Sarah Walsh
Director, Regulatory Affairs

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

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

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3861
Cell: (604) 230-7874
Fax: (604) 576-7074
www.fortisbc.com

May 15, 2025

British Columbia Municipal Electrical Utilities
c/o Nelson Hydro
101- 310 Ward Street
Nelson, BC
V1L 5S4

Attention: Scott Spencer

Dear Scott Spencer:

Re: FortisBC Inc. (FBC)

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

Response to the British Columbia Municipal Electrical Utilities (BCMEU) Information Request (IR) No. 1

On February 14, 2025, FBC filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-60-25 for the review of the Application, FBC respectfully submits the attached response to BCMEU IR No. 1.

For convenience and efficiency, if FBC has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FBC intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

1.0 Reference: Exhibit B-1, Application, excel Appendix B: FBC Final COSA 2025 Model, Rate Schedule 41

BCUC PROJECT 1598939, Exhibit B-2 Application, excel Appendix B – FBC Final COSA 2017 Model

A comparison of methods for developing revenue estimates indicates a significant departure from the 2017 COSA method to the 2025 COSA method with respect to Rate Schedule 41.

1.1 Please describe the meaning of the value 73% as shown in cell L130 of the tab "Revenues" in the 2025 COSA, and confirm if the mathematics is correctly applying the ratio (i.e., should it be multiplied in cells L131 to L142, or divided).

Response:

The following response has been provided by EES Consulting:

The 73% value in cell L130 is the average annual ratio of Billing Demand to measured demand for RS 41 for the 2022 reference year. EES confirms that there was a calculation error in the original model for ratchet demands resulting in the incorrect mathematic application of the ratio.

In addition, given that RS 41 is a unique rate class composed of a single customer, the determination of demand values for the calculation of Wires and Power Supply demand charges can be based on actual historical monthly values reflecting the 80% ratchet provided for in the tariff.

Accordingly, EES has revised the COSA model to reflect the following changes, which also address BCMEU IR1 1.2, 1.2.1, 1.3, and 2.1:

- RS 41 historical load for 2022 has been updated to reflect the load parameters found in the billing system, including the value for November that is the subject of BCMEU IR1 1.3 which was the result of a keying error.
- RS 30, 40 and 41 demand values have been revised to use actual monthly ratchet values from the historical year, rather than an annual average. This is the best approach to the ratchet for this purpose as these historical monthly values reflect the diversity of ratchet values regardless of the number of meters.
- RS 31 demand values use a ratchet value calculated on the forecast year values due to RS 38 adjustments not in the historical year.

FBC has filed an Updated Application concurrently with these IR responses which includes an updated COSA model filed as Appendix B to the Updated Application. This provides the corrected calculation of the RS 40 and RS 41 revenues as requested in BCMEU IR1 2.1.

A summary of the impact of these revisions to the total revenue for RS 40 and RS 41 is shown in the table below. In order to isolate the impact of these changes, the updated COSA values include all the other changes to the original COSA model that have been made as a result of items noted in the cover letter to the Updated Application, so will not match the values in the version of the COSA model filed with the original Application.

Table 1: Updated RS 40 and RS 41 Revenue

Rate Class	Total Revenue Reflecting Only Unrelated COSA Changes	Updated Revenue	Change
RS 40	$53,105,528	$54,138,777	1.9%
RS 41	$8,141,693	$8,746,523	7.4%

1.2 Please confirm that the intent of the calculation leading to cell L144 is to determine the billing determinants that Rate Schedule 41 will pay for Demand related charges for Wires Services. If confirmed, please indicate why the monthly billed demand units (cells L131 to L 142) do not reflect the 80% ratchet that applies to Wires billing demand units, as indicated in FortisBC's Rate Schedule 41 at pdf page 187 of Exhibit B-1.

1.2.1 Please indicate if the correct values for determination of the Wires billing demand units are as shown in Excel Appendix B at cells AQ131 to AQ142 (or those values scaled to 2024). If not, please indicate why not. If yes, please correct the estimate of revenue from Rate Schedule 41.

<u>Response:</u>

Please refer to the response to BCMEU IR1 1.1.

