EPCOR Natural Gas Limited Partnership

Southern Bruce

2026 Custom Incentive Rate Adjustment Application

EB-2025-0178

Rates Effective: January 1, 2026

Filed: August 1, 2025

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Certification of Evidence

The undersigned, being EPCOR Ontario Utilities Inc.'s Vice President, Ontario Region, Susannah Robinson hereby certifies for and on behalf of EPCOR Natural Gas Limited Partnership (ENGLP), as general partner of ENGLP that:

1. I am a senior officer of EPCOR Ontario Utilities Inc., which is the general partner of ENGLP;

2. ENGLP confirms that the documents filed in support of this application do not include any personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), that is not otherwise redacted in accordance with rule 9A of the OEB's Rules of Practice and Procedure;

3. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's Filing Requirements for Natural Gas Rate Applications dated February 16, 2017; and

4. The evidence submitted in support of ENGLP's 2026 Custom Incentive Rate Adjustment Application for its Southern Bruce operations is accurate consistent and complete to the best of my knowledge.

DATED this 1st day of August, 2025

Susannah Robinson
Vice President, Ontario Region
EPCOR Ontario Utilities Inc.

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 (Sched. B), as amended (the "**OEB Act**");

AND IN THE MATTER OF an application by EPCOR Natural Gas Limited Partnership pursuant to section 36(1) of the OEB Act for an order or orders approving or fixing just and reasonable rates and other charges for the sale and distribution of gas to be effective January 1, 2026 for the EPCOR Natural Gas Limited Partnership gas distribution system to serve the Municipality of Arran-Elderslie, the Municipality of Kincardine and the Township of Huron-Kinloss ("Southern Bruce Municipalities").

Application

1. The Applicant, EPCOR Natural Gas Limited Partnership ("**ENGLP**"), is a wholly-owned indirect subsidiary of EPCOR Utilities Inc. ("**EUI**"). The general partner of ENGLP is EPCOR Ontario Utilities Inc. an Ontario corporation, and the sole limited partner is EPCOR Commercial Services Inc. ("**ECSI**"), an Alberta corporation, which are both subsidiaries of EUI. ENGLP was formed pursuant to a limited partnership agreement, which provides that EPCOR Ontario Utilities Inc., as general partner, will control and have the full and exclusive power, authority and responsibility for the management and day-to-day operations of ENGLP. In accordance with the limited partnership agreement, ECSI, as limited partner, has an economic interest in the partnership but does not control or otherwise play a role in the day-to-day operations and management of EPCOR.

2. ENGLP filed a Custom Incentive Rate setting plan ("**Custom IR**") Application (EB-2018-0264) with the Ontario Energy Board ("**Board**") on October 2, 2018 (updated April 11, 2019) for Southern Bruce to seek approval for a tariff and other matters under which it would provide service to the Southern Bruce Municipalities. The Application sought approval for distribution rates based on a ten-year Custom IR effective January 1, 2019, establishment of certain deferral and variance accounts, approval of the proposed performance score card, and as well as further orders in all other respects to give effect to the proposals described in that Application and Evidence.

3. The parties to EB-2018-0264 submitted a settlement proposal on several issues. On October 3, 2019, the Board issued a Decision on Settlement Proposal and Procedural Order No. 6 in which it approved the settlement proposal. On November 28, 2019, the Board issued its Decision and Order in which it decided issues that were not settled in the approved settlement proposal and approved Southern Bruce's rates to be effective January 1, 2019 (the "**Rate Decision**"). A final Rate Order was issued on January 9, 2020.

4. Consistent with EB-2019-0264 (the Southern Bruce IRM Application), per the terms of the settlement proposal, and the Rate Decision, ENGLP will file an annual Incentive Rate Adjustment ("**IR**"). This IR is to be applied to the Monthly Fixed Charge and Delivery Charge in each rate class and the Authorized Overrun and Unauthorized Overrun charges for Rates 11 & 16. The agreed to formula for determining the IR is as follows:

Incentive Rate Adjustment (IR) = [(1.0 – 0.314) x 0.0127] + [0.314 x Inflation (I)]

5. The Inflation factor ("**I**") will equal the inflation value the Board determines each year in its annual generic inflation amount. ENGLP has used an inflation factor of 3.7%, which is the Input Price Index ("**IPI**") issued by the Board for the year 2026[1].

6. Specifically in this application, ENGLP is applying for:

   a) An order or orders granting that distribution rates be updated effective January 1, 2026 and adjusted in accordance with the EB-2018-0264 Decision and Order, including adjusting the Monthly Fixed Charge and Delivery Charge for each rate class and the Authorized Overrun and Unauthorized Overrun charges for Rates 11 & 16 by the IR factor as calculated in this application.

   b) Approval to dispose of eight approved deferral and variance accounts as part of this application (balances as of December 31, 2024):
      - Energy Content Variance Account ("**ECVA**");
      - Contribution in Aid of Construction Variance Account ("**CIACVA**");
      - Municipal Taxes Variance Account ("**MTVA**");

[1] Board Letter: 2026 Inflation Parameters, June 11 2025.

- Other Revenue Deferral Account (“**ORDA**”);
- Customer Volume Variance Account (“**CVVA**”);
- Unaccounted for Gas Variance Account (“**UFGVA**”);
- Storage and Transportation Variance Account R1/6/11 (“**S&TVA**”); and,
- Transportation Variance Account - R16 (“**TVA**”).

7. ENGLP has prepared an Excel workbook based on the 2026 Annual Incentive Rate Adjustment Model to support the calculation of rates in the Application. A live working version of this model has been filed as supporting material. A copy of the model is provided in **Appendix A**.

8. ENGLP seeks a Decision and Order by December 1, 2025 to ensure the rates can be implemented by January 1, 2026. In the event that the Board does not issue a rate order by December 1, 2025, ENGLP requests that the Board issue an Interim Rate Order declaring the current distribution rates as interim until the decided implementation date of the approved 2026 distribution rates.

9. In the event that the Board’s implementation date for 2026 distribution rates is later than the effective date, ENGLP requests permission to recover the incremental revenue from the effective date of January 1, 2026 to the implementation date through the implementation of a fixed-term rate rider.

10. ENGLP requests that, pursuant to Rule 32 of the Board’s Rules of Practice and Procedure, this proceeding be conducted by way of written hearing.

11. The persons affected by this Application are the ratepayers of ENGLP’s Southern Bruce service territory.

12. ENGLP confirms that the Application and related documents will be published on its website (EPCOR.com).

Application Contact Information

EPCOR requests that copies of all documents filed with the Board in connection with this proceeding be served as follows:

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Dated at Collingwood, Ontario this 1st day of August, 2025

EPCOR NATURAL GAS LIMITED PARTNERSHIP

T. H

Tim Hesselink
Senior Manager, Regulatory Affairs

Manager's Summary

Annual Incentive Rate Adjustment

The approved IR formula is as follows:

Incentive Rate Adjustment (IR) = [(1.0 – 0.314) x 0.0127] + [0.314 x Inflation (I)]

The Inflation factor ("**I**") will equal the inflation value the Board determines each year in its annual generic inflation amount.

