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March 5, 2025

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. – Mainland and Vancouver Island Service Area, and Fort Nelson Service Area

Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) Quarterly Gas Cost Report

2025 First Quarter Gas Cost Report

The attached materials provide the FortisBC Energy Inc. (FEI or the Company) 2025 First Quarter Gas Cost Report for the Mainland and Vancouver Island Service Area, and Fort Nelson Service Area (2025 First Quarter Gas Cost Report) as required under the British Columbia Utilities Commission (BCUC) guidelines for gas cost rate setting (Guidelines).[1]

The gas cost forecast used within the attached 2025 First Quarter Gas Cost Report is based on the five-day average of the February 13, 14, 18, 19, and 20, 2025 forward prices (five-day average forward prices ending February 20, 2025).

CCRA Deferral Account and Commodity Rate Setting Mechanism

Based on the five-day average forward prices ending February 20, 2025, the March 31, 2025 CCRA balance is projected to be approximately $29 million surplus after tax. At the existing commodity rate, the CCRA trigger ratio is calculated to be 105.7 percent, which falls slightly outside the deadband range of 95 percent to 105 percent. The tested rate decrease that would produce a 100 percent commodity recovery-to-cost ratio is calculated to be $0.121/GJ, which falls within the ± $0.50/GJ minimum rate change threshold. The results of the two-criterion rate adjustment mechanism indicate that no rate change is required at this time.

[1] The BCUC established guidelines for gas cost rate setting in Letter L-5-01, dated February 5, 2001, and further modified the guidelines pursuant to Letter L-40-11, dated May 19, 2011, and Letter L-15-16, dated June 16, 2016.

The schedules at Tab 2, Pages 1 and 2, provide details of the recorded and forecast, based on the five-day average forward prices ending February 20, 2025, CCRA gas supply costs. The schedule at Tab 2, Page 3 provides the information related to the unitization of the forecast CCRA gas supply costs for the April 1, 2025 to March 31, 2026 prospective period.

Discussion

The forward western Canadian natural gas prices have increased from the forward prices used in the FEI 2024 Fourth Quarter Gas Cost Report for the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area. Western Canadian natural gas prices increased due to higher demand from colder weather for parts of January and February. This has caused storage inventory volumes to come back towards the five-year average, putting some upward pressure on forward prices.

The commodity rate was last reset by way of a decrease, effective October 1, 2023, via the 2023 Third Quarter Gas Cost Report for the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area (2023 Third Quarter Gas Cost Report). The CCRA opening balance at the start of the 12-month prospective period has changed to the $29 million surplus after tax projected at March 31, 2025, in the 2025 First Quarter Gas Cost Report, from the $21 million surplus after tax projected at September 30, 2023, in the 2023 Third Quarter Gas Cost Report. While the 12-month prospective period average CCRA commodity cost, including hedging, of $2.364/GJ forecast in the 2025 First Quarter Gas Cost Report, and shown at Tab 1, Page 7, Line 11, is comparable to the $2.420/GJ forecast within the 2023 Third Quarter Gas Cost Report.

MCRA Deferral Account

Based on the five-day average forward prices ending February 20, 2025, the MCRA balances after tax at December 31, 2025 and December 31, 2026 are projected to be approximately $12 million surplus and $17 million deficit, respectively. The monthly MCRA deferral account balances are shown on the schedule provided at Tab 1, Page 3.

The schedules at Tab 2, Pages 4 to 6, provide details of the recorded and forecast MCRA gas supply costs for calendar 2024, 2025 and 2026 based on the five-day average forward prices ending February 20, 2025. Tab 2, Pages 7 and 7.1 provide the information related to the forecast MCRA gas supply costs for the April 1, 2025 to March 31, 2026 prospective period.

The schedules at Tab 3, Pages 1 to 4 provide details of the forecast costs for the Revelstoke propane supply portfolio. The schedule at Tab 4, Page 1 provides details of the forecast costs for the Fort Nelson natural gas supply portfolio.

FEI requests the information contained within Tabs 3 and 4 be treated as CONFIDENTIAL.

FEI will continue to monitor and report the MCRA deferral account balances consistent with the Company's position that midstream recoveries and costs be reported on a quarterly basis, and that under normal circumstances, midstream rates be adjusted on an annual basis with a January 1 effective date.

RNG Charge for Voluntary RNG Service to Non-NGV Sales Customers

Pursuant to Order G-77-24 and the accompanying Decision, dated March 20, 2024, FEI obtained approval to continue providing Voluntary RNG service to non-NGV Sales customers at a subsidized rate which is a $7 per GJ premium above the Conventional Gas Cost which is defined as the sum of the Commodity Cost Recovery Charge, the carbon tax and any other taxes applicable to conventional natural gas sales. FEI's proposal to eliminate the $1 per GJ discount on any future long-term Voluntary RNG service contracts was approved, effective March 20, 2024.

Additionally, FEI obtained approval, pursuant to Order G-160-24 dated June 13, 2024, to set the RNG Charge for Voluntary RNG service to non-NGV Sales customers, effective July 1, 2024, on an interim and refundable/recoverable basis, equal to $13.216/GJ, which was subsequently approved on a permanent basis pursuant to Order G-242-24, dated September 11, 2004.

The BC Carbon Tax on natural gas is scheduled to increase from the current $3.9859/GJ, effective April 1, 2024, to $4.7334/GJ, effective April 1, 2025. The table below summarizes the inputs used in the calculation of the RNG Charge for Voluntary RNG service to non-NGV Sales customers and reflects the expected carbon tax increase at April 1, 2025.

Table 1 – Effective & Proposed RNG Charge for Voluntary RNG Service to Non-NGV Sales Customers

Particulars	($/GJ)	Effective *July 1, 2024*	Proposed *April 1, 2025*
Commodity Cost Recovery Charge		$ 2.230	$ 2.230
BC Carbon Tax		$ 3.986	$ 4.733
Premium		$ 7.000	$ 7.000
RNG Charge for Voluntary RNG Service to Non-NGV Sales Customers		**$ 13.216**	**$ 13.963**

FEI requests an increase of $0.747/GJ to the RNG Charge for Voluntary RNG service to non-NGV Sales customers from $13.216/GJ to $13.963/GJ, effective April 1, 2025.

CONFIDENTIALITY

FEI requests that the information contained in Tabs 3 and 4 be filed on a confidential basis and held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24, and section 71(5) of the *Utilities Commission Act*. FEI requests that the BCUC exercise its discretion under Section 6.0 of the Rules for Natural Gas Energy Supply Contracts and allow these documents to remain confidential.

Tabs 3 and 4 contain confidential and commercially sensitive information related to FEI's gas (natural gas and propane) resourcing strategies, including confidential information of third parties that FEI is obligated to protect. FEI procures its gas resources in a competitive market and it is customary for competing parties to keep their gas portfolio strategies and contracts confidential. Keeping the information confidential will ensure FEI's ability to obtain favourable commercial terms for future gas contracting is not impaired. FEI is unable to foresee a time when its gas resourcing strategies may no longer be commercially sensitive or when its confidentiality obligations to third parties may end, and therefore requests the information remain confidential in perpetuity.

Summary

The Company requests BCUC approval of the following, effective April 1, 2025:

- Approval for the Commodity Cost Recovery Charge applicable to all affected sales rate classes, including Rate Schedule 46 LNG Service, within the Mainland and Vancouver Island service area and the Fort Nelson service area to remain unchanged from the current $2.230/GJ.
- Approval for the RNG Charge for Voluntary RNG service to non-NGV Sales customers applicable to Rate Schedules 1RNG, 2RNG, 3RNG, 5RNG, 7RNG, and 46, within the Mainland and Vancouver Island service area and the Fort Nelson service area to increase from the current $13.216/GJ to $13.963/GJ.

FEI will continue to monitor the forward prices and will report CCRA and MCRA balances in its 2025 Second Quarter Gas Cost Report.

We trust the BCUC will find the attached to be in order. However, should further information be required, please contact Gurvinder Sidhu at (604) 592-7675.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
CCRA BALANCES AT EXISTING RATES (AFTER ADJUSTMENTS FOR ENERGY DIFFERENCES)
FOR THE FORECAST PERIOD FROM APR 2025 TO MAR 2027
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025
$(Millions)

Line	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**2024**
2		Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	**Total**
3	CCRA Balance - Beginning (Pre-tax) [a]	$ 32	$ 50	$ 56	$ 59	$ 52	$ 44	$ 33	$ 22	$ 9	$ (4)	$ (17)	$ (23)	**$ 32**
4	Gas Costs Incurred	48	31	32	21	20	17	17	16	15	15	23	27	283
5	Revenue from **APPROVED** Recovery Rates	(30)	(26)	(29)	(28)	(29)	(28)	(28)	(29)	(28)	(28)	(29)	(30)	(341)
6	**CCRA Balance - Ending (Pre-tax)**	$ 50	$ 56	$ 59	$ 52	$ 44	$ 33	$ 22	$ 9	$ (4)	$ (17)	$ (23)	$ (26)	**$ (26)**
7														
8	Tax Rate	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
9														
10	**CCRA Balance - Ending (After-tax) [c]**	$ 37	$ 41	$ 43	$ 38	$ 32	$ 24	$ 16	$ 6	$ (3)	$ (13)	$ (16)	$ (19)	**$ (19)**
11														
12		Recorded	Projected	Projected										**Jan-25 to**
13		Jan-25	Feb-25	Mar-25										**Mar-25**
14	CCRA Balance - Beginning (Pre-tax) [a]	$ (26)	$ (29)	$ (36)										**$ (26)**
15	Gas Costs Incurred	27	20	25										72
16	Revenue from **APPROVED** Recovery Rates	(30)	(27)	(30)										(88)
17	**CCRA Balance - Ending (Pre-tax) [b]**	$ (29)	$ (36)	$ (40)										**$ (40)**
18														
19	Tax Rate	27.0%	27.0%	27.0%										27.0%
20														
21	**CCRA Balance - Ending (After-tax) [c]**	$ (21)	$ (26)	$ (29)										**$ (29)**
22														
23														**Apr-25**
24		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**to**
25		Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	**Mar-26**
26	CCRA Balance - Beginning (Pre-tax) [a]	$ (40)	$ (48)	$ (56)	$ (63)	$ (70)	$ (75)	$ (80)	$ (83)	$ (72)	$ (59)	$ (44)	$ (31)	**$ (40)**
27	Gas Costs Incurred	22	22	22	24	25	24	27	40	44	45	40	42	375
28	Revenue from **EXISTING** Recovery Rates	(29)	(30)	(29)	(30)	(30)	(29)	(30)	(29)	(30)	(30)	(27)	(30)	(354)
29	**CCRA Balance - Ending (Pre-tax) [b]**	$ (48)	$ (56)	$ (63)	$ (70)	$ (75)	$ (80)	$ (83)	$ (72)	$ (59)	$ (44)	$ (31)	$ (19)	**$ (19)**
30														
31	Tax Rate	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
32														
33	**CCRA Balance - Ending (After-tax) [c]**	$ (35)	$ (41)	$ (46)	$ (51)	$ (55)	$ (58)	$ (61)	$ (53)	$ (43)	$ (32)	$ (22)	$ (14)	**$ (14)**
34														
35														**Apr-26**
36		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**to**
37		Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	**Mar-27**
38	CCRA Balance - Beginning (Pre-tax) [a]	$ (19)	$ (10)	$ (2)	$ 6	$ 16	$ 25	$ 34	$ 44	$ 61	$ 80	$ 102	$ 120	**$ (19)**
39	Gas Costs Incurred	39	39	38	40	40	38	41	46	50	52	46	44	512
40	Revenue from **EXISTING** Recovery Rates	(30)	(31)	(30)	(31)	(31)	(30)	(31)	(30)	(31)	(31)	(28)	(31)	(359)
41	**CCRA Balance - Ending (Pre-tax) [b]**	$ (10)	$ (2)	$ 6	$ 16	$ 25	$ 34	$ 44	$ 61	$ 80	$ 102	$ 120	$ 134	**$ 134**
42														
43	Tax Rate	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
44														
45	**CCRA Balance - Ending (After-tax) [c]**	$ (7)	$ (1)	$ 5	$ 12	$ 18	$ 25	$ 32	$ 44	$ 59	$ 74	$ 87	$ 97	**$ 97**

Notes:
(a) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts.
(b) For rate setting purposes CCRA pre-tax balances include grossed-up projected deferred interest of approximately $1.0 million as at March 31, 2025.
(c) For rate setting purposes CCRA after-tax balances are independently grossed-up to reflect pre-tax amounts.

Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
CCRA RATE CHANGE TRIGGER MECHANISM
FOR THE FORECAST PERIOD APR 2025 TO MAR 2026
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025

Line	Particulars	Pre-Tax ($Millions)	Forecast Energy (TJ)	Percentage	Unit Cost ($/GJ)	Reference / Comment
	(1)	(2)	(3)	(4)	(5)	(6)
1	**CCRA RATE CHANGE TRIGGER RATIO**					
2						
3	Projected Deferral Balance at Apr 1, 2025 [(a)]	$ (40.4)				(Tab 1, Page 1, Col.14, Line 26)
4	Forecast Incurred Gas Costs - Apr 2025 to Mar 2026	$ 375.5				(Tab 1, Page 1, Col.14, Line 27)
5	Forecast Recovery Gas Costs at Existing Recovery Rate - Apr 2025 to Mar 2026	$ 354.2				(Tab 1, Page 1, Col.14, Line 28)
6						
7	**CCRA** = Forecast Recovered Gas Costs (Line 5)	= $ 354.2		= **105.7%**		
8	**Ratio** Forecast Incurred Gas Costs (Line 4) + Projected CCRA Balance (Line 3)	$ 335.1				**Outside 95% to 105% deadband**
9						
10						
11						
12						
13	**Existing Cost of Gas (Commodity Cost Recovery Rate), effective October 1, 2023**				**$ 2.230**	
14						
15						
16						
17						
18	**CCRA RATE CHANGE THRESHOLD (+/- $0.50/GJ)**					
19						
20	Forecast 12-month CCRA Baseload - Apr 2025 to Mar 2026		158,855			(Tab1, Page 7, Col.5, Line 10)
21						
22	CCRA Deferral Amortization	$ (41.4)			$ (0.2608)	
23	CCRA Deferred Interest Drawdown	1.0			0.0066	
24	Projected Deferral Balance at Apr 1, 2025 [(a)]	$ (40.4)			$ (0.2542) [(b)]	
25	Forecast 12-month CCRA Activities - Apr 2025 to Mar 2026	21.2			0.1337 [(b)]	
26	(Over) / Under Recovery at Existing Rate	$ (19.1)				(Line 3 + Line 4 - Line 5)
27						
28	**Tested Rate (Decrease) / Increase**				$ (0.121) [(b)]	**Within minimum +/- $0.50/GJ threshold**

Notes:

(a) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts.

(b) Commodity cost recovery rate in tariff is set at 3 decimal places. Individual rate components are shown to 4 decimals places.

Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
MCRA BALANCES AT EXISTING RATES (AFTER ADJUSTMENTS FOR ENERGY DIFFERENCES)
FOR THE FORECAST PERIOD FROM APR 2025 TO DEC 2026
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025
$(Millions)

Line	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1			Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**Total**
2			Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	**2024**
3	MCRA Cumulative Balance - Beginning (Pre-tax) [(a)]		$ (231)	$ (193)	$ (180)	$ (165)	$ (151)	$ (133)	$ (112)	$ (94)	$ (71)	$ (53)	$ (40)	$ (29)	**$ (231)**
4	**2024 MCRA Activities**														
5	Rate Rider 6														
6	*Rider 6 Amortization at APPROVED 2024 Rates*	**$ (130)**	$ 19	$ 15	$ 14	$ 10	$ 7	$ 5	$ 4	$ 4	$ 5	$ 9	$ 14	$ 17	**$ 122**
7	Midstream Base Rates														
8	*Gas Costs Incurred*		$ 65	$ 35	$ 29	$ 17	$ 11	$ 5	$ 1	$ 4	$ 2	$ 11	$ 25	$ 27	$ 230
9	*Revenue from APPROVED 2024 Recovery Rates*		(46)	(36)	(27)	(14)	1	11	13	15	12	(7)	(28)	(41)	(149)
10	Total Midstream Base Rates (Pre-tax)		$ 18	$ (1)	$ 1	$ 4	$ 12	$ 16	$ 14	$ 20	$ 13	$ 3	$ (3)	$ (15)	**$ 82**
11															
12	**MCRA Cumulative Balance - Ending (Pre-tax)**		$ (193)	$ (180)	$ (165)	$ (151)	$ (133)	$ (112)	$ (94)	$ (71)	$ (53)	$ (40)	$ (29)	$ (27)	**$ (27)**
13	Tax Rate		27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
14															
15	**MCRA Cumulative Balance - Ending (After-tax)** [(c)]		$ (141)	$ (131)	$ (120)	$ (110)	$ (97)	$ (82)	$ (69)	$ (52)	$ (38)	$ (29)	$ (21)	$ (19)	**$ (19)**
16			Recorded	Projected	Projected	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
17			Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	**2025**
18	MCRA Balance - Beginning (Pre-tax) [(a)]		$ (27)	$ (42)	$ (55)	$ (67)	$ (64)	$ (49)	$ (37)	$ (28)	$ (19)	$ (11)	$ (9)	$ (11)	**$ (27)**
19	**2025 MCRA Activities**														
20	Rate Rider 6														
21	*Rider 6 Amortization at APPROVED 2025 Rates*	**$ (25)**	$ 2	$ 3	$ 3	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 2	$ 3	$ 4	**$ 24**
22	Midstream Base Rates														
23	*Gas Costs Incurred*		$ 31	$ 32	$ 20	$ 15	$ 9	$ 1	$ (6)	$ (7)	$ (3)	$ 10	$ 28	$ 46	$ 176
24	*Revenue from **APPROVED** Recovery Rates*		(49)	(48)	(33)	(15)	5	10	15	15	11	(10)	(33)	$ (56)	(188)
25	Total Midstream Base Rates (Pre-tax)		$ (17)	$ (16)	$ (13)	$ 0	$ 14	$ 11	$ 8	$ 8	$ 8	$ 0	$ (5)	$ (10)	**$ (11)**
26															
27	**MCRA Cumulative Balance - Ending (Pre-tax)** [(b)]		$ (42)	$ (55)	$ (67)	$ (64)	$ (49)	$ (37)	$ (28)	$ (19)	$ (11)	$ (9)	$ (11)	$ (16)	**$ (16)**
28	Tax Rate		27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
29															
30	**MCRA Cumulative Balance - Ending (After-tax)** [(c)]		$ (30)	$ (40)	$ (49)	$ (47)	$ (36)	$ (27)	$ (20)	$ (14)	$ (8)	$ (6)	$ (8)	$ (12)	**$ (12)**
31															
32			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**Total**
33			Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	**2026**
34	MCRA Balance - Beginning (Pre-tax) [(a)]		$ (16)	$ (22)	$ (26)	$ (25)	$ (23)	$ (13)	$ (6)	$ 1	$ 8	$ 14	$ 16	$ 20	**$ (16)**
35	**2026 MCRA Activities**														
36	Rate Rider 6														
37	*Rider 6 Amortization at APPROVED 2025 Rates*		$ 4	$ 3	$ 3	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 2	$ 3	$ 4	**$ 25**
38	Midstream Base Rates														
39	*Gas Costs Incurred*		$ 47	$ 41	$ 31	$ 14	$ 5	$ (4)	$ (8)	$ (8)	$ (6)	$ 10	$ 33	$ 55	$ 210
40	*Revenue from **EXISTING** Recovery Rates*		$ (56)	(48)	(33)	(15)	4	10	14	15	10	(10)	(32)	(56)	(196)
41	Total Midstream Base Rates (Pre-tax)		$ (9)	$ (7)	$ (2)	$ (1)	$ 10	$ 5	$ 6	$ 7	$ 5	$ (0)	$ 1	$ (1)	**$ 14**
42															
43	**MCRA Cumulative Balance - Ending (Pre-tax)** [(b)]		$ (22)	$ (26)	$ (25)	$ (23)	$ (13)	$ (6)	$ 1	$ 8	$ 14	$ 16	$ 20	$ 23	**$ 23**
44	Tax Rate		27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%	27.0%
45															
46	**MCRA Cumulative Balance - Ending (After-tax)** [(c)]		$ (16)	$ (19)	$ (18)	$ (17)	$ (9)	$ (4)	$ 0	$ 6	$ 10	$ 11	$ 14	$ 17	**$ 17**

Notes:
(a) Pre-tax opening balances are restated based on current income tax rates, to reflect grossed-up after tax amounts.
(b) For rate setting purposes MCRA pre-tax balances include grossed-up projected deferred interest of approximately $2.3 million credit as at March 31, 2025.
(c) For rate setting purposes MCRA after-tax balances are independently grossed-up to reflect pre-tax amounts.
Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
SUMAS INDEX FORECAST FOR THE PERIOD ENDING MAR 2027
AND US DOLLAR EXCHANGE RATE FORECAST UPDATE

Line No	Particulars			Five-day Average Forward Prices - February 13,14,18,19,and 20, 2025 2025 Q1 Gas Cost Report		Five-day Average Forward Prices - November 1, 4, 5, 6, and 7, 2024 2024 Q4 Gas Cost Report		Change in Forward Price
	(1)			(2)		(3)		(4) = (2) - (3)
1	**SUMAS Index Prices - presented in $US/MMBtu**							
2								
3	**2024**	October		$ 2.14	**Settled**	$ 2.14		$ -
4		November		$ 3.91	**Forecast**	$ 4.05		$ (0.14)
5		December		$ 4.83		$ 6.75		$ (1.92)
6	**2025**	January	**Settled**	$ 4.30		$ 6.88		$ (2.58)
7		February	**Forecast**	$ 3.62		$ 5.48		$ (1.86)
8		March		$ 3.18		$ 3.05		$ 0.13
9		April		$ 2.91		$ 2.20		$ 0.71
10		May		$ 2.34		$ 1.79		$ 0.55
11		June		$ 2.54		$ 2.05		$ 0.49
12		July		$ 3.34		$ 2.88		$ 0.46
13		August		$ 3.50		$ 3.05		$ 0.45
14		September		$ 3.41		$ 2.96		$ 0.45
15		October		$ 3.27		$ 2.62		$ 0.64
16		November		$ 4.57		$ 5.40		$ (0.82)
17		December		$ 7.34		$ 8.46		$ (1.12)
18	**2026**	January		$ 7.52		$ 8.48		$ (0.96)
19		February		$ 6.39		$ 6.98		$ (0.59)
20		March		$ 3.81		$ 4.24		$ (0.43)
21		April		$ 2.75		$ 2.54		$ 0.21
22		May		$ 2.35		$ 2.31		$ 0.04
23		June		$ 2.78		$ 2.63		$ 0.15
24		July		$ 3.35		$ 3.31		$ 0.04
25		August		$ 3.41		$ 3.37		$ 0.04
26		September		$ 3.40		$ 3.35		$ 0.05
27		October		$ 2.97		$ 3.01		$ (0.04)
28		November		$ 4.57		$ 5.82		$ (1.25)
29		December		$ 7.22		$ 8.33		$ (1.11)
30	**2027**	January		$ 7.50				
31		February		$ 6.04				
32		March		$ 3.51				
33								
34	*Simple Average (Apr 2025 - Mar 2026)*			*$ 4.25*		*$ 4.26*	*-0.3%*	*$ (0.01)*
35	*Simple Average (Jul 2025 - Jun 2026)*			*$ 4.25*		*$ 4.38*	*-2.9%*	*$ (0.13)*
36	*Simple Average (Oct 2025 - Sep 2026)*			*$ 4.25*		*$ 4.47*	*-5.1%*	*$ (0.23)*
37	*Simple Average (Jan 2026 - Dec 2026)*			*$ 4.21*		*$ 4.53*	*-7.1%*	*$ (0.32)*
38	*Simple Average (Apr 2026 - Mar 2027)*			*$ 4.15*				

Conversation Factors
1 MMBtu = 1.055056 GJ

Morningstar Average Exchange Rate ($1US=$x.xxxCDN)

	Forecast Apr 2025 - Mar 2026	Forecast Jan 2025 - Dec 2025		
	$ 1.4067	$ 1.3795	*2.0%*	*$ 0.0272*

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
SUMAS INDEX FORECAST FOR THE PERIOD ENDING MAR 2027

Line No	Particulars			Five-day Average Forward Prices - February 13,14,18,19,and 20, 2025 2025 Q1 Gas Cost Report			Five-day Average Forward Prices - November 1, 4, 5, 6, and 7, 2024 2024 Q4 Gas Cost Report			Change in Forward Price	
	(1)					(2)			(3)		(4) = (2) - (3)
1	**SUMAS Index Prices - presented in $CDN/GJ**										
2											
3		**2024**	October		$	2.74	**Settled**	$	2.74	$	-
4			November		$	5.16	**Forecast**	$	5.30	$	(0.14)
5			December		$	6.41		$	8.89	$	(2.47)
6		**2025**	January	**Settled**	$	5.86		$	9.04	$	(3.18)
7			February	**Forecast**	$	4.92		$	7.19	$	(2.27)
8			March		$	4.27		$	3.99	$	0.28
9			April		$	3.91		$	2.89	$	1.02
10			May		$	3.14		$	2.35	$	0.79
11			June		$	3.39		$	2.68	$	0.71
12			July		$	4.47		$	3.77	$	0.70
13			August		$	4.68		$	3.99	$	0.69
14			September		$	4.55		$	3.86	$	0.69
15			October		$	4.36		$	3.42	$	0.94
16			November		$	6.09		$	7.03	$	(0.94)
17			December		$	9.74		$	10.99	$	(1.25)
18		**2026**	January		$	9.98		$	11.02	$	(1.03)
19			February		$	8.48		$	9.07	$	(0.59)
20			March		$	5.04		$	5.50	$	(0.46)
21			April		$	3.64		$	3.30	$	0.34
22			May		$	3.11		$	2.99	$	0.12
23			June		$	3.66		$	3.40	$	0.26
24			July		$	4.42		$	4.28	$	0.13
25			August		$	4.49		$	4.36	$	0.14
26			September		$	4.46		$	4.32	$	0.14
27			October		$	3.89		$	3.88	$	0.01
28			November		$	5.99		$	7.51	$	(1.51)
29			December		$	9.43		$	10.72	$	(1.29)
30		**2027**	January		$	9.81					
31			February		$	7.90					
32			March		$	4.57					
33											
34	*Simple Average (Apr 2025 - Mar 2026)*				*$*	*5.65*		*$*	*5.55*	*1.9% $*	*0.11*
35	*Simple Average (Jul 2025 - Jun 2026)*				*$*	*5.65*		*$*	*5.69*	*-0.8% $*	*(0.04)*
36	*Simple Average (Oct 2025 - Sep 2026)*				*$*	*5.62*		*$*	*5.81*	*-3.2% $*	*(0.18)*
37	*Simple Average (Jan 2026 - Dec 2026)*				*$*	*5.55*		*$*	*5.86*	*-5.3% $*	*(0.31)*
38	*Simple Average (Apr 2026 - Mar 2027)*				*$*	*5.45*					

Conversation Factors
1 MMBtu = 1.055056 GJ

Morningstar Average Exchange Rate ($1US=$x.xxxCDN)

	Forecast Apr 2025 - Mar 2026	Forecast Jan 2025 - Dec 2025		
	$ 1.4067	$ 1.3795	2.0%	$ 0.0272

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
AECO INDEX FORECAST FOR THE PERIOD ENDING MAR 2027

Line No	Particulars (1)			Five-day Average Forward Prices - February 13,14,18,19,and 20, 2025 2025 Q1 Gas Cost Report (2)		Five-day Average Forward Prices - November 1, 4, 5, 6, and 7, 2024 2024 Q4 Gas Cost Report (3)		Change in Forward Price (4) = (2) - (3)
1	**AECO Index Prices - $CDN/GJ**							
2								
3	**2024**	October		$ 0.55		$ 0.55		$ -
4		November		$ 1.72	**Settled**	$ 1.89		$ (0.17)
5		December		$ 1.88	**Forecast**	$ 1.75		$ 0.13
6	**2025**	January	**Settled**	$ 2.00		$ 1.84		$ 0.16
7		February	**Forecast**	$ 1.89		$ 1.84		$ 0.05
8		March		$ 1.93		$ 1.68		$ 0.25
9		April		$ 1.83		$ 1.58		$ 0.25
10		May		$ 1.77		$ 1.53		$ 0.24
11		June		$ 1.81		$ 1.60		$ 0.21
12		July		$ 1.89		$ 1.67		$ 0.22
13		August		$ 1.98		$ 1.73		$ 0.25
14		September		$ 1.94		$ 1.73		$ 0.20
15		October		$ 2.17		$ 2.00		$ 0.17
16		November		$ 2.80		$ 2.68		$ 0.11
17		December		$ 3.10		$ 3.05		$ 0.05
18	**2026**	January		$ 3.21		$ 3.13		$ 0.08
19		February		$ 3.19		$ 3.11		$ 0.08
20		March		$ 2.90		$ 2.80		$ 0.10
21		April		$ 2.80		$ 2.50		$ 0.29
22		May		$ 2.70		$ 2.44		$ 0.26
23		June		$ 2.70		$ 2.48		$ 0.22
24		July		$ 2.80		$ 2.47		$ 0.33
25		August		$ 2.80		$ 2.46		$ 0.33
26		September		$ 2.79		$ 2.46		$ 0.32
27		October		$ 2.86		$ 2.60		$ 0.26
28		November		$ 3.31		$ 3.24		$ 0.08
29		December		$ 3.59		$ 3.54		$ 0.05
30	**2027**	January		$ 3.71				
31		February		$ 3.64				
32		March		$ 3.04				
33								
34	*Simple Average (Apr 2025 - Mar 2026)*			*$ 2.38*		*$ 2.22*	*7.4%*	*$ 0.16*
35	*Simple Average (Jul 2025 - Jun 2026)*			*$ 2.61*		*$ 2.44*	*7.0%*	*$ 0.17*
36	*Simple Average (Oct 2025 - Sep 2026)*			*$ 2.83*		*$ 2.63*	*7.5%*	*$ 0.20*
37	*Simple Average (Jan 2026 - Dec 2026)*			*$ 2.97*		*$ 2.77*	*7.3%*	*$ 0.20*
38	*Simple Average (Apr 2026 - Mar 2027)*			*$ 3.06*				

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
STATION 2 INDEX FORECAST FOR THE PERIOD ENDING MAR 2027

Line No	Particulars			Five-day Average Forward Prices - February 13,14,18,19,and 20, 2025 2025 Q1 Gas Cost Report			Five-day Average Forward Prices - November 1, 4, 5, 6, and 7, 2024 2024 Q4 Gas Cost Report		Change in Forward Price	
	(1)				(2)			(3)		(4) = (2) - (3)
1	**Station 2 Index Prices - $CDN/GJ**									
2										
3	**2024**	October		$	0.26	**Settled**	$	0.26		$ -
4		November		$	1.31	**Forecast**	$	1.47		$ (0.16)
5		December		$	1.41		$	1.37		$ 0.04
6	**2025**	January	**Settled**	$	1.37		$	1.67		$ (0.29)
7		February	**Forecast**	$	0.94		$	1.62		$ (0.68)
8		March		$	1.18		$	1.45		$ (0.27)
9		April		$	1.06		$	1.21		$ (0.15)
10		May		$	0.99		$	1.15		$ (0.16)
11		June		$	1.03		$	1.23		$ (0.20)
12		July		$	1.20		$	1.30		$ (0.10)
13		August		$	1.29		$	1.35		$ (0.07)
14		September		$	1.25		$	1.36		$ (0.11)
15		October		$	1.48		$	1.63		$ (0.14)
16		November		$	2.59		$	2.61		$ (0.02)
17		December		$	2.90		$	2.98		$ (0.08)
18	**2026**	January		$	3.00		$	3.06		$ (0.06)
19		February		$	2.98		$	3.03		$ (0.05)
20		March		$	2.69		$	2.72		$ (0.03)
21		April		$	2.54		$	2.33		$ 0.21
22		May		$	2.44		$	2.26		$ 0.18
23		June		$	2.44		$	2.30		$ 0.14
24		July		$	2.54		$	2.29		$ 0.25
25		August		$	2.54		$	2.29		$ 0.25
26		September		$	2.53		$	2.29		$ 0.24
27		October		$	2.60		$	2.43		$ 0.18
28		November		$	3.22		$	3.14		$ 0.08
29		December		$	3.50		$	3.44		$ 0.06
30	**2027**	January		$	3.62					
31		February		$	3.54					
32		March		$	2.94					
33										
34	*Simple Average (Apr 2025 - Mar 2026)*			*$*	*1.87*		*$*	*1.97*	*-4.9%*	*$ (0.10)*
35	*Simple Average (Jul 2025 - Jun 2026)*			*$*	*2.23*		*$*	*2.24*	*-0.5%*	*$ (0.01)*
36	*Simple Average (Oct 2025 - Sep 2026)*			*$*	*2.56*		*$*	*2.48*	*3.0%*	*$ 0.07*
37	*Simple Average (Jan 2026 - Dec 2026)*			*$*	*2.75*		*$*	*2.63*	*4.6%*	*$ 0.12*
38	*Simple Average (Apr 2026 - Mar 2027)*			*$*	*2.87*					