1.3 In tab "Load" there appears to be an input error in cell L144, where it is noted the Rate Schedule 41 load in November is 56,874 kW. Please provide a corrected version of the COS file, and confirm this will change the estimated revenues from the Rate Schedule

<u>Response:</u>

Please refer to the response to BCMEU IR1 1.1.

2.0 Reference: Exhibit B-1, Application, excel Appendix B: FBC Final COSA 2025 Model, Rate Schedules 40 and 41

BCUC PROJECT 1598939, Exhibit B-2 Application, excel Appendix B – FBC Final COSA 2017 Model

2.1 Please provide the same information as in question 1.2 above, for Rate Schedule 40, similarly correcting the values in tab “Revenues” cells K131 to K144.

Response:

Please refer to the response to BCMEU IR1 1.1.

3.0 Reference: Exhibit B-1, Application, excel Appendix B: FBC Final COSA 2025 Model, Rate Schedule 41

BCUC PROJECT 1598939, Exhibit B-2 Application, excel Appendix B – FBC Final COSA 2017 Model

The Excel models indicate, as represented in the respective "Load" tabs, energy increases from 2017 to 2025 which show extremely limited increases in energy (from 505.9 to 506.8 GWh and from 81.4 to 83.2 GWh respectively for Rate Schedules 40 and 41, at row 380 in each respective Excel model) with much larger increases in Individual NCP demand (from 1014.9 to 1175.6 MW, and from 204.7 to 295.9 MW per the respective rows 480)

3.1 Please confirm the energy and capacity growth for the two Rate Classes and provide a detailed explanation for the degree of growth and change in customer loads factors.

<u>Response:</u>

The following response has been provided by EES Consulting:

The best place to compare the two models on a load and demand basis is the Unit Costs tab. Below is a comparison of the forecast summary billing determinants for RS 40 and RS 41 for the 2017 COSA and the 2025 COSA as revised in the updated COSA model filed as Appendix B to the Updated Application filed concurrently with these IR responses.

	<u>Wholesale Primary 40</u>	<u>Wholesale Transmission 41</u>
2017 COSA		
Billing Determinants		
Total kVA (with ratchet)	1,104,374	263,181
Total Demand (kW)	1,014,925	204,739
Total Energy (kWh)	505,880,576	81,420,354
2025 Study – Updated Application		
Billing Determinants		
Total kVA (with ratchet)	1,212,329	304,912
Total Demand (kW)	1,161,133	231,004
Total Energy (kWh)	500,604,721	89,395,279
% Change		
Total kVA (with ratchet)	9.78%	15.86%
Total Demand (kW)	14.41%	12.83%
Total Energy (kWh)	-1.04%	9.79%

Between the two studies, there is a forecast energy reduction of -1.04% for RS 40 and energy growth for RS 41 at 9.79%. However, the respective COSA models show significant demand growth for both RS 40 and RS 41 at 14.41% and 12.83%, respectively.

The following response has also been provided by FBC:

FBC notes that the growth in demand for RS 40 and RS 41 between the forecast used in the 2017 COSA (which was based on the forecast from FBC's 2017 Annual Review) and the 2025 COSA (which was based on the forecast from FBC's 2024 Annual Review) aligns with the overall increase in winter peak demand that has occurred over the 7-year period (from 2017 to 2024). Further, the 2024 peak demand forecast includes the actual impact of the very cold winter experienced in 2022. For energy consumption, the change in the forecast between 2017 and 2024 for RS 40 is relatively minor, however, there has been higher growth for RS 41. FBC notes that RS 41 currently has only one customer and the energy forecast is based on the customer's own expectation of their load growth.

3.2 Please explain how Rate Schedule 41, which contains only one customer, can have a Group Coincidence Factor (in 2025 varies by month, while in 2017 the coincidence factor is 100% as expected, at rows 484 to 496 of the 'Load' tab). Similarly please provide an explanation for the Group coincidence factor in Appendix A, Tab 'COSA Factors Summary' cells K88 to K99.

