	279,136	69,420	107,780	50,104	27,222	1,107	16,751	93,438	17,008	3,818
Oct-22	522,050	203,971	50,807	88,488	44,982	26,669	980	8,972	80,852	16,330	3,096
Nov-22	721,108	315,383	76,839	115,210	49,109	33,418	1,031	2,835	101,934	25,349	5,488
Dec-22	846,336	426,159	80,248	106,957	47,923	27,868	1,150	1,899	120,726	33,406	7,105
Maximum	846,336	426,159	80,248	118,319	52,828	33,418	1,364	19,583	120,726	33,406	7,105
Winter Peak Month	7,766,734	426,159	80,248	115,210	49,677	33,418	1,221	2,835	120,726	33,406	7,105
Summer Peak Month		325,145	75,566	118,319	52,828	27,853	1,364	19,583	97,913	22,382	4,172

System Coincidence Factor		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22		89.57%	78.72%	86.15%	70.72%	82.64%	100.00%	76.36%	96.79%	98.21%	90.13%
Feb-22		84.28%	81.04%	91.51%	78.51%	120.85%	100.00%	71.24%	96.79%	91.42%	84.24%
Mar-22		86.24%	80.01%	91.58%	85.71%	69.29%	100.00%	66.50%	93.45%	98.21%	91.19%
Apr-22		91.19%	82.41%	96.45%	89.93%	129.81%	100.00%	33.57%	96.79%	78.07%	74.28%
May-22		75.40%	83.05%	94.27%	86.51%	109.66%		55.71%	89.86%	85.32%	19.07%
Jun-22		88.53%	76.45%	90.93%	95.47%	96.41%		69.30%	96.79%	17.15%	28.52%
Jul-22		91.19%	76.21%	91.33%	96.83%	42.75%		70.28%	97.15%	82.37%	56.83%
Aug-22		90.78%	75.42%	92.09%	77.40%	84.07%		71.13%	95.52%	13.33%	50.54%
Sep-22		91.19%	72.80%	88.98%	83.83%	86.38%		61.56%	95.05%	55.77%	65.26%
Oct-22		91.19%	68.48%	78.13%	85.36%	125.47%	100.00%	29.73%	55.48%	92.25%	89.72%
Nov-22		91.19%	68.39%	75.16%	74.14%	126.49%	100.00%	48.59%	91.71%	95.22%	84.86%
Dec-22		91.19%	81.07%	92.51%	66.58%	150.58%	100.00%	82.02%	95.24%	96.70%	89.64%
								61.33%	91.72%		69%

HISTORIC CUSTOMER DEMAND
Schedule 8.2, Cont'd

Coincident Peak (CP) @ Input (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22	666,217	337,024	54,981	85,386	32,343	23,202	1,090	1,340	102,549	28,301	4,244
Feb-22	607,841	268,414	56,188	90,146	39,003	*34,062*	1,221	1,055	92,255	25,498	3,662
Mar-22	511,860	223,687	48,023	81,323	41,157	19,300	1,053	1,028	74,308	21,981	3,043
Apr-22	481,918	197,318	44,191	78,692	39,877	*35,730*	1,038	1,965	66,032	17,075	2,014
May-22	403,607	143,580	41,169	77,497	38,968	29,827		6,496	55,071	11,000	447
Jun-22	496,711	221,250	46,409	88,365	41,234	26,235		12,644	58,149	2,424	888
Jul-22	629,312	296,502	57,589	108,058	50,327	11,693		13,764	79,033	12,345	2,371
Aug-22	599,578	271,424	53,390	103,007	40,886	22,969		12,835	93,525	1,541	1,971
Sep-22	575,116	254,546	50,538	95,901	42,004	23,513		10,312	88,817	9,486	2,492
Oct-22	425,358	186,003	34,793	69,137	38,396	33,461	980	2,667	44,858	15,064	2,778
Nov-22	625,443	287,600	52,548	86,591	36,408	42,272	1,031	1,378	93,479	24,136	4,657
Dec-22	776,480	388,618	65,056	98,950	31,907	41,965	1,150	1,557	114,973	32,304	6,369
Total	6,799,441	3,075,966	604,875	1,063,053	472,510	344,228	7,564	67,041	963,049	201,155	34,936
Peak Month	776,480	388,618	65,056	98,950	31,907	41,965	1,150	1,557	114,973	32,304	6,369
Winter Peak Month	776,480	388,618	65,056	98,950	41,157	42,272	1,221	1,557	114,973	32,304	6,369
Summer Peak Month	629,312	296,502	57,589	108,058	50,327	35,730	1,038	13,764	93,525	17,075	2,778

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

HISTORIC kWh AT INPUT
Schedule 8.3

kWh @ Input Voltage	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-22	399,481,415	178,579,364	39,572,269	63,815,386	25,836,796	20,070,762	937,747	911,266	56,559,711	13,198,114	2,322,305
Feb-22	339,584,568	147,842,476	34,094,339	55,918,683	23,737,533	17,824,470	848,972	707,727	47,164,702	11,445,666	1,570,053
Mar-22	320,707,171	131,528,771	32,958,022	56,325,145	25,782,867	19,405,151	738,769	776,024	43,322,424	9,869,997	1,050,803
Apr-22	282,862,781	112,855,115	28,769,994	51,133,596	23,887,622	18,523,065	624,484	1,501,386	37,799,515	7,768,004	551,764
May-22	268,287,597	99,074,147	27,425,728	51,365,761	26,235,968	19,742,488	524,485	4,153,970	35,243,487	4,521,562	441,802
Jun-22	247,531,246	90,606,639	26,946,118	51,873,508	25,304,245	18,344,893	472,445	7,436,597	25,815,098	731,705	342,687
Jul-22	311,167,142	124,152,164	32,990,979	63,141,686	29,385,785	17,012,014	498,975	10,012,459	33,315,576	657,503	534,150
Aug-22	328,542,669	123,859,169	33,282,169	65,494,659	29,696,162	18,259,601	586,730	10,246,100	46,312,172	805,907	775,562
Sep-22	263,085,931	91,969,570	27,026,658	53,866,634	25,780,416	18,881,487	697,953	6,215,730	34,995,657	3,651,825	631,562
Oct-22	256,652,045	98,528,731	27,129,156	53,648,421	24,787,587	17,573,706	811,218	3,721,169	24,703,745	5,748,312	945,654
Nov-22	356,959,835	154,655,418	35,519,392	59,768,170	25,088,686	19,465,566	913,257	1,159,923	48,761,874	11,627,549	2,482,042
Dec-22	424,766,979	195,538,349	41,402,138	66,077,683	24,754,519	19,025,578	968,359	1,032,209	61,270,087	14,698,057	3,249,616
Total Purchases - Bottom Up	3,799,629,380	1,549,189,914	387,116,963	692,429,333	310,278,185	224,128,782	8,623,395	47,874,560	495,264,047	84,724,199	14,898,000
	3,619,089										

Historic Load Reconciliation	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Secondary Line Losses		**5.08%**	5.08%	5.08%			5.08%	5.08%			5.08%
Primary Line Losses		4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%
	-9.4%	9.44%									

	Actual Gross Energy MWh	Bottom-Up Energy MWh	*% Difference*
Total	3,863,956	3,799,629	**1.7%**
Jan-22	**402,340**	399,481	0.7%
Feb-22	**339,886**	339,585	0.1%
Mar-22	**322,306**	320,707	0.5%
Apr-22	**284,470**	282,863	0.6%
May-22	**273,057**	268,288	1.8%
Jun-22	**264,013**	247,531	6.7%
Jul-22	**324,883**	311,167	4.4%
Aug-22	**327,668**	328,543	-0.3%
Sep-22	**263,342**	263,086	0.1%
Oct-22	**270,265**	256,652	5.3%
Nov-22	**362,941**	356,960	1.7%
Dec-22	**428,785**	424,767	0.9%

	Actual Gross System Peak MW	CP @ Input Demand kW	*% Difference*
Total	7,568	6,799	11.3%
Jan-22	**732**	666	9.9%
Feb-22	**678**	608	11.5%
Mar-22	**577**	512	12.7%
Apr-22	**507**	482	5.2%
May-22	**463**	404	14.7%
Jun-22	**565**	497	13.7%
Jul-22	**720**	629	14.4%
Aug-22	**688**	600	14.7%
Sep-22	**627**	575	9.0%
Oct-22	**478**	425	12.4%
Nov-22	**698**	625	11.6%
Dec-22	**835**	776	7.5%

FortisBC 2025 COSA for Electric Service **Prepared By EES Consulting, Inc.**

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.4

Number of Customers / Services	Total	Residential	Small General Service	General Service	Industrial Primary	Rate 31 Industrial	Lighting	Irrigation	Wholesale Primary	Wholesale Transmission	Net Metering
Jan-24	150,713	**131,139**	**15,295**	**1,790**	**38**	**4**	**1,341**	**1,094**	**10**	**1**	**847**
Feb-24	150,972	**131,392**	**15,304**	**1,788**	**38**	**4**	**1,341**	**1,093**	**10**	**1**	**865**
Mar-24	151,130	**131,554**	**15,309**	**1,776**	**38**	**4**	**1,341**	**1,097**	**10**	**1**	**879**
Apr-24	151,473	**131,886**	**15,319**	**1,775**	**38**	**4**	**1,341**	**1,099**	**10**	**1**	**902**
May-24	151,788	**132,179**	**15,328**	**1,778**	**38**	**4**	**1,341**	**1,108**	**10**	**1**	**926**
Jun-24	152,054	**132,435**	**15,336**	**1,781**	**38**	**4**	**1,341**	**1,109**	**10**	**1**	**960**
Jul-24	152,198	**132,547**	**15,368**	**1,782**	**38**	**4**	**1,341**	**1,107**	**10**	**1**	**995**
Aug-24	152,322	**132,664**	**15,376**	**1,780**	**38**	**4**	**1,341**	**1,108**	**10**	**1**	**1,019**
Sep-24	152,600	**132,949**	**15,375**	**1,778**	**38**	**4**	**1,341**	**1,104**	**10**	**1**	**1,053**
Oct-24	152,763	**133,126**	**15,364**	**1,773**	**38**	**4**	**1,341**	**1,106**	**10**	**1**	**1,073**
Nov-24	152,951	**133,291**	**15,382**	**1,778**	**38**	**4**	**1,341**	**1,106**	**10**	**1**	**1,091**
Dec-24	153,168	**133,506**	**15,378**	**1,785**	**38**	**4**	**1,341**	**1,104**	**10**	**1**	**1,099**
Total Average	152,011	132,389	15,345	1,780	38	4	1,341	1,103	10	1	976
2024 Projected Evidentiary Update	152,000	132,389	17,125		38	4	1,341	1,103			

Historic Energy, Demand And Customer Count
Historic Year

	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Input Recorded Data											
Energy Sales (kWh)	3,396,293,260	1,299,000,000	349,268,877	624,731,123	268,127,895	218,165,365	9,000,000	38,000,000	506,820,191	83,179,809	12,492,095
Total Billing Capacity (kVa)											
Avg. Monthly Billing Capacity (kVa)											
Number of Customers	284,400	132,389	15,345	1,780	38	4	1,341	1,103	10	1	976
Ratio of NCP to Avg. Billing Capacity											
Rate Classes NCP Demand at Meter	1,152,126	359,822	72,905	107,494	45,738	32,555	1,433	15,652	123,777	32,824	5,999
Estimated Based on Recorded Data											
Annual NCP Load Factor	49%	41%	55%	66%	67%	76%	72%	28%	47%	29%	24%
Rate Classes CP Demand at Input Voltage	1,149,022	359,822	64,813	107,654	45,471	42,356	1,359	12,064	123,013	32,647	5,897
Annual CP Load Factor	51%	41%	62%	72%	106%	59%	78%	318%	47%	29%	24%