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
GAS BUDGET COST SUMMARY FOR THE FORECAST PERIOD APR 2025 TO MAR 2026
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025

Line	Particulars	Costs ($000)		Quantities (TJ)			Unit Cost ($/GJ)	Reference / Comments
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CCRA**							
2	Commodity							
3	STN 2		$ 213,979		124,502		$ 1.719	
4	AECO		94,114		40,230		$ 2.339	
5	Commodity Costs before Hedging		$ 308,093		164,732		$ 1.870	Incl. Receipt Point Fuel.
6	Hedging Cost / (Gain)		65,818		-			
7	Subtotal Commodity Purchased		$ 373,911		164,732		$ 2.270	
8	Core Market Administration Costs		1,570		-			
9	Fuel Gas Provided to Midstream				(5,878)			
10	**Total CCRA Baseload**				**158,855**			
11	**Total CCRA Costs**		**$ 375,481**				**$ 2.364**	Commodity available for sale average unit cost
12	**MCRA**							
13	Midstream Commodity Related Costs							
14	Total Cost of Propane	$ 4,886				353		
15	Propane Costs Recovered based on Commodity Rates	(754)				(338)		
16	Propane Costs to be Recovered via Midstream Rates		$ 4,132					
17	FEFN Supply Portfolio Costs	$ 1,212			507			
18	FEFN Costs Recovered from Commodity Rates	(1,125)			(504)			
19	FEFN Costs to be Recovered via Midstream Rates		88					
20	Midstream Natural Gas Costs before Hedging		63,566		22,373			
21	Imbalance		(789)		(495)			
22	Company Use Gas Recovered from O&M		(5,995)		(703)			
23	Injections into Storage	$ (50,637)		(26,054)				
24	Withdrawals from Storage	53,036		29,686				
25	Storage Withdrawal / (Injection) Activity		2,399		3,631			
26	Total Midstream Commodity Related Costs		$ 63,401		24,809			
27	Storage Related Costs							
28	Storage Demand - Third Party Storage	$ 70,282						
29	On-System Storage - Mt. Hayes (LNG)	19,738						
30	Total Storage Related Costs		90,020					
31	Transport Related Costs		227,805					
32	Mitigation							
33	Commodity Mitigation	$ (69,152)			(33,541)			
34	Storage Mitigation	(2,794)						
35	Transportation Mitigation	(104,622)						
36	Total Mitigation		(176,569)					
37	GSMIP Incentive Sharing		2,500					
38	Core Market Administration Costs		4,710					
39	Net Transportation Fuel [(a)]			10,021				
40	UAF (Sales and T-Service) [(b)]			(1,289)				
41	UAF & Net Transportation Fuel				8,732			
42	Propane Own Use/UAF					(15)		
43	Net MCRA Commodity (Lines 27, 33 & 43)				-			
44	**Total MCRA Costs** (Lines 26, 30, 31, 36, 37 & 38)		**$ 211,867**				**$ 1.262**	Midstream average unit cost
45	**Total Sales Quantities for RS1-RS7 & RS46**				**167,874**			Reference to Tab 2, Page 7, Line 1, Col. 10
46	**Total Forecast Gas Costs** (Lines 11 & 44)		$ 587,348					

Notes: (a) Net Transportation Fuel is the difference between fuel gas collected from Commodity Providers and the fuel gas consumed.
(b) The total cost of UAF (Sales Rate Classes and T-Service) is included as a component of gas purchased. Sales UAF costs are recovered via gas cost recovery rates. As the T-Service UAF costs are recovered via delivery revenues, they are excluded from the storage and transport rate flow-through calculation.

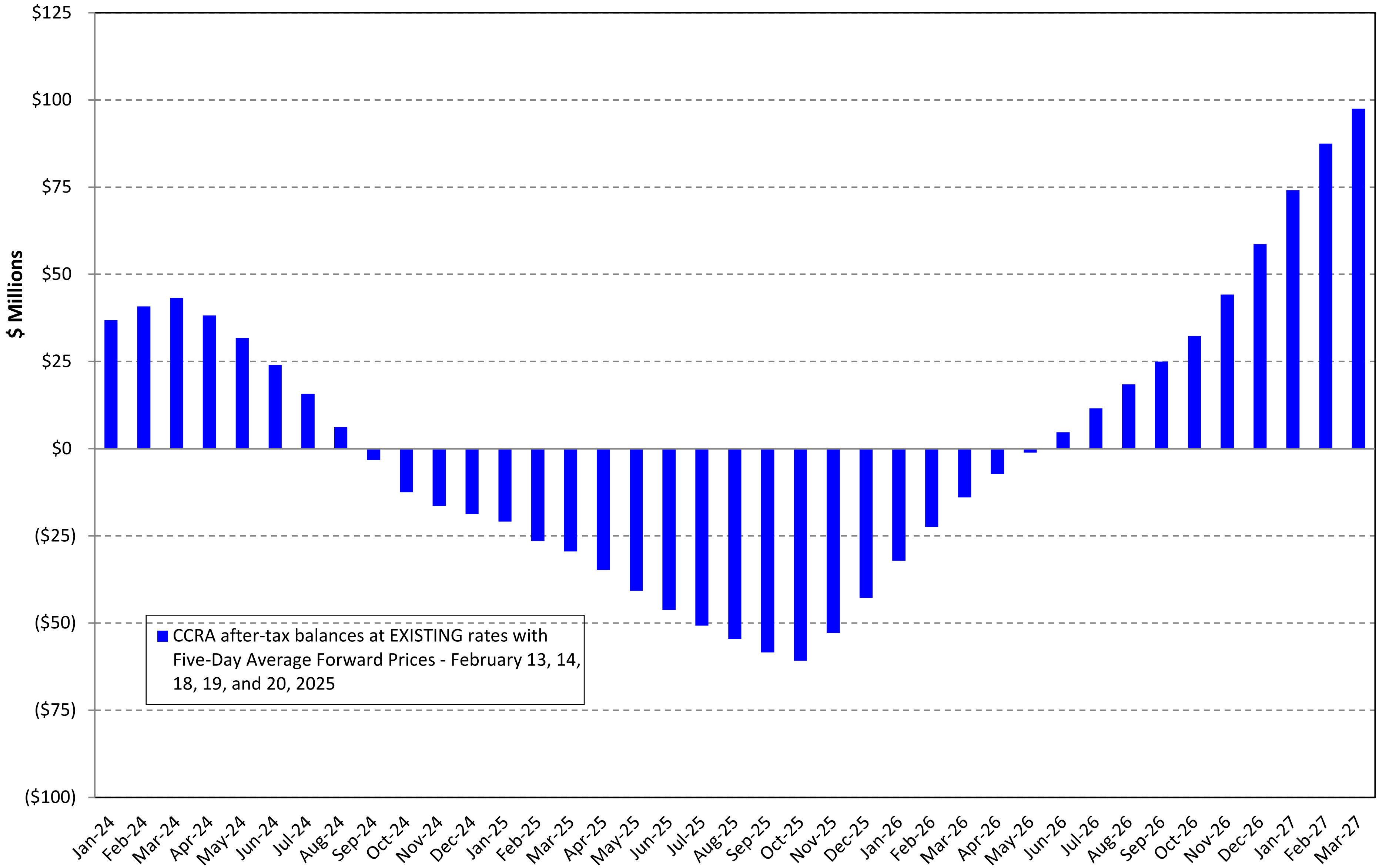
Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVKICE AREA, AND FORT NELSON SERVICE AREA
RECONCILIATION OF GAS COST INCURRED
FOR THE FORECAST PERIOD APR 2025 TO MAR 2026
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025
$(Millions)

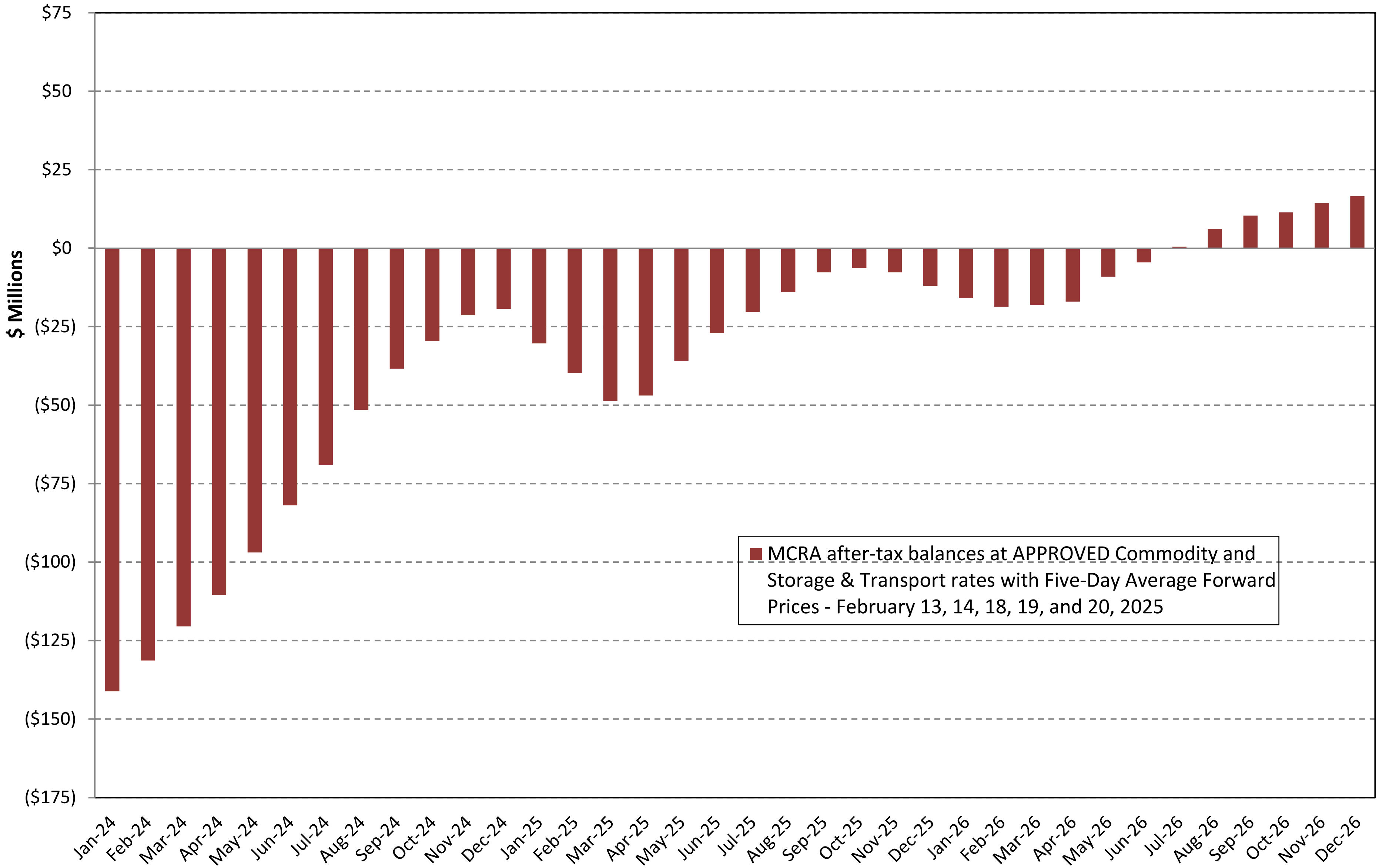
Line	Particulars	CCRA / MCRA Deferral Account Forecast	Gas Budget Cost Summary	References
	(1)	(2)	(3)	(4)
1	Gas Cost Incurred			
2	CCRA	$ 375		(Tab 1, Page 1, Col.14, Line 27)
3	MCRA	212		(Tab 2, Page 7.1, Col.15, Line 36)
4				
5				
6	Gas Budget Cost Summary			
7	CCRA		$ 375	(Tab 1, Page 7, Col.3, Line 11)
8	MCRA		212	(Tab 1, Page 7, Col.3, Line 44)
9				
10				
11	**Totals Reconciled**	$ 587	$ 587	

Slight differences in totals due to rounding.

FortisBC Energy Inc. - Mainland and Vancouver Island Service Area, and Fort Nelson Service Area
CCRA After-Tax Monthly Balances
Recorded to January 2025 and Forecast to March 2027



FortisBC Energy Inc. - Mainland and Vancouver Island Service Area, and Fort Nelson Service Area
MCRA After-Tax Monthly Balances
Recorded to January 2025 and Forecast to December 2026



FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
CCRA INCURRED MONTHLY ACTIVITIES
RECORDED PERIOD TO JAN 2025 AND FORECAST TO MAR 2026
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13,14, 18, 19, AND 20, 2025

Line	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1			Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	**2024**
2			Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	**Total**
3	**CCRA QUANTITIES**														
4	Commodity Purchase	(TJ)													
5	STN 2		10,038	9,394	10,047	9,739	10,064	9,738	10,056	10,056	9,732	9,754	10,106	10,455	119,178
6	AECO		3,410	2,668	3,185	3,087	3,190	3,086	3,187	3,187	3,085	3,190	3,210	3,321	37,806
7	Total Commodity Purchased		13,448	12,062	13,232	12,826	13,253	12,824	13,243	13,243	12,816	12,944	13,316	13,776	156,984
8	Fuel Gas Provided to Midstream		(493)	(462)	(494)	(479)	(494)	(478)	(494)	(494)	(478)	(494)	(475)	(492)	(5,827)
9	**Commodity Available for Sale**		12,955	11,600	12,738	12,348	12,759	12,346	12,749	12,749	12,338	12,450	12,841	13,285	151,157
10															
11	**CCRA COSTS**														
12	Commodity Costs	($000)													
13	STN 2		$ 27,260	$ 16,087	$ 13,707	$ 10,175	$ 8,127	$ 5,900	$ 4,258	$ 3,802	$ 3,125	$ 2,204	$ 12,481	$ 15,241	$ 122,368
14	AECO		8,781	5,330	5,326	4,659	3,977	3,189	2,581	2,324	1,987	2,382	5,019	6,100	51,655
15	Commodity Costs before Hedging		$ 36,041	$ 21,417	$ 19,033	$ 14,834	$ 12,104	$ 9,089	$ 6,840	$ 6,126	$ 5,112	$ 4,586	$ 17,500	$ 21,341	$ 174,023
16	Hedging Cost / (Gain)		11,477	9,857	12,902	5,936	7,858	7,879	9,949	9,686	9,614	10,770	5,680	5,209	106,817
17	Core Market Administration Costs		322	108	169	139	150	76	129	123	135	124	109	150	1,734
18	**Total CCRA Costs**		$ 47,839	$ 31,382	$ 32,104	$ 20,909	$ 20,113	$ 17,044	$ 16,918	$ 15,935	$ 14,861	$ 15,480	$ 23,289	$ 26,700	$ 282,574
19															
20															
21	CCRA Unit Cost	($/GJ)	$ 3.693	$ 2.705	$ 2.520	$ 1.693	$ 1.576	$ 1.381	$ 1.327	$ 1.250	$ 1.204	$ 1.243	$ 1.814	$ 2.010	$ 1.869
22															
23															
24															
25															
26															**Jan-25 to**
27			Recorded	Projected	Projected										**Mar-25**
28			Jan-25	Feb-25	Mar-25										**Total**
29	**CCRA QUANTITIES**														
30	Commodity Purchase	(TJ)													
31	STN 2		10,605	9,551	10,574										30,730
32	AECO		3,369	3,086	3,417										9,872
33	Total Commodity Purchased		13,974	12,637	13,991										40,601
34	Fuel Gas Provided to Midstream		(499)	(451)	(499)										(1,449)
35	**Commodity Available for Sale**		13,475	12,186	13,492										39,153
36															
37	**CCRA COSTS**														
38	Commodity Costs	($000)													
39	STN 2		$ 15,905	$ 8,933	$ 12,198										$ 37,036
40	AECO		6,436	5,835	6,504										18,775
41	Commodity Costs before Hedging		$ 22,341	$ 14,768	$ 18,702										$ 55,811
42	Hedging Cost / (Gain)		4,721	4,684	6,130										15,534
43	Core Market Administration Costs		194	131	131										456
44	**Total CCRA Costs**		$ 27,256	$ 19,583	$ 24,963										$ 71,801
45															
46															
47	CCRA Unit Cost	($/GJ)	$ 2.023	$ 1.607	$ 1.850										$ 1.834

Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
CCRA INCURRED MONTHLY ACTIVITIES
FORECAST PERIOD FROM APR 2025 TO MAR 2027
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13,14, 18, 19, AND 20, 2025

Line No.	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**1-12 months**
2			Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	**Total**
3	**CCRA QUANTITIES**														
4	Commodity Purchase	(TJ)													
5	STN 2		10,233	10,574	10,233	10,574	10,574	10,233	10,574	10,233	10,574	10,574	9,551	10,574	124,502
6	AECO		3,307	3,417	3,307	3,417	3,417	3,307	3,417	3,307	3,417	3,417	3,086	3,417	40,230
7	Total Commodity Purchased		13,540	13,991	13,540	13,991	13,991	13,540	13,991	13,540	13,991	13,991	12,637	13,991	164,732
8	Fuel Gas Provided to Midstream		(483)	(499)	(483)	(499)	(499)	(483)	(499)	(483)	(499)	(499)	(451)	(499)	(5,878)
9	**Commodity Available for Sale**		13,057	13,492	13,057	13,492	13,492	13,057	13,492	13,057	13,492	13,492	12,186	13,492	158,855
10															
11	**CCRA COSTS**	($000)													
12	Commodity Costs														
13	STN 2		$ 8,315	$ 7,860	$ 7,949	$ 9,896	$ 10,600	$ 10,376	$ 13,221	$ 26,484	$ 30,617	$ 31,737	$ 28,492	$ 28,433	$ 213,979
14	AECO		5,870	5,831	5,766	6,204	6,482	6,208	7,207	9,245	10,601	10,963	9,846	9,892	94,114
15	Commodity Costs before Hedging		$ 14,185	$ 13,690	$ 13,715	$ 16,100	$ 17,082	$ 16,584	$ 20,428	$ 35,729	$ 41,217	$ 42,699	$ 38,337	$ 38,326	$ 308,093
16	Hedging Cost / (Gain)		7,505	8,077	7,713	7,764	7,564	7,119	6,320	4,106	2,518	1,924	1,921	3,286	65,818
17	Core Market Administration Costs		131	131	131	131	131	131	131	131	131	131	131	131	1,570
18	**Total CCRA Costs**		$ 21,821	$ 21,898	$ 21,559	$ 23,995	$ 24,778	$ 23,834	$ 26,879	$ 39,966	$ 43,866	$ 44,754	$ 40,389	$ 41,743	$ 375,481
19															
20															
21	CCRA Unit Cost	($/GJ)	$ 1.671	$ 1.623	$ 1.651	$ 1.778	$ 1.837	$ 1.825	$ 1.992	$ 3.061	$ 3.251	$ 3.317	$ 3.314	$ 3.094	$ 2.364
22															
23															
24			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	**13-24 months**
25			Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	**Total**
26	**CCRA QUANTITIES**														
27	Commodity Purchase	(TJ)													
28	STN 2		10,382	10,728	10,382	10,728	10,728	10,382	10,728	10,382	10,728	10,728	9,690	10,728	126,319
29	AECO		3,355	3,467	3,355	3,467	3,467	3,355	3,467	3,355	3,467	3,467	3,131	3,467	40,817
30	Total Commodity Purchased		13,737	14,195	13,737	14,195	14,195	13,737	14,195	13,737	14,195	14,195	12,821	14,195	167,136
31	Fuel Gas Provided to Midstream		(490)	(506)	(490)	(506)	(506)	(490)	(506)	(490)	(506)	(506)	(457)	(506)	(5,963)
32	**Commodity Available for Sale**		13,247	13,689	13,247	13,689	13,689	13,247	13,689	13,247	13,689	13,689	12,364	13,689	161,172
33															
34															
35	**CCRA COSTS**	($000)													
36	Commodity Costs														
37	STN 2		$ 26,330	$ 26,209	$ 25,316	$ 27,296	$ 27,254	$ 26,235	$ 27,936	$ 33,453	$ 37,537	$ 38,816	$ 34,347	$ 31,594	$ 362,324
38	AECO		9,381	9,371	9,050	9,719	9,705	9,344	9,922	11,120	12,449	12,862	11,387	10,528	124,840
39	Commodity Costs before Hedging		$ 35,712	$ 35,580	$ 34,367	$ 37,016	$ 36,959	$ 35,579	$ 37,858	$ 44,573	$ 49,986	$ 51,679	$ 45,734	$ 42,122	$ 487,164
40	Hedging Cost / (Gain)		2,846	3,193	3,061	2,815	2,827	2,768	2,598	1,117	256	(119)	16	1,986	23,364
41	Core Market Administration Costs		131	131	131	131	131	131	131	131	131	131	131	131	1,570
42	**Total CCRA Costs**		$ 38,688	$ 38,904	$ 37,559	$ 39,961	$ 39,917	$ 38,478	$ 40,587	$ 45,821	$ 50,373	$ 51,691	$ 45,881	$ 44,238	$ 512,098
43															
44															
45	CCRA Unit Cost	($/GJ)	$ 2.920	$ 2.842	$ 2.835	$ 2.919	$ 2.916	$ 2.905	$ 2.965	$ 3.459	$ 3.680	$ 3.776	$ 3.711	$ 3.232	$ 3.177

Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
COMMODITY COST RECONCILIATION ACCOUNT (CCRA)
COST OF GAS (COMMODITY COST RECOVERY CHARGE) FLOW-THROUGH
FOR THE FORECAST PERIOD APR 1, 2025 TO MAR 31, 2026
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025

Line	Particulars	Unit		RS-1 to RS-7
	(1)			(2)
1	**CCRA Baseload**	TJ		158,855
2				
3				
4	**CCRA Incurred Costs**	$000		
5	STN 2		$	213,978.8
6	AECO			94,114.4
7	CCRA Commodity Costs before Hedging		$	308,093.2
8	Hedging Cost / (Gain)			65,818.1
9	Core Market Administration Costs			1,570.0
10	**Total Incurred Costs before CCRA deferral amortization**		$	375,481.3
11				
12	Pre-tax CCRA Deficit / (Surplus) as of Apr 1, 2025			(40,380.6)
13	**Total CCRA Incurred Costs**		$	335,100.7
14				
15				
16	**CCRA Incurred Unit Costs**	$/GJ		
17	CCRA Commodity Costs before Hedging		$	1.9395
18	Hedging Cost / (Gain)			0.4143
19	Core Market Administration Costs			0.0099
20	Total Incurred Costs before CCRA deferral amortization		$	2.3637
21	Pre-tax CCRA Deficit / (Surplus) as of Apr 1, 2025			(0.2542)
22	**CCRA Gas Costs Incurred -- Flow-Through**		$	2.1095
23				
24				
25				
26				
27				
28				
29	**Cost of Gas (Commodity Cost Recovery Charge)**			**RS-1 to RS-7**
30				
31	**TESTED Flow-Through Cost of Gas effective Apr 1, 2025** (a)		**$**	**2.109**
32				
33	Existing Cost of Gas (effective since Oct 1, 2023)		$	2.230
34				
35	**Tested Cost of Gas Increase / (Decrease)**	$/GJ	$	(0.121)
36				
37	Tested Cost of Gas Percentage Increase / (Decrease)			-5.43%

Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA
MCRA INCURRED MONTHLY ACTIVITIES FOR THE YEAR 2024

Line	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
			Recorded Jan-24	Recorded Feb-24	Recorded Mar-24	Recorded Apr-24	Recorded May-24	Recorded Jun-24	Recorded Jul-24	Recorded Aug-24	Recorded Sep-24	Recorded Oct-24	Recorded Nov-24	Recorded Dec-24	**2024 Total**
1	**MCRA COSTS** ($000)														
2	Midstream Commodity Related Costs														
3	Propane Available for Sale - Purchase & Inventory Change		$ 797.4	$ 547.4	$ 470.7	$ 299.9	$ 132.7	$ 136.5	$ 128.1	$ 160.7	$ 136.6	$ 337.0	$ 407.9	$ 533.0	$ 4,088.1
4	Propane Costs Recoveies via Commodity Rates		(112.5)	(85.1)	(79.1)	(51.6)	(32.0)	(23.5)	(23.8)	(26.1)	(29.4)	(59.6)	(71.6)	(93.8)	(688.2)
5	Propane Costs to be Recovered via Midstream Rates		$ 684.9	$ 462.3	$ 391.6	$ 248.3	$ 100.7	$ 113.1	$ 104.3	$ 134.6	$ 107.2	$ 277.4	$ 336.3	$ 439.3	$ 3,399.8
6	FEFN Supply Portfolio Costs		$ 422.3	$ 244.7	$ 184.0	$ 119.9	$ 26.0	$ 17.7	$ 1.4	$ 3.0	$ 10.5	$ 8.6	$ 163.7	$ 182.3	$ 1,384.2
7	FEFN Costs Recovered from Commodity Rates		(203.6)	(102.1)	(153.2)	(77.9)	(52.1)	(28.8)	(16.8)	(16.0)	(35.0)	(39.1)	(141.3)	(203.1)	(1,069.0)
8	FEFN Costs to be Recovered via Midstream Rates		$ 218.7	$ 142.6	$ 30.8	$ 42.0	$ (26.0)	$ (11.1)	$ (15.4)	$ (13.0)	$ (24.6)	$ (30.4)	$ 22.4	$ (20.8)	$ 315.2
9	Midstream Natural Gas Costs before Hedging [(a)]		$ 32,864.9	$ 10,926.4	$ 8,509.8	$ 2,293.1	$ 509.3	$ 351.8	$ 201.7	$ 515.3	$ 495.3	$ 263.5	$ 8,064.9	$ 9,413.0	$ 74,408.9
10	Imbalance [(b)]	$ 1,740.3	(84.0)	(776.1)	(74.6)	(139.8)	(200.2)	71.9	(292.8)	(83.7)	5.4	60.5	568.5	164.6	(780.2)
11	Company Use Gas Recovered from O&M		(560.0)	(285.3)	(233.3)	(46.9)	107.4	56.5	271.2	177.1	55.2	13.7	(146.0)	(427.5)	(1,017.8)
12	Storage Withdrawal / (Injection) Activity [(c)]		22,134.7	12,676.5	6,871.3	(504.0)	(3,454.8)	(3,217.4)	(1,933.8)	(2,785.8)	(3,966.0)	(629.4)	4,405.9	4,930.8	34,528.1
13	Total Midstream Commodity Related Costs		$ 55,259.2	$ 23,146.4	$ 15,495.6	$ 1,892.7	$ (2,963.6)	$ (2,635.1)	$ (1,664.8)	$ (2,055.4)	$ (3,327.6)	$ (44.6)	$ 13,252.0	$ 14,499.4	$ 110,854.0
14															
15	Storage Related Costs														
16	Storage Demand - Third Party Storage		$ 3,014.4	$ 2,988.4	$ 3,012.2	$ 2,693.7	$ 3,817.2	$ 4,110.4	$ 4,189.4	$ 5,244.8	$ 5,286.0	$ 5,407.3	$ 4,064.2	$ 5,216.4	$ 49,044.4
17	On-System Storage - Mt. Hayes (LNG)		1,682.1	1,589.3	1,511.4	2,005.9	1,703.6	1,535.1	1,525.2	1,524.0	1,521.3	1,851.0	1,570.7	1,668.4	19,688.2
18	Total Storage Related Costs		$ 4,696.6	$ 4,577.7	$ 4,523.6	$ 4,699.7	$ 5,520.8	$ 5,645.5	$ 5,714.6	$ 6,768.8	$ 6,807.3	$ 7,258.3	$ 5,634.9	$ 6,884.9	$ 68,732.6
19															
20	Transportation Related Costs														
21	Enbridge (BC Pipeline) - Westcoast Energy		$ 18,950.9	$ 14,230.5	$ 17,488.4	$ 14,430.3	$ 12,803.7	$ 13,071.9	$ 13,379.5	$ 13,211.0	$ 8,730.1	$ 13,384.0	$ 16,259.1	$ 17,154.4	$ 173,093.7
22	TC Energy (Foothills BC)		772.6	772.6	767.3	582.2	582.2	583.1	582.2	582.2	582.2	582.2	772.6	772.5	7,934.0
23	TC Energy (NOVA Alta)		1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	1,080.9	12,970.3
24	Northwest Pipeline		885.8	796.8	820.2	451.1	452.2	450.3	452.0	438.5	439.3	463.0	604.8	1,111.6	7,365.7
25	FortisBC Huntingdon Inc.		11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.0	11.0	134.4
26	Southern Crossing Pipeline		1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	1,110.0	13,320.5
27	Total Transportation Related Costs		$ 22,811.4	$ 18,002.0	$ 21,278.0	$ 17,665.8	$ 16,040.3	$ 16,307.5	$ 16,615.9	$ 16,433.9	$ 11,953.8	$ 16,631.3	$ 19,838.3	$ 21,240.3	$ 214,818.5
28															
29	Mitigation														
30	Commodity Related Mitigation		$ (9,563.5)	$ (6,691.6)	$ (5,434.8)	$ (3,470.0)	$ (3,257.2)	$ (5,317.3)	$ (7,024.8)	$ (2,975.8)	$ (2,670.7)	$ (3,046.6)	$ (3,862.4)	$ (6,399.8)	$ (59,714.6)
31	Storage Related Mitigation		(1,076.5)	(390.1)	(4,220.3)	3,007.1	1,755.5	69.0	(1,829.1)	(2,374.9)	(45.5)	1,358.9	(3,291.8)	(296.1)	(7,333.7)
32	Transportation Related Mitigation		(9,154.1)	(4,608.0)	(3,487.4)	(7,151.9)	(6,935.3)	(9,228.3)	(11,865.5)	(11,973.5)	(11,337.1)	(11,996.5)	(7,238.7)	(9,996.9)	(104,973.3)
33	Total Mitigation		$ (19,794.0)	$ (11,689.8)	$ (13,142.5)	$ (7,614.8)	$ (8,437.0)	$ (14,476.7)	$ (20,719.4)	$ (17,324.1)	$ (14,053.3)	$ (13,684.3)	$ (14,392.9)	$ (16,692.8)	$ (172,021.6)
34															
35	GSMIP Incentive Sharing		$ 826.8	$ 498.7	$ 297.3	$ 245.9	$ 162.3	$ 208.3	$ 302.6	$ 239.5	$ 209.3	$ 228.3	$ 351.5	$ 320.6	$ 3,891.0
36															
37	Core Market Administration Costs		$ 745.1	$ 251.7	$ 405.4	$ 325.1	$ 343.0	$ 177.8	$ 302.1	$ 287.4	$ 314.3	$ 289.5	$ 253.3	$ 349.2	$ 4,044.0
38	**TOTAL MCRA COSTS** ($000) (Line 13, 18, 27, 33, 35 & 37)		$ 64,545.1	$ 34,786.7	$ 28,857.3	$ 17,214.4	$ 10,665.8	$ 5,227.2	$ 550.9	$ 4,350.1	$ 1,903.9	$ 10,678.4	$ 24,937.1	$ 26,601.6	$ 230,318.5

Notes:

(a) The total cost of UAF is included as a component of gas purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(b) Imbalance is composed of two components, Enbridge imbalance (difference between Enbridge metered and authorized deliveries) and Transportation imbalance (difference between the authorized receipts and customers' consumption or "burn").
The 2024 opening balance reflects FEI owed Enbridge / Transportation Marketers 840 TJ of gas valued at $1,740K. As imbalance amounts can be either a debit or credit value, and typically remain within a narrow range, FEI does not forecast future imbalance amounts.