<u>Response:</u>

The following response has been provided by EES Consulting:

Although RS 41 contains only one account, RS 41 load is measured by three totalized meters. The billing demand is the coincident maximum of these three meters, not the sum of the individual max values of each, thus requiring a group coincidence factor to avoid overstating demand. The calculated group coincidence of these three meters was not always 100 percent but was always very close to 100 percent.

The change in the coincidence factor in the 2025 study compared to the 2017 study is a result of EES receiving interval data for all three meters as opposed to one totalized meter. This is consistent with how EES calculated group coincidence factors for other rate classes and is appropriate here.

3.3 Please also explain the significant increases in Rate Class NCP @ input voltage at rows 534 to 549 of each respective model 'Load' tab from 2017 to 2025.

Response:

The following response has been provided by EES Consulting:

Row 534 is the value for system losses and is for reference only and not a dependent variable.

The Rate Class NCP @ Input Voltage (kW) contained in Rows 535-546 in the 2017 and 2025 models are the results of multiplying Rows 517-528 (Rate class NCP above) by (1+ Rows 201 (Primary line losses). This is the same logic as previous models.

These values are driven by the actual historical load from the respective years, and, while EES does not view the differences as significant, the specific reasons for the change in load characteristics are not something that can be gleaned from the model.

EES performed a bottom-up comparison of gross MWh sales to the Actual Gross Energy recorded on the system for 2022, which can be found in the “Load” tab of the COSA model at cells B316:B329. This comparison showed that the loss assumptions were within 1.7 percent on a top down versus bottom-up comparison basis. The secondary loss assumption of 5.08 percent, the primary loss assumption of 4.36 percent, and the transmission loss assumption of 2.86 percent all roll up into this purchases-to-sales adjustment consistent with previous studies. The only difference between these assumptions for the 2025 COSA study and the assumptions from the 2017 COSA study is that the secondary losses is slightly lower, as the losses were 5.75 percent in the 2017 study. Nothing in the comparison indicates anything other than changes in the levels of sales is driving the difference.

3.4 With reference to Exhibit B-1, Appendix A Excel model (tab ‘Clean hourly’ or other), please provide a detailed calculation of the coincidence factors cited at rows 219 to 230 of the 2025 model.

Response:

The following response has been provided by EES Consulting:

The system coincidence factors in Rows 219 to 230 of the Load tab calculate the percentage difference between the rate class coincident peak and the rate class non-coincident peak. For example, cell k219 = cell K234 divided by cell K202.

The coincident and non-coincident peak values result from the comparison of hourly metered values for the respective periods. The rate class coincident peak would be the sum of all metered hourly values for a rate class at the hour of the system peak. The rate class non-coincident peak would max the hourly value for the month of that same summation.

4.0 Reference: Wholesale Classes (RS 40 and 41) and customer contributions

4.1 For each of the customer classes, please provide an explanation including methodology used and supporting calculations for how Fortis calculates the customer contribution portion of connection charges versus the utility maximum investment when a customer is connecting to the system or expanding. Please provide any supporting data for any calculations used in determining the amounts.

Response:

The scope of the COSA does not include an examination of connection or other standard charges. These matters, including updates to the input costs, are appropriately dealt with in a rate design process.

Connection Charges (as contained in Section 17 of the FBC Electric Tariff) are based on actual costs as determined by FBC and updated from time to time. These calculations were provided in detail as part of the 2009 COSA and RDA proceeding, and the methodology is unchanged. The values were updated as part of the 2017 COSA.

For additional information, see Appendix F[1] of the 2009 Application and Appendix D[2] of the 2017 Application.

4.2 Please provide transmission capacity limits for each BCMEU customer's Point of Delivery (i.e. the physical transmission capacity limits on infrastructure capabilities) – both for wholesale primary and wholesale transmission.