Customer Information	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Weighting Factors for:											
Points of Delivery per Customer		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.2	3.0	1
Customers Meters & Services		**$398.20**	**$442.06**	**$508.55**	**$499.35**	**$474.57**	**$1.00**	**$461.41**	**$237.39**	**$237.39**	**410.2**
Customer Retail		1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Customer Accounting/Metering		1.0	1.0	1.0	500.0	500.0	1.0	1.0	500.0	500.0	2.0
Weighted Number of Customers											
Customers (PODs)	284,404	132,389	15,345	1,780	38	4	1,341	1,103	12	3	976
Customers Meters & Services	113,669,220	52,717,020	6,783,260	905,459	18,975	1,898	1,341	508,934	2,849	712	400,239
Customer Retail	152,015	132,389	15,345	1,780	38	4	1,341	1,103	12	3	-
Customer Accounting/Metering	313,823	132,389	15,345	1,780	19,000	2,000	1,341	1,103	6,000	1,500	1,951
Provided Services											
Power Purchased from Utility*		1	1	1	1	1	1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1	1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1	1	1	1	1	1
Uses Primary Distribution*		1	1	1	1		1	1	1		1
Uses Secondary Distribution*		1	1	1			1	1			1

* (yes=1,no=0)

Updated Application dated May 15, 2025

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.4, Cont'd

Load Data And Customer Sales by Rate Class

kWh Sales at the Meter	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24	357,418,804	149,736,603	35,703,323	57,576,212	22,326,950	19,536,738	978,701	723,309	57,879,435	12,957,533	1,947,272
Feb-24	303,992,773	123,967,127	30,760,965	50,451,562	20,512,866	17,350,212	886,049	561,752	48,265,210	11,237,029	1,316,502
Mar-24	287,421,625	110,288,054	29,735,745	50,818,285	22,280,348	18,888,837	771,033	615,962	44,333,279	9,690,082	881,107
Apr-24	253,545,586	94,629,938	25,957,177	46,134,309	20,642,565	18,030,220	651,757	1,191,712	38,681,502	7,626,406	462,659
May-24	240,401,234	83,074,484	24,744,339	46,343,776	22,671,897	19,217,198	547,391	3,297,176	36,065,833	4,439,141	370,455
Jun-24	220,343,067	75,974,409	24,311,619	46,801,881	21,866,745	17,856,788	493,078	5,902,731	26,417,449	718,367	287,346
Jul-24	275,996,182	104,102,606	29,765,480	56,968,379	25,393,821	16,559,374	520,767	7,947,299	34,092,939	645,517	447,889
Aug-24	293,341,339	103,856,928	30,028,201	59,091,304	25,662,034	17,773,766	612,354	8,132,750	47,392,788	791,216	650,315
Sep-24	235,818,592	77,117,237	24,384,285	48,600,141	22,278,230	18,379,106	728,435	4,933,680	35,812,221	3,585,258	529,570
Oct-24	228,747,550	82,617,148	24,476,763	48,403,262	21,420,273	17,106,121	846,645	2,953,644	25,280,165	5,643,530	792,939
Nov-24	319,468,394	129,679,835	32,046,693	53,924,688	21,680,469	18,947,644	953,142	920,678	49,899,650	11,415,596	2,081,213
Dec-24	379,798,113	163,955,629	37,354,287	59,617,326	21,391,697	18,519,363	1,010,650	819,307	62,699,720	14,430,134	2,724,829
Total Sales	3,396,293,260	1,299,000,000	349,268,877	624,731,123	268,127,895	218,165,365	9,000,000	38,000,000	506,820,191	83,179,809	12,492,095

FortisBC 2025 COSA for Electric Service

Prepared By EES Consulting, Inc.

FORECAST CUSTOMER DEMAND
Schedule 8.5

Individual Load Factor		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24		27.6%	41.0%	58.2%	57.3%	93.7%	67.1%	26.5%	69.1%	56.1%	32.0%
Feb-24		25.6%	38.5%	55.8%	51.0%	87.5%	60.7%	26.0%	66.5%	57.5%	24.5%
Mar-24		22.7%	36.4%	54.7%	59.1%	90.6%	52.3%	18.7%	58.8%	56.6%	16.7%
Apr-24		20.8%	33.8%	52.6%	52.0%	89.5%	43.1%	11.6%	58.9%	42.7%	9.5%
May-24		18.8%	32.1%	52.0%	60.1%	94.8%	34.5%	20.4%	70.7%	38.0%	7.7%
Jun-24		18.0%	31.3%	49.7%	60.8%	90.6%	29.8%	34.4%	55.1%	6.5%	6.2%
Jul-24		22.1%	34.0%	51.9%	61.1%	81.1%	32.2%	41.6%	54.9%	5.8%	8.4%
Aug-24		22.3%	35.2%	55.1%	62.8%	88.3%	39.9%	45.3%	53.7%	8.1%	12.0%
Sep-24		18.0%	30.8%	49.2%	59.2%	94.3%	49.0%	30.7%	51.4%	28.6%	10.1%
Oct-24		18.2%	30.7%	50.8%	54.6%	85.8%	57.8%	20.8%	33.7%	35.0%	13.3%
Nov-24		25.8%	38.3%	57.4%	58.6%	74.5%	65.3%	22.5%	65.9%	27.6%	29.0%
Dec-24		28.4%	40.4%	56.9%	57.7%	89.2%	69.1%	26.8%	66.7%	58.6%	32.1%
		22.4%	35.2%	53.7%	57.9%	88.3%	50.1%	27.1%	58.8%	35.1%	16.8%

Individual NCP (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
	Power Factor:	100%	100%	100%	90%	95%	100%	100%	99.0%		
Jan-24	1,207,684	728,145	116,946	132,952	52,390	28,037	1,961	3,674	112,530	31,046	8,172
Feb-24	1,165,195	696,539	114,928	129,864	57,825	28,474	2,098	3,103	104,262	28,102	7,736
Mar-24	1,097,301	653,373	109,737	124,757	50,698	28,013	1,981	4,422	101,308	23,011	7,081
Apr-24	1,076,525	632,473	106,645	121,850	55,161	27,975	2,101	14,262	91,233	24,826	6,744
May-24	1,004,233	594,891	103,562	119,759	50,667	27,254	2,131	21,680	68,594	15,696	6,493
Jun-24	1,009,461	585,155	108,050	130,791	49,968	27,370	2,301	23,834	66,613	15,379	6,409
Jul-24	1,108,572	634,036	117,516	147,424	55,857	27,435	2,177	25,659	83,407	15,061	7,209
Aug-24	1,123,819	624,893	114,695	144,274	54,955	27,068	2,063	24,142	118,585	13,143	7,310
Sep-24	1,059,314	594,185	110,078	137,250	52,242	27,074	2,066	22,314	96,707	17,399	7,286
Oct-24	1,069,029	610,655	107,096	128,162	52,710	26,786	1,969	19,082	100,913	21,655	8,039
Nov-24	1,201,863	698,258	116,161	130,453	51,355	35,333	2,028	5,678	105,119	57,478	9,952
Dec-24	1,283,436	775,193	124,280	140,750	49,849	27,918	1,965	4,109	126,278	33,093	11,408
Maximum	1,283,436	775,193	124,280	147,424	57,825	35,333	2,301	25,659	126,278	57,478	11,408
Total	13,406,433	7,827,798	1,349,694	1,588,285	633,677	338,738	24,842	171,960	1,175,550	295,887	93,841

FortisBC 2025 COSA for Electric Service

FORECAST CUSTOMER DEMAND
Schedule 8.5, Cont'd

Group Coincidence Factor		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24		43.63%	54.26%	67.73%	75.58%	97.55%	58.41%	38.17%	96.53%	91.20%	48.65%
Feb-24		38.60%	54.81%	68.91%	74.38%	96.43%	59.04%	38.14%	93.72%	97.52%	47.45%
Mar-24		33.52%	49.69%	64.67%	82.00%	96.86%	55.89%	27.94%	80.47%	95.58%	39.79%
Apr-24		28.89%	45.68%	60.83%	69.60%	95.85%	51.91%	32.80%	76.66%	86.57%	33.94%
May-24		27.03%	43.49%	62.36%	76.97%	97.22%	55.35%	42.98%	91.60%	80.71%	30.50%
Jun-24		36.06%	51.04%	67.50%	74.84%	96.85%	62.29%	61.18%	92.46%	90.29%	41.00%
Jul-24		43.30%	58.42%	72.91%	80.56%	97.14%	63.59%	61.00%	100.00%	97.78%	48.86%
Aug-24		40.40%	56.07%	70.43%	83.23%	98.33%	63.70%	59.74%	84.65%	86.40%	45.04%
Sep-24		39.67%	57.29%	71.34%	83.04%	97.95%	56.30%	60.00%	99.06%	96.05%	44.25%
Oct-24		28.20%	43.10%	62.73%	73.89%	96.99%	52.30%	37.58%	82.15%	74.09%	32.52%
Nov-24		38.14%	60.10%	80.23%	82.79%	92.14%	53.44%	39.91%	99.42%	43.33%	46.56%
Dec-24		46.42%	58.66%	69.04%	83.23%	97.24%	61.51%	36.92%	98.02%	99.19%	52.58%
											42.6%

Rate Class NCP @ Meter (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24		317,693	63,456	90,045	39,597	27,350	1,146	1,403	108,623	28,316	3,976
Feb-24		268,893	62,990	89,493	43,010	27,459	1,239	1,184	97,719	27,404	3,671
Mar-24		219,006	54,528	80,679	41,572	27,134	1,107	1,236	81,523	21,992	2,818
Apr-24		182,698	48,718	74,126	38,390	26,814	1,091	4,678	69,943	21,491	2,289
May-24		160,784	45,038	74,685	38,999	26,497	1,179	9,319	62,833	12,668	1,981
Jun-24		211,004	55,152	88,285	37,395	26,508	1,433	14,582	61,593	13,885	2,628
Jul-24		274,532	68,652	107,494	44,998	26,649	1,384	15,652	83,407	14,727	3,522
Aug-24		252,444	64,314	101,618	45,738	26,616	1,314	14,422	100,388	11,355	3,292
Sep-24		235,685	63,068	97,919	43,380	26,519	1,163	13,388	95,800	16,712	3,224
Oct-24		172,220	46,158	80,392	38,945	25,981	1,030	7,171	82,896	16,045	2,614
Nov-24		266,290	69,808	104,669	42,519	32,555	1,084	2,266	104,511	24,907	4,633
Dec-24		359,822	72,905	97,171	41,491	27,149	1,209	1,517	123,777	32,824	5,999
Maximum		359,822	72,905	107,494	45,738	32,555	1,433	15,652	123,777	32,824	5,999
Winter Peak Month		359,822	72,905	104,669	43,010	32,555	1,239	2,266	123,777	32,824	5,999
Summer Peak Month		274,532	68,652	107,494	45,738	27,134	1,433	15,652	100,388	21,992	3,522