(c) The net impact to the MCRA related to the movement of commodity costs into or out of the Gas in Storage inventory account. Gas injections to storage result in credits to the MCRA, while withdrawals result in costs being debited to the MCRA.

Slight difference in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
MCRA INCURRED MONTHLY ACTIVITIES FOR THE YEAR 2025
FORECAST PERIODS WITH FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025

Line	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Opening balance	Recorded Jan-25	Projected Feb-25	Projected Mar-25	Forecast Apr-25	Forecast May-25	Forecast Jun-25	Forecast Jul-25	Forecast Aug-25	Forecast Sep-25	Forecast Oct-25	Forecast Nov-25	Forecast Dec-25	**2025 Total**
1	**MCRA COSTS** ($000)														
2	Midstream Commodity Related Costs														
3	Propane Available for Sale - Purchase & Inventory Change		$ 836.3	$ 752.0	$ 605.5	$ 381.9	$ 195.2	$ 166.5	$ 154.0	$ 141.0	$ 159.1	$ 343.1	$ 535.2	$ 769.7	$ 5,039.6
4	Propane Cost Recoveries via Commodity Rates		(112.2)	(103.2)	(87.7)	(58.3)	(31.4)	(27.7)	(25.7)	(23.0)	(25.6)	(52.5)	(80.7)	(114.8)	(742.9)
5	Propane Costs to be Recovered via Midstream Rates		$ 724.1	$ 648.8	$ 517.7	$ 323.7	$ 163.8	$ 138.8	$ 128.3	$ 118.0	$ 133.5	$ 290.6	$ 454.5	$ 655.0	$ 4,296.7
6	FEFN Supply Portfolio Costs		$ 135.0	$ 122.2	$ 110.4	$ 57.7	$ 25.8	$ 16.3	$ 13.4	$ 15.7	$ 26.4	$ 64.6	$ 144.9	$ 234.0	$ 966.5
7	FEFN Costs Recovered from Commodity Rates		(119.6)	(166.1)	(142.7)	(83.8)	(36.7)	(21.6)	(15.5)	(18.5)	(32.5)	(76.6)	(130.3)	(197.0)	(1,040.7)
8	FEFN Costs to be Recovered via Midstream Rates		$ 15.3	$ (43.9)	$ (32.3)	$ (26.0)	$ (10.8)	$ (5.2)	$ (2.1)	$ (2.7)	$ (6.1)	$ (12.0)	$ 14.6	$ 37.0	$ (74.2)
9	Midstream Natural Gas Costs before Hedging [a]		$ 11,635.4	$ 4,350.6	$ 5,011.4	$ 30.3	$ 29.5	$ 29.6	$ 35.0	$ 37.6	$ 35.3	$ 42.9	$ 11,149.4	$ 13,553.9	$ 45,940.8
10	Imbalance [b]	$ 960.0	(165.3)	-	-	-	-	-	-	-	-	-	-	(789.1)	(954.4)
11	Company Use Gas Recovered from O&M		(504.5)	(856.7)	(729.2)	(509.8)	(285.7)	(253.2)	(192.5)	(128.4)	(179.0)	(267.8)	(574.0)	(931.7)	(5,412.5)
12	Storage Withdrawal / (Injection) Activity [c]		7,996.6	7,892.4	6,192.9	(261.0)	(6,415.8)	(7,671.4)	(9,379.2)	(8,393.5)	(8,009.8)	(3,431.1)	6,491.7	11,202.0	(3,786.3)
13	Total Midstream Commodity Related Costs		$ 19,701.6	$ 11,991.3	$ 10,960.4	$ (442.9)	$ (6,519.1)	$ (7,761.4)	$ (9,410.6)	$ (8,369.1)	$ (8,026.1)	$ (3,377.4)	$ 17,536.3	$ 23,727.1	$ 40,010.1
14															
15	Storage Related Costs														
16	Storage Demand - Third Party Storage		$ 3,020.6	$ 4,079.1	$ 4,095.6	$ 4,473.9	$ 7,084.2	$ 7,072.8	$ 7,074.0	$ 7,069.1	$ 7,047.7	$ 7,054.0	$ 5,554.4	$ 4,470.1	$ 68,095.6
17	On-System Storage - Mt. Hayes (LNG)		1,391.6	1,591.9	1,511.6	2,021.0	1,709.6	1,536.0	1,525.9	1,524.7	1,521.9	1,861.5	1,572.7	1,673.4	19,441.8
18	Total Storage Related Costs		$ 4,412.2	$ 5,671.0	$ 5,607.2	$ 6,494.9	$ 8,793.8	$ 8,608.9	$ 8,599.9	$ 8,593.8	$ 8,569.6	$ 8,915.4	$ 7,127.1	$ 6,143.5	$ 87,537.4
19															
20	Transportation Related Costs														
21	Enbridge (BC Pipeline) - Westcoast Energy		$ 18,554.7	$ 17,386.9	$ 17,436.0	$ 14,383.0	$ 14,328.0	$ 14,322.7	$ 14,311.3	$ 14,389.8	$ 14,333.1	$ 14,389.1	$ 15,209.8	$ 15,321.4	$ 184,365.9
22	TC Energy (Foothills BC)		775.9	775.9	775.9	585.6	585.6	585.6	585.6	585.6	585.6	585.6	777.1	777.1	7,981.3
23	TC Energy (NOVA Alta)		1,283.8	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	15,408.1
24	Northwest Pipeline		901.1	814.8	878.5	477.9	479.9	467.0	477.2	468.6	465.2	473.2	837.7	855.7	7,596.8
25	FortisBC Huntingdon Inc.		11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	131.7
26	Southern Crossing Pipeline		1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	13,284.1
27	Total Transportation Related Costs		$ 22,633.6	$ 21,379.6	$ 21,492.5	$ 17,848.5	$ 17,795.5	$ 17,777.3	$ 17,776.1	$ 17,846.1	$ 17,786.0	$ 17,850.0	$ 19,226.5	$ 19,356.2	$ 228,767.8
28															
29	Mitigation														
30	Commodity Related Mitigation		$ (6,286.8)	$ (2,178.2)	$ (11,046.9)	$ (1,600.1)	$ (3,359.6)	$ (4,476.7)	$ (9,992.8)	$ (12,273.5)	$ (8,037.4)	$ (1,455.6)	$ (10,652.9)	$ (500.0)	$ (71,860.6)
31	Storage Related Mitigation		(293.3)	(282.3)	(423.4)	(112.9)	(188.2)	(188.2)	(376.3)	(376.3)	(329.3)	(423.4)	(423.4)	(376.3)	(3,793.3)
32	Transportation Related Mitigation		(10,125.0)	(5,581.3)	(6,976.6)	(7,808.6)	(7,790.6)	(13,371.9)	(13,371.9)	(13,371.9)	(13,371.9)	(11,976.6)	(5,581.3)	(2,790.6)	(112,118.0)
33	Total Mitigation		$ (16,705.1)	$ (8,041.7)	$ (18,446.9)	$ (9,521.6)	$ (11,338.4)	$ (18,036.7)	$ (23,741.1)	$ (26,021.7)	$ (21,738.6)	$ (13,855.5)	$ (16,657.5)	$ (3,667.0)	$ (187,771.8)
34															
35	GSMIP Incentive Sharing		$ 608.4	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 2,900.1
36															
37	Core Market Administration Costs		$ 453.1	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 4,770.6
38	**TOTAL MCRA COSTS** (Line 13, 18, 27, 33, 35 & 37) ($000)		$ 31,103.9	$ 31,601.1	$ 20,214.1	$ 14,979.8	$ 9,332.7	$ 1,188.8	$ (6,174.8)	$ (7,350.1)	$ (2,808.4)	$ 10,133.3	$ 27,833.2	$ 46,160.6	$ 176,214.2

Notes:

(a) The total cost of UAF is included as a component of gas purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(b) Imbalance is composed of two components, Enbridge imbalance (difference between Enbridge metered and authorized deliveries) and Transportation imbalance (difference between the authorized receipts and customers' consumption or "burn").
The 2025 opening balance reflects FEI owed Enbridge / Transportation Marketers 621 TJ of gas valued at $960K. As imbalance amounts can be either a debit or credit value, and typically remain within a narrow range, FEI does not forecast future imbalance amounts.

(c) The net impact to the MCRA related to the movement of commodity costs into or out of the Gas in Storage inventory account. Gas injections to storage result in credits to the MCRA, while withdrawals result in costs being debited to the MCRA.

Slight difference in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
MCRA INCURRED MONTHLY ACTIVITIES FOR THE YEAR 2026
FORECAST PERIODS WITH FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025

Line	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Opening balance	Forecast Jan-26	Forecast Feb-26	Forecast Mar-26	Forecast Apr-26	Forecast May-26	Forecast Jun-26	Forecast Jul-26	Forecast Aug-26	Forecast Sep-26	Forecast Oct-26	Forecast Nov-26	Forecast Dec-26	**2026 Total**
1	**MCRA COSTS** ($000)														
2	Midstream Commodity Related Costs														
3	Propane Available for Sale - Purchase & Inventory Change		$ 796.8	$ 689.0	$ 554.3	$ 340.0	$ 177.3	$ 152.9	$ 141.4	$ 127.5	$ 144.6	$ 309.1	$ 484.6	$ 695.8	$ 4,613.3
4	Propane Cost Recoveries via Commodity Rates		(117.9)	(106.2)	(90.3)	(59.9)	(32.2)	(28.4)	(26.3)	(23.6)	(26.3)	(54.0)	(83.1)	(118.1)	(766.2)
5	Propane Costs to be Recovered via Midstream Rates		$ 678.9	$ 582.7	$ 464.0	$ 280.1	$ 145.1	$ 124.6	$ 115.1	$ 103.9	$ 118.3	$ 255.1	$ 401.6	$ 577.7	$ 3,847.1
6	FEFN Supply Portfolio Costs		255.9	196.2	161.4	92.9	41.0	25.1	19.4	22.6	37.8	88.4	185.8	293.0	1,419.4
7	FEFN Costs Recovered from Commodity Rates		(210.6)	(162.3)	(139.5)	(82.0)	(35.9)	(21.1)	(15.2)	(18.1)	(31.8)	(75.0)	(127.7)	(192.6)	(1,111.6)
8	FEFN Costs to be Recovered via Midstream Rates		$ 45.3	$ 33.9	$ 21.9	$ 11.0	$ 5.1	$ 4.0	$ 4.2	$ 4.5	$ 6.1	$ 13.4	$ 58.1	$ 100.3	$ 307.9
9	Midstream Natural Gas Costs before Hedging [a]		$ 14,045.6	$ 12,610.1	$ 11,966.9	$ 87.7	$ 87.4	$ 84.4	$ 90.9	$ 90.8	$ 87.4	$ 93.1	$ 13,185.4	$ 15,572.2	$ 68,001.8
10	Imbalance [b]	$ -	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Company Use Gas Recovered from O&M		(1,086.6)	(856.7)	(729.2)	(509.8)	(285.7)	(253.2)	(192.5)	(128.4)	(179.0)	(267.8)	(574.0)	(931.7)	(5,994.6)
12	Storage Withdrawal / (Injection) Activity [c]		10,175.7	9,667.8	8,423.8	(831.3)	(10,464.8)	(14,773.2)	(16,489.9)	(14,018.8)	(13,511.5)	(4,760.6)	10,083.8	17,578.3	(18,920.5)
13	Total Midstream Commodity Related Costs		$ 23,859.0	$ 22,038.0	$ 20,147.4	$ (962.4)	$ (10,513.0)	$ (14,813.4)	$ (16,472.1)	$ (13,947.9)	$ (13,478.8)	$ (4,666.8)	$ 23,154.9	$ 32,896.8	$ 47,241.6
14															
15	Storage Related Costs														
16	Storage Demand - Third Party Storage		$ 4,472.1	$ 4,451.4	$ 4,458.1	$ 4,454.9	$ 7,034.5	$ 7,013.9	$ 7,019.0	$ 7,010.1	$ 6,989.6	$ 6,995.8	$ 4,439.0	$ 4,450.2	$ 68,788.7
17	On-System Storage - Mt. Hayes (LNG)		1,687.5	1,591.9	1,511.6	2,021.0	1,709.6	1,536.0	1,525.9	1,524.7	1,521.9	1,861.5	1,572.7	1,673.4	19,737.7
18	Total Storage Related Costs		$ 6,159.6	$ 6,043.3	$ 5,969.7	$ 6,475.9	$ 8,744.1	$ 8,550.0	$ 8,544.9	$ 8,534.8	$ 8,511.5	$ 8,857.3	$ 6,011.7	$ 6,123.6	$ 88,526.4
19															
20	Transportation Related Costs														
21	Enbridge (BC Pipeline) - Westcoast Energy		$ 17,655.1	$ 17,386.9	$ 17,436.0	$ 14,387.2	$ 14,331.8	$ 14,326.5	$ 14,315.0	$ 14,394.1	$ 14,337.0	$ 14,393.4	$ 15,203.7	$ 15,314.7	$ 183,481.3
22	TC Energy (Foothills BC)		777.1	777.1	777.1	585.6	585.6	585.6	585.6	585.6	585.6	585.6	777.1	777.1	7,984.6
23	TC Energy (NOVA Alta)		1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	15,408.3
24	Northwest Pipeline		853.6	812.3	862.0	472.3	476.0	472.6	470.1	461.7	458.3	466.3	825.4	843.1	7,473.7
25	FortisBC Huntingdon Inc.		11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	131.7
26	Southern Crossing Pipeline		1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	13,284.1
27	Total Transportation Related Costs		$ 21,687.8	$ 21,378.3	$ 21,477.1	$ 17,847.1	$ 17,795.5	$ 17,786.7	$ 17,772.7	$ 17,843.4	$ 17,783.0	$ 17,847.2	$ 19,208.1	$ 19,336.8	$ 227,763.6
28															
29	Mitigation														
30	Commodity Related Mitigation		$ (688.1)	$ (4,594.3)	$ (11,521.2)	$ (3,511.3)	$ (4,781.2)	$ (5,165.6)	$ (7,587.4)	$ (9,921.9)	$ (7,822.7)	$ (3,001.4)	$ (10,809.0)	$ (1,658.8)	$ (71,062.7)
31	Storage Related Mitigation		-	-	-	-	-	-	-	-	-	-	-	-	-
32	Transportation Related Mitigation		(4,672.9)	(4,672.9)	(5,841.1)	(6,431.5)	(6,431.5)	(11,104.4)	(11,104.4)	(11,104.4)	(11,104.4)	(9,936.2)	(4,672.9)	(2,336.5)	(89,413.2)
33	Total Mitigation		$ (5,361.0)	$ (9,267.2)	$ (17,362.3)	$ (9,942.8)	$ (11,212.7)	$ (16,270.0)	$ (18,691.8)	$ (21,026.3)	$ (18,927.1)	$ (12,937.6)	$ (15,481.9)	$ (3,995.2)	$ (160,476.0)
34															
35	GSMIP Incentive Sharing		$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 2,500.0
36															
37	Core Market Administration Costs		$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 4,710.0
38	**TOTAL MCRA COSTS** (Line 13, 18, 27, 33, 35 & 37) ($000)		$ 46,946.2	$ 40,793.1	$ 30,832.7	$ 14,018.6	$ 5,414.8	$ (4,145.8)	$ (8,245.4)	$ (7,995.2)	$ (5,510.6)	$ 9,701.0	$ 33,493.6	$ 54,962.9	$ 210,265.7

Notes:

(a) The total cost of UAF is included as a component of gas purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(b) Imbalance is composed of two components, Enbridge imbalance (difference between Enbridge metered and authorized deliveries) and Transportation imbalance (difference between the authorized receipts and customers' consumption or "burn").

(c) The net impact to the MCRA related to the movement of commodity costs into or out of the Gas in Storage inventory account. Gas injections to storage result in credits to the MCRA, while withdrawals result in costs being debited to the MCRA.