In the Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, the Board adopted a 2-factor IPI methodology. The Board uses the year-over-year change in the GDP-IPI ("**FDD**"), and the Average Weekly Earnings ("**AWE**") of all employees in Ontario, to calculate the IPI. The percentage change is calculated as the weighted sum of 70% of the annual percentage change in the FDD for the prior year relative to the index value for two years prior and 30% of the annual percentage change in the AWE for the prior year relative to the data for years prior. For the purposes of this Application, ENGLP has used an inflation factor of 3.7%, which is the IPI issued by the Board for the year 2026.[2]

The calculation of the IR is as follows: I**R = [(1.0 – 0.314) x 0.0127] + [0.314 x 0.0370] = 0.0203**

The IR of 2.03% has been used in the 2026 Annual Incentive Rate Adjustment model to determine the proposed distribution rates. The IR has been applied to the Monthly Fixed Charge and Delivery Charge in each rate class. It has also been applied to the Authorized and Unauthorized Overrun Charges for Rate 11 and 16 Customers. For comparison purposes, the following Tables 1 and 2, provide the current and proposed distribution rates:

[2] Board Letter: 2025 Inflation Parameters, June 20 2024.

Table 1 - Current Distribution Rates

Rate Class	Fixed Monthly Base $/month	Delivery Charge Tier 1 ₵ / m3	Tier 2 ₵ / m3	Tier 3 ₵ / m3	Contract Demand ₵ /CD/m3	Upstream Recovery Charge (A)	Transp & Storage ₵ / m3	Transport – Dawn ₵ /CD/m3	Transport – Kirkwall ₵ /CD/m3	Transport – Parkway ₵ /CD/m3
Rate 1	28.00	29.9921	29.4012	28.5328		1.4740	2.6982			
Rate 6	114.17	27.6684	24.9017	23.6564		2.9200	5.6413			
Rate 11	228.35	17.1868	17.1868	17.1868		0.0352	1.8166			
Rate 16	1,678.98				114.5223	14.2434		18.2999	11.8480	11.8480

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

Table 2 - Proposed Distribution Rates

Rate Class	Fixed Monthly Base $/month	Delivery Charge Tier 1 ₵ / m3	Tier 2 ₵ / m3	Tier 3 ₵ / m3	Contract Demand ₵ /CD/m3	Upstream Recovery Charge (A)	Transp & Storage ₵ / m3	Transport – Dawn ₵ /CD/m3	Transport – Kirkwall ₵ /CD/m3	Transport – Parkway ₵ /CD/m3
Rate 1	28.57	30.6018	29.9990	29.1129		1.4740	2.6982			
Rate 6	116.49	28.2309	25.4079	24.1373		2.9200	5.6413			
Rate 11	232.99	17.5362	17.5362	17.5362		0.0352	1.8166			
Rate 16	1,713.12				116.8506	14.2434		18.2999	11.8480	11.8480

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

Monthly Fixed Charges in the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19 has been excluded from this comparison for both current and proposed rates.

Deferral and Variance Accounts

In Rate Order EB-2018-0264[3], ENGLP was granted approval to establish the following deferral and variance accounts:

a) Purchased Gas Commodity Variance Account;
b) Gas Purchase Rebalancing Account;
c) Storage and Transportation Variance Account for Rates 1, 6 and 11;
d) Transportation Variance Account for Rate 16;
e) Unaccounted for Gas Variance Account;
f) Greenhouse Gas Emissions Administration Deferral Account;
g) Federal Carbon Charge – Customer Variance Account;
h) Federal Carbon Charge – Facility Deferral/Variance Account;
i) Municipal Tax Variance Account;
j) Energy Content Variance Account;
k) Contribution in Aid of Construction Variance Account; and,
l) External Funding Variance Account.

In Rate Order EB-2021-0216[4], ENGLP was granted approval to establish the following deferral and variance accounts:

m) Approved Deferral/Variance Disposal Account; and,
n) Other Revenues Deferral Account.

In addition, ENGLP received approval to modify the wording of the Municipal Tax Variance Account to align with the intent of the original Common Infrastructure Plan ("**CIP**") decision.[5]

In the Decision & Order (Phase 2) EB-2022-0184[6], ENGLP was granted approval to establish the Customer Volume Variance Account.

[3] EB-2018-0264 Rate Order, January 9, 2020, Schedule B
[4] EB-2021-0216 Decision & Order, December 9, 2021, Page 9/EB-2021-0216 Rate Order, February 17, 2022 Page 5
[5] EB-2021-0216 Rate Order, February 17, 2022 Page 9
[6] EB-2022-0184 Decision & Order, Phase 2, Page 22, April 6, 2023

As part of this application, ENGLP is seeking approval for the disposition of the December 31, 2024 audited balances of the following deferral and variance accounts:

a) Energy Content Variance Account ("**ECVA**");
b) Contribution in Aid of Construction Variance Account ("**CIACVA**");
c) Municipal Tax Variance Account ("**MTVA**");
d) Other Revenue Deferral Account ("**ORDA**");
e) Customer Volume Variance Account ("**CVVA**");
f) Unaccounted for Gas Variance Account ("**UFGVA**");
g) Storage and Transportation Variance Account R1/6/11 ("**S&TVA**"); and,
h) Transportation Variance Account - R16 ("**TVA**").

The auditor's report on the December 31, 2024 balances for each of the accounts above has been included as part of this Application in **Appendix E**.

A summary of the account balances can be seen below in Table 3:

Table 3 – Deferral Accounts Requested for Disposition

	2024		**2025 Carrying Charges**				**Total**
	Principal	**Carrying Charges**	**Q1** 3.64%	**Q2** 3.16%	**Q3** 2.91%	**Q4** 2.91%	
CIACVA	$300,025	$0	$2,730	$2,370	$2,183	$2,183	$309,491
ECVA	$21,913	$0	$199	$173	$159	$159	$22,604
MTVA	($78,984)	$13,239	($719)	($624)	($575)	($575)	($68,237)
ORDA	($28,358)	($615)	($258)	($224)	($206)	($206)	($29,868)
CVVA	$552,604	$15,719	$5,029	$4,366	$4,020	$4,020	$585,757
UFGVA	($79,913)	($8,908)	($727)	($631)	($581)	($581)	($91,343)
	2024		**2025 Carrying Charges**				**Total**
	Principal	**Carrying Charges**	**Q1** 3.72%	**Q2** 3.72%	**Q3** 3.72%	**Q4** 3.72%	
S&TVA	$3,271,747	$308,464	$30,427	$30,427	$30,427	$30,427	$3,701,919
TVA	$381,952	$48,121	$3,552	$3,552	$3,552	$3,552	$444,282
Total	**$3,959,033**	**$327,898**	**$36,682**	**$35,857**	**$35,427**	**$35,427**	**$4,430,324**

With the exception of the TVA and S&TVA, as explained further in this section, the 2025 carrying charges have been calculated using the Board’s prescribed rates for Q1-Q3 and projected for Q4 2025 using the Q3 rate.