Rate Class NCP @ Primary Voltage (kW)		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
	Line Losses:	5.08%	5.08%	5.08%			5.08%	5.08%			5.08%
Jan-24		333,845	66,682	94,623	39,597	27,350	1,204	1,474	108,623	28,316	4,178
Feb-24		282,563	66,192	94,043	43,010	27,459	1,302	1,244	97,719	27,404	3,857
Mar-24		230,140	57,300	84,780	41,572	27,134	1,163	1,299	81,523	21,992	2,961
Apr-24		191,986	51,195	77,894	38,390	26,814	1,146	4,916	69,943	21,491	2,405
May-24		168,959	47,327	78,482	38,999	26,497	1,239	9,793	62,833	12,668	2,081
Jun-24		221,731	57,956	92,774	37,395	26,508	1,506	15,323	61,593	13,885	2,762
Jul-24		288,489	72,142	112,958	44,998	26,649	1,454	16,448	83,407	14,727	3,702
Aug-24		265,278	67,583	106,784	45,738	26,616	1,381	15,155	100,388	11,355	3,459
Sep-24		247,667	66,275	102,897	43,380	26,519	1,222	14,069	95,800	16,712	3,388
Oct-24		180,976	48,505	84,479	38,945	25,981	1,082	7,535	82,896	16,045	2,747
Nov-24		279,828	73,357	109,990	42,519	32,555	1,139	2,381	104,511	24,907	4,869
Dec-24		378,116	76,612	102,111	41,491	27,149	1,270	1,595	123,777	32,824	6,304
Maximum		378,116	76,612	112,958	45,738	32,555	1,506	16,448	123,777	32,824	6,304
Winter Peak Month		378,116	76,612	109,990	43,010	32,555	1,302	2,381	123,777	32,824	6,304
Summer Peak Month		288,489	72,142	112,958	45,738	27,134	1,506	16,448	100,388	21,992	3,702

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FORECAST CUSTOMER DEMAND
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Rate Class NCP @ Input Voltage (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
	Line Losses:	4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%
Jan-24	731,438	348,383	69,586	98,744	41,321	28,131	1,256	1,538	113,354	29,124	4,360
Feb-24	668,025	294,868	69,075	98,138	44,883	28,243	1,359	1,298	101,975	28,186	4,025
Mar-24	569,985	240,163	59,795	88,473	43,383	27,909	1,214	1,355	85,073	22,620	3,090
Apr-24	504,118	200,347	53,425	81,286	40,062	27,580	1,196	5,130	72,989	22,104	2,510
May-24	465,667	176,317	49,388	81,900	40,697	27,254	1,293	10,219	65,569	13,029	2,172
Jun-24	551,089	231,388	60,480	96,814	39,023	27,265	1,572	15,991	64,276	14,281	2,882
Jul-24	689,451	301,053	75,284	117,878	46,958	27,410	1,518	17,164	87,039	15,147	3,863
Aug-24	667,594	276,831	70,527	111,435	47,730	27,376	1,441	15,815	104,760	11,679	3,610
Sep-24	640,656	258,453	69,161	107,378	45,269	27,276	1,276	14,682	99,972	17,189	3,535
Oct-24	506,998	188,857	50,617	88,158	40,641	26,722	1,129	7,864	86,506	16,503	2,867
Nov-24	699,555	292,014	76,552	114,780	44,370	33,485	1,189	2,485	109,062	25,618	5,081
Dec-24	818,230	394,582	79,948	106,558	43,298	27,924	1,326	1,664	129,168	33,761	6,578
Maximum	818,230	394,582	79,948	117,878	47,730	33,485	1,572	17,164	129,168	33,761	6,578
Winter Peak Month	7,512,806	394,582	79,948	114,780	44,883	33,485	1,359	2,485	129,168	33,761	6,578
Summer Peak Month		301,053	75,284	117,878	47,730	27,909	1,572	17,164	104,760	22,620	3,863

System Coincidence Factor		Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24		89.57%	78.72%	86.15%	70.72%	82.64%	100.00%	76.36%	96.79%	98.21%	90.13%
Feb-24		84.28%	81.04%	91.51%	78.51%	120.85%	100.00%	71.24%	96.79%	91.42%	84.24%
Mar-24		86.24%	80.01%	91.58%	85.71%	69.29%	100.00%	66.50%	93.45%	98.21%	91.19%
Apr-24		91.19%	82.41%	96.45%	89.93%	129.81%	100.00%	33.57%	96.79%	78.07%	74.28%
May-24		75.40%	83.05%	94.27%	86.51%	109.66%		55.71%	89.86%	85.32%	19.07%
Jun-24		88.53%	76.45%	90.93%	95.47%	96.41%		69.30%	96.79%	17.15%	28.52%
Jul-24		91.19%	76.21%	91.33%	96.83%	42.75%		70.28%	97.15%	82.37%	56.83%
Aug-24		90.78%	75.42%	92.09%	77.40%	84.07%		71.13%	95.52%	13.33%	50.54%
Sep-24		91.19%	72.80%	88.98%	83.83%	86.38%		61.56%	95.05%	55.77%	65.26%
Oct-24		91.19%	68.48%	78.13%	85.36%	125.47%	100.00%	29.73%	55.48%	92.25%	89.72%
Nov-24		91.19%	68.39%	75.16%	74.14%	126.49%	100.00%	48.59%	91.71%	95.22%	84.86%
Dec-24		91.19%	81.07%	92.51%	66.58%	150.58%	100.00%	82.02%	95.24%	96.70%	89.64%
											68.7%

Coincident Peak (CP) @ Input (kW)	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24	645,119	312,052	54,776	85,068	29,222	23,248	1,256	1,175	109,720	28,602	3,930
Feb-24	590,440	248,525	55,978	89,809	35,239	34,130	1,359	925	98,706	25,769	3,391
Mar-24	496,333	207,112	47,844	81,020	37,185	19,338	1,214	901	79,504	22,215	2,818
Apr-24	467,776	182,698	44,026	78,398	36,029	35,801	1,196	1,722	70,649	17,257	1,865
May-24	391,990	132,942	41,015	77,208	35,207	29,887		5,693	58,922	11,117	414
Jun-24	478,418	204,857	46,236	88,035	37,255	26,287		11,082	62,215	2,450	822
Jul-24	605,849	274,532	57,374	107,654	45,471	11,717		12,064	84,560	12,477	2,195
Aug-24	579,954	251,313	53,191	102,623	36,941	23,015		11,250	100,066	1,557	1,825
Sep-24	556,740	235,685	50,350	95,543	37,950	23,560		9,038	95,028	9,586	2,307
Oct-24	410,667	172,220	34,663	68,879	34,691	33,528	1,129	2,338	47,995	15,224	2,572
Nov-24	606,965	266,290	52,352	86,268	32,895	42,356	1,189	1,208	100,016	24,392	4,312
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	5,897
Total	6,582,694	2,848,048	602,618	1,059,085	426,913	344,917	8,668	58,759	1,030,393	203,293	32,347
Peak Month	752,444	359,822	64,813	107,654	45,471	42,356	1,359	12,064	123,013	32,647	5,897
Winter Peak Month		359,822	64,813	98,581	37,185	42,356	1,359	1,365	123,013	32,647	5,897
Summer Peak Month		274,532	57,374	107,654	45,471	35,801	1,196	12,064	100,066	17,257	2,572

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FortisBC 2025 COSA for Electric Service

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CP (kW) Net Amount	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24	645,119	312,052	54,776	85,068	29,222	23,248	1,256	1,175	109,720	28,602	3,930
Feb-24	590,440	248,525	55,978	89,809	35,239	34,130	1,359	925	98,706	25,769	3,391
Mar-24	496,333	207,112	47,844	81,020	37,185	19,338	1,214	901	79,504	22,215	2,818
Apr-24	467,776	182,698	44,026	78,398	36,029	35,801	1,196	1,722	70,649	17,257	1,865
May-24	391,990	132,942	41,015	77,208	35,207	29,887		5,693	58,922	11,117	414
Jun-24	478,418	204,857	46,236	88,035	37,255	26,287		11,082	62,215	2,450	822
Jul-24	605,849	274,532	57,374	107,654	45,471	11,717		12,064	84,560	12,477	2,195
Aug-24	579,954	251,313	53,191	102,623	36,941	23,015		11,250	100,066	1,557	1,825
Sep-24	556,740	235,685	50,350	95,543	37,950	23,560		9,038	95,028	9,586	2,307
Oct-24	410,667	172,220	34,663	68,879	34,691	33,528	1,129	2,338	47,995	15,224	2,572
Nov-24	606,965	266,290	52,352	86,268	32,895	42,356	1,189	1,208	100,016	24,392	4,312
Dec-24	752,444	359,822	64,813	98,581	28,828	42,049	1,326	1,365	123,013	32,647	5,897
Total	6,582,694	2,848,048	602,618	1,059,085	426,913	344,917	8,668	58,759	1,030,393	203,293	32,347
Peak Month	752,444	359,822	64,813	107,654	45,471	42,356	1,359	12,064	123,013	32,647	5,897
Winter Peak Month	752,444	359,822	64,813	98,581	37,185	42,356	1,359	2,338	123,013	32,647	5,897
Summer Peak Month	605,849	274,532	57,374	107,654	45,471	29,887		12,064	100,066	12,477	2,307

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FortisBC 2025 COSA for Electric Service

FORECAST kWh AT INPUT
Schedule 8.6

kWh @ Input Voltage	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Jan-24	387,532,102	165,343,230	39,424,580	63,577,219	23,343,563	20,110,904	1,080,708	798,698	60,514,857	13,338,343	2,150,230
Feb-24	329,500,795	136,887,873	33,967,094	55,709,987	21,446,877	17,860,119	978,399	620,302	50,462,868	11,567,275	1,453,717
Mar-24	311,330,146	121,783,069	32,835,019	56,114,932	23,294,838	19,443,962	851,396	680,162	46,351,905	9,974,864	972,942
Apr-24	274,569,857	104,492,952	28,662,621	50,942,759	21,582,483	18,560,111	719,688	1,315,920	40,442,785	7,850,538	510,881
May-24	260,239,618	91,733,105	27,323,372	51,174,058	23,704,215	19,781,973	604,444	3,640,831	37,708,018	4,569,603	409,066
Jun-24	239,084,674	83,893,009	26,845,551	51,679,909	22,862,403	18,381,582	544,470	6,517,956	27,620,314	739,479	317,295
Jul-24	299,983,379	114,952,929	32,867,852	62,906,033	26,550,077	17,046,038	575,045	8,775,624	35,645,291	664,488	494,572
Aug-24	318,238,220	114,681,645	33,157,956	65,250,225	26,830,502	18,296,120	676,177	8,980,403	49,550,722	814,469	718,096
Sep-24	255,343,957	85,154,951	26,925,791	53,665,597	23,292,624	18,919,250	804,357	5,447,904	37,442,857	3,690,625	584,765
Oct-24	248,145,679	91,228,102	27,027,907	53,448,198	22,395,601	17,608,854	934,889	3,261,494	26,431,246	5,809,388	875,584
Nov-24	346,292,021	143,196,001	35,386,830	59,545,107	22,667,645	19,504,497	1,052,485	1,016,638	52,171,728	11,751,090	2,298,132
Dec-24	411,981,845	181,044,265	41,247,620	65,831,073	22,365,725	19,063,629	1,115,987	904,701	65,554,624	14,854,222	3,008,831
Total Purchases - Bottom Up	3,682,242,292	1,434,391,131	385,672,193	689,845,098	280,336,552	224,577,040	9,938,045	41,960,634	529,897,215	85,624,385	13,794,111
	420,347										

Historic Load Reconciliation	Total	Residential	Small Commercial 20	Commercial 21/22	Large Comm Primary 30/32	Large Comm Transmission 31	Lighting	Irrigation	Wholesale Primary 40	Wholesale Transmission 41	Net Metering
Secondary Line Losses		5.08%	5.08%	5.08%			5.08%	5.08%			5.08%
Primary Line Losses		4.36%	4.36%	4.36%	4.36%	2.86%	4.36%	4.36%	4.36%	2.86%	4.36%

8 Appendix B – Minimum System Analysis

As discussed in the body of the report, this and previous studies relied on a Minimum System approach for allocating distribution system costs.

The minimum system analysis is used to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place, to meet varying customer demands. FortisBC staff provided the data necessary to complete the minimum system study using 2023 data. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the analysis.

