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September 25, 2025

Industrial Customers Group
c/o Robert Hobbs
2206 Happy Valley Road
PO Box 1552
Rossland, BC
V0G 1Y0

Attention: Robert Hobbs

Dear Robert Hobbs:

Re: FortisBC Inc. (FBC)
2025 and 2026 Annual Review of Rates (Application)
Response to the Industrial Customers Group (ICG) Information Request (IR) No. 1

On July 31, 2025, FBC filed the Application referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-180-25 for the review of the Application, FBC respectfully submits the attached response to ICG IR No. 1.[1]

FBC has filed a portion of the response to ICG IR1 2.1 on a confidential basis as identified in that response and has provided a redacted version for the public record of this proceeding.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registrar
Registered Interveners

[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.

1 Reference: Exhibit B-2, Section 1.1.2, p. 2

"This increase includes the proposed revenue surplus deferred from 2025 as discussed above, which FBC is proposing to return to customers through amortization in 2026 rates."

1.1 Please calculate the rate of return (carrying benefits) to customers of the deferral of the revenue surplus and explain how the carrying benefits accrue to customers?

Response:

FBC is proposing to capture the revenue surplus proposed to be deferred from 2025 (i.e., $10.199 million) in the existing 2023 Revenue Deficiency deferral account and to rename the account the Revenue Deficiency/Surplus deferral account. This deferral account was approved as a non-rate base deferral account attracting FBC's Weighted Cost of Capital (WACC) by Order G-276-23. As such, the financing costs (credits) of the revenue surplus will be calculated at 5.95 percent for both 2025 and 2026.[1] For the $10.199 million of revenue surplus ($7.445 million net of tax), the cumulative financing costs accrued in 2025 and 2026 equal to a credit of approximately $0.456 million, which is a benefit for customers.

All financing costs (and credits) for FBC's non-rate base deferral accounts at WACC are shown on Line 20 of Schedule 12.2 in Section 11 of the Application. If approved, the carrying cost (in the case of the revenue surplus, these are credits) will accrue in the deferral account for the benefit of customers and will be amortized to customers in rates in 2026 and 2027 (i.e., financing costs or credits accrued in 2025 will be amortized into 2026 rates and financing costs or credits accrued in 2026 will be amortized into 2027 rates).

[1] Please refer to Table 8-2 of the Application for the calculation of FBC's 2025 and 2026 Allowance for Funds Used During Construction (AFUDC) rates, which are equal to FBC's 2025 and 2026 WACC.

2 Reference: Exhibit B-2, Section 3.3.4, pp. 23-24

"As shown in Figure 3-7 below, the 2024 Actual industrial load is 53.9 GWh or 9.6 percent higher than 2024 Approved, primarily due to higher-than-expected load from one customer. For 2025, the projected industrial load is 713.3 GWh, which is an increase of 149.8 GWh from 2024 Approved (or 95.9 GWh from 2024 Actual). For 2026, the forecast industrial load is 773.8 GWh, which is an increase of 60.5 GWh from 2025 Projected. The increases in both 2025 Projected and 2026 Forecast are primarily due to higher forecasts from one customer."

2.1 Please break down the industrial load by rate schedule for the period 2021 to 2026F?

Response:

For this response, FBC has redacted certain information that FBC is filing on a confidential basis and requests be held confidential by the BCUC in perpetuity, pursuant to Section 23 of the BCUC's Rules of Practice and Procedure regarding confidential documents, as set out in Order G-192-25.[2] FBC has redacted this information as, due to the small number of industrial customers served and the large difference in load between the customers, the identity of the customers is easily identifiable. Therefore, in order to protect the private customer information, FBC is filing it confidentially. FBC is unable to foresee a time when this information would no longer be considered private and confidential, and therefore requests that it remain confidential in perpetuity. Given the private nature of the information, FBC submits that only the BCUC should have access to the unredacted confidential version. FBC has provided a redacted version for the public record.

The following table provides the breakdown of industrial load by rate schedule, including actuals for 2021 through 2024, 2025 Projected and 2026 Forecast.

[redacted]

[2] As amended by Order G-228-25.