Response:

Please see the following information on the transmission capacity limits for each of the BCMEU customer's Points of Delivery (POD):

City of Grand Forks

- Ruckles Substation – Summer/Winter: 10 MVA / 10 MVA
- Donaldson Drive – Summer/Winter: 6 MVA / 8 MVA

District of Summerland

- Trout Creek Substation – Summer/Winter: 6 MVA / 10 MVA
- Donaldson Drive – Summer/Winter: 16 MVA / 20 MVA

1 FortisBC Inc. 2009 Rate Design and Cost of Service.
2 FortisBC Inc. 2017 Cost of Service Analysis & Rate Design.

City of Nelson

- Rosemont Substation – Summer/Winter: 40 MVA / 40 MVA
- Coffee Creek Substation – Summer/Winter: 5 MVA /5 MVA

City of Penticton

- Huth Substation 13 kV – Summer/Winter: 32 MVA / 40 MVA
- Waterford Substation – Summer/Winter: 32 MVA / 40 MVA
- Westminster Substation – Summer/Winter: 31 MVA / 38 MVA
- R.G. Substation – Summer/Winter: 20 MVA / 25 MVA

BC Hydro

- Yahk: 1,500 kVA
- Lardeau: Not Available[3]

[3] FBC was unable to complete a study of the capacity limit in time to file with these responses; however, FBC notes that the load has not exceeded 2.1 MVA in the past 4 years.

5.0 Reference: Exhibit B-1, Application, Appendix A: EES Consulting COSA Report, Section 3.5.2 Demand Allocation Factors

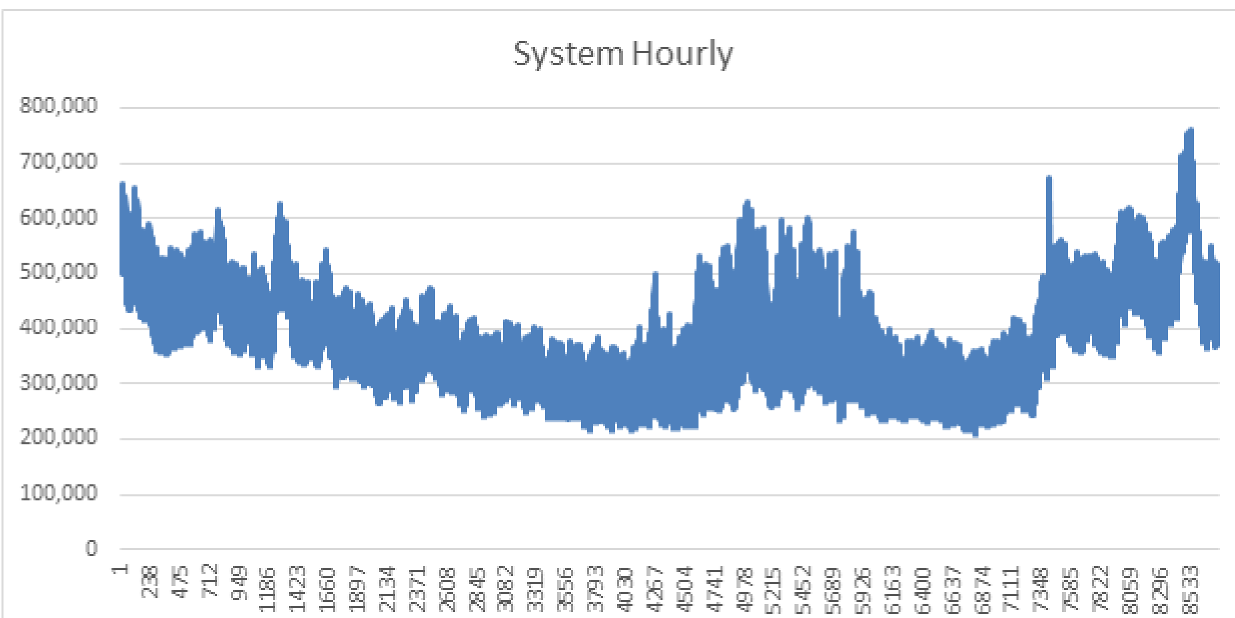
In response to BCUC IR 115.1.1 in the 2017 COSA & Rate Rebalancing application (Exhibit B-21) where FBC was asked which factors in future would FBC use to determine if 2 CP allocator is still appropriate, FBC responded that:

> FBC would look at the overall shape of the system, how close the summer peaks are to winter peaks, whether the load shape has changed since the last COSA, the results of the FERC and OEB tests, whether any other factors related to planning for system facilities have changed and whether any precedents in BC or other jurisdictions have changed enough to warrant a change for FBC.