The minimum system approach reflects the philosophy that the system is in place, in part, because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers use a delivery quantity greater than the minimum unit up to the level of their peak demand, therefore, that portion of the costs should be treated as demand related.

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the number of poles, conductors, and transformers in place at the utility separating them according to size. The cost associated with these facilities are then determined. Next, it is assumed that the actual numbers by size could be replaced by the minimum sized pole, conductor and transformer. The cost associated with the minimum size is then calculated.

The total costs of the minimum sized system are then compared to the cost of the as-built system to reflect the percentage of costs attributed to the system that would be in place if all customers used a minimum amount of power. The remaining percentage of costs is then attributed to the demand-related component.

The following summarizes the resulting classification and allocation for the distribution accounts.

- Substations, including land and station equipment. These costs are classified as demand related as they are sized on the basis of the peak load for the area served. The non-coincident peak at primary (NCPP) is used as the allocation factor.

- Poles, Towers & Fixtures. The results of the minimum system analysis are 86% customer-related and 14% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the non-coincident peak (NCP) split between primary and secondary.

- Conductors & Devices. The results of the minimum system analysis are 71% customer-related and 29% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the NCP split between primary and secondary.

- Line Transformers. The results of the minimum system analysis are 43% customer-related and 57% demand-related. The customer-related costs are allocated on the basis of actual customers. The demand-related component is allocated on the basis of the NCPS.

- Services, Meters and Installation on Customer Premises. These costs are all related to the customer component as they are installed for each customer served. They are allocated on the basis of customers weighted according to the average cost of meters by class.

- Street Lights & Signal Systems. These costs are all directly related to the lighting class of customers and are directly assigned to that class.

To develop the minimum system percentage splits, FortisBC provided analysis for the poles, conductors and transformer categories. The following provides the technical information provided by staff to calculate the percentage splits for the minimum system analysis.

Poles

FortisBC has a total of 84,510 poles ranging from 30 feet to 80 feet, with both single- and three-phase configuration. The cost per pole, before overhead, ranges from $756 to $5,152 per pole, based on the current purchase price, with installation and material costs, also before overhead, ranging from $1,691 to $2,526. In the case of poles, it was determined that the size of the poles is a function of the location of the pole rather than the peak load on the system. Because of the diverse topography in the region, the pole size is determined based primarily on the physical requirements at each location rather than the voltage of the line. The minimum pole, therefore, varies in size but reflects the slightly lower costs associated with a single-phase configuration. The cost of the cross arms, anchor plates and insulators were included in the installed cost of the poles. The difference between the cost of installed poles at single-phase versus the cost for three-phase was determined to be the demand-related portion of pole costs.

When the minimum size was applied across all poles, the results showed a minimum system cost of $215.6 million compared to an installed cost of $250.3 million. This means that 86% of the costs were related to the minimum size pole and were therefore classified as customer-related costs. The remaining 14% was classified as demand related. This compares to an 81% customer/19% demand split resulting from the last minimum system study, which was conducted in 2017 and used again in the 2020 update.

Conductors

FortisBC has a total of 7,417 kilometers of overhead conductor of various sizes and configurations. The installed cost, before overhead, ranges from $1,130 to $42,430 per kilometer based on the current purchase price. The minimum sized conductor was determined to be two lines of 2 ACSR, with a loaded cost of $1,130 per kilometer. When this minimum size was applied across all conductors, with an adjustment to comparable single-phase km, the results showed a minimum system cost of $56.7 million compared to an installed cost of $79.5 million. This means that 71% of the costs were related to the minimum size conductor and were therefore classified as customer-related costs. The remaining 29% was classified as demand related. This compares to a 65% customer/35% demand split resulting from the last minimum system study, which was conducted in 2017.

Transformers

FortisBC has a total of 39,479 transformers ranging from 10 kVA to 2500 kVA. The installed cost per transformer, before overhead, ranges from $827 to $58,515 per transformer based on the current purchase price. The minimum sized transformer was determined to be a 15-kVA transformer, with a loaded cost of $2,499. While there are a number of transformers within the system at 10 kVA, this size is no longer readily available or routinely installed by FortisBC. When this minimum size was applied across all transformers, the results showed a minimum system cost of $98.7 million compared to an installed cost of $231.7 million. This means that 43% of the costs were related to the minimum size transformer and were therefore classified as customer-related costs. The remaining 57% was classified as demand related. This compares to a 69% customer/31% demand split resulting from the last minimum system study, which was conducted in 2017. This same split was used in the 2020 COSA.

EES also surveyed methods of selected other utilities to check the reasonableness of the results above. The table below shows some of the assumptions used by others.

TABLE 8-1: COMPARATIVE METHODOLOGIES FOR ALLOCATING DISTRIBUTION SYSTEM COSTS

	BC Hydro	ATCO Electric Alberta	Fortis Alberta	Manitoba Hydro
Substations	100% Demand	100% Demand	Skips Step Where Costs are Split Between Demand and Customer and Allocates Directly by Class	100% Demand
Poles, Towers & Fixtures	Primary: 100% Demand Secondary: 50% Demand 50% Customer	Primary: 100% Demand Secondary: 30-35% Demand 65-70% Customer		100% Demand
Conductors & Devices	Primary: 100% Demand Secondary: 50% Demand 50% Customer	Primary: 100% Demand Secondary: 30-35% Demand 65-70% Customer		100% Demand
Line Transformers	50% Demand 50% Customer	47.6% Demand 52.4% Customer		100% Demand
Services, Meters	100% Customer*	100% Customer	100% Customer	100% Customer
Street Lights & Signals	Direct Assigned	*N/A*	*N/A*	*N/A*
	Hydro Quebec	**Nova Scotia Power**	**Newfoundland Power**	**New Brunswick Power**
Substations	100% Demand	100% Demand	100% Demand	100% Demand
Poles, Towers & Fixtures	Primary: 100% Demand Secondary:79.8% Demand 20.2% Customer	26% Demand 74% Customer	63% Demand 37% Customer	50% Demand 50% Customer

Conductors & Devices	Primary: 100% Demand Secondary:79.8 % Demand 20.2% Customer	45.7% Demand 54.3% Customer	63% Demand 37% Customer	50% Demand 50% Customer
Line Transformers	79.8% Demand 20.2% Customer	100% Demand	72% Demand 28% Customer	75% Demand 25% Customer
Services, Meters	100% Customer	100% Customer	100% Customer	"Specifically Assigned"
Street Lights & Signals	*N/A*	100% Demand	100% Direct Street Lighting	"Specifically Assigned"

Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size can carry some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each classification is allocated demand costs based on the total classification's non-coincident peaks. As such, it has been argued that a classification's non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over-allocation demand can be achieved by the application of a PLCC adjustment. The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In the FortisBC case, the engineers that provided the data associated with the minimum system method determined that the average PLCC for the FortisBC system is 0.97 kW per customer.

The PLCC adjustment determines how much demand for a rate classification can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification's non-coincident peak demands used for determining demand allocators. The adjusted classification's non-coincident peaks can then be used to allocate the distributor's demand-related costs, eliminating the double-counting.

9 Appendix C – Load Summary

[Excel Spreadsheet]

Appendix B

UPDATED FBC 2025 COSA MODEL

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix C
CONSULTATION MATERIALS

2024 Cost of Service Analysis FortisBC Inc.

Corey Sinclair, Manager, Regulatory Affairs, FBC

Russ Schneider, ESS Consulting
(a GDS Associates Company)

December 17, 2024

Updated Application dated May 15, 2025

Workshop Purpose – COSA Specific

To provide context and information in support of a COSA Filing

Electric Cost of Service Analysis (COSA) Approach and Methodology Review

Initial COSA Results and Impact on Rates

Gather Feedback and Answer Questions

Background

1. The amount of revenue that FBC is permitted to recover from customers is determined by the BC Utilities Commission (BCUC) in a separate public process. This is called the ***Revenue Requirement,*** and it is based on the cost of providing service (cost to serve).

2. Utilities file a *Cost-of-Service-Analysis (COSA)* with the goal of equitably allocating the cost of service to the various customer classes (i.e., residential, commercial, etc.) and to either support or suggest revisions to current rates or create rate structures that will recover those costs.

3. Nothing that occurs in either the COSA or rate design process changes the total amount of revenue approved by the BCUC to be collected by FBC.

4. FBC last filed a combined COSA and Rate Design Application (RDA) in 2017, and last updated its COSA in 2020.

5. The 2025 filing is a COSA and revenue rebalancing evaluation with no accompanying proposal for rate structure or rate design changes.

6. Future rate design applications will consider these results along with other programmatic evaluation efforts.

Agenda

Topic	Lead
Introduction & Agenda	Corey Sinclair
Part I – Scope of 2024 COSA • Introduction and Background	Corey Sinclair
Part II – COSA Approach and Methodology • Cost of Service Methods and Data • Supporting Analysis and Documentation	Russ Schneider, ESS Consulting (a GDS Associates Company)
Part III – COSA Results • Revenue to Cost Ratios • Rebalancing Options • Next Steps	Corey Sinclair
Part IV – Open Question Period	All

Tariff Rate Schedules Review

Default Rate Schedules

Rate Schedule 1	• Residential Service • ***2024 Average Number of Customers – 132,389***
Rate Schedule 20	• Small Commercial Service (<40 kW) • ***2024 Average Number of Customers – 15,345***
Rate Schedule 21	• Commercial Service (40 kW > 500 kW) • ***2024 Average Number of Customers – 1,780***
Rate Schedule 30	• Large Commercial Service - Primary (>500 kVA) • ***2024 Average Number of Customers - 38***
Rate Schedule 31	• Large Commercial Service -Transmission (>5,000 kVA) • ***2024 Average Number of Customers - 4***
Rate Schedule 40	• Wholesale Service - Primary • ***2024 Average Number of Customers – 5***
Rate Schedule 41	• Wholesale Service - Transmission • ***2024 Average Number of Customers – 1***
Rate Schedule 50	• Street lighting • ***2024 Average Number of Customers – 1,341***
Rate Schedule 60	• Irrigation • ***2024 Average Number of Customers – 1,103***

Optional Rate Schedules

Time of Use	• Available for all Customer Classes • ***Residential Closed to new Customers***
Net Metering	• For the interconnection of customer-owned generation limited to personal consumption and 50 kW
Stand-by & Maintenance	• Available to RS 31 customers with self-generation
Interruptible Load	• Market-based RS 38 interruptible power available to RS 31 customers
Other	• Transmission and related, • Standard Charges • Extensions • DSM, Green riders, etc.

Cost of Service Approach and Methodology

Part II

Steps in FBC COSA and Rate Design Process

1

Step 1: Revenue Requirement

- Annual Review of Rates Applications

2

Step 2: Perform Cost of Service Study

3

Step 3: Rebalancing

4

Step 4: Design Rates and Programs

Future Application

Current Application

Updated Application dated May 15, 2025

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Cost of Service Approach and Methodology

The 2024 COSA is consistent with the approach used in 2017/2020:

- Forecast year 2024 is the test period for the allocation of costs.
- Hourly aggregate load data by rate class for all meters in each rate class from the historical year 2022 provided the basis for energy and demand allocation factors for the 2024 forecast year.
- The 2024 forecast revenue requirement and sales as contained in the Annual Review for 2024 Rates (Application) Evidentiary Update to the Application, October 2023, using actual results for 2022 for detailed items.
- The 2024 forecast total sales as contained in the Annual Review for 2024 Rates, using actual load and demand data results for 2022 for detailed billing determinants with current rates.
- Monthly power supply costs are classified as demand and energy based on wholesale rate 3808 from BC Hydro and allocated monthly. Power costs are from the October 2023 filing.
- Distribution plant is classified based on an updated minimum system study with a peak load carrying capability (PLCC) credit.
- Demand-related transmission costs are allocated using the 2 CP (coincident peak) method (sum of 2 winter and 2 summer peaks).