Q1	3.64%
Q2	3.16%
Q3	2.91%
Q4	2.91%
Annual	**3.16%**

An excel version of the calculation of all rate riders has been included in this application and secondary workbooks have been included for the S&TVA, TVA and CVVA deferral accounts due to their complexity:

ENGLP_APPL_2026 Custom IR_SB_DVA_Excel
ENGLP_APPL_2026 Custom IR_SB_CVVA_Excel
ENGLP_APPL_2026 Custom IR_SB_STVA_Excel

Finally, as part of the S&TVA disposition, ENGLP has included an analysis on the continuance of Compressed Natural Gas (“**CNG**”) included as **Appendix F** as instructed as part of ENGLP’s 2024 Gas Supply Plan[7].

[7] EB-2024-0139 OEB Staff Report to the Ontario Energy Board, February 28, 2025, Pages 32/33/41/42

Energy Content Variance Account

The ECVA records differences in variable revenues resulting from differences in the energy content of the gas actually delivered and the assumed energy content of 38.89MJ/M^3 used in determining ENGLP's revenue requirement and delivery rates as approved in EB-2018-0264. Differences in the energy content of the gas delivered from the assumed energy content would impact the actual volumes delivered, thereby impacting the amount of revenue collected over ENGLP's 10-year rate stability period.

As per the ECVA accounting order,[8] the audited balance in this account, together with carrying charges, will be brought forward for disposition on an annual basis. The balance in this account will be apportioned to Rates 1, 6 and 11 based on forecasted volumes underpinning CIP revenues for each rate class.

The calculation of the projected total amount proposed for disposal is summarized in Table 4 below and further details of the specific items making up these balances are provided in the continuity schedule in Appendix E.

Table 4 - Total ECVA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	$21,913		$21,913
Carrying Charges	$0	$691	$691
Total	**$21,913**	**$691**	**$22,604**

Balance Allocation:

ENGLP is proposing to allocate the balance in this account to Rates 1, 6 and 11 based on forecasted volumes underpinning CIP revenues for each rate class, consistent with the approved accounting order.

As per EB-2018-0264, Exhibit 3, Tab 1, Schedule 2, pg. 3, the CIP volumes for 2024 are:

[8] EB-2018-0264 Rate Order, January 9, 2020, page 30 of 34

Table 5 – CIP Forecasted Volumes

	Unit	Row Sum	Rate 1	Rate 6	Rate 11
Volume	000's m^3	16,247	11,436	3,458	1,353
Allocation	%	100%	70%	21%	8%
Total	**$**	**$22,604**	**$15,910**	**$4,811**	**$1,883**

Balance Recovery:

ENGLP proposes to recover the costs as allocated above from customers in Rates 1, 6 and 11 based on revised forecast volumes. ENGLP proposes to recover the ECVA balances through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2026. The calculation of the proposed rate rider is shown in Table 6 below.

Table 6 - Calculation of Proposed ECVA Rate Rider

	Unit	Row Sum	Rate 1	Rate 6	Rate 11
Volume	000's m^3	13,162	8,868	2,468	1,826
Allocation	%	100%	70%	21%	8%
Total	**$**	**$22,604**	**$15,910**	**$4,811**	**$1,883**
Rate Rider	**¢/m^3**		**0.1794**	**0.1949**	**0.1031**

Contribution in Aid of Construction Variance Account

The CIACVA records the revenue requirement impact of any differences between the actual capital contributions that ENGLP Southern Bruce pays to Enbridge Gas/Union Gas related to Enbridge's Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the capital contribution included for these projects for the purposes of determining ENGLP's approved rates.

As per the CIACVA accounting order,[9] the balance in this account, together with carrying charges, will be brought forward for disposition on an annual basis at which time ENGLP will propose a methodology and timing for disposition of the balance that aligns with customers' use of the capacity and ENGLP's rate smoothing objectives.

The calculation of the projected total amount proposed for disposal is summarized in Table 7 below and further details of the specific items making up these balances are provided in the continuity schedule in **Appendix E**.

Table 7 - Total CIACVA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	$300,025		$300,025
Carrying Charges	$0	$9,466	$9,466
Total	$300,025	$9,466	$309,491

Balance Allocation:

Consistent with the final decision of ENGLP's previous applications[10], ENGLP proposes to allocate the CIACVA balance based on the CIP distribution and non-distribution rate base for all rate classes.

[9] EB-2018-0264 Rate Order, January 9, 2020, page 30 of 34
[10] EB-2023-0161 Decision & Order, November 9, 2023, page 4

Referencing: EB-2018-0624, Exhibit 7, Tab 1, Schedule 2, Table 7-25:

Table 8 – CIP Rate Base

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Rate 16
Rate Base	$000's	$54,946	$32,657	$11,611	$1,418	$9,261
Allocation	%	100%	59%	21%	3%	17%
Total	**$**	**$309,491**	**$183,944**	**$65,398**	**$7,985**	**$52,163**

Balance Recovery:

ENGLP proposes to recover costs from customers in Rates 1, 6, 11 and 16 (all rate classes) based on revised forecast volumes allocated by rate base referenced in Table 8 above. ENGLP proposes to recover the CIACVA balances through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2026. The calculation of the proposed rate rider is shown in Table 9 below. Rate riders for Rates 1,6 & 11 are projected based on m^3 volumes and rate 16 is based on monthly contract demand ("**CD**").

Table 9 - Calculation of Proposed CIACVA Rate Rider

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Unit	Rate 16
Volume	000's m^3	13,162	8,868	2,468	1,826	CD	95,824
Allocation	%	100%	59%	21%	3%	%	17%
Total	**$**	**$309,491**	**$183,944**	**$65,398**	**$7,985**	**$**	**$52,164**
Rate Rider	**¢/m^3**		**2.0743**	**2.6496**	**0.4372**	**¢/CD/month**	**4.5364**

Municipal Tax Variance Account

The Board approved the MTVA in ENGLP's Custom IR application and this variance account was modified as part of the Decision and Order of Phase 2 of ENGLP's 2022 rate application[11].

In accordance with the approved accounting order, the MTVA records the difference between the actual annual municipal taxes paid, net of municipal contributions related to municipal taxes, and the net municipal taxes billed to customers by ENGLP. The effective date of this account is January 1, 2019.

The net municipal taxes billed to customers by ENGLP is calculated by multiplying the annual distribution revenues billed to customers and accrued for the year by the proportion of annual municipal taxes included in the annual revenue requirement for ENGLP's Southern Bruce operations as approved in EB- 2018-0264 for each year of the rate stability period.

The calculation of the projected total amount proposed for disposal is summarized in Table 10 below and further details of the specific items making up these balances are provided in the continuity schedule in **Appendix E**.