3 Reference: Exhibit B-2, Section 3.5, p. 33

"Finally, FBC is also approved to apply an idling charge of $0.40 per minute that begins five minutes after the end of a charging session. As idling charge implementation was delayed due to vendor system limitations, FBC was directed to file a revised RS 96 tariff with the BCUC for endorsement reflecting the idling charge at least 15 days prior to the effective date. FBC continues to monitor for vendor updates and will provide notice once the system can implement the idling charge. As such, FBC has not included a forecast of idling charge revenue in Table 3-5 above."

3.1 Please describe the vendor system limitation for the inability to implement the idling charge? How much idling charge revenue does FBC expect once it is implemented?

Response:

FLO's current rate setting system does not support idling charges as part of its standard configuration, and enabling this functionality would require extensive development work. FLO intends to replace its current platform with a new system that will support the application of idling charges. Although the rollout of this new system has been delayed, FBC will work with FLO to implement the idling charge once the functionality becomes available.

As noted on page 33 of the Application, FBC currently does not forecast any idling charge revenue for 2025 and 2026. Further, as discussed in the FBC EV Energy-Based Rate Application proceeding, FBC has not included any forecast idling charge revenue in the overall recovery of the 10-year levelized rate. The purpose of the idling charge is to encourage customers to exit the station once their vehicle is charged and is not intended as a revenue generation mechanism. Ideally, all EV customers would exit the station within five minutes after the end of their charging session, resulting in no idling charge revenue. As such, FBC expects limited revenue from the idling charge once implemented; however, any revenue would be captured in the Flow-through deferral account and amortized to all customers.

3.2 How long is the average charging session?

Response:

Based on FBC's historical data from its charging stations, an average charging session at FBC's EV DCFC stations lasts approximately 36 minutes.

4 Reference: Exhibit B-2, Section 4.5, p. 38

"A key driver of the increase in gross load is an increase in the amount of non-firm load on the system, for which FBC intends to supply the energy and capacity on a short-term basis from the wholesale market and flow through the costs to the non-interruptible customers in accordance with RS 38."

4.1 Please explain the difference, if any, between "non-firm" and "non-interruptible" load/service?

Response:

The term "non-interruptible" was used in error in the passage quoted above. The correct phrasing should have been:

> A key driver of the increase in gross load is the growth in non-firm load on the system. FBC intends to supply energy and capacity for this load on a short-term basis from the wholesale market, with costs flowed through to interruptible customers in accordance with RS 38.

Please note that FBC has historically used the terms *interruptible* and *non-firm* interchangeably in the context of RS 38.

5 Reference: Exhibit B-2, Section 4.5, Table 4-2, p. 38

5.1 Please explain and provide the calculation of the 2025 Projected Power Purchase Expense, including the use of 2025 actuals?

Response:

The 2025 Projected Power Purchase Expense (PPE) is calculated using the current load forecast. It assumes firm resources are used to meet firm load obligations, and short-term market purchases to meet non-firm load. It reflects a combination of forecast energy volumes and market pricing, as well as known contract terms and volumes and key operational planning assumptions. The projection includes:

- Partial-year actuals through May 2025;
- Long-term power purchase agreements with known pricing; and
- Forward wholesale market purchases, forecast short term market purchases for RS 37 and 38, and forecast market savings.

While the detailed calculations include some confidential pricing, FBC has provided aggregate volumes and blended rates for the categories in the table below.

Please also refer to the response to MoveUP IR1 1.2 for a discussion on how FBC manages load uncertainty.

Line No.	Description	Projected 2025
1	Brilliant	$ 49.352
2	BC Hydro PPA	$ 67.215
3	Waneta Expansion	$ 37.376
4	Market and Contracted Purchases	$ 33.026
5	Independent Power Producers	$ 0.179
6	Self-Generators	-
7	CPA Balancing Pool	$ 0.841
8	Transmission Service Loss Recoveries	-
9	Special and Accounting Adjustments	$ (0.170)
10	Total	$ 187.819
11		
12	Gross Load (GWh)	3,973
13		
14	Total Volume	
15	FBC Resources	1599
16	Brilliant	914
17	BC Hydro PPA	923
18	Waneta Expansion	0
19	Market and Contracted Purchases	509
20	Independent Power Producers	3
21	Self-Generators	0
22	CPA Balancing Pool	16
23	Transmission Service Loss Recoveries	11
24	Special and Accounting Adjustments	0
25	Total	3973
26		
27	Average Cost	
28	FBC Resources	N/A
29	Brilliant	$ 54.01
30	BC Hydro PPA	$ 72.79
31	Waneta Expansion	N/A
32	Market and Contracted Purchases	$ 64.94
33	Independent Power Producers	$ 68.11
34	Self-Generators	$ -
35	CPA Balancing Pool	$ -
36	Transmission Service Loss Recoveries	N/A
37	Special and Accounting Adjustments	N/A
38	Total	$ 47.27