Summary of Revenue Requirements Based on Evidentiary Update

Summary Source for 2024 Revenue Requirement:
Annual Review for 2024 Rates (Evidentiary update 101023)
- Forecast levels for most items
- Aggregate details only for some items

Source for 2022:
2022 Annual Report to the British Columbia Utilities Commission (BCUC)
- Detailed results for all items
- Used to provide underlying detail to forecasted 2024

Cost Category	2024 Forecast (Million)
Production	**$193.4**
Transmission	**$27.5**
Distribution	**$13.9**
Customer Service, Accounts & Sales	**$7.3**
Administrative & General	**$14.6**
Depreciation	**$64.8**
Taxes	**$19.3**
Return & Income Tax	**$128.6**
Other Revenues	**-$15.9**
Net Revenue Requirements	**$453.4**

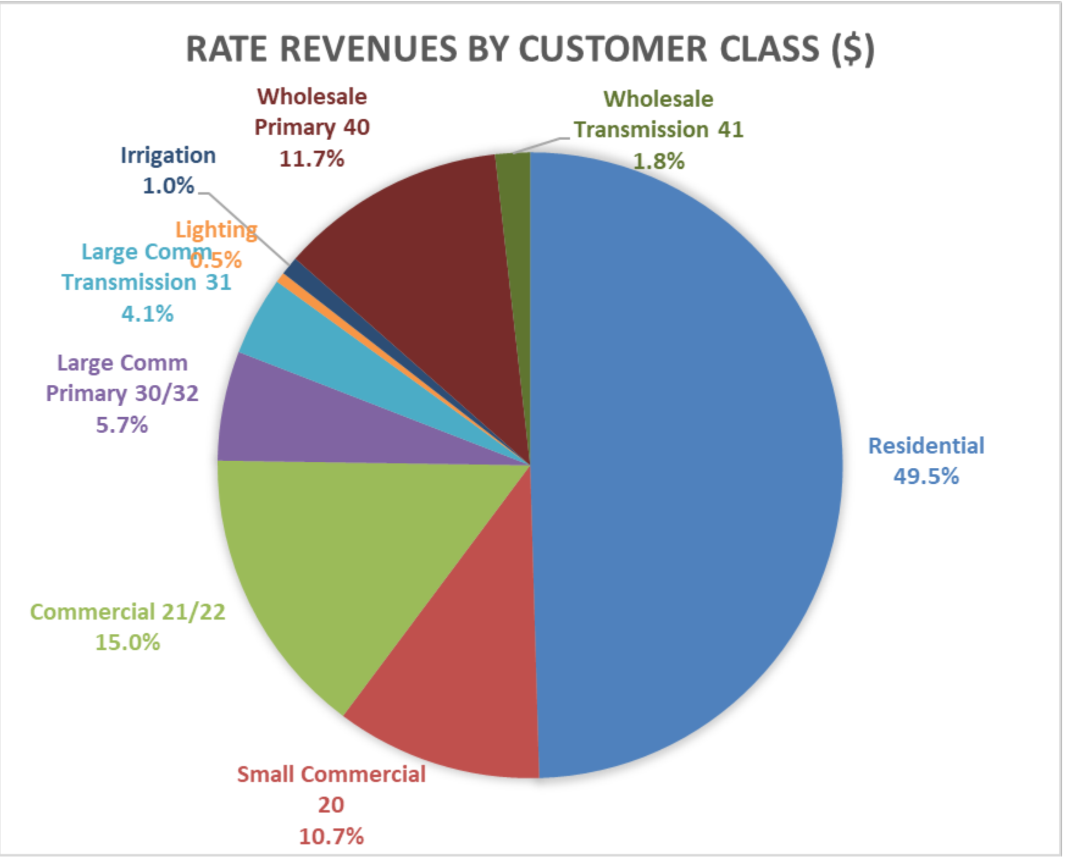
Summary of Rate Based on Evidentiary Update

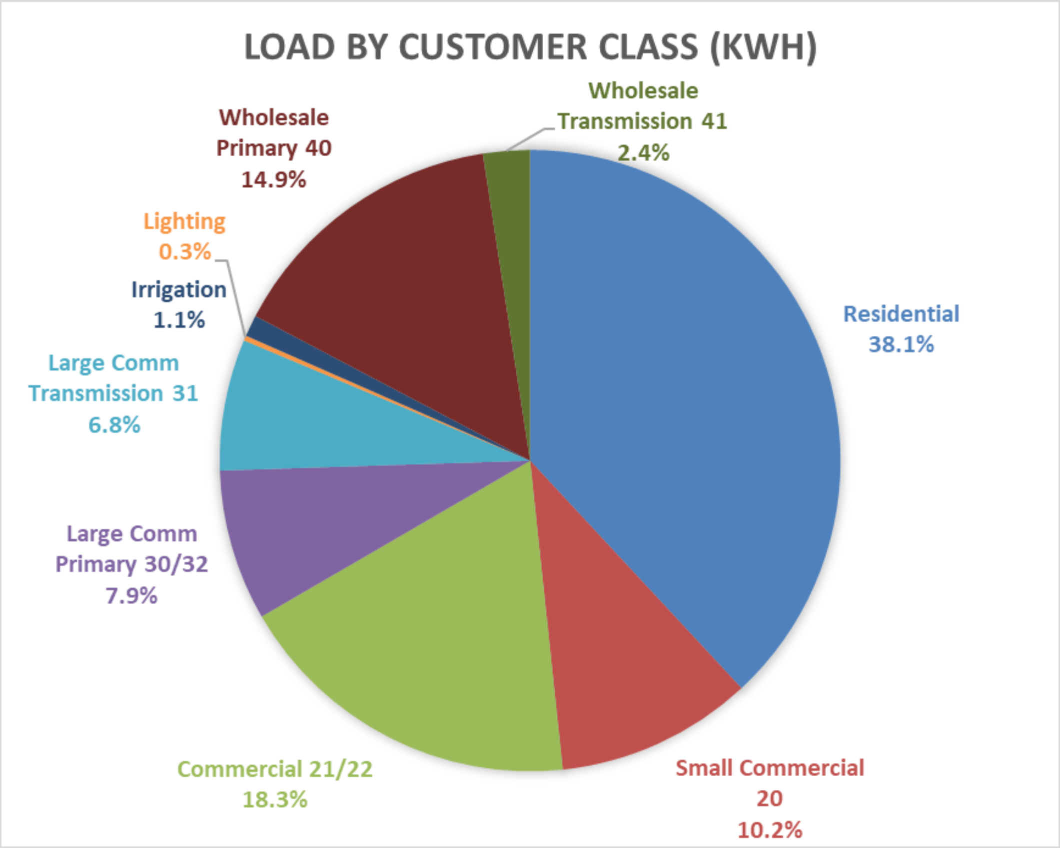
Source for both 2021 and 2022: *2022 Annual Report to the British Columbia Utilities Commission (BCUC)*

- The study uses a mid-year average of two historical years
- The function of rate base is to provide allocation of plan related revenue requirement expenses
- For example, a distribution O&M expense may be allocated based on distribution rate base net investment in that same plant item the expense maintains

Millions	2020 COSA	2024 COSA
Total Gross Plant	$2,150.5	$2,316.1
Less Accumulated Depreciation	-653.6	-669.2
Less Customer Contributions	-215.3	-231.7
Working Capital, Deferred and Other	102.0	127.1
Total Base Rate	$1,383.7	$1,542.4

Summary of Customer Class Contribution to Overall Revenues and Load





Total Load:	3,411 GWh
Total Revenue:	$453.4 M

Cost Causation = How is the System Built?

Meters and Services

- One customer means one service line and meter – but different sizes by class

Distribution

- Poles, wires and transformers are built to meet each customer's highest peak load, whenever it occurs (Non-coincident peak)

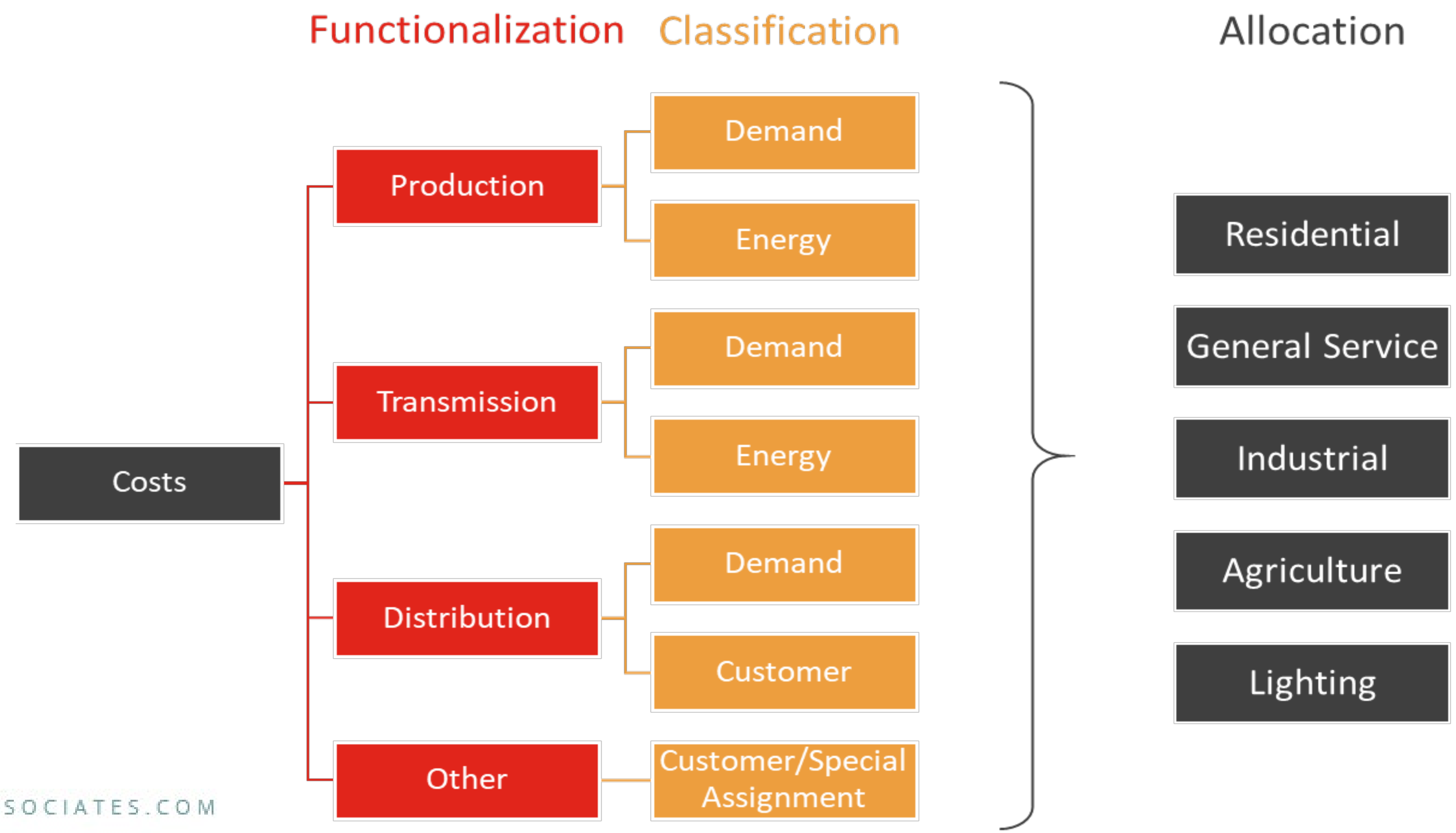
Transmission

- Built to transmit generated and purchased power to the distribution system, sized to meet system peak loads (Coincident Peak)