As FBC is not requesting any changes to this allocator it is assumed it has concluded the method is still appropriate and cost causative.

FBC has not provided the same level of analysis in its 2025 COSA Report as in the 2017 COSA Report.

5.1 Please provide all analysis FBC undertook regarding its load shape, the results of FERC and OEB tests, and an explanation of any system facility changes to confirm its current 2 CP approach (2 winter and 2 summer peaks) to demand allocation remains the most appropriate, and compare to the results in the 2017 Application review. Specifically explain how FBC determined in the past that 2 winter and 2 summer peaks would make up the 2 CP method



The system hourly graph above is provided in the excel file Appendix A, C_EES COSA Report – Load Summary file, tab 'Clean System Hourly'.

Response:

The following response has been provided by EES Consulting:

In the 2017 application, EES selected the demand allocation method after consideration of precedent, FERC and OEB tests, and comparisons of load shapes and growth of winter and summer peaks. The current 2 CP approach for the 2025 COSA study continues to be appropriate based on the following considerations.

EES rejected the 12 CP approach as five of the six of the FERC/OEB tests indicate that 12 CP would not be appropriate

EES selected the 2 CP approach rather than a 1 CP or 4 CP approach because FBC has a significant summer peak in addition to a significant winter peak. The hourly load profile included in the preamble to BCMEU IR1 5.1 shows this is still the case.

Test	Criteria	Resulting Value	Result
FERC #1	12CP if < 20%	15%	**12CP**
FERC #2	12CP if > 65%	54%	**Other CP including 2CP**
FERC #3	12CP if Peak Months < Non-Peak	20%	**Other CP including 2CP**
FERC #4	12CP if >81%	75%	**Other CP including 2CP**
OEB #1	12CP if > 83%	75%	*Perform Test #2*
OEB #2	4CP if >= 83%, if less then 1CP	90%	**4CP**

In addition, both summer and winter peaks continue to grow, although in more recent years, the summer peak is not growing as quickly as winter.

2009 - 2017	Summer	Winter
Growth (MW)	73	47
Growth %/yr	1.5%	0.8%
2017 - 2022		
Growth (MW)	104	127
Growth %/yr	2.2%	3.3%

Based on the annual hourly shape of the system and a comparison to previous results, EES believes the use of 2 CP is still appropriate.

5.2 Please comment on how the system load profile for the forecast 2026 year (for which rates are being applied) compares to each of the 2022 year AMI metered data and to the 2017 COSA review, including the degree to which net metering or solar installations are now affecting, or are expected to affect, summer peak customer loads on the utility, including noting the materiality.

Response:

FBC does not have a system load profile forecast for 2026 and is thus unable to respond to the first portion of this question.

Total Net Metering installations and consumption figures are included in the response to CEC IR1 6.1. While Net Metering installations have increased each year since the program began, the pace of growth is slowing. The majority of Net Metering installations provide no capacity in peak winter evening demand periods and the capacity contribution in the summer is diminished during peak evening hours as the sun begins to set. FBC does not expect that customer-owned distributed generation will have a material impact on system peaks for the foreseeable future.

6.0 Reference: Generation Classification between Energy and Demand

Exhibit B-1, Appendix B – FBC Final COSA 2025 Model, Power Supply tab

On page 17 of Exhibit B-1 Appendix A, EES consulting report states:

> 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 BC Hydro 3808 energy rate input data is shown in tab 'Power Supply' at row 147, but varies throughout the summer without explanation as to the reason this rate does not match the BCUC approved RS 3808 rate.

6.1 Please explain FBC's approach for including BC Hydro's Deferral Account Rate Rider (DARR) and Trade Income Rate Rider (TIRR) in the classification methodology for generation related costs.