1

2

6 Reference: Exhibit B-2, Section 4.5.1, p. 38

"The Brilliant expense is projected to increase in 2025 by $4.919 million compared to 2024 Approved due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast."

6.1 Please provide the breakdown of the increased operating and maintenance costs of Brilliant that are driving the greater than 10 percent increase in expense from 2024 to 2025? Please provide the breakdown by category for the last 5 years.

Response:

Brilliant rates are primarily comprised of three parts: (i) a forecast of capital costs; (ii) a forecast of the O&M costs of the plant; and (iii) a true-up to the prior years' actual costs compared to forecast. These are based on a forecast provided by Brilliant Power Corporation each year.

As shown in the table below, the majority of the $4.919 million variance is a result of the annual true-ups applied to 2024 and 2025 rates. There was a true-up of -$2.311 million applied to 2024 rates, whereas 2025 had a true-up of $1.202 million, resulting in a year-over-year change of $3.513 million. The remainder of the increase is due to an estimated increase of $0.428 million in capital costs, and an increase of $0.978 in plant O&M costs.

	2021	2022	2023	2024	2025
Forecast Capital Costs (000's)	$ 30,099	$ 30,396	$ 31,125	$ 32,240	$ 32,668
Forecast O&M Costs (000's)	$ 12,689	$ 13,088	$ 13,175	$ 14,308	$ 15,287
True Up from Prior Year (000's)	$ (1,958)	$ (1,833)	$ (442)	$ (2,311)	$ 1,202

7 Reference: Exhibit B-2, Section 4.5.2, p. 39

"However, the 2024 Approved BC Hydro PPA expense included a reduction of $3.000 million to account for anticipated real-time market opportunities that could enable lower-cost purchases in place of PPA volumes. For 2025, a smaller adjustment (i.e., $0.146 million) has been included for similar opportunities."

Reference: Exhibit B-2, Section 4.6.2, p. 40

"However, FBC has reduced its 2006 Forecast by $2.000 million to reflect anticipated real-time market opportunities."

7.1 Please explain and provide the 2024 actuals for real-time market opportunities?

Response:

In 2024, FBC achieved incremental savings of $1.756 million through market purchase activity, in addition to the $3.000 million embedded in the 2024 Approved PPE forecast. These savings were primarily driven by energy purchases from the market starting in Q2, where FBC was able to procure power at rates lower than both the Tranche 1 PPA energy rate and the Tranche 1 over-nomination rate, to which FBC had planned exposure in August and September.

7.2 Please explain the underlying changes in conditions and/or opportunities between 2025 and 2026 that created the difference between $0.146 million and $2.000 million?

Response:

For 2025, the adjustment is smaller ($0.146 million) because the projection includes actual data through May, which covers the spring period when most real-time market displacement typically occurs (due to low market prices driven by surplus hydro and mild weather). As those months have already passed, the opportunity for further displacement in the remainder of the year is limited. Furthermore, FBC is forecasting only displacement of lower-cost Tranche 1 PPA energy for the rest of 2025.

In contrast, 2026 includes a full year forecast and reflects some FBC exposure to Tranche 2 PPA energy. This Tranche 2 energy is likely to be displaced by lower-cost spot market purchases due to its relatively high cost. The $2.000 million adjustment assumes that market conditions throughout the year will allow for more cost-effective purchases that eliminate any reliance on Tranche 2 volumes.

8 Reference: Exhibit B-2, Section 6.1, p. 48

"In the RSF Decision, the BCUC approved a Base 2024 O&M for FBC based on the adjusted actual 2023 O&M plus net incremental funding in certain areas."