Power Supply

- Combination of generation and power contracts to meet both system peak loads and energy throughout the year (Coincident Peak)

Cost of Service – Allocation Buckets



Source: GDSASSOCIATES.COM

Functionalization

System of Accounts generally defines functions

- Production/Power Supply
- Transmission
- Distribution

Applies to Rate Base and Revenue Requirements

Shared Categories/Functions Include

- General Plant (Rate Base)
- Customer Service, Accounts & Sales
- Administrative & General

Types of Costs

- Operation & Maintenance (O&M)
- Depreciation
- Taxes
- Return
- Income Tax
- Other Revenues

Classification

Splits each rate base/revenue requirement account into demand, energy and/or customer factors

- Rate Base first
- Expense items often follows rate base

Main task within the COSA

Follows cost causation

- Standard practice includes several options
- Unique to the circumstances of the utility
- Often unique to the jurisdiction and past precedents

Allocation

Takes costs classified to customer and allocates on the basis of number of customers, same for energy and demand

Multiple types of allocation factors for each type

Customer – standard, weighted for meters/service, weighted for accounting/metering	Energy – annual energy	Demand – non-coincident (NCP), monthly coincident peak (12 CP), winter/summer coincident peaks (2 CP)

Development of Load Data for Allocation

Energy
- Based on actual metered hourly loads by class for 2022

NCP
- Based on metered demand for all AMI meters

CP
- Based on hourly AMI data by class, highest for class and system peak

Losses
- Loss factors differentiated by voltage level

COSA Methodology

Cost Item	Classification Method	Allocator Used
Power Supply	Generation Rate Base Split approximately 20% demand and 80% energy based on the equivalent of purchasing all power from BC Hydro 3808 tariff	Costs calculated for each month and then allocated on the basis of each month's demand and energy
Transmission	100% Demand	2 CP (average of winter and summer coincident peaks)
Distribution - **Stations**	100% Demand	Non-coincident peak (NCP)
Distribution **- Poles, wires and transformers**	Minimum System Study to split between customers and demand	Actual customers and non-coincident peak (NCP) adjusted for PLCC
Distribution - **Meters & services** - **Customer service, etc.**	100% Customer	- Weighted for meters and services - Weighted for accounting and metering
General Plant and A&G	Labour Ratios used to split between production, transmission and distribution	Follows rate base in each function
Stand-by Service and Interruptible Rate Service	Treated as other revenues, classified same as all rate base	Allocated same as all rate base

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COSA Minimum System Study (MSS)

- Looks at all facilities for poles, wires and transformers
- Some portion of facilities are in place just to connect our customers to the system, this is the minimum system
- MSS basically prices all facilities as if it were the minimum size
- The value of the minimum system divided by the actual value of all the facilities is the percentage classified as ‘Customer’
- The balance is classified as ‘Demand’
- PLCC Adjustment accounts for the fact that the minimum system can carry some amount of load

Poles = 86% Customer

Wires = 71% Customer

Transformers = 43% Customer

PLCC = 0.97 kW

COSA Customer Weight Factor

- Study differentiates the cost associated with small customers vs. large customers
- Calculated as a ratio to the cost for a residential customer
- Ratio used to scale upwards the average number of customers in a customer group
- Meters & Services based on cost differentials for average cost of new meter/service
- Customer Accounting & Metering based on level of effort associated with call centre, billing, etc.

RS1 = $398/1.0

RS20 = $442/1.0

RS21 = $509/1.0

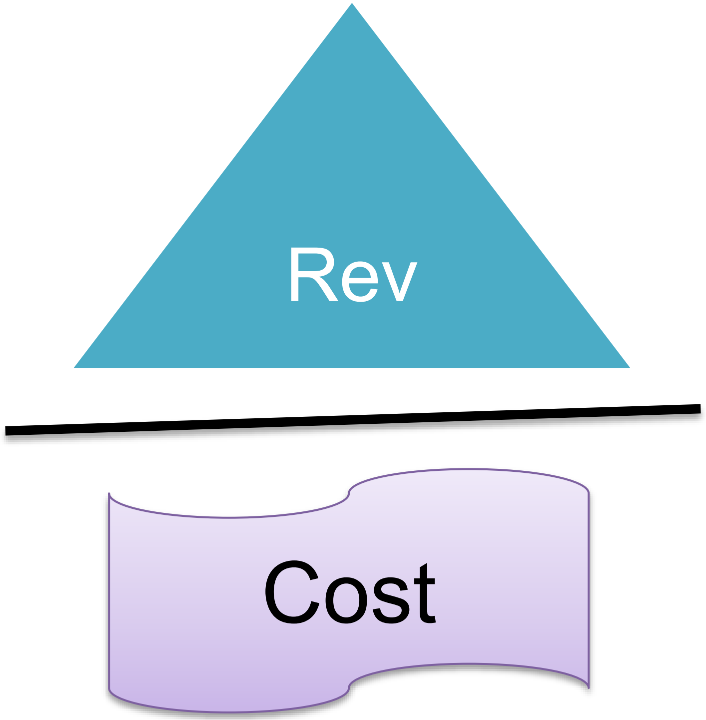
RS30/31 = $499/475

RS40/41 = $238

Cost of Service Results and Next Steps

Part III

Revenue to Cost Ratio



- If a customer group's R/C ratio is within a range around unity, their rates are assumed to be fair and reasonable from a cost allocation perspective
- A range is appropriate given the dynamic nature of inputs, classifications and allocations over time
- For FBC, the range is 95% to 105%
- Sometimes rebalancing may be required
  - *Revenue shift recoveries between customer groups (reduce one customer group's rates and increase another group's rates)*
  - *Should consider the rate making principle of gradual change and the avoidance of rate shock*

Resulting RC Ratios

	2024 Revenue to Cost Ratio
Residential	99.7%
Small Commercial	108.3%
Commercial	103.8%
Large Commercial Primary	99.2%
Large Commercial Transmission	104.5%
Lighting	100.6%
Irrigation	82.9%
Wholesale Primary	91.9%
Wholesale Transmission	94.4%
Total	100.0%

FBC's Rate Design Principles

- *The weight placed on each of these principles is not always equal*

Recovering the cost of service	Fair appointment of costs among customers	Price signals to encourage efficient use
Customer understanding and acceptance	Practical and cost effective to implement	Rate stability
Revenue stability	Avoidance of undue discrimination	

Potential Rebalancing Options

Adjust revenues for rates classes outside of the range of reasonableness (95% - 105%) to the nearest boundary

Rebalancing Option	COSA Rev/Cost	COSA Indicated Rebalancing	Rebalancing Option 1	Rebalancing Option 2	Rebalancing Option 3	Rebalancing Option 4	Rebalancing Option 5
Small Commercial 20	108.3%	-3.1%	-3.1%	-3.1%	-3.1%	-3.1%	-3.0%
Irrigation	82.9%	14.6%	8.5%	2.6%	2.5%	8.5%	0.0%
Wholesale Primary 40	91.9%	3.3%	2.0%	2.6%	2.5%	2.1%	2.7%
Wholesale Transmission 41	94.4%	0.7%	0.7%	0.0%	0.7%	0.0%	0.7%

Average Monthly Billing Impacts of Potential Options

Rebalancing Option	Current Rev/Cost	Indicated Rebalancing	Avg Monthly Bill Impact	Proposed Rebalancing Option 1	Avg Monthly Bill Impact	Proposed Rebalancing Option 2	Avg Monthly Bill Impact	Proposed Rebalancing Option 3	Avg Monthly Bill Impact	Proposed Rebalancing Option 4	Avg Monthly Bill Impact
Small Commercial 20	108.3%	-3.1%	-$8	-3.1%	-$8	-3.1%	-$8	-3.1%	-$8	-3.1%	-$8
Irrigation	82.9%	14.6%	$48	8.5%	$28	2.6%	$8	2.5%	$8	8.5%	$28
Wholesale Primary 40	91.9%	3.3%	$14,828	2.0%	$8,833	2.6%	$11,434	2.5%	$11,017	2.1%	$9,284
Wholesale Transmission 41	94.4%	0.7%	$4,511	0.7%	$4,511	0.0%	$0	0.7%	$4,511	0.0%	$0

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Summary

- COSA developed using 2024 test year
- COSA methods are consistent with 2017 as approved
- RC Ratios outside the range of reasonableness used to determine the need for rebalancing
- COSA results are one of the many considerations when designing rates

Next Steps

- Slides will be circulated after the workshop
- Written feedback provided by January 10, 2025
- COSA and Revenue Rebalancing Application filed with BCUC in Q1 2025

- Please email feedback to: electric.regulatory.affairs@fortisbc.com

Open for Questions

Part IV

Thank you

For further information, please contact:

FortisBC

electric.regulatory.affairs@fortisbc.com

Find FortisBC at:
fortisbc.com
talkingenergy.ca
604-576-7000

Follow us **@fortisbc**

Historic RC Ratios

	2017 Revenue to Cost Ratio	2020 Revenue to Cost Ratio	2024 Revenue to Cost Ratio
Residential	98.4%	99.7%	99.7%
Small Commercial	102.2%	101.5%	108.3%
Commercial	104.7%	99.5%	103.8%
Large Commercial Primary	104.0%	105.7%	99.2%
Large Commercial Transmission	107.0%	110.4%	104.5%
Lighting	92.2%	84.9%	100.6%
Irrigation	97.2%	96.5%	82.9%
Wholesale Primary	96.7%	96.7%	91.9%
Wholesale Transmission	103.9%	95.8%	94.4%
Total	100.0%	100.0%	100.0%

	COSA Results					
	Small Commercial	Irrigation	Wholesale Primary	Wholesale Transmission		Total Revenue
	Rate 20	Rate 60	Rate 40	Rate 41		
Allocated Revenue Requirement	$ 44,700,440	$ 5,233,827	$ 57,856,703	$ 8,639,925		$ 116,430,895
Revenue at Existing Rates	$ 48,419,566	$ 4,340,386	$ 53,184,490	$ 8,153,799		$ 114,098,241
Revenue to Cost Ratio	108.3%	82.9%	91.9%	94.4%		

	Rebalancing Options					
Target R/C Ratio	105%	95%	95%	95%		
Rebalancing Option 1	-3.1%	8.5%	2.0%	0.7%		
Revenue	$ 46,918,559	$ 4,709,319	$ 54,248,180	$ 8,210,876		$ 114,086,934
Ending R/C Ratio	105.0%	90.0%	93.8%	95.0%		
Rebalancing Option 2	-3.1%	2.6%	2.6%	0.0%		
Revenue	$ 46,918,559	$ 4,453,236	$ 54,567,287	$ 8,153,799		$ 114,092,881
Ending R/C Ratio	105.0%	85.1%	94.3%	94.4%		
Rebalancing Option 3	-3.1%	2.5%	2.5%	0.7%		
Revenue	$ 46,918,559	$ 4,448,896	$ 54,514,102	$ 8,210,876		$ 114,092,433
Ending R/C Ratio	105.0%	85.0%	94.2%	95.0%		
Rebalancing Option 4	-3.1%	8.5%	2.1%	0.0%		
Revenue	$ 46,918,559	$ 4,709,319	$ 54,301,364	$ 8,153,799		$ 114,083,041
Ending R/C Ratio	105.0%	90.0%	93.9%	94.4%		
Rebalancing Option 5	-3.0%	0.0%	2.7%	0.7%		
Revenue	$ 46,966,979	$ 4,340,386	$ 54,620,471	$ 8,210,876		$ 114,138,712
Ending R/C Ratio	105.1%	82.9%	94.4%	95.0%		

Appendix D

UPDATED FBC ELECTRIC TARIFF - BLACKLINED

RATE SCHEDULE 20 - SMALL COMMERCIAL SERVICE

APPLICABLE: To Commercial Customers whose electrical Demand is generally not more than 40 kW and can be supplied through one meter. Where there is more than one service to the same location and they are of the same voltage and phase classification and they were connected prior to January 5, 1977, the electrical energy and Demands registered for such services will be combined and billed at this rate.