Slight difference in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
STORAGE AND TRANSPORT RELATED CHARGES FLOW-THROUGH BY RATE SCHEDULE
FOR THE FORECAST PERIOD APR 2025 TO MAR 2026
FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025

			Residential			Commercial			General			For Information Only			
				FEFN		FEFN		FEFN	Firm	NGV	Total MCRA Gas	Seasonal	General Interruptible	LNG (Sales)	Off-System Interruptible Sales
Line	Particulars	Unit	RS-1	RS-1	RS-2	RS-2	RS-3	RS-3	RS-5	RS-6	Costs	RS-4	RS-7	RS-46	RS-30
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	**MCRA Sales Quantity** (Natural Gas & Propane)	TJ	82,556.3	225.2	29,201.6	164.2	32,803.6	114.8	22,787.0 [d]	21.4	*167,874.2*	170.4	7,765.3	350.0	33,191.2
2															
3	**Load Factor Adjusted Quantity**														
4	Load Factor [a]	%	31.0%	31.0%	30.3%	30.3%	35.6%	35.6%	53.3%	100.0%					
5	Load Factor Adjusted Quantity	TJ	266,000.5	36.3	96,276.7	27.1	92,202.1	16.1	42,723.3	21.4	*497,303.6*				
6	Load Factor Adjusted Volumetric Allocation	%	53.489%	0.007%	19.360%	0.005%	18.540%	0.003%	8.591%	0.004%	100.000%				
7															
8	**MCRA Cost of Gas - Load Factor Adjusted Allocation**														
9	Midstream Commodity Related Costs (Net of Mitigation)	$000	$ (3,383.9)	$ (0.5)	$ (1,224.8)	$ (0.3)	$ (1,172.9)	$ (0.2)	$ (543.5)	$ (0.3)	**$ (6,326.4)**				
10	Storage Related Costs (Net of Mitigation)	$000	46,655.5	6.4	16,886.6	4.7	16,171.9	2.8	7,493.5	3.8	**87,225.2**				
11	Transportation Related Costs (Net of Mitigation)	$000	65,888.9	9.0	23,847.9	6.7	22,838.7	4.0	10,582.7	5.3	**123,183.1**				
12	GSMIP Incentive Sharing	$000	1,337.2	0.2	484.0	0.1	463.5	0.1	214.8	0.1	**2,500.0**				
13	Core Market Administration Costs - MCRA 70%	$000	2,519.3	0.3	911.8	0.3	873.3	0.2	404.6	0.2	**4,710.0**				
14	**Total Midstream Cost of Gas Allocated by Rate Class**	$000	$ 113,017.0	$ 15.4	$ 40,905.6	$ 11.5	$ 39,174.4	$ 6.8	$ 18,152.1	$ 9.1	**$ 211,291.9**				
15	T-Service UAF to be recovered via delivery revenues [b]										575.3				
16	**Total MCRA Gas Costs** [c]										$ 211,867.2				
17	**1/2 of Pre-Tax Amort. MCRA Deficit/(Surplus) as of Apr 1, 2025**	$000	$ (17,829.0)	$ (2.4)	$ (6,453.1)	$ (1.8)	$ (6,180.0)	$ (1.1)	$ (2,863.6)	$ (1.4)	**$ (33,332.5)**				
18															
19											**Average**				
20	**MCRA Cost of Gas Unitized**										**Costs**				
21	**MCRA Flow-Through Costs before MCRA deferral amortization**	$/GJ	$ 1.3690	$ 0.0685	$ 1.4008	$ 0.0700	$ 1.1942	$ 0.0596	$ 0.7966	$ 0.4247	$ 1.2586				
22	**MCRA Deferral Amortization via Rate Rider 6**	$/GJ	$ (0.2160)	$ (0.0108)	$ (0.2210)	$ (0.0110)	$ (0.1884)	$ (0.0094)	$ (0.1257)	$ (0.0670)	$ (0.1986)				

Notes:
(a) Based on the historical 3-year (2021, 2022, and 2023 data) rolling average load factors for Rate Schedules 1, 2, 3 and 5.
(b) The total cost of UAF (Sales Rate Classes and T-Service) is included as a component of gas purchased. Sales UAF costs are recovered via gas cost recovery rates; T-Service UAF costs recovered via delivery revenues which are excluded from the above flow-through calculation.
(c) Reconciled to the Total MCRA Costs on Tab 1, Page 7, Col. 3, Line 44, with monthly breakdown on Tab 2, Page 7.1.
(d) Storage & Transport and MCRA Rate Rider 6 charges for RS-4, RS-6P (Fueling Stations), RS-7, and RS-46 (Sales) are set at the RS-5 tariff rates. For midstream cost allocation purposes the RS-5 allocations include RS-4, RS-5, RS-6P (Fueling Stations),
Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - MAINLAND AND VANCOUVER ISLAND SERVICE AREA, AND FORT NELSON SERVICE AREA
MCRA INCURRED MONTHLY ACTIVITIES FOR THE PERIOD FROM APR 2025 TO MAR 2026
FORECAST PERIODS WITH FIVE-DAY AVERAGE FORWARD PRICES - FEBRUARY 13, 14, 18, 19, AND 20, 2025

Line	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Opening balance	Forecast Apr-25	Forecast May-25	Forecast Jun-25	Forecast Jul-25	Forecast Aug-25	Forecast Sep-25	Forecast Oct-25	Forecast Nov-25	Forecast Dec-25	Forecast Jan-26	Forecast Feb-26	Forecast Mar-26	**Apr-25 to Mar-26 Total**
1	**MCRA COSTS** ($000)														
2	Midstream Commodity Related Costs														
3	Propane Available for Sale - Purchase & Inventory Change		$ 381.9	$ 195.2	$ 166.5	$ 154.0	$ 141.0	$ 159.1	$ 343.1	$ 535.2	$ 769.7	$ 796.8	$ 689.0	$ 554.3	$ 4,885.9
4	Propane Costs Recoveries via Commodity Rates		(58.3)	(31.4)	(27.7)	(25.7)	(23.0)	(25.6)	(52.5)	(80.7)	(114.8)	(117.9)	(106.2)	(90.3)	(754.2)
5	Propane Costs to be Recovered via Midstream Rates		$ 323.7	$ 163.8	$ 138.8	$ 128.3	$ 118.0	$ 133.5	$ 290.6	$ 454.5	$ 655.0	$ 678.9	$ 582.7	$ 464.0	$ 4,131.7
6	FEFN Supply Portfolio Costs		$ 57.7	$ 25.8	$ 16.3	$ 13.4	$ 15.7	$ 26.4	$ 64.6	$ 144.9	$ 234.0	$ 255.9	$ 196.2	$ 161.4	$ 1,212.3
7	FEFN Costs Recovered from Commodity Rates		(83.8)	(36.7)	(21.6)	(15.5)	(18.5)	(32.5)	(76.6)	(130.3)	(197.0)	(210.6)	(162.3)	(139.5)	(1,124.6)
8	FEFN Costs to be Recovered via Midstream Rates		$ (26.0)	$ (10.8)	$ (5.2)	$ (2.1)	$ (2.7)	$ (6.1)	$ (12.0)	$ 14.6	$ 37.0	$ 45.3	$ 33.9	$ 21.9	$ 87.7
9	Midstream Natural Gas Costs before Hedging [(a)]		$ 30.3	$ 29.5	$ 29.6	$ 35.0	$ 37.6	$ 35.3	$ 42.9	$ 11,149.4	$ 13,553.9	$ 14,045.6	$ 12,610.1	$ 11,966.9	$ 63,566.1
10	Imbalance [(b)]		-	-	-	-	-	-	-	-	(789.1)	-	-	-	(789.1)
11	Company Use Gas Recovered from O&M		(509.8)	(285.7)	(253.2)	(192.5)	(128.4)	(179.0)	(267.8)	(574.0)	(931.7)	(1,086.6)	(856.7)	(729.2)	(5,994.6)
12	Storage Withdrawal / (Injection) Activity [(c)]		(261.0)	(6,415.8)	(7,671.4)	(9,379.2)	(8,393.5)	(8,009.8)	(3,431.1)	6,491.7	11,202.0	10,175.7	9,667.8	8,423.8	2,399.2
13	Total Midstream Commodity Related Costs		$ (442.9)	$ (6,519.1)	$ (7,761.4)	$ (9,410.6)	$ (8,369.1)	$ (8,026.1)	$ (3,377.4)	$ 17,536.3	$ 23,727.1	$ 23,859.0	$ 22,038.0	$ 20,147.4	$ 63,401.0
14															
15	Storage Related Costs														
16	Storage Demand - Third Party Storage		$ 4,473.9	$ 7,084.2	$ 7,072.8	$ 7,074.0	$ 7,069.1	$ 7,047.7	$ 7,054.0	$ 5,554.4	$ 4,470.1	$ 4,472.1	$ 4,451.4	$ 4,458.1	$ 70,281.9
17	On-System Storage - Mt. Hayes (LNG)		2,021.0	1,709.6	1,536.0	1,525.9	1,524.7	1,521.9	1,861.5	1,572.7	1,673.4	1,687.5	1,591.9	1,511.6	19,737.7
18	Total Storage Related Costs		$ 6,494.9	$ 8,793.8	$ 8,608.9	$ 8,599.9	$ 8,593.8	$ 8,569.6	$ 8,915.4	$ 7,127.1	$ 6,143.5	$ 6,159.6	$ 6,043.3	$ 5,969.7	$ 90,019.6
19															
20	Transportation Related Costs														
21	Enbridge (BC Pipeline) - Westcoast Energy		$ 14,383.0	$ 14,328.0	$ 14,322.7	$ 14,311.3	$ 14,389.8	$ 14,333.1	$ 14,389.1	$ 15,209.8	$ 15,321.4	$ 17,655.1	$ 17,386.9	$ 17,436.0	$ 183,466.2
22	TC Energy (Foothills BC)		585.6	585.6	585.6	585.6	585.6	585.6	585.6	777.1	777.1	777.1	777.1	777.1	7,984.6
23	TC Energy (NOVA Alta)		1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	1,284.0	15,408.3
24	Northwest Pipeline		477.9	479.9	467.0	477.2	468.6	465.2	473.2	837.7	855.7	853.6	812.3	862.0	7,530.4
25	FortisBC Huntingdon Inc.		11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	131.7
26	Southern Crossing Pipeline		1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	1,107.0	13,284.1
27	Total Transportation Related Costs		$ 17,848.5	$ 17,795.5	$ 17,777.3	$ 17,776.1	$ 17,846.1	$ 17,786.0	$ 17,850.0	$ 19,226.5	$ 19,356.2	$ 21,687.8	$ 21,378.3	$ 21,477.1	$ 227,805.3
28															
29	Mitigation														
30	Commodity Related Mitigation		$ (1,600.1)	$ (3,359.6)	$ (4,476.7)	$ (9,992.8)	$ (12,273.5)	$ (8,037.4)	$ (1,455.6)	$ (10,652.9)	$ (500.0)	$ (688.1)	$ (4,594.3)	$ (11,521.2)	$ (69,152.2)
31	Storage Related Mitigation		(112.9)	(188.2)	(188.2)	(376.3)	(376.3)	(329.3)	(423.4)	(423.4)	(376.3)	-	-	-	(2,794.4)
32	Transportation Related Mitigation		(7,808.6)	(7,790.6)	(13,371.9)	(13,371.9)	(13,371.9)	(13,371.9)	(11,976.6)	(5,581.3)	(2,790.6)	(4,672.9)	(4,672.9)	(5,841.1)	(104,622.1)
33	Total Mitigation		$ (9,521.6)	$ (11,338.4)	$ (18,036.7)	$ (23,741.1)	$ (26,021.7)	$ (21,738.6)	$ (13,855.5)	$ (16,657.5)	$ (3,667.0)	$ (5,361.0)	$ (9,267.2)	$ (17,362.3)	$ (176,568.7)
34	GSMIP Incentive Sharing		$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 208.3	$ 2,500.0
35	Core Market Administration Costs		$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 392.5	$ 4,710.0
36	**TOTAL MCRA COSTS** (Line 13, 18, 27, 33, 34 & 35) ($000)		$ 14,979.8	$ 9,332.7	$ 1,188.8	$ (6,174.8)	$ (7,350.1)	$ (2,808.4)	$ 10,133.3	$ 27,833.2	$ 46,160.6	$ 46,946.2	$ 40,793.1	$ 30,832.7	$ 211,867.2

Notes:

(a) The total cost of UAF is included as a component of gas purchased. Sales UAF costs are recovered via gas cost recovery rates, while T-Service UAF costs are recovered via delivery revenues.

(b) Imbalance is composed of two components, Enbridge imbalance (difference between Enbridge metered and authorized deliveries) and Transportation imbalance (difference between the authorized receipts and customers' consumption or "burn").

(c) The net impact to the MCRA related to the movement of commodity costs into or out of the Gas in Storage inventory account. Gas injections to storage result in credits to the MCRA, while withdrawals result in costs being debited to the MCRA.

Slight difference in totals due to rounding.

Line No.	RATE SCHEDULE 1RNG: RESIDENTIAL RENEWABLE NATURAL GAS SERVICE Particulars	EXISTING RATES JANUARY 1, 2025 Mainland and Vancouver Island	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES Mainland and Vancouver Island	PROPOSED APRIL 1, 2025 RATES Mainland and Vancouver Island
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$0.4085**	**$0.0000**	**$0.4085**
3	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	$0.0131	$0.0000	$0.0131
4	Subtotal of per Day **Delivery Margin Related Charges**	**$0.4216**	**$0.0000**	**$0.4216**
5				
6	Delivery Charge per GJ	$7.327	$0.000	$7.327
7	Rider 5 RSAM per GJ	$0.149	$0.000	$0.149
8	Subtotal of Per GJ **Delivery Margin Related Charges**	**$7.476**	**$0.000**	**$7.476**
9				
10				
11	Commodity Related Charges			
12	Storage and Transport Charge per GJ	$1.260	$0.000	$1.260
13	Rider 6 MCRA per GJ	($0.164)	$0.000	($0.164)
14	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
15	Subtotal **Storage and Transport Related Charges per GJ**	**$1.397**	**$0.000**	**$1.397**
16				
17				
18	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
19				
20	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
21	(Renewable Natural Gas Charge)			

Line No.	**RATE SCHEDULE 1RNG: RESIDENTIAL RENEWABLE NATURAL GAS SERVICE - FORT NELSON SERVICE AREA** Particulars	**EXISTING RATES JANUARY 1, 2025** Fort Nelson	**DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES** Fort Nelson	**PROPOSED APRIL 1, 2025 RATES** Fort Nelson
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$0.4085**	**$0.0000**	**$0.4085**
3	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	$0.0131	$0.0000	$0.0131
4	Subtotal of per Day **Delivery Margin Related Charges**	**$0.4216**	**$0.0000**	**$0.4216**
5				
6	Delivery Charge per GJ	$7.327	$0.000	$7.327
7	Rider 4 Fort Nelson Residential Customer Common Rate Phase-in	($0.609)	$0.000	($0.609)
8	Rider 5 RSAM per GJ	$0.149	$0.000	$0.149
9	Subtotal of Per GJ **Delivery Margin Related Charges**	**$6.867**	**$0.000**	**$6.867**
10				
11				
12	Commodity Related Charges			
13	Storage and Transport Charge per GJ	$0.063	$0.000	$0.063
14	Rider 6 MCRA per GJ	($0.008)	$0.000	($0.008)
15	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
16	Subtotal **Storage and Transport Related Charges per GJ**	**$0.356**	**$0.000**	**$0.356**
17				
18				
19	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
20				
21	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
22	(Renewable Natural Gas Charge)			

Line No.	RATE SCHEDULE 2RNG: SMALL COMMERCIAL RENEWABLE NATURAL GAS SERVICE	EXISTING RATES JANUARY 1, 2025	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2025 RATES
	Particulars	**Mainland and Vancouver Island**	**Mainland and Vancouver Island**	**Mainland and Vancouver Island**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$1.4178**	**$0.0000**	**$1.4178**
3	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	$0.0131	$0.0000	$0.0131
4	Subtotal of per Day **Delivery Margin Related Charges**	**$1.4309**	**$0.0000**	**$1.4309**
5				
6	Delivery Charge per GJ	$4.994	$0.000	$4.994
7	Rider 5 RSAM per GJ	$0.149	$0.000	$0.149
8	Subtotal of Per GJ **Delivery Margin Related Charges**	**$5.143**	**$0.000**	**$5.143**
9				
10				
11	Commodity Related Charges			
12	Storage and Transport Charge per GJ	$1.289	$0.000	$1.289
13	Rider 6 MCRA per GJ	($0.168)	$0.000	($0.168)
14	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
15	Subtotal **Storage and Transport Related Charges per GJ**	**$1.422**	**$0.000**	**$1.422**
16				
17	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
18				
19	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
20	(Renewable Natural Gas Charge)			