8.1 Please compare the incremental funding proposed in the RSF application to the incremental funding approved in the RSF application and identify the operating changes made by FBC to accommodate the lower approved incremental funding? Please include a comparison of the number of "new hires" proposed in the RSF Application and the actual number of new hires?

Response:

In the RSF Decision, the BCUC directed that FBC's 2024 Base O&M be reduced by $1.000 million, resulting in a reduction in 2024 Base O&M from $76.269 million to $75.269 million. In the compliance filing to the RSF Decision, FBC provided the revised 2024 Base Unit Cost O&M of $494 per customer. This 2024 Base Unit Cost O&M has been used (in conjunction with the approved net inflation factor, the 2025 forecast of average customers and the true-up of average customers from 2023) to determine FBC's 2025 formula O&M, as described in Section 6.2 of the Application.

FBC has approval for a formula O&M funding envelope for the term of the RSF at an aggregate level and will manage within this envelope. Consistent with this approval, FBC declines to provide the requested comparison of new hires proposed in the RSF Application to the actual number of new hires, as this is outside the scope of the Annual Reviews. To the extent that savings are achieved in formula O&M annually, they will be included in the calculation of the earnings sharing mechanism and shared with customers through amortization of the ESM deferral account in subsequent years.

9 Reference: Exhibit B-2, Section 7.3.1, Table 7-3, p. 57

9.1 The greater than 50 percent increase in 2025 Projected capital expenditures over 2024 Approved capital expenditures is shown to continue for 2026 Forecast capital expenditures. Please provide a detailed breakdown of these capital expenditures by category and program for the years 2023 through 2026 and explain whether this increased capital expenditure environment is expected to continue into 2027.

Response:

FBC's 2025 through 2027 forecasts of regular capital (Sustainment, Growth and Other) were reviewed extensively in the 2025-2027 RSF proceeding[3] and the BCUC approved the three-year regular capital forecasts as applied for in the RSF Decision and Order G-70-25. For reference, FBC provides the following table from the RSF Decision (page 50), which presents the approved 2025, 2026 and 2027 regular capital forecasts.

Table 11: FBC Approved and Forecast Regular Capital Expenditures 2023 to 2027 ($000s)[302]

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Growth Capital	30,072	24,568	41,349	45,035	46,357
Sustainment Capital	44,710	51,652	75,664	72,116	71,310
Other Capital	17,658	17,213	25,070	24,922	22,699
Total Regular Capital (Gross)	**92,440**	**93,434**	**142,082**	**142,074**	**140,365**

As the forecasts for 2025 and 2027 (including the reasons for the increased expenditures compared to 2024 Approved) were justified and approved as part of the RSF Decision, FBC refers ICG to the RSF proceeding and declines to provide further details in this response.

[3] E.g., Section C3.4 of the Application, Tables C3-27, C3-29, C3-30, C3-31, C3-33, C3-34, C3-35, C3-36, C3-37 and C3-38.

10 Reference: Exhibit B-2, Section 7.3.2.2, p. 60

10.1 Please provide the annual Mandatory Reliability Standards incremental capital expenditures for each of the last 10 years.

Response:

Please refer to Table 1 below for the actual incremental capital spending related to Mandatory Reliability Standards (MRS) in the past 10 years. FBC has also included the 2025 Projected and 2026 Forecast MRS capital for comparison.

Table 1: 2015 to 2024 Actual, 2025 Projected, and 2026 Forecast Incremental MRS Related Capital Expenditures ($ millions)

Year	MRS Capital
2015	-
2016	-
2017	1.370
2018	0.072
2019	2.780
2020	-
2021	0.065
2022	0.870
2023	-
2024	-
2025 Projected	0.850
2026 Forecast	0.400

11 Reference: Exhibit B-2, Section 13.2.3.1, p. 163

"There were four Major Event Days that met the threshold for normalization in 2024. During a windstorm in the Kootenay region on August 6, 2024, a large tree fell and damaged multiple transmission structures, resulting in outages to 4,200 customers and 63,500 customer hours lost."