Table 10 - Total MTVA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	($78,984)		($78,984)
Carrying Charges	$13,239	($2,492)	$10,747
Total	($65,745)	($2,492)	($68,237)

Balance Allocation:

ENGLP proposes to allocate the MTVA balance based on the property tax allocation used in the customer IR application for all rate classes[12].

[11] EB-2021-0216, Decision and Order (Phase 1 and Phase 2), February 17, 2022, page 11 of 15
[12] EB-2018-0624, Exhibit 7, Tab 1, Schedule 2, Table 7-27

Table 11 – CIP Property Tax Allocations

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Rate 16
Property Taxes	$000's	$630.03	$338.90	$156.36	$19.14	$115.63
Allocation	%	100%	54%	25%	3%	18%
Total	**$**	**($68,237)**	**($36,705)**	**($16,935)**	**($2,073)**	**($12,524)**

Balance Recovery:

ENGLP proposes to recover costs from customers in Rates 1, 6, 11 and 16 (all rate classes) based on revised forecast volumes allocated by property tax referenced in Table 11 above. ENGLP proposes to recover the MTVA balances through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2026. The calculation of the proposed rate rider is shown in Table 12 below. Rate riders for Rates 1,6 & 11 are projected based on m^3 volumes and rate 16 is based on monthly CD.

Table 12 - Calculation of Proposed MTVA Rate Rider

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Unit	Rate 16
Volume	000's m^3	13,162	8,868	2,468	1,826	CD	95,824
Allocation	%	100%	54%	25%	3%	%	18%
Total	**$**	**($68,237)**	**($36,705)**	**($16,935)**	**($2,073)**	**$**	**($12,524)**
Rate Rider	**¢/m^3**		**(0.4139)**	**(0.6861)**	**(0.1135)**	**¢/CD/month**	**(1.0891)**

Other Revenue Deferral Account

The ORDA records customer service charge revenue amounts (as per the schedule of Miscellaneous and Service Charges on the Distributors approved rate order). For the duration of the 10-year rate stability period, ENGLP was approved to collect specific service charges as part of the Settlement Proposal. The Board approved $0 in Other Revenues for ratemaking purposes for the periods of 2019-2021 and also established a deferral account to track actual other revenues for the remaining years of the rate stability period.

As per the ORDA accounting order,[13] the audited balance in this account, together with carrying charges, will be brought forward for disposition on an annual basis and the manner of disposition will be proposed at the time the account is brought forward.

The calculation of the projected total amount proposed for disposal is summarized in Table 13 below and further details are provided in the continuity schedule in **Appendix E**.

Table 13 - Total ORDA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	($28,358)		($28,358)
Carrying Charges	($615)	($895)	($1,510)
Total	($28,973)	($895)	($29,868)

Balance Allocation:

ENGLP proposes to allocate the ORDA balance based on the CIP OM&A allocation for all rate classes[14], consistent with the EB-2023-0161 decision.[15]

Table 14 – CIP Rate Base

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Rate 16
OM&A	$000's	$5,653	$4,160	$938	$229	$327
Allocation	%	100%	74%	17%	4%	6%
Total	**$**	**($29,868)**	**($21,978)**	**($4,955)**	**($1,209)**	**($1,726)**

[13] EB-2018-0264 Rate Order, January 9, 2020, page 30 of 34
[14] EB-2018-0624, Exhibit 7, Tab 1, Schedule 2, Table 7-28
[15] EB-2023-0161 Decision & Order, November 9, 2023, pages 5-6

Balance Recovery:

ENGLP proposes to recover costs from customers in Rates 1, 6, 11 and 16 (all rate classes) based on revised forecast volumes allocated by rate base referenced in Table 14 above. ENGLP proposes to recover the ORDA balances through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2025. The calculation of the proposed rate rider is shown in Table 15 below. Rate riders for Rates 1,6 & 11 are projected based on m^3 volumes and Rate 16 is based on monthly CD.

Table 15 - Calculation of Proposed ORDA Rate Rider

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Unit	Rate 16
Volume	000's m^3	13,162	8,868	2,468	1,826	CD	95,824
Allocation	%	100%	74%	17%	4%	%	6%
Total	**$**	**($29,868)**	**($21,978)**	**($4,955)**	**($1,209)**	**$**	**($1,726)**
Rate Rider	**¢/m^3**		**(0.2478)**	**(0.2007)**	**(0.0662)**	**¢/CD/month**	**(0.1501)**

Customer Volume Variance Account

The CVVA records the variance in revenue by rate class resulting from the difference between customer volume forecast based on common assumptions and the Actual Normalized Average Customer Volume ("**NACV**") as defined below. This account will record such resulting variances in revenue for Rate 1 and Rate 6 since a common assumption related to customer usage volume was used for these rate classes in the development of the Common Infrastructure Plan as submitted by ENGLP in EB-2016-0137 / EB-2016-0138 / EB-2016-0139.

To ensure ENGLP retains the risk related to customer connection counts, for the purposes of calculating amounts to be recorded in the CVVA, the common assumption volumes per customer outlined in the accounting order will be applied to the actual customer connections for each corresponding customer segment and rate class to determine the "Common Assumptions Customer Volume".

The NACV shall be calculated as the actual average monthly consumption per customer, adjusting it to remove the impact of the Energy Content Variance Account ("**ECVA**"), and applying the weather normalization methodology. Differences are to be shared on a 50/50 basis between ENGLP and its customers.

Accordingly, the monthly balance to be recorded in this account will be calculated as 50% of the variance in revenue resulting in the difference between the Common Assumptions Customer Volume and the NACV, both determined in the applicable manner described above for Rate 1 and Rate 6 customers. The revenue difference shall be calculated by applying approved rate schedules (including volumetric charges, monthly fixed charges and the delay in revenue rate rider) to the calculated difference between the Common Assumptions Customer Volume and the NACV.

The calculation of the projected total amount proposed for disposal is summarized in Table 16 below and further details are provided in the continuity schedule in **Appendix E**. The supporting calculations for the CVVA are included in the excel workbook *ENGLP_APPL_2026 Custom IR_SB_CVVA_Excel*

ENGLP utilized the services of Power Advisory Inc. to complete the weather normalization calculation as part of the balance determination (consistent with ENGLP's Gas Supply Plan filing/forecast and the prior year).

Table 16 - Total CVVA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	$552,604		$552,604
Carrying Charges	$15,719	$17,435	$33,153
Total	$568,323	$17,435	$585,757

Return on Equity

As per the accounting order: *ENGLP shall only be eligible for the recovery of the annual net balance in the CVVA from its customers until such point that ENGLP's actual Return on Equity (ROE) reach 300 basis points below 8.78%, consistent with the ROE in the 10-year revenue requirement*[16]*.*

ENGLP's regulated net income was ($1.618M) loss in 2024, resulting in a calculated ROE of (4.75%). The addition of the $586K CVVA balance requested for disposition leaves the ROE as a negative balance. As such, the ROE deadband is not applicable for 2024.