Response:

The values contained in Row 147 of the Power Supply tab are single values that represent a blending of several factors, including BC Hydro 3808 Tranche 1 and Tranche 2 prices, as well as estimated rate riders (including the DARR and TIRR (0%) noted in the question), and estimated BC Hydro rate increases. As provided for in the BC Hydro 3808 tariff, there can also be an over-nomination factor equal to 150% of the Tranche 1 Energy Price, for each kWh of such Scheduled Energy taken or deemed taken that that exceeds the Annual Energy Nomination. FBC has forecast this to occur in July to September as noted below. The actual rate that applies under BC Hydro 3808 will vary with the amount of power taken, which leads to a blended rate that fluctuates by month. For the 2025 COSA, the numbers were based on information available when the forecast was made and was based on information provided by BC Hydro at the time. For 2017, FBC did not anticipate any purchases at the Over-nomination rate. Therefore, the rates in the 2017 COSA are simply the BC Hydro 3808 rates in effect at the time, multiplied by the 5% DARR. The specific values in the referenced row for the 2025 COSA are the result of the calculations below.

- For January to March: Forecast 3808 rate of $51.45 x (1+(-0.01 rate rider)) = $50.94/MWh
- For April to June: (Forecast 3808 rate of $51.45 x 1+ estimated rate increase of 2.18%) x (1+(-0.01 estimated rate rider)) = $52.31
- For June: The rate is the result of a calculated blended Tier 1 and Over-nomination rate ($52.31x 15,437 MWh) + ($52.31x 1.50x 19,662 MWh)/35,099MWh = $66.96
- For July to September: The rate of $78.46 is the result of a calculated Over-nomination rate of $52.31 x 1.50

- For October to December: The rate is $52.31/MWh calculated on the same basis as April to June.

6.2 Please provide all supporting materials for the BCH 3808 energy and demand rates used to calculate the power supply classification split between energy and demand. Please specifically explain why the BCH 3808 energy rates are much higher in July – September than in other months (providing supporting calculations), and explain the rationale behind this change for differential rates compared to the 2017 COSS (which used a consistent energy charge for each month).

Response:

Please refer to the response to BCMEU IR1 6.1.

7.0 Reference: Exhibit B-1, Appendix B to the EES FBC 2025 Cost Of Service Study, Minimum System Analysis (pdf pages 139 – 142).

The results of the Minimum Systems Analysis is explained on pdf pages 140 & 141 for Poles, Conduits, and Transformers.

FBC's Attachment B – Final COSA 2025 Model excel file includes the following table to classify distribution related costs within the COSA Model, however all values in blue are hard entered:

Primary/Secondary Split	NCPP	NCPS	Customer	Total
Poles & Towers	80%	20%		100%
Conduits	80%	20%		100%
Transformers		100%		100%
Minimum System Analysis				Total
MINSYSP-Poles & Towers	11%	3%	86%	100%
MINSYSC-Conduits	23%	6%	71%	100%
MINSYST-Transformers		57%	43%	100%

PLCC Adjustment For Distribution Costs

PLCC Adjustment = 0.97 kW

7.1 Please fill in the below table that supports the minimum system analysis results as reported in Appendix B, and provide all supporting calculations:

	Poles & Towers	Conduits	Transformers
Average Unit Cost of Minimum Sized Asset			
Number of Units (Assets)			
Resulting Minimum System Cost (customer-related)	$215.6 million	$56.7 million	$98.7 million
Total Installed Cost	$250.3 million	$79.5 million	$231.7 million

Response:

The following response has been provided by EES Consulting and reflects the results from the corrected COSA model included in the Updated Application filed concurrently with these IR responses:

Please refer to the table below. Regarding Conduits, the value shown is the full conduit kilometer costs for the minimum system. This value in the original COSA model did not include the neutral conduit, which was included in the 2017 MSS. EES revised the MSS based on confirming the current amount of neutral conduits and this modifies the results as shown below.

	Poles & Towers	Conduits (per Updated COSA Model)	Transformers
Average Unit Cost of Minimum Sized Asset	$2,551.64	$3,813.34	$2,499
Number of Units (Assets)	84,510	14,872	39,479
Resulting Minimum System Cost (customer-related)	$215.6 million	$56.7 million	$98.7 million
Total Installed Cost	$250.3 million	$87.9 million	$231.7 million

7.2 Please explain the methodology employed in support of the proposed splits between NCPP (NCP Primary) and NCPS (NCP Secondary) at 80:20. Provide all supporting calculations to support the resulting splits.