BI-MONTHLY RATE: All kW.h @ 12.481¢ per kW.h A

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plus:

CUSTOMER CHARGE: $57.43 per two Month period A

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DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power service when taken at FortisBC's standard secondary voltage. A discount of 1.5% will be applied to the above rate if the electric service is metered at a primary distribution voltage.

OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

NOTE: For the purposes of Monthly billing the Customer Charge will be prorated on a Monthly basis.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

RATE SCHEDULE 21 - COMMERCIAL SERVICE (Cont'd)

(b) A discount of 48.41¢ per kW of Billing Demand will be applied to the above rate if the Customer supplies the transformation from the primary to the secondary voltage. A

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(c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a primary voltage is to be applied first.

POWER FACTOR: If at FortisBC's option, the Demand is measured in kVA instead of kW then;

40 kW will become 45 kVA
48.41¢ per kW will become 43.57¢ per kVA A
$14.53 per kW will become $13.06 per kVA
where used in this schedule.

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BILLING CODES: The following letter designations may appear on Customer's bills:

"A" – Demand measured in kW, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
"B" – Demand measured in kVA, FortisBC owned transformation from primary to secondary distribution voltage, metering at secondary distribution voltage
"C" – Demand measured in kW, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage
"D" – Demand measured in kVA, Customer owned transformation from primary to secondary distribution voltage, metering at primary distribution voltage

OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

RATE SCHEDULE 22 A - COMMERCIAL SERVICE – SECONDARY – TIME OF USE

APPLICABLE: To Commercial Customers whose electrical Demand is less than 500 kW and is supplied at a secondary distribution voltage through one meter. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

		¢/kW.h
Summer (July, August)	On-Peak Hours: 9:00 am - 11:00 am Monday-Friday 3:00 pm – 11:00 pm Monday-Friday	18.874
	Off-Peak Hours: 11:00 pm - 9:00 am Monday-Friday 11:00 am – 3:00pm Monday-Friday All hours on Saturday and Sunday	6.117
All other months	On-Peak Hours: 8:00 am - 1:00 pm Monday-Friday 5:00 pm - 10:00 pm Monday-Friday	18.874
	Off-Peak Hours: 10:00 pm to 8:00 am Monday-Friday 1:00 pm - 5:00 pm Monday-Friday All hours on Saturday and Sunday	6.117

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plus:

CUSTOMER CHARGE: $20.57 per Month A

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BILLING: FortisBC may, at its option, bill this rate bimonthly in which case the Customer Charge will be doubled.

OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

RATE SCHEDULE 30 - LARGE COMMERCIAL SERVICE - PRIMARY (Cont'd)

DELIVERY AND METERING VOLTAGE DISCOUNTS: The above rate applies to power service when taken at FortisBC's standard primary distribution voltage available in the area.

(a) A discount of 1.5% will be applied to the above rate if the electric service is metered at a transmission line voltage.

(b) A discount of $5.98 per kVA of billing Demand will be applied to the above rate if the Customer supplies the transformation from the transmission line voltage to the primary distribution voltage. A

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(c) If a Customer is entitled to both of the above discounts, the discount applicable to the metering at a transmission line voltage is to be applied first.

OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

RATE SCHEDULE 31 - LARGE COMMERCIAL SERVICE - TRANSMISSION

AVAILABLE: In all areas served by FortisBC for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available.

APPLICABLE: Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement.

MONTHLY RATE: A Wires Charge of:

$6.07 per kVA of Billing Demand; plus: [Deleted: 9]

A Power Supply Charge of:

$4.24 per kVA of maximum Demand in current billing Month; plus: A [Deleted: 5]

An Energy Charge of:

All kW.h @ 6.611¢ per kW.h [Deleted: 3]

CUSTOMER CHARGE: $3,935.13 per Month A [Deleted: 46] [Deleted: 97]

"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or

ii. The maximum Demand in kVA for the current billing Month; or

iii. eighty percent (80%) of the maximum Demand in kVA recorded during the previous eleven Month period.

Plus, for Customers with a Stand-by Billing Demand under Rate Schedule 37 (except when Rate Schedule 37, Special Provision 7 applies);

Stand-by Billing Demand.

OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

RATE SCHEDULE 33 - LARGE COMMERCIAL SERVICE - TRANSMISSION - TIME OF USE

APPLICABLE: In all areas served by FortisBC for supply at 60 hertz, three phase with a nominal potential of 60,000 volts or higher as available. Applicable to industrial Customers with loads of 5,000 kVA or more, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	22.408
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	6.346
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	29.883
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	4.940
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	7.170
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	3.781

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plus:

CUSTOMER CHARGE: $3,652.75 per Month A

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OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

RATE SCHEDULE 40 - WHOLESALE SERVICE - PRIMARY

AVAILABLE: In Grand Forks, Kelowna, Penticton, Princeton, Summerland, Lardeau and Yahk.

APPLICABLE: To service for resale, subject to written agreement.

MONTHLY RATE: A Wires Charge of:

$11.62 per kVA of Billing Demand A

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plus:

A Power Supply Charge of:

$6.24 per kVA of maximum Demand in current billing Month A

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plus:

An Energy Charge of:

All kW.h @ 6.966¢ per kW.h A

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CUSTOMER CHARGE: $5,847.11 per Point of Delivery per Month A

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"Billing Demand"

The greatest of:

i. eighty percent (80%) of the Contract Demand, or

ii. the maximum Demand in kVA for the current billing Month, or

iii. eighty percent (80%) of the maximum Demand in kVA registered during the previous eleven Month period.

RATE SCHEDULE 40 - WHOLESALE SERVICE - PRIMARY (Cont'd)

OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

DELIVERY VOLTAGE DISCOUNT: The above rate applies to power service when taken at FortisBC's standard primary voltage.

A discount of 0.926¢ per kW.h will be applied to the Energy Charge and a discount of $3.78 per kVA will be applied to the Wires Charge if the Customer supplies the transformation from the transmission line voltage to the primary distribution voltage. C

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INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year.

RATE SCHEDULE 42 - WHOLESALE SERVICE - PRIMARY -TIME OF USE

APPLICABLE: To power Service to Grand Forks, Kelowna, Penticton, Summerland, Lardeau, and Yahk, at a Primary Voltage for resale, subject to written agreement. This rate is applicable to Customers with satisfactory, as determined by FortisBC, Load Factors. Service under this Schedule is available for a minimum of 12 consecutive Months after commencement of Service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	31.580
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	6.438
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	30.323
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	5.012
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	7.274
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	3.828

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plus:

CUSTOMER CHARGE: $3,419.78 per Month per Point of Delivery A

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OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

RATE SCHEDULE 60 - IRRIGATION AND DRAINAGE

AVAILABLE:	For an irrigation and drainage season commencing April 1st each year and terminating October 31st each year. Meter readings will be taken within 10 Business Days of the commencement and termination of the irrigation and drainage season. During the non-irrigation season Customers will be automatically transferred to the applicable Commercial rate and billings prorated for a partial first or final service Month when read dates are outside of the 10 Day band.
APPLICABLE:	To motors at one point of delivery, which are to be used primarily for irrigation and drainage purposes. This schedule applies to electric service when taken at FortisBC's standard secondary voltage. Incidental lighting essential to the pumping operation will be allowed on this schedule provided that the Customer supplies and installs their own transformers and other necessary equipment as required. Service to motors of 5 HP or less will be single phase, unless FortisBC specifically agrees to supply three phase.
BILLING:	Bills will be rendered Monthly or bimonthly but may be estimated in periods of low consumption or when access is restricted.
MONTHLY RATE:	All kW.h @ 9.619¢ per kW.h A
CUSTOMER CHARGE:	$29.35 per Month A
OVERDUE ACCOUNTS:	A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.
INTERIM RATE ESTABLISHMENT:	Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

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Updated Application dated May 15, 2025

RATE SCHEDULE 61 - IRRIGATION AND DRAINAGE - TIME OF USE

APPLICABLE: For Customers normally supplied under Rate Schedule 60. Service to motors of 5 HP or less will be single phase, unless FortisBC specifically agrees to supply three phase. This rate is applicable to Customers with satisfactory, as determined by FortisBC, load factors. Service under this Schedule is available for a minimum of 12 consecutive Months and will continue, at the election of the Customer, to be available for a minimum of 36 consecutive Months after commencement of service.

RATES BY PRICING PERIOD:

		¢/kW.h
Winter (Nov. - Feb.)	On-Peak Hours: 7:00 am - 12:00 pm business days 4:00 pm - 10:00 pm business days	25.557
	Off-Peak Hours: 10:00 pm to 7:00 am business days 12:00 pm - 4:00 pm business days All hours on weekends and statutory holidays	6.408
Summer (July, August)	On-Peak Hours: 10:00 am - 9:00 pm business days	24.594
	Off-Peak Hours: 9:00 pm - 10:00 am All hours on weekends and statutory holidays	5.314
Shoulder (all other months)	On-Peak Hours: 6:00 am - 10:00 pm, Monday to Saturday	7.038
	Off-Peak Hours: 10:00 pm to 6:00 am - Monday to Saturday, All day Sunday	4.415

A

plus:

CUSTOMER CHARGE: $68.55 per Month A

OVERDUE ACCOUNTS: A late payment charge of 1.5% will be assessed each month (compounded monthly 19.56% per annum) on all outstanding balances not paid by the due date.

INTERIM RATE ESTABLISHMENT: Pursuant to the British Columbia Utilities Commission Order G-314-24, rates are set on an interim basis for consumption on and after January 1, 2025 until such time as a decision on the FortisBC 2025 through 2027 Rate Setting Framework Application and 2025 rates is issued by the British Columbia Utilities Commission. The interim rates are subject to refund/recovery with interest at the average prime rate of FortisBC's principal bank for its most recent year. N

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Appendix E

REGULATORY ACCOUNT FILING CHECKLIST

Item	Consideration	2025 COSA Deferral Account
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.	FBC requests the establishment of one new deferral account to capture the actual regulatory proceeding costs associated with the Application.
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 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 the Application. It typically includes BCUC costs, participant funding costs, external legal and consulting fees, notice publication costs, and miscellaneous facilities, stationary, and supplies costs.
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 as well as the filing of the relevant regulatory application and its review by the BCUC.
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 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.

Item	Consideration	2025 COSA Deferral Account
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.
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.
c)	the materiality of the costs	FBC estimates the total regulatory costs for this proceeding to be approximately $450,000.
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.
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 application, which serves to match the costs and benefits of the application.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash account.
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the BCUC's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant 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 FBC's index-based O&M expense.
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.

Item	Consideration	2025 COSA Deferral Account
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.	Based on the total estimated regulatory proceeding costs of $450,000 which includes the BCUC costs, Participant Cost Award funding, external legal fees, and consulting fees for EES Consulting, FBC considers a one-year amortization period, commencing January 1, 2026, appropriate as the rate impact to customers is relatively small at 0.13 percent (compared to 2025 rates approved on interim basis by Order G-314-24), which equates to approximately $1.70 per year for an average residential customer with 9,900 kWh of annual consumption.
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).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of this Application.