	Without CVVA	With CVVA
Regulatory Net Income	($1,618,439)	($1,032,682)
Regulated Equity		
Opening Ratebase	$95,165,484	$95,165,484
Closing Ratebase	$94,223,330	$94,223,330
Mid-Year Ratebase	$94,694,407	$94,694,407
Equity Component	36%	36%
	$34,089,987	$34,089,987
ROE %	**-4.75%**	**-3.03%**

[16] EB-2022-0184 Accounting Order, October 26, 2023, Page 11.

Balance Allocation:

ENGLP proposes to allocate the CVVA balance to Rate 1 and Rate 6 customers, consistent with the NACV calculation as outlined in the accounting order[17]. The calculation results in the following amounts:

Table 17 – 2024 Calculated CVVA Amounts (100%)

	2024	
R1 RES	NAC REV	$3,840,138
	CIP REV	$4,868,856
	DIFFERENCE	**$1,028,718**
R1 COM	NAC REV	$232,578
	CIP REV	$267,134
	DIFFERENCE	**$34,557**
R1 Ag	NAC REV	$1,708
	CIP REV	$1,799
	DIFFERENCE	**$91**
R6 M COMM	NAC REV	$238,293
	CIP REV	$314,261
	DIFFERENCE	**$75,968**
R6 L COMM	NAC REV	$382,327
	CIP REV	$348,201
	DIFFERENCE	**($34,126)**
TOTAL	NAC REV	$4,695,044
	CIP REV	$5,800,252
	DIFFERENCE	**$1,105,208**

Table 18 – 2024 Calculated CVVA Amounts by Rate Class (50%)

CVVA Allocation	**2024 Actual**	**50% Recovery**	**Allocation**
R1	$ 1,063,366	$ 531,683	96%
R6	$ 41,842	$ 20,921	4%
Total	**$ 1,105,208**	**$ 552,604**	100%

[17] EB-2022-0184 Accounting Order, October 26, 2023, Pages 10-11

Balance Recovery:

Consistent with ENGLP's 2025 Custom IR update application[18], ENGLP proposes to recover the balance from customers in Rates 1 & 6 based on forecasted customer accounts, allocated by the calculations referenced in Table 18 above. ENGLP proposes to recover the CVVA balances through the implementation of a twelve-month fixed rate rider commencing on January 1, 2026. The calculation of the proposed rate rider is shown in Table 19 below.

Table 19 - Calculation of Proposed CVVA Rate Rider

	Unit	Row Sum	Rate 1	Rate 6
Customer Count	#	5,574	5,503	71
Allocation	%	100%	96%	4%
Total	**$**	**$585,757**	**$563,581**	**$22,176**
Rate Rider	**$ per month**		**$8.53**	**$26.03**

[18] EB-2024-0238 Decision & Rate Order, December 3, 2024, page 6

Unaccounted for Gas Variance Account

The UFGVA is to record the cost of gas for EPCOR Southern Bruce that is associated with volumetric variances between the actual volume of Unaccounted for Gas ("**UFG**") and the Board-approved UFG volumetric forecast included in the determination of rates. The effective date of this account is January 1, 2019.

The gas costs associated with the UFG variance will be calculated at the end of each calendar year based on the estimated volumetric variance between the applicable Board-approved level of UFG and the estimate of the actual UFG. The UFG annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGCVA reference price. If required, an adjustment will be made in the subsequent year to record any differences between the estimated UFG and actual UFG. Where there are recoveries of gas loss amounts invoiced as part of third-party damages, the gas loss amounts will be removed from the gas cost associated with UFG for the purposes of determining and recording a UFGVA balance.

The calculation of the projected total amount proposed for disposal is summarized in Table 20 below and further details of the specific items making up these balances are provided in the continuity schedule in **Appendix E**.

Table 20 - Total UFGVA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	($79,913)		($79,913)
Carrying Charges	($8,908)	($2,521)	($11,430)
Total	($88,821)	($2,521)	($91,343)

Balance Allocation:

ENGLP proposes to allocate the UFGVA balance based on the actual 2021-2024 volumes for all rate classes:

Table 21 – UFGVA Allocation - Historical Volumes

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Rate 16
Volume	000's m^3	28,971	16,497	4,578	5,479	2,417
Allocation	%	100%	57%	16%	19%	8%
Total	**$**	**($91,343)**	**($52,013)**	**($14,434)**	**($17,274)**	**($7,622)**

Balance Recovery:

ENGLP proposes to recover costs from customers in Rates 1, 6, 11 and 16 (all rate classes) based on revised forecast volumes allocated by rate base referenced in Table 21 above. ENGLP proposes to recover the UFGVA balances through the implementation of a twelve-month variable-rate rate rider commencing on January 1, 2026. The calculation of the proposed rate rider is shown in Table 9 below. Rate riders for Rates 1,6 & 11 are projected based on m^3 volumes and rate 16 is based on monthly CD.

Table 22 - Calculation of Proposed UFGVA Rate Rider

	Unit	Row Sum	Rate 1	Rate 6	Rate 11	Unit	Rate 16
Volume	000's m^3	13,162	8,868	2,468	1,826	CD	95,824
Allocation	%	100%	57%	16%	19%	%	8%
Total	**$**	**($91,342)**	**($52,013)**	**($14,434)**	**($17,274)**	**$**	**($7,621)**
Rate Rider	**¢/m^3**		**(0.5865)**	**(0.5848)**	**(0.9459)**	**¢/CD/month**	**(0.6628)**

Storage and Transportation Variance Account

The Storage and Transportation Variance Account for Rates 1, 6 & 11 (“**S&TVA Rates 1, 6 & 11**” or “**S&TVA**”)) is to record the difference between actual total upstream costs, including all Transportation and Storage Costs and Upstream Recovery Costs, incurred for all customers in Rates 1, 6 and 11 and the Upstream Charges (including all Upstream Recovery Charges and Transportation and Storage Charges) recovered from these customers. The S&TVA Rates 1, 6 & 11 records the difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow-through to customers. The effective date of this account is January 1, 2019.

The S&TVA Rates 1, 6 & 11 will record: (a) the variance between the forecast storage and transportation demand levels and the actual storage and transportation demand levels; (b) amounts credited or invoiced from storage and transportation suppliers related to the disposition of the suppliers’ deferral/variance accounts; (c) the variance between the forecasted commodity cost for fuel and the updated reference price set through the Quarterly Rate Adjustment Mechanism (QRAM) process; and (d) the variance between the forecast and actual administrative costs for storage and transportation including costs associated with daily nominations, load balancing, and storage procurement.

The calculation of the projected total amount proposed for disposal is summarized in Table 23 below and further details of the specific items making up these balances are provided in the continuity schedule in **Appendix E**.