Line No.	RATE SCHEDULE 2RNG: SMALL COMMERCIAL RENEWABLE NATURAL GAS SERVICE - FORT NELSON SERVICE AREA	EXISTING RATES JANUARY 1, 2025	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2025 RATES
	Particulars	**Fort Nelson**	**Fort Nelson**	**Fort Nelson**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$1.4178**	**$0.0000**	**$1.4178**
3	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	$0.0131	$0.0000	$0.0131
4	Subtotal of per Day **Delivery Margin Related Charges**	**$1.4309**	**$0.0000**	**$1.4309**
5				
6	Delivery Charge per GJ	$4.994	$0.000	$4.994
7	Rider 4 Fort Nelson Residential Customer Common Rate Phase-in	$0.000	$0.000	$0.000
8	Rider 5 RSAM per GJ	$0.149	$0.000	$0.149
9	Subtotal of Per GJ **Delivery Margin Related Charges**	**$5.143**	**$0.000**	**$5.143**
10				
11				
12	Commodity Related Charges			
13	Storage and Transport Charge per GJ	$0.065	$0.000	$0.065
14	Rider 6 MCRA per GJ	($0.008)	$0.000	($0.008)
15	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
16	Subtotal **Storage and Transport Related Charges per GJ**	**$0.358**	**$0.000**	**$0.358**
17				
18	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
19				
20	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
21	(Renewable Natural Gas Charge)			

Line No.	RATE SCHEDULE 3RNG: LARGE COMMERCIAL RENEWABLE NATURAL GAS SERVICE	EXISTING RATES JANUARY 1, 2025	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2025 RATES
	Particulars	**Mainland and Vancouver Island**	**Mainland and Vancouver Island**	**Mainland and Vancouver Island**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$4.3395**	**$0.0000**	**$4.3395**
3	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	$0.0131	$0.0000	$0.0131
4	Subtotal of per Day **Delivery Margin Related Charges**	**$4.3526**	**$0.0000**	**$4.3526**
5				
6	Delivery Charge per GJ	$4.650	$0.000	$4.650
7	Rider 5 RSAM per GJ	$0.149	$0.000	$0.149
8	Subtotal of Per GJ **Delivery Margin Related Charges**	**$4.799**	**$0.000**	**$4.799**
9				
10				
11	Commodity Related Charges			
12	Storage and Transport Charge per GJ	$1.099	$0.000	$1.099
13	Rider 6 MCRA per GJ	($0.143)	$0.000	($0.143)
14	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
15	Subtotal **Storage and Transport Related Charges per GJ**	**$1.257**	**$0.000**	**$1.257**
16				
17	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
18				
19	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
20	(Renewable Natural Gas Charge)			

Line No.	RATE SCHEDULE 3RNG: LARGE COMMERCIAL RENEWABLE NATURAL GAS SERVICE - FORT NELSON SERVICE AREA	EXISTING RATES JANUARY 1, 2025	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2025 RATES
	Particulars	**Fort Nelson**	**Fort Nelson**	**Fort Nelson**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Day**	**$4.3395**	**$0.0000**	**$4.3395**
3	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	$0.0131	$0.0000	$0.0131
4	Subtotal of per Day **Delivery Margin Related Charges**	**$4.3526**	**$0.0000**	**$4.3526**
5				
6	Delivery Charge per GJ	$4.650	$0.000	$4.650
7	Rider 4 Fort Nelson Residential Customer Common Rate Phase-in	$0.000	$0.000	$0.000
8	Rider 5 RSAM per GJ	$0.149	$0.000	$0.149
9	Subtotal of Per GJ **Delivery Margin Related Charges**	**$4.799**	**$0.000**	**$4.799**
10				
11				
12	Commodity Related Charges			
13	Storage and Transport Charge per GJ	$0.055	$0.000	$0.055
14	Rider 6 MCRA per GJ	($0.007)	$0.000	($0.007)
15	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
16	Subtotal **Storage and Transport Related Charges per GJ**	**$0.349**	**$0.000**	**$0.349**
17				
18	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
19				
20	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
21	(Renewable Natural Gas Charge)			

Line No.	RATE SCHEDULE 5RNG: GENERAL FIRM RENEWABLE NATURAL GAS SERVICE	EXISTING RATES JANUARY 1, 2025	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2025 RATES
	Particulars	Mainland and Vancouver Island	Mainland and Vancouver Island	Mainland and Vancouver Island
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$469.0000	$0.0000	$469.0000
3	**Rider 2 Clean Growth Innovation Fund Rate Rider per Month**	$0.4000	$0.0000	$0.4000
4	Subtotal of per Month **Delivery Margin Related Charges**	**$469.4000**	**$0.0000**	**$469.4000**
5				
6	**Demand Charge per GJ**	$34.020	$0.000	$34.020
7				
8	**Delivery Charge per GJ**	$1.219	$0.000	$1.219
9				
10	Commodity Related Charges			
11	Storage and Transport Charge per GJ	$0.733	$0.000	$0.733
12	Rider 6 MCRA per GJ	($0.095)	$0.000	($0.095)
13	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
14	Subtotal **Storage and Transport Related Charges per GJ**	**$0.939**	**$0.000**	**$0.939**
15				
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
17				
18	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
19	(Renewable Natural Gas Charge)			

Line No.	RATE SCHEDULE 7RNG: GENERAL INTERRUPTIBLE RENEWABLE NATURAL GAS SERVICE	EXISTING RATES JANUARY 1, 2025	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2025 RATES
	Particulars	**Mainland and Vancouver Island**	**Mainland and Vancouver Island**	**Mainland and Vancouver Island**
	(1)	(2)	(3)	(4)
1	Delivery Margin Related Charges			
2	**Basic Charge per Month**	$880.0000	$0.0000	$880.0000
3	**Rider 2 Clean Growth Innovation Fund Rate Rider per Month**	$0.4000	$0.0000	$0.4000
4	Subtotal of per Month **Delivery Margin Related Charges**	**$880.4000**	**$0.0000**	**$880.4000**
5				
6	**Delivery Charge per GJ**	$1.988	$0.000	$1.988
7				
8	Commodity Related Charges			
9	Storage and Transport Charge per GJ	$0.733	$0.000	$0.733
10	Rider 6 MCRA per GJ	($0.095)	$0.000	($0.095)
11	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
12	Subtotal **Storage and Transport Related Charges per GJ**	**$0.939**	**$0.000**	**$0.939**
13				
14	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
15				
16	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
17	(Renewable Natural Gas Charge)			

Line No.	RATE SCHEDULE 46: LNG SERVICE	EXISTING RATES JANUARY 1, 2025	DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES	PROPOSED APRIL 1, 2025 RATES
	Particulars	Mainland and Vancouver Island	Mainland and Vancouver Island	Mainland and Vancouver Island
	(1)	(2)	(3)	(4)
1	Dispensing Service Charges per GJ			
2	**LNG Facility Charge per GJ**	$4.810	$0.000	$4.810
3	**Electricity Surcharge per GJ**	$1.100	$0.000	$1.100
4	**LNG Spot Charge per GJ**	$6.160	$0.000	$6.160
5				
6				
7	Commodity Related Charges			
8	Storage and Transport Charge per GJ	$0.733	$0.000	$0.733
9	Rider 6 MCRA per GJ	($0.095)	$0.000	($0.095)
10	Rider 8 S&T RNG Rider	$0.301	$0.000	$0.301
11	Subtotal Storage and Transport Related Charges per GJ	**$0.939**	**$0.000**	**$0.939**
12				
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$2.230**	**$0.000**	**$2.230**
14				
15	**Cost of Renewable Natural Gas per GJ**	**$13.216**	**$0.747**	**$13.963**
16	(Renewable Natural Gas Charge)			
17				
18	**Cost of Vehicle Renewable Natural Gas per GJ**	**$23.346**	**$0.000**	**$23.346**
19	(Vehicle Renewable Natural Gas Charge)			
20				
21				
22	Total Variable Cost per gigajoule (excluding LNG Spot Charge per GJ)	$9.079	$0.000	$9.079
23	(includes Conventional Natural Gas cost only and excludes RNG and VRNG cost)			

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25
RATE SCHEDULE 1RNG - RESIDENTIAL RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025						PROPOSED APRIL 1, 2025 RATES						Annual Increase/Decrease		
		Quantity		Rate		Annual $		Quantity		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**															
2	Delivery Margin Related Charges															
3	Basic Charge per Day	365.25	days x	$0.4085	=	$149.20		365.25	days x	$0.4085	=	$149.20		$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131	=	4.78		365.25	days x	$0.0131	=	4.78		$0.0000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges					**$153.98**						**$153.98**			**$0.00**	**0.00%**
6																
7	Delivery Charge per GJ	90.0	GJ x	$7.327	=	$659.46		90.0	GJ x	$7.327	=	$659.46		$0.000	$0.00	0.00%
8	Rider 5 RSAM per GJ	90.0	GJ x	$0.149	=	13.41		90.0	GJ x	$0.149	=	13.41		$0.000	0.00	0.00%
9	Subtotal of Per GJ Delivery Margin Related Charges					**$672.87**						**$672.87**			**$0.00**	**0.00%**
10	Commodity Related Charges															
11	Storage and Transport Charge per GJ	90.0	GJ x	$1.260	=	$113.40		90.0	GJ x	$1.260	=	$113.40		$0.000	$0.00	0.00%
12	Rider 6 MCRA per GJ	90.0	GJ x	($0.164)	=	(14.76)		90.0	GJ x	($0.164)	=	(14.76)		$0.000	0.00	0.00%
13	Rider 8 S&T RNG Rider	90.0	GJ x	$0.301	=	27.09		90.0	GJ x	$0.301	=	27.09		$0.000	0.00	0.00%
14	Subtotal Storage and Transport Related Charges per GJ					$125.73						$125.73			$0.00	0.00%
15	Cost of Gas (Commodity Cost Recovery Charge) per GJ	90.0	GJ x 90% x	$2.230	=	$180.63		90.0	GJ x 90% x	$2.230	=	$180.63		$0.000	$0.00	0.00%
16	Cost of Renewable Natural Gas	90.0	GJ x 8% x	$13.216	=	$95.16		90.0	GJ x 8% x	$13.963	=	$100.53		$0.747	$5.37	0.44%
17	Subtotal Commodity Related Charges					**$401.52**						**$406.89**			**$5.37**	**0.44%**
18																
19	Total *(with effective $/GJ rate)*	90.0		*$13.649*		**$1,228.37**		90.0		*$13.708*		**$1,233.74**		*$0.060*	**$5.37**	**0.44%**

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25
RATE SCHEDULE 1RNG - RESIDENTIAL RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025 Quantity		Rate		Annual $	PROPOSED APRIL 1, 2025 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$0.4085	=	$149.20	365.25	days x	$0.4085	=	$149.20	$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131	=	4.78	365.25	days x	$0.0131	=	4.78	$0.0000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges					**$153.98**					**$153.98**		**$0.00**	**0.00%**
6														
7	Delivery Charge per GJ	125.0	GJ x	$7.327	=	$915.92	125.0	GJ x	$7.327	=	$915.92	$0.000	$0.00	0.00%
8	Rider 4 Fort Nelson Residential Customer Common Rate Phase-in	125.0	GJ x	($0.609)	=	(76.13)	125.0	GJ x	($0.609)	=	(76.13)	$0.000	0.00	0.00%
9	Rider 5 RSAM per GJ	125.0	GJ x	$0.149	=	18.63	125.0	GJ x	$0.149	=	18.63	$0.000	0.00	0.00%
10	Subtotal of Per GJ Delivery Margin Related Charges					**$858.42**					**$858.42**		**$0.00**	**0.00%**
11	Commodity Related Charges													
12	Storage and Transport Charge per GJ	125.0	GJ x	$0.063	=	$7.88	125.0	GJ x	$0.063	=	$7.88	$0.000	$0.00	0.00%
13	Rider 6 MCRA per GJ	125.0	GJ x	($0.008)	=	(1.00)	125.0	GJ x	($0.008)	=	(1.00)	$0.000	0.00	0.00%
14	Rider 8 S&T RNG Rider	125.0	GJ x	$0.301	=	37.63	125.0	GJ x	$0.301	=	37.63	$0.000	0.00	0.00%
15	Subtotal Storage and Transport Related Charges per GJ					$44.50					$44.50		$0.00	0.00%
16	Cost of Gas (Commodity Cost Recovery Charge) per GJ	125.0	GJ x 90% x	$2.230	=	$250.88	125.0	GJ x 90% x	$2.230	=	$250.88	$0.000	$0.00	0.00%
17	Cost of Renewable Natural Gas	125.0	GJ x 8% x	$13.216	=	132.16	125.0	GJ x 8% x	$13.963	=	139.63	$0.747	7.47	0.52%
18	Subtotal Commodity Related Charges					**$427.54**					**$435.01**		**$7.47**	**0.52%**
19														
20	Total *(with effective $/GJ rate)*	125.0		*$11.520*		**$1,439.94**	125.0		*$11.579*		**$1,447.41**	*$0.060*	**$7.47**	**0.52%**

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).
Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25

RATE SCHEDULE 2RNG-SMALL COMMERCIAL RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025					PROPOSED APRIL 1, 2025 RATES					Annual Increase/Decrease		
		Quantity		Rate		Annual $	Quantity		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$1.4178	=	$517.83	365.25	days x	$1.4178	=	$517.83	$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131	=	4.78	365.25	days x	$0.0131	=	4.78	$0.0000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges					**$522.61**					**$522.61**		**$0.00**	**0.00%**
6														
7	Delivery Charge per GJ	324.8	GJ x	$4.994	=	$1,622.16	324.8	GJ x	$4.994	=	$1,622.16	$0.000	$0.00	0.00%
8	Rider 5 RSAM per GJ	324.8	GJ x	$0.149	=	48.40	324.8	GJ x	$0.149	=	48.40	$0.000	0.00	0.00%
9	Subtotal of Per GJ Delivery Margin Related Charges					**$1,670.56**					**$1,670.56**		**$0.00**	**0.00%**
10														
11	Commodity Related Charges													
12	Storage and Transport Charge per GJ	324.8	GJ x	$1.289	=	$418.73	324.8	GJ x	$1.289	=	$418.73	$0.000	$0.00	0.00%
13	Rider 6 MCRA per GJ	324.8	GJ x	($0.168)	=	(54.57)	324.8	GJ x	($0.168)	=	(54.57)	$0.000	0.00	0.00%
14	Rider 8 S&T RNG Rider	324.8	GJ x	$0.301	=	97.78	324.8	GJ x	$0.301	=	97.78	$0.000	0.00	0.00%
15	Subtotal Storage and Transport Related Charges per GJ					$461.94					$461.94		$0.00	0.00%
16	Cost of Gas (Commodity Cost Recovery Charge) per GJ	324.8	GJ x 90% x	$2.230	=	$651.97	324.8	GJ x 90% x	$2.230	=	$651.97	$0.000	$0.00	0.00%
17	Cost of Renewable Natural Gas	324.8	GJ x 8% x	$13.216	=	343.46	324.8	GJ x 8% x	$13.963	=	362.87	$0.747	19.41	0.53%
18	Subtotal Commodity Related Charges per GJ					**$1,457.37**					**$1,476.78**		**$19.41**	**0.53%**
19	Total *(with effective $/GJ rate)*	324.8		*$11.238*		**$3,650.54**	324.8		*$11.297*		**$3,669.95**	*$0.060*	**$19.41**	**0.53%**