Appendix F-1

DRAFT PROCEDURAL ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2025 Cost of Service Allocation and Revenue Rebalancing Application

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 14, 2025, FortisBC Inc. (FBC) filed with the British Columbia Utilities Commission (BCUC), pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA), its 2025 Cost of Service Allocation (COSA) study and application for approval of revenue rebalancing, as well as approval to establish a new rate base deferral account to record the regulatory proceeding costs associated with the review of the application, effective January 1, 2026 (Application);

B. By Decision and Order G-40-19 dated February 25, 2019, the BCUC issued its Decision on FBC's 2017 Cost of Service Allocation (COSA) and revenue to cost ratios, and on December 31, 2020, FBC submitted an updated COSA (2020 COSA) in compliance with Decision and Order G-40-19;

C. In the Application, FBC requests approval of revenue and rate rebalancing proposals, including the following changes to rate schedules effective January 1, 2026:

   i. For Rate Schedules (RS) 20 and 22, rebalancing of all billing-determinant-related rate components such that revenues are decreased by 3.1 percent;

   ii. For RS 60 and 61, rebalancing of all billing-determinant-related rate components such that revenues are increased by 2.5 percent;

   iii. For RS 40 and 42, rebalancing of all billing-determinant-related rate components such that revenues are increased by 2.5 percent; and

   iv. For RS 41 and 43, rebalancing of all billing-determinant-related rate components such that revenues are increased by 0.4 percent;

D. FBC also requests approval in the Application to update the transformation discount as a result of the 2025 COSA study under RS 21, 30, and 40 for customers who choose to take service at the primary distribution voltage level (RS 21) or at the transmission voltage level (RS 30 and 40), effective January 1, 2026:

   i. For RS 21, an update to the transformation discount from $0.409 per kW of Billing Demand to $0.247 per kW of Billing Demand;

   ii. For RS 30, an update to the transformation discount from $6.727 per kVA of Billing Demand to $6.237 per kVA of Billing Demand; and

   iii. For RS 40, an update to the transformation discount under the Wires Charge from $3.390 per kVA of Billing Demand to $3.118 per kVA of Billing Demand, and a reduction to the Energy Charge from $0.00985 per kWh to $0.00642 per kWh; and

E. The BCUC has commenced review of the Application and determines that establishment of a public hearing process is warranted.

NOW THEREFORE the BCUC orders as follows:

1. A regulatory timetable for the review of the Application is established as set out in Appendix A to this order.

2. On or before DATE, FBC is directed to provide:

   a. electronically where possible, a copy of the Application, this order and a link to the proceeding webpage to the registered interveners in FBC's 2017 COSA and Rate Design Application and Annual Review for 2024 Rates proceedings;

   b. notice of the Application and this order on its existing social media platforms; and

   c. notice of the Application and this order on FBC's website at www.fortisbc.com.

3. FBC is directed to provide to the BCUC, by DATE, written confirmation of compliance with the notice requirements in Directive 2 of this order, including a list of social media platforms on which notice of the Application was posted.

4. In accordance with the BCUC's Rules of Practice and Procedure, parties who wish to actively participate in this proceeding must submit the Request to Intervene Form, available on the BCUC's website at https://www.bcuc.com/GetInvolved/GetInvolvedProceeding, by Day/DATE, as established in the regulatory timetable. Parties may also submit letters of comment by completing a Letter of Comment Form, available on the BCUC's website.

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

Attachment

FortisBC Inc.
2025 Cost of Service Allocation and Revenue Rebalancing Application

REGULATORY TIMETABLE

Action	Date (2025)
FBC provides notice of Application	Friday, March 21
FBC provides confirmation of compliance with public notice requirements	Tuesday, March 25
Intervener registration deadline	Tuesday, April 8
BCUC Information Request (IR) No. 1	Wednesday, April 9
Intervener IR No. 1	Wednesday, April 16
FBC response to IR No. 1	Thursday, May 15
FBC final argument	Thursday, May 29
Intervener final arguments	Thursday, June 12
FBC reply argument	Thursday, June 26

British Columbia Utilities Commission

We want to hear from you

FortisBC Inc. 2025 Cost of Service Allocation and Revenue Rebalancing Application

On February 14, 2025, FortisBC filed its Cost of Service Allocation and Revenue Rebalancing Application (Application). FBC seeks approval of certain adjustments to the rate schedules for small commercial, irrigation, and wholesale service, in order to rebalance the revenue-to-cost ratios of these rate schedules to within the accepted Range of Reasonableness of 95 per cent to 105 percent.

HOW TO PARTICIPATE

- **Submit a letter of comment**
- **Request intervener status**

IMPORTANT DATES

1. **[Day/DATE** – Deadline to register as an intervener with the BCUC

For more information about the Application, please visit the Proceeding Webpage on bcuc.com under "Our Work – Proceedings." To learn more about getting involved, please visit our website (www.bcuc.com/get-involved) or contact us at the information below.

GET MORE INFORMATION

FortisBC Energy Inc. Regulatory Affairs

16705 Fraser Highway
Surrey, BC Canada V4N 0E8

E: gas.regulatory.affairs@fortisbc.com

P: 604.592.7664

British Columbia Utilities Commission

Suite 410, 900 Howe Street
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E: Commission.Secretary@bcuc.com

P: 604.660.4700

Appendix F-2

UPDATED DRAFT FINAL ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
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P: 604.660.4700
TF: 1.800.663.1385

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2025 Cost of Service Allocation and Revenue Rebalancing Application

BEFORE:
[X. X. Last Name, Panel Chair]
[X. X. Last Name, Commissioner]
[X. X. Last Name, Commissioner]

on [Month Day, Year]

ORDER

WHEREAS:

A. On February 14, 2025, FortisBC Inc. (FBC) filed with the British Columbia Utilities Commission (BCUC), pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA), its 2025 Cost of Service Allocation (COSA) study and application for approval of revenue rebalancing, as well as approval to establish a new rate base deferral account to record the regulatory proceeding costs associated with the review of the application, effective January 1, 2026 (Application);

B. By Decision and Order G-40-19 dated February 25, 2019, the BCUC issued its Decision on FBC's 2017 Cost of Service Allocation (COSA) and revenue to cost ratios, and on December 31, 2020, FBC submitted an updated COSA (2020 COSA) in compliance with Decision and Order G-40-19;

C. In the Application, as amended by the Updated Application dated May 15, 2025, FBC requests approval of revenue and rate rebalancing proposals, including the following changes to rate schedules effective January 1, 2026:

   1. For Rate Schedules (RS) 20 and 22, rebalancing of all billing-determinant-related rate components such that revenues are decreased by 2.4 percent;

   2. For RS 31 and 33, rebalancing of all billing-determinant-related rate components such that revenues are decreased by 0.3 percent;

   3. For RS 40 and 42, rebalancing of all billing-determinant-related rate components such that revenues are increased by 1.1 percent; and

4. For RS 60 and 61, FBC seeks approval to phase-in the rebalancing of all billing-determinant-related rate components such that revenues are increased by 3.0 percent each year for five years, with the in-season irrigation rate from April to October increasing by 3.9 percent each year;

D. With regard to the approvals sought for RS 60, FBC also seeks approval of a non-rate base deferral account titled the Irrigation Rebalancing Phase-in deferral account, attracting FBC's weighted average cost of capital (WACC), to be amortized over the proposed five-year phase-in period and recovered from all customers through FBC's general rate increases;

E. FBC also requests approval in the Application to update the transformation discount as a result of the 2025 COSA study under RS 21, 30, and 40 for customers who choose to take service at the primary distribution voltage level (RS 21) or at the transmission voltage level (RS 30 and 40), effective January 1, 2026:

1. For RS 21, an update to the transformation discount from $0.409 per kW of Billing Demand to $0.4841 per kW (from $0.371 to $0.4357 on a kVA basis) of Billing Demand;
2. For RS 30, an update to the transformation discount from $6.727 per kVA of Billing Demand to $5.98 per kVA of Billing Demand; and
3. For RS 40, an update to the transformation discount under the Wires Charge from $3.390 per kVA of Billing Demand to $3.78 per kVA of Billing Demand and under the Energy Charge reduced from $0.00985 per kWh to $0.00926 per kWh;

F. By Orders G-60-25 and G-##-##, the BCUC established the regulatory timetable for the proceeding, which included intervener registration, two rounds of information requests (IRs), and final and reply arguments; and

G. The BCUC has reviewed the Application, evidence and submissions of the parties and makes the following determinations.

NOW THEREFORE pursuant to sections 58 to 61 of the *Utilities Commission Act*, the BCUC orders as follows:

1. FBC is approved to:

   a. Rebalance all billing-determinant-related rate components of RS 20 and 22 such that revenues are decreased by 2.4 percent;

   b. Rebalance all billing-determinant-related rate components of RS 31 and 33 such that revenues are decreased by 0.3 percent;

   c. Rebalance all billing-determinant-related rate components of RS 40 and 42 such that revenues are increased by 1.1 percent; and

   d. Phase-in the rebalancing of all billing-determinant-related rate components included in RS 60 and 61 such that revenues are increased by 3.0 percent each year for five years, with the in-season irrigation rate from April to October increasing by 3.9 percent each year during the five-year phase-in.

2. To facilitate the phase-in for RS 60 and 61, FBC is approved to establish a new non-rate base deferral account, titled the Irrigation Rebalancing Phase-in deferral account, attracting FBC's weighted average cost of capital (WACC), to be amortized over five years, effective January 1, 2026 and recovered from all customers through FBC's general rate increases.

3. FBC is directed to update the transformation discount under RS 21, 30, and 40 as a result of the 2025 COSA study as follows, effective January 1, 2026:

    a. For RS 21, an update to the transformation discount from $0.409 per kW of Billing Demand to $0.4841 per kW (from $0.371 to $0.4357 on a kVA basis) of Billing Demand;

    b. For RS 30, an update to the transformation discount from $6.727 per kVA of Billing Demand to $5.98 per kVA of Billing Demand; and

    c. For RS 40, an update to the transformation discount under the Wires Charge from $3.390 per kVA of Billing Demand to $3.78 per kVA of Billing Demand and under the Energy Charge reduced from $0.00985 per kWh to $0.00926 per kWh.

4. FBC is approved to establish a new rate base deferral account, titled the 2025 COSA deferral account, to record the costs associated with the regulatory review of the Application, and to amortize the deferral account over one year, commencing January 1, 2026.

5. FBC is directed to file revised tariff pages reflecting the Decision with the BCUC for endorsement at the same time FBC files tariff pages for the general rate changes effective January 1, 2026, by no later than December 15, 2025.

DATED at the City of Vancouver, in the Province of British Columbia, this [XXth] day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Appendix F-3

DRAFT PROCEDURAL ORDER – AMENDED TIMETABLE

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2025 Cost of Service Allocation and Revenue Rebalancing

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On February 14, 2025, FortisBC Inc. (FBC) filed with the British Columbia Utilities Commission (BCUC), pursuant to sections 58 to 61 of the *Utilities Commission Act*, its 2025 Cost of Service Allocation study and application for approval of revenue rebalancing, as well as approval to establish a new rate base deferral account to record the regulatory proceeding costs associated with the review of the application, effective January 1, 2026 (Application);

B. By Order G-60-25, the BCUC established the regulatory timetable for the proceeding, which included intervener registration, one round of information requests (IRs), and final and reply arguments;

C. On May 15, 2025, FBC filed its Updated Application and responses to IRs No. 1, which resulted in amendments to its approvals sought, and proposed a second round of IRs; and

D. The BCUC has considered the Updated Application and determines that an amended regulatory timetable is warranted.

NOW THEREFORE the BCUC amends the regulatory timetable as set out in Appendix A to 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

Attachment

FortisBC Inc.
2025 Cost of Service Allocation and Revenue Rebalancing

REGULATORY TIMETABLE

Action	Date (2025)
BCUC Information Request (IR) No. 2	Thursday, June 5
Intervener IR No. 2	Thursday, June 12
FBC responses to IR No. 2	Friday, July 4
FBC final argument	Friday, July 18
Intervener final arguments	Friday, August 1
FBC reply argument	Monday, August 18