Table 23 - Total S&TVA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	$3,271,747		$3,271,747
Carrying Charges	$308,464	$121,709	$430,173
Total	$3,580,210	$121,709	$3,701,919

Due to the complexity and various elements included in this account, ENGLP has included a stand-alone workbook calculating each element of inclusion in this deferral account. Refer to excel workbook *ENGLP_APPL_2026 Custom IR_SB_STVA_Excel.*

Transportation & Storage:

ENGLP is requesting recovery of $2,310,282 related to shortfalls of transportation, storage, nomination, gas supply and CNG incurred for the period of 2020-2024:

Table 24 - S&TVA - Transportation Costs and Revenue

	2020 Total	**2021 Total**	**2022 Total**	**2023 Total**	**2024 Total**
Storage	$54,077	$85,496	$86,224	$86,015	$85,909
Transportation	$98,472	$295,538	$285,072	$308,494	$324,986
Nomination/ECNG	$15,741	$39,042	$45,579	$53,288	$56,956
Gas Supply	$118,785	$199,475	$255,603	$251,943	$189,003
CNG	$0	$0	$0	$0	$127,333
Total Cost	**$287,075**	**$619,551**	**$672,478**	**$699,740**	**$784,187**
Revenue	**$2,129**	**$34,033**	**$171,843**	**$239,462**	**$305,281**
Variance	$284,945	$585,518	$500,635	$460,278	$478,906
Cumulative Variance	$284,945	$870,463	$1,371,098	$1,831,376	$2,310,282

Transportation & Storage: As part of the M17 Transportation rate from Enbridge Gas, ENGLP incurs costs based on the Rate 1/6/11 customers share of the overall CD.

Nomination/ECNG: ENGLP also pays a nomination fee for all volumes ($0.04/GJ) along with a fee for consulting services including:

- A strategy to acquire the necessary services to meet the 5 year Demand Forecast (under a variety of weather and operating conditions), taking into account varying usage patterns due to variations in weather, average use per customer and growth rates
- Levels of seasonal storage needed to manage system supply requirements (including injection, withdrawal and space parameters).
- Level of Hub Services to manage variations in load.
- Amount of upstream transportation required on Enbridge to meet projected design day hourly demands.

Gas Supply: ENGLP has included incremental internal costs related to gas supply administration costs, consistent with the October 1, 2020 QRAM filing[19] (which also refers to the incremental ECNG costs included in the previous category:

In response to questions from OEB staff regarding the use of S&TVA Rates 1, 6 &11 to track the incremental administrative costs associated with the procurement of gas supply, ENGLP indicated that the purpose of the S&TVA Rate 1, 6, & 11 is to record the difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow-through to customers. ENGLP opined that it considers the gas supply administration costs as an integral component of providing upstream services. ENGLP stated that with the exception of the ECNG nomination fee, the incremental gas supply administrative costs were not included as part of the existing Upstream Recovery charge at the time of its Customer IR application as the decision on whether ENGLP is to operate under the Rate M17 was not approved by the OEB until April 2020.4 As the Rate M17 is a point-to-point transportation service agreement, ENGLP stated that it is responsible to administer the gas supply function, which also includes procurement. ENGLP agreed to separately track the gas supply administration costs in the S&TVA Rate 1, 6 & 11.

The OEB agrees with ENGLP that the incremental costs to administer the gas supply function would not have been known by ENGLP at the time of its Custom IR application as it preceded the approval of the Rate M17 which applies to ENGLP. The OEB also agrees that reasonable administrative costs associated with the gas supply function ought to be recoverable in rates or in a similar manner as proposed by ENGLP as they are necessary to provide upstream services. While the OEB is not making a determination in this application on the prudence of the costs incurred, the OEB will approve the inclusion of the incremental gas supply administrative costs in the S&TVA Rates 1, 6 & 11 for future disposition. ENGLP is requested to maintain detailed tracking and records to support amounts that have been recorded, for the OEB's future consideration. ENGLP may seek disposition of the balance in the variance account in a future IRM application where the prudence of these incremental administrative costs would be examined.

The costs included are the actual costs incurred during the period of 2020-2024.

[19] EB-2020-0206 Decision & Interim Rate Order, September 24, 2020, pages 3-4

Compressed Natural Gas ("CNG"): In 2024, ENGLP procured CNG on a pilot basis during periods of non-coincident peak demand. In the 2023-24 fall/winter season, ENGLP experienced delivery pressure issues in the southern parts of its distribution system. Given the expected growth of the system this year beyond what was contemplated in the CIP (largely concentrated in the southern part of its system), there is a possibility further pressure issues may present itself again in the southern end of the system during periods of non-coincident peak demand. To mitigate the risk of system deliverability issues in the southern end of the system, ENGLP entered into an agreement to provide CNG during this fall season.

In the 2024 OEB Staff report (which the OEB supported), the following recommendations were provided:[20]

OEB staff is of the view that EPCOR's proposed pilot program to use CNG for Southern Bruce is appropriate as a temporary measure for the 2024 heating season and that EPCOR should complete an analysis of options to alleviate the pressure issues. OEB staff believes that EPCOR be allowed to recuperate costs, both commodity and transportation, associated with the CNG pilot program for the 2024 heating season, pending a prudence review on the transportation cost in its annual IRM application.

OEB staff recommends that the OEB request EPCOR file its analysis and recommendations in its 2026 IRM application (expected to be filed in July 2025). EPCOR, in its January 2025 QRAM (approved on an interim basis), stated that CNG was used from October to December 2024, so presumably EPCOR will seek to dispose of the S&TVA where the CNG transportation costs are held in its upcoming IRM application for 2026 rates. This would allow for thorough testing of the evidence without needing to wait until after the 2025 GSP consultation is completed (which may include a recommendation that the issue go to a hearing).

Summary (page 41/42):

- *EPCOR's proposed pilot program to use CNG for Southern Bruce is reasonable as a temporary measure and its use for the 2024/25 planning period should be made final.*
- *EPCOR should complete an analysis of options to alleviate the pressure issue for future*

[20] EB-2024-0139 OEB Staff Report to the Ontario Energy Board, February 28, 2025, Pages 32/33/41/42

planning periods as part of EPCOR's 2026 IRM filing. This includes cost estimates, timelines, recommendations, and any available historical or forecast information on the low-pressure system.

ENGLP has included this requested analysis as **Appendix F** in this application.

The costs referenced above are offset by revenue collected using ENGLP's approved transportation rate.

Upstream Recovery:

ENGLP has set its Upstream Recovery Charges so as to defer the recovery of a portion of the Upstream Recovery Costs related to the CIAC paid to Enbridge Gas/Union Gas for the Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the additional capacity ENGLP was required to contract with Enbridge Gas/Union Gas initially in order to provide service to its customer base in future years.