Response:

The following response has been provided by EES Consulting:

EES did not re-evaluate the 80%/20% Primary and Secondary split for this study and therefore there are no supporting calculations. However, this continues to be a reasonable assumption given the application of 80:20 is only to Poles, Towers, and Conduit. Most poles and conduit are primary up to the transformer, which is 100 percent secondary in the model, as most of the poles and wires to get to the transformer are on primary and the transformer is typically located close to the service.

7.3 Please explain whether FBC undertook any analysis for differing demand/customer classification treatment between primary and secondary distribution costs, as is done by BC Hydro, ATCO Electric and Hydro Quebec for some distribution assets (as shown in Table 8.1) and provide supporting rationale for the methodology that classification treatment should be consistent between primary and secondary distribution assets.

Response:

The following response has been provided by EES Consulting:

EES did not undertake additional analysis, as the previously approved MSS method did not differentiate for the customer versus demand allocation and there has been no indication that further investigation or analysis would be required. However, the EES COSA model does provide different treatment for primary and secondary distribution costs by excluding secondary costs from rates that take service at primary voltage and providing calculations for discounts for service at higher voltage levels.

8.0 2024 Forecast kWh Sales AMI to Evidentiary Adjustment

Reference: Exhibit B-1, Appendix B – FBC Final COSA 2025 Model, Load tab

Pdf page 72 of the Application explains the use of historical year 2022 AMI data for use in the COSA to develop allocators for each rate class:

> 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.

It appears that FBC's 2025 COSA model updates the coincidence factors from the 2022 AMI data (calculated in the Load tab, rows 413 to 426) for each rate class uniformly each month using load differential weightings from the 2024 forecast year.

The weightings are provided on row 658 of the Load tab and provided below for each rate class:

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
2024 Forecast kwh sales (calculated)	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
2024 Forecast kwh sales (evidentiary update)	3,474,000,000	1,299,000,000	974,000,000	-	-	564,000,000	-	9,000,000	38,000,000	590,000,000	-
2022 Actual kwh sales calculated (AMI data)	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
2022 Actual kwh sale (annual report billed)	3,542,000,000	1,398,000,000	967,000,000	-	-	542,000,000	-	9,000,000	37,000,000	589,000,000	-
AMI to Evidentiary Adjustment	0.9%	-7.4%	-0.4%	-0.4%		-9.650%	0.200%	15.2%	-12.4%	6.993%	1.062%

8.1 Please provide the supporting calculations for each 'AMI to Evidentiary Adjustment' weighting and explain how FBC forecasts resulted in the usage changes between rate classes when the overall energy usage is not expected to change materially.

<u>Response:</u>

The following response has been provided by EES Consulting:

These adjustments are simply a goal seek adjustment to match the forecast in the Evidentiary Update to the Annual Review for 2024 Rates on a percentage basis, with the exception of the RS 38 adjustments as described in the Updated Application. As such, no additional supporting calculations are available.

FBC methodology adds the 'AMI to Evidentiary Adjustment' weightings uniformly across all periods such that the kWh sales at meter (Load tab, rows 413 to 426), Individual NCP (kW) (Load tab, rows 465 to 480), CP @ Input (kW) (Load tab, rows 566 to 582), and Rate Class NCP @ Input Voltage (Load tab, rows 533 to 549) are all uniformly increasing in each month by the 'AMI to Evidentiary Adjustment' weightings compared to the 2022 AMI based counterparts. So for example, Wholesale Primary data is increasing by 7% for all monthly load data characteristics and resulting allocators that these figures are based on compared to actual 2022 data.

8.2 Please provide FBC's justification for the uniform approach to adjusting load data for the 2024 year especially given some customer classes, such as Wholesale Primary & Wholesale Transmission, do not use energy uniformly in each period in such a way that it would have a 1-to-1 impact on both the NCP and CP, individually and at a class level.

Response:

The following response has been provided by EES Consulting:

The one-to-one adjustment method preserves the historical year energy to demand relationships for all classes. If EES were to treat forecast adjustments differently for some rate classes, that would need to be done for all classes and it would dilute the integrity of the metered results.