11.1 Please explain why the single localized event of the August 5, 2024 tree-caused outage should be treated "2.5 Beta" event normally applied to widespread system events?

Response:

Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method "2.5 Beta" consistent with Electricity Canada standard for reporting. The August 5, 2024, outage met the threshold criteria for a major event for 2024.

11.2 Please provide the Canadian Electricity Association Major Event Day Determination Reference Guide.

Response:

The Canadian Electricity Association Major Event Day Determination Reference Guide is available online on the Electricity Canada website at the following link:

https://www.electricity.ca/files/reports/english/MED-Methods_CEA_2015-1.pdf.

11.3 Please provide details of the outage, including the specific transmission line and structures involved. Why was this tree not identified in FBC's transmission right-of-way vegetation management program, and was the event reportable under Mandatory Reliability Standards requirements?

Response:

The August 6, 2024 outage impacted two 63 kV radial transmission lines. The specific lines impacted were 9 Line and 10 Line as well as a 12.5 kV distribution line underbuilt on the 9 Line structures. The incident resulted in damage to 15 transmission structures. The cause of the

outage was a large green cottonwood tree located outside of FBC's right-of-way that fell and landed across both transmission lines.

FBC's vegetation management program, specifically the hazard tree program, identifies off right-of-way trees that are dead or in decline. Since the tree in question was a green (i.e., live) tree without visual signs of deterioration, it would not have been flagged for removal under the program criteria.

As the affected transmission lines are not part of the Bulk Electric System and operate below the 200 kV threshold required by FAC-003 standard for vegetation management, Mandatory Reliability Standards do not apply to these two lines and, therefore, this event is not reportable under Mandatory Reliability Standards.

12 Reference: Exhibit B-2, Appendix A2, Section 5.3, p. 8

12.1 Please explain why the DSM (GWh) Without Losses for 2026F is almost double the average amount of the previous 6 years? Please describe and quantify the specific DSM programs and associated costs that are the source of these savings.

Response:

Please refer to the response to BCSEA IR1 1.1.

13 Reference: Exhibit A-4, BCUC IR 1.2

13.1 Assuming the use of 5 months of actual results in 2025 is retroactive rate making, please propose an alternative for calculating the 2025 revenue requirement?

Response:

Please refer to the response to BCUC IR1 1.1.

14 Reference: Exhibit A-4, BCUC IR 5.2

14.1 Please comment on the revenue to cost ratio for RS 96 service that could reasonably be expected to fully recover the cost of service on a 10-year levelized basis?

Response:

Please refer to the response to CEC IR1 7.1 which explains that all costs, including FBC's EV DCFC assets and revenues, are directly assigned to the commercial customer class under RS 21 as part of the Cost of Service Allocation (COSA) Study. In the most recently filed COSA study (filed as part of the FBC 2025 COSA and Revenue Rebalancing Application which is currently awaiting a BCUC decision), the revenue to cost (R/C) ratio for RS 21 was 102.4 percent, which is within the range of reasonableness of 95 to 105 percent.

If the current estimate of the overall recovery of RS 96 over the 10-year levelization period were increased to 100 percent, the energy-based rate would need to increase from $0.33 per kWh to $0.36 per kWh (or from $0.39 per kWh to $0.41 when including the 15 percent transaction fee) in 2026. However, as noted in the response to CEC IR1 7.1, the impact of RS 96 on the COSA study is minimal, and increasing the overall recovery of RS 96 from 93 percent to 100 percent over the 10-year levelization period would have no material impact on the RS 21 R/C ratio.

Please also refer to the response to BCUC IR1 5.2 for an explanation of why it is not reasonable to consider a change to the RS 96 rate at this time.

14.2 Please forecast the change to the EV charging rate of $0.39 kWh that would be expected to fully recover the cost of service on a 10-year levelized basis?

Response:

Please refer to the response to ICG IR1 14.1.

15 Reference: Exhibit A-4, BCUC IR 6.1

15.1 Please calculate the rate increases for 2026 and 2026 assuming 2024 actual capital expenditures matched the 2024 approved capital expenditures?

Response:

Please refer to the response to BCUC IR1 6.1 for the calculation of the impact of the 2024 Actual capital expenditures exceeding the 2024 Approved capital expenditures.