Table 25 - S&TVA - Upstream Costs and Revenue

	2020 Total	2021 Total	2022 Total	2023 Total	2024 Total
CIAC Revenue Requirement	$370,518	$242,236	$238,143	$234,050	$229,957
Revenue	($173)	$16,368	$76,945	$110,993	$149,306
Variance	$370,691	$225,869	$161,198	$123,056	$80,651
Cumulative Variance	$370,691	$596,559	$757,757	$880,814	$961,464

The S&TVA portion of the upstream CIAC revenue requirement has been calculated using the depreciation and return on rate base (debt and equity) as per ENGLP's EB-2018-0264 application[21] and allocated based on the Enbridge CIAC allocation of rate base.[22]

[21] EB-2018-0264, Exhibit 2, Tab 1, Schedule 2, Tables 2-9 & 2-10, April 11, 2019, Pages 2-3 of 10
[22] EB-2018-0264, Exhibit 7, Tab 1, Schedule 2, Tables 2-25, April 11, 2019, Pages 10 of 21

Table 26 - S&TVA - CIAC Rate Base

	Unit	Sum	Rate 1	Rate 6	Rate 11	Rate 16
Rate Base - ENG	$000's	4,186	1,579	959	0.0000	1,648
Allocation	%	100%	38%	23%	0%	39%

These costs are offset by revenue collected using ENGLP's approved upstream revenue rate.

Carrying Charges:

Consistent with the accounting order, *ENGLP has calculated carrying charges the opening monthly balance of this account using the Board approved interest rate for long term debt and is using the Board's approved interest rate for long term debt as the balance of this deferral account will be financed over a long term period (i.e. remaining life of 30-year upstream transportation contract).*

ENGLP has used a rate of 3.72% to calculate carrying charges on this deferral account.[23]

Balance Allocation:

ENGLP is proposing to allocate the S&TVA balance to rates 1/6/11 based on the following:

Allocation of the Storage and Transportation related balances (including nomination/gas supply and CNG). Source: EB-2018-0624, Exhibit 3, Tab 1, Schedule 2, Table 3-9 - Throughput Volumes by Rate Class:

Table 27 - S&TVA Allocation - Transportation & Storage

	Unit	Row Sum	Rate 1	Rate 6	Rate 11
Volume	000's m^3	127,861	90,784	26,453	10,624
Allocation	%	100%	71%	21%	8%
Total	**$**	**$2,592,739**	**$1,840,909**	**$536,405**	**$215,424**

Allocation of the Upstream Charge related balances. Source: EB-2018-0624, Exhibit 7, Tab 1,

[23] EB-2018-0264, Exhibit 5, Tab 1, Schedule 1, Tables 5-1, April 11, 2019, Pages 1 of 2

Schedule 2, Table 7-24 - Enbridge CIAC Rate Base

Table 28 - S&TVA Allocation - Upstream Recovery

	Unit	Row Sum	Rate 1	Rate 6	Rate 11
Volume	$000's	2,538	1,579	959	0
Allocation	%	100%	62%	38%	0%
Total	**$**	**$1,109,181**	**$689,957**	**$419,224**	**$0**

This results in a combined allocation of:

Table 29 - S&TVA Allocation - Combined

	Unit	Row Sum	Rate 1	Rate 6	Rate 11
Allocation	%	100%	68%	26%	6%
Total	**$**	**$3,701,919**	**$2,530,866**	**$955,629**	**$215,424**

Balance Recovery:

Consistent with the accounting order, *ENGLP proposes to bring forward the balance in this account, together with any carrying charges for disposition after the maximum balance has been reached. The balance in this account together with any carrying charges will be collected over the remaining life of the 30-year upstream transportation contract with Enbridge Gas/Union Gas.*

ENGLP has calculated a rate rider for the 2024 balance based on the 2024 weather normalized volumes prorated as a portion of the remaining duration of the 30-year upstream contract.

Agreement Commence	19-Nov-20	
Agreement Conclude	19-Nov-50	(30 years)
Rate Rider Commence	1-Jan-26	
Rate Rider Conclude	19-Nov-50	
Months	299	

Table 30 - Calculation of Proposed S&TVA Rate Rider

	Unit	Row Sum	Rate 1	Rate 6	Rate 11
Volume	000's m^3	13,162	8,868	2,468	1,826
Allocation	%	100%	68%	26%	6%
Total	**$**	**$148,572**	**$101,573**	**$38,353**	**$8,646**
Rate Rider	**¢/m^3**		**1.1454**	**1.5539**	**0.4734**

Future Years:

As per the accounting order, *when the balance in this account is brought forward for disposition ENGLP will also bring forward a proposal for the treatment of the variances related to upstream costs for these customers in subsequent years. This proposal will recognize that variances related to upstream costs in subsequent years should no longer be materially impacted by the deferred recovery of the Upstream Recovery Costs and therefore would more appropriately be brought forward for disposition on an annual basis and recovered over a shorter term.*

ENGLP is proposing to recover an equivalent portion of the balance annually until November 30, 2050 (12 of 119 months equaling $148,572 in a full year). ENGLP also recommends recalculating the rate rider annually as customer volumes may fluctuate over the long length of recovery as per the accounting order.

ENGLP also proposes to track the recovery in a separate sub-account in the existing Approved Deferral and Variance Account Disposition Account (“**ADVADA**”).

For the remaining years, ENGLP proposes to dispose of the S&TVA on an annual basis, consistent with the basis of the accounting order. The calculation of the S&TVA balance for disposition will be the equivalent of the annual total, with the appropriate share of the initial disposition included. For example, if the December 2025 balance is $100,000, the total disposition request will be the $100,000 + $148,572 calculated above for a total of $248,572. This will compensate for changes in load/CD that will be experienced.

Transportation Variance Account

The TVA for Rate 16 ("**TVA Rate 16**" or "**TVA**") records the difference between actual total upstream costs, including all Transportation Costs and Upstream Recovery Costs, incurred for all customers in Rate 16 and the Upstream Charges (including all Upstream Recovery Charges and Transportation Charges) recovered from these customers. The TVA Rate 16 records difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow- through to customers. The effective date of this account is January 1, 2019.

The TVA Rate 16 will record, as applicable: (a) the variance between the forecast transportation demand levels and the actual transportation demand levels; (b) amounts credited or invoiced from transportation suppliers related to the disposition of the suppliers' deferral/variance accounts; (c) the variance between the forecasted commodity cost for fuel and the updated reference price set through the Quarterly Rate Adjustment Mechanism (QRAM) process; and (d) the variance between the forecast and actual administrative gas supply costs including costs associated with daily nominations and load balancing.

The calculation of the projected total amount proposed for disposal is summarized in Table 31 below and further details of the specific items making up these balances are provided in the continuity schedule in **Appendix E**.

Table 31 - Total TVA Balance Requested for Disposition

	2024 Balance	2025 Carrying Charges	2025 Balance
Principal	$381,952		$381,952
Carrying Charges	$48,121	$14,209	$62,329
Total	**$430,073**	**$14,209**	**$444,282**

As noted with the S&TVA, due to the complexity and various elements of this account, ENGLP has included a stand-alone workbook calculating each element of inclusion in this deferral account. Refer to workbook *ENGLP_APPL_2026 Custom IR_SB_STVA_Excel.*

Transportation:

ENGLP is requesting recovery of $222,303 related to shortfalls for transportation costs incurred for the period of 2020-2024:

Table 32 - TVA - Transportation Costs and Revenue

	2020 Total	2021 Total	2022 Total	2023 Total	2024 Total
Storage	$0	$0	$0	$0	$0
Transportation	$51,570	$210,464	$229,295	$238,507	$247,539
Nomination/ECNG	$11,618	$31,245	$32,197	$30,740	$30,533
Gas Supply	$0	$0	$0	$0	$0
CNG	$0	$0	$0	$0	$0
Total Cost	**$63,188**	**$241,709**	**$261,493**	**$269,246**	**$278,072**
Revenue	**$57,522**	**$190,671**	**$220,691**	**$212,093**	**$210,428**
Variance	$5,665	$51,038	$40,802	$57,154	$67,643
Cumulative Variance	$5,665	$56,703	$97,506	$154,659	$222,303

Transportation: As part of the M17 Transportation rate from Enbridge Gas, ENGLP incurs costs based on the Rate 16 customers share of the overall CD.