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25
RATE SCHEDULE 2RNG-SMALL COMMERCIAL RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025 Quantity		Rate		Annual $	PROPOSED APRIL 1, 2025 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$1.4178	=	$517.83	365.25	days x	$1.4178	=	$517.83	$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131	=	4.78	365.25	days x	$0.0131	=	4.78	$0.0000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges					**$522.61**					**$522.61**		**$0.00**	**0.00%**
6														
7	Delivery Charge per GJ	377.7	GJ x	$4.994	=	$1,886.07	377.7	GJ x	$4.994	=	$1,886.07	$0.000	$0.00	0.00%
8	Rider 4 Fort Nelson Residential Customer Common Rate Phase-in	377.7	GJ x	$0.000	=	0.00	377.7	GJ x	$0.000	=	0.00	$0.000	0.00	0.00%
9	Rider 5 RSAM per GJ	377.7	GJ x	$0.149	=	56.28	377.7	GJ x	$0.149	=	56.28	$0.000	0.00	0.00%
10	Subtotal of Per GJ Delivery Margin Related Charges					**$1,942.35**					**$1,942.35**		**$0.00**	**0.00%**
11														
12	Commodity Related Charges													
13	Storage and Transport Charge per GJ	377.7	GJ x	$0.065	=	$24.55	377.7	GJ x	$0.065	=	$24.55	$0.000	$0.00	0.00%
14	Rider 6 MCRA per GJ	377.7	GJ x	($0.008)	=	(3.02)	377.7	GJ x	($0.008)	=	(3.02)	$0.000	0.00	0.00%
15	Rider 8 S&T RNG Rider	377.7	GJ x	$0.301	=	113.69	377.7	GJ x	$0.301	=	113.69	$0.000	0.00	0.00%
16	Subtotal Storage and Transport Related Charges per GJ					$135.22					$135.22		$0.00	0.00%
17	Cost of Gas (Commodity Cost Recovery Charge) per GJ	377.7	GJ x 90% x	$2.230	=	$758.04	377.7	GJ x 90% x	$2.230	=	$758.04	$0.000	$0.00	0.00%
18	Cost of Renewable Natural Gas	377.7	GJ x 8% x	$13.216	=	399.33	377.7	GJ x 8% x	$13.963	=	421.91	$0.747	22.58	0.60%
19	Subtotal Commodity Related Charges per GJ					**$1,292.59**					**$1,315.17**		**$22.58**	**0.60%**
20	Total *(with effective $/GJ rate)*	377.7		*$9.949*		**$3,757.55**	377.7		*$10.008*		**$3,780.13**	*$0.060*	**$22.58**	**0.60%**

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).
Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25

RATE SCHEDULE 3RNG - LARGE COMMERCIAL RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025 Quantity		Rate		Annual $	PROPOSED APRIL 1, 2025 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$4.3395	=	$1,585.00	365.25	days x	$4.3395	=	$1,585.00	$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131	=	4.78	365.25	days x	$0.0131	=	4.78	$0.0000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges					**$1,589.78**					**$1,589.78**		**$0.00**	**0.00%**
6														
7	Delivery Charge per GJ	3,628.9	GJ x	$4.650	=	$16,874.48	3,628.9	GJ x	$4.650	=	$16,874.48	$0.000	$0.00	0.00%
8	Rider 5 RSAM per GJ	3,628.9	GJ x	$0.149	=	540.71	3,628.9	GJ x	$0.149	=	540.71	$0.000	0.00	0.00%
9	Subtotal of Per GJ Delivery Margin Related Charges					**$17,415.18**					**$17,415.18**		**$0.00**	**0.00%**
10														
11	Commodity Related Charges													
12	Storage and Transport Charge per GJ	3,628.9	GJ x	$1.099	=	$3,988.18	3,628.9	GJ x	$1.099	=	$3,988.18	$0.000	$0.00	0.00%
13	Rider 6 MCRA per GJ	3,628.9	GJ x	($0.143)	=	(518.94)	3,628.9	GJ x	($0.143)	=	(518.94)	$0.000	0.00	0.00%
14	Rider 8 S&T RNG Rider	3,628.9	GJ x	$0.301	=	1,092.30	3,628.9	GJ x	$0.301	=	1,092.30	$0.000	0.00	0.00%
15	Subtotal Storage and Transport Related Charges per GJ					$4,561.55					$4,561.55		$0.00	0.00%
16	Cost of Gas (Commodity Cost Recovery Charge) per GJ	3,628.9	GJ x 90% x	$2.230	=	$7,283.24	3,628.9	GJ x 90% x	$2.230	=	$7,283.24	$0.000	$0.00	0.00%
17	Cost of Renewable Natural Gas	3,628.9	GJ x 8% x	$13.216	=	3,836.78	3,628.9	GJ x 8% x	$13.963	=	4,053.65	$0.747	216.87	0.63%
18	Subtotal Commodity Related Charges per GJ					**$15,681.57**					**$15,898.44**		**$216.87**	**0.63%**
19														
20	Total *(with effective $/GJ rate)*	3,628.9		*$9.558*		**$34,686.53**	3,628.9		*$9.618*		**$34,903.40**	*$0.060*	**$216.87**	**0.63%**

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25
RATE SCHEDULE 3RNG - LARGE COMMERCIAL RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025 Quantity		Rate		Annual $	PROPOSED APRIL 1, 2025 RATES Quantity		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**FORT NELSON SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge per Day	365.25	days x	$4.3395	=	$1,585.00	365.25	days x	$4.3395	=	$1,585.00	$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131	=	4.78	365.25	days x	$0.0131	=	4.78	$0.0000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges					**$1,589.78**					**$1,589.78**		**$0.00**	**0.00%**
6														
7	Delivery Charge per GJ	5,724.1	GJ x	$4.650	=	$26,617.07	5,724.1	GJ x	$4.650	=	$26,617.07	$0.000	$0.00	0.00%
8	Rider 4 Fort Nelson Residential Customer Common Rate Phase-in	5,724.1	GJ x	$0.000	=	0.00	5,724.1	GJ x	$0.000	=	0.00	$0.000	0.00	0.00%
9	Rider 5 RSAM per GJ	5,724.1	GJ x	$0.149	=	852.89	5,724.1	GJ x	$0.149	=	852.89	$0.000	0.00	0.00%
10	Subtotal of Per GJ Delivery Margin Related Charges					**$27,469.96**					**$27,469.96**		**$0.00**	**0.00%**
11														
12	Commodity Related Charges													
13	Storage and Transport Charge per GJ	5,724.1	GJ x	$0.055	=	$314.83	5,724.1	GJ x	$0.055	=	$314.83	$0.000	$0.00	0.00%
14	Rider 6 MCRA per GJ	5,724.1	GJ x	($0.007)	=	(40.07)	5,724.1	GJ x	($0.007)	=	(40.07)	$0.000	0.00	0.00%
15	Rider 8 S&T RNG Rider	5,724.1	GJ x	$0.301	=	1,722.95	5,724.1	GJ x	$0.301	=	1,722.95	$0.000	0.00	0.00%
16	Subtotal Storage and Transport Related Charges per GJ					$1,997.71					$1,997.71		$0.00	0.00%
17	Cost of Gas (Commodity Cost Recovery Charge) per GJ	5,724.1	GJ x 90% x	$2.230	=	$11,488.27	5,724.1	GJ x 90% x	$2.230	=	$11,488.27	$0.000	$0.00	0.00%
18	Cost of Renewable Natural Gas	5,724.1	GJ x 8% x	$13.216	=	6,051.98	5,724.1	GJ x 8% x	$13.963	=	6,394.05	$0.747	342.07	0.70%
19	Subtotal Commodity Related Charges per GJ					**$19,537.96**					**$19,880.03**		**$342.07**	**0.70%**
20														
21	Total *(with effective $/GJ rate)*	5,724.1		*$8.490*		**$48,597.70**	5,724.1		*$8.550*		**$48,939.77**	*$0.060*	**$342.07**	**0.70%**

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

Slight differences in totals due to rounding

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25

RATE SCHEDULE 5RNG - GENERAL FIRM RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025					PROPOSED APRIL 1, 2025 RATES					Annual Increase/Decrease		
1		Quantity		Rate		Annual $	Quantity		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge per Month	12	months x	$469.0000	=	$5,628.00	12	months x	$469.0000	=	$5,628.00	$0.0000	$0.00	**0.00%**
5	Rider 2 Clean Growth Innovation Fund Rate Rider per Month	12	months x	$0.4000	=	4.80	12	months x	$0.4000	=	4.80	$0.0000	0.00	0.00%
6	Subtotal of per Month Delivery Margin Related Charges					**$5,632.80**					**$5,632.80**		**$0.00**	**0.00%**
7														
8	Demand Charge per Month per GJ of Daily Demand	91.7	GJ x	$34.020	=	**$37,435.61**	91.7	GJ x	$34.020	=	**$37,435.61**	$0.000	**$0.00**	**0.00%**
9														
10	Delivery Charge per GJ	18,940.9	GJ x	$1.219	=	$23,089.02	18,940.9	GJ x	$1.219	=	$23,089.02	$0.000	$0.00	0.00%
11	Subtotal of Per GJ Delivery Margin Related Charges					**$23,089.02**					**$23,089.02**		**$0.00**	**0.00%**
12														
13	Commodity Related Charges													
14	Storage and Transport Charge per GJ	18,940.9	GJ x	$0.733	=	$13,883.72	18,940.9	GJ x	$0.733	=	$13,883.72	$0.000	$0.00	0.00%
15	Rider 6 MCRA per GJ	18,940.9	GJ x	($0.095)	=	(1,799.39)	18,940.9	GJ x	($0.095)	=	(1,799.39)	$0.000	0.00	0.00%
16	Rider 8 S&T RNG Rider	18,940.9	GJ x	$0.301	=	5,701.23	18,940.9	GJ x	$0.301	=	5,701.23	$0.000	0.00	0.00%
17	Subtotal Storage and Transport Related Charges per GJ					$17,785.55					$17,785.55		$0.00	0.00%
18														
19	Cost of Gas (Commodity Cost Recovery Charge) per GJ	18,940.9	GJ x 90% x	$2.230	=	$38,014.49	18,940.9	GJ x 90% x	$2.230	=	$38,014.49	$0.000	$0.00	0.00%
20														
21	Cost of Renewable Natural Gas	18,940.9	GJ x 8% x	$13.216	=	20,025.89	18,940.9	GJ x 8% x	$13.963	=	21,157.80	$0.747	1,131.91	0.80%
22	Subtotal Commodity Related Charges per GJ					**$75,825.93**					**$76,957.84**		**$1,131.91**	
23														
24	Total *(with effective $/GJ rate)*	18,940.9		*$7.496*		**$141,983.36**	18,940.9		*$7.556*		**$143,115.27**	*$0.060*	**$1,131.91**	**0.80%**

Slight differences in totals due to rounding

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

FORTISBC ENERGY INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES CHANGES
BCUC ORDERS G-XX-25

RATE SCHEDULE 7RNG - GENERAL INTERRUPTIBLE RENEWABLE NATURAL GAS SERVICE

Line No.	Particular	EXISTING RATES JANUARY 1, 2025				PROPOSED APRIL 1, 2025 RATES				Annual Increase/Decrease		
1		Quantity		Rate	Annual $	Quantity		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge per Month	12	months x	$880.0000 =	$10,560.00	12	months x	$880.0000 =	$10,560.00	$0.0000	$0.00	0.00%
5	Rider 2 Clean Growth Innovation Fund Rate Rider per Month	12	months x	$0.4000 =	4.80	12	months x	$0.4000 =	4.80	$0.0000	0.00	0.00%
6	Subtotal of per Month Delivery Margin Related Charges				**$10,564.80**				**$10,564.80**		**$0.00**	**0.00%**
7												
8	Delivery Charge per GJ	132,620.3	GJ x	$1.988 =	$263,649.23	132,620.3	GJ x	$1.988 =	$263,649.23	$0.000	$0.00	0.00%
9	Subtotal of Per GJ Delivery Margin Related Charges				**$263,649.23**				**$263,649.23**		**$0.00**	**0.00%**
10												
11	Commodity Related Charges											
12	Storage and Transport Charge per GJ	132,620.3	GJ x	$0.733 =	$97,210.71	132,620.3	GJ x	$0.733 =	$97,210.71	$0.000	$0.00	0.00%
13	Rider 6 MCRA per GJ	132,620.3	GJ x	($0.095) =	(12,598.93)	132,620.3	GJ x	($0.095) =	(12,598.93)	$0.000	0.00	0.00%
14	Rider 8 S&T RNG Rider	132,620.3	GJ x	$0.301 =	39,918.72	132,620.3	GJ x	$0.301 =	39,918.72	$0.000	0.00	0.00%
15	Subtotal Storage and Transport Related Charges per GJ				$124,530.50				$124,530.50		$0.00	**0.00%**
16												
17	Cost of Gas (Commodity Cost Recovery Charge) per GJ	132,620.3	GJ x 90% x	$2.230 =	$266,169.02	132,620.3	GJ x 90% x	$2.230 =	$266,169.02	$0.000	$0.00	0.00%
18												
19	Cost of Renewable Natural Gas	132,620.3	GJ x 8% x	$13.216 =	140,216.83	132,620.3	GJ x 8% x	$13.963 =	148,142.22	$0.747	7,925.39	0.98%
20	Subtotal Commodity Related Charges per GJ				**$530,916.35**				**$538,841.74**		**$7,925.39**	
21												
22	Total *(with effective $/GJ rate)*	132,620.3		*$6.071*	**$805,130.38**	132,620.3		*$6.131*	**$813,055.77**	*$0.060*	**$7,925.39**	**0.98%**

Slight differences in totals due to rounding

Notes: Commodity Cost Recovery Related Charge is based on 90% of the Cost of Gas (Commodity Cost Related Charge) per GJ, 8% of the Cost of RNG per GJ, and 2% RNG recovered through Rider 8 (Approved under BCUC Order G-325-24A).

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

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Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
2025 First Quarter Gas Cost Report and Rate Changes effective April 1, 2025
for the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On March 5, 2025, FortisBC Energy Inc. (FEI) filed its 2025 First Quarter Gas Cost Report on the Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) for the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area based on the five-day average February 13, 14, 18, 19, and 20, 2025 forward gas prices (Five-Day Average Forward Prices ending February 20, 2025) (altogether the First Quarter Report);

B. The British Columbia Utilities Commission (BCUC) established guidelines for gas cost rate setting in Letter L-5-01 dated February 5, 2001, and further modified the guidelines in Letter L-40-11 dated May 19, 2011 and Letter L-15-16 dated June 16, 2015 (together the Guidelines);

C. By Order G-244-23 dated September 14, 2023, the BCUC approved the current Commodity Cost Recovery Charge (CCRC) for the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area at $2.230 per gigajoule ($/GJ) effective October 1, 2023;

D. By Order G-160-24 dated June 13, 2024, the BCUC approved the current RNG Charge for Voluntary RNG service to non-NGV Sales customers for the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area at $13.216 per gigajoule ($/GJ) effective July 1, 2024, which was subsequently approved on a permanent basis pursuant to Order G-242-24, dated September 11, 2024;

E. In the First Quarter Report, using the Five-Day Average Forward Prices ending February 20, 2025, the CCRA is projected to have an after-tax surplus balance of approximately $29 million on March 31, 2025. FEI calculates the CCRA recovery-to-cost ratio at the existing rate would be 105.7 percent for the following 12 months, and the rate decrease related to the forecast over recovery of gas costs would be $0.121/GJ, which falls within the minimum rate change threshold set out in the Guidelines, indicating that no rate change to the Commodity Cost Recovery Charge is required at this time;

F. The First Quarter Gas Cost Report requests an increase to the RNG Charge for Voluntary RNG service to non-NGV Sales customers applicable to Rate Schedules 1RNG, 2RNG, 3RNG, 5RNG, 7RNG, and 46, within the Mainland and Vancouver Island service area and the Fort Nelson service area by $0.747/GJ, from $13.216/GJ to $13.963/GJ, effective April 1, 2025;

G. FEI requests that Tabs 3 and 4 of the First Quarter Report be kept confidential as they contain market sensitive information; and

H. The BCUC reviewed the First Quarter Report and considers the following determinations are warranted.

NOW THEREFORE pursuant to section 61(4) of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

1. FEI is approves the Commodity Cost Recovery Charge applicable to the Sales Rate Classes and Rate Schedule 46 LNG Service within the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area to remain unchanged at $2.230/GJ, effective April 1, 2025.

2. FEI is approved to increase the RNG Charge for Voluntary RNG service to non-NGV Sales customers for the Mainland and Vancouver Island Service Area, and the Fort Nelson Service Area by $0.747/GJ, from $13.216/GJ to $13.963/GJ, effective April 1, 2025.

3. FEI will notify all customers that are affected by the rate changes with a bill insert or bill message to be included with the next monthly gas billing.

4. The BCUC will hold confidential the information in Tabs 3 and 4 of the First Quarter Report, as requested by FEI, as it contains market sensitive information.

5. FEI is directed to file revised tariff pages with the BCUC within 15 days of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month) 2025.

BY ORDER

(X. X. last name)
Commissioner