Nomination/ECNG: ENGLP also pays a nomination fee for all volumes ($0.04/GJ) along with a fee for consulting services including:

- A strategy to acquire the necessary services to meet the 5 year Demand Forecast (under a variety of weather and operating conditions), taking into account varying usage patterns due to variations in weather, average use per customer and growth rates
- Levels of seasonal storage needed to manage system supply requirements (including injection, withdrawal and space parameters).
- Level of Hub Services to manage variations in load.
- Amount of upstream transportation required on Enbridge to meet projected design day hourly demands.

These costs are offset by transportation revenue collected using ENGLP's approved transportation rate.

Upstream Recovery:

Similar to the S&TVA, ENGLP has set its Upstream Recovery Charges so as to defer the recovery of a portion of the Upstream Recovery Costs related to the CIAC paid to Enbridge Gas/Union Gas for the Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the additional capacity ENGLP was required to contract with Enbridge Gas/Union Gas initially in order to provide service to its customer base in future years.

Table 33 - TVA - Upstream Costs and Revenue

	2020 Total	2021 Total	2022 Total	2023 Total	2024 Total
CIAC Revenue Requirement	$240,523	$157,249	$154,592	$151,934	$149,277
Revenue	$44,772	$148,405	$171,900	$165,065	$163,783
Variance	$195,751	$8,843	($17,309)	($13,130)	($14,506)
Cumulative Variance	$195,751	$204,595	$187,286	$174,156	$159,650

The TVA Rate 16 portion of the upstream CIAC revenue requirement has been calculated using the depreciation and return on rate base (debt and equity) as per ENGLP's EB-2018-0264 application[24] and allocated based on the Enbridge CIAC allocation of rate base.[25]

Table 34 - TVA - CIAC Rate Base

	Unit	Sum	Rate 1	Rate 6	Rate 11	Rate 16
Rate Base - ENG	$000's	4,186	1,579	959	0.0000	1,648
Allocation	%	100%	38%	23%	0%	39%

These costs are offset by revenue collected using ENGLP's approved upstream revenue rate.

[24] EB-2018-0264, Exhibit 2, Tab 1, Schedule 2, Tables 2-9 & 2-10, April 11, 2019, Pages 2-3 of 10
[25] EB-2018-0264, Exhibit 7, Tab 1, Schedule 2, Tables 2-25, April 11, 2019, Pages 10 of 21

Carrying Charges:

Consistent with the accounting order, *ENGLP has calculated carrying charges the opening monthly balance of this account using the Board approved interest rate for long term debt and is using the Board's approved interest rate for long term debt as the balance of this deferral account will be financed over a long term period (i.e. remaining life of 30-year upstream transportation contract).*

ENGLP has used a rate of 3.72% to calculate carrying charges on this deferral account.[26]

Balance Allocation:

Summarizing the variances in the previous two sections, the balance in the TVA is allocated 100% to Rate 16 customers:

Table 35 - TVA Allocation

	Unit	**Row Sum**	**Rate 16**
Allocation	%	100%	100%
Total	**$**	**$444,282**	**$444,282**

Balance Recovery:

Consistent with the accounting order, *ENGLP proposes to bring forward the balance in this account, together with any carrying charges for disposition after the maximum balance has been reached. The balance in this account together with any carrying charges will be collected over the remaining life of the 30-year upstream transportation contract with Enbridge Gas/Union Gas.*

ENGLP has calculated a rate rider for the 2024 balance based on the current CD levels prorated as a portion of the remaining lives of the 15-year contracts with Rate 16 customers.

Agreement Commence	19-Nov-20	
Agreement Conclude	19-Nov-35	(15 years)
Rate Rider Commence	1-Jan-26	
Rate Rider Conclude	19-Nov-35	
Months	119	

[26] EB-2018-0264, Exhibit 5, Tab 1, Schedule 1, Tables 5-1, April 11, 2019, Pages 1 of 2

Table 36 - Calculation of Proposed TVA Rate Rider

	Unit	Row Sum	Rate 16
Volume	CD	95,824	95,824
Allocation	%	100%	100%
Total	**$**	**$444,286**	**$444,286**
Rate Rider	**¢/CD/month**		**3.8962**

Future Years:

As per the accounting order, *when the balance in this account is brought forward for disposition ENGLP will also bring forward a proposal for the treatment of the variances related to upstream costs for these customers in subsequent years. This proposal will recognize that variances related to upstream costs in subsequent years should no longer be materially impacted by the deferred recovery of the Upstream Recovery Costs and therefore would more appropriately be brought forward for disposition on an annual basis and recovered over a shorter term.*

ENGLP is proposing to recover an equivalent portion of the balance annually until November 30, 2035 (12 of 119 months equaling $44,802 in a full year). ENGLP also recommends recalculating the rate rider annually as customer CD may fluctuate over the long length of recovery as per the accounting order.

ENGLP also proposes to track the recovery in a separate sub-account in the existing ADVADA.

For remaining years, ENGLP proposes to dispose of the TVA on an annual basis, consistent with the basis of the accounting order. The calculation of the TVA balance for disposition will be the equivalent of the annual total, but the appropriate share of the initial disposition. For example, if the December 2025 balance is $100,000, the total disposition request will be the $100,000 + $44,802 calculated above for a total of $144,802. This will compensate for changes in load/CD that will be experienced.

Bill Impacts

The following table provides a summary of bill impacts for each rate class assuming the average consumption level of the rate class based on the forecasted 2026 customer connections and volumes. The bill impact provided assumes a full 12 months of distribution service and consumption. Further details on the bill impacts as summarized below are provided in the 2026 Incentive Rate Adjustment Model.

Table 37 – Illustrative Bill Impact Summary

Rate Class		Fixed Charge ($/year)	Fixed Charge (%)	Volumetric Charge ($/year)	Volumetric Charge (%)	Rate Riders ($/year)	Rate Riders (%)	Total ($/year)	Total (%)
Rate 1	Residential	$6.83	2%	$8.61	2%	$28.90	23%	$44.34	4%
Rate 1	Small Commercial	$6.83	2%	$25.02	2%	$11.30	5%	$43.14	2%
Rate 1	Small Agricultural	$6.83	2%	$44.42	2%	($9.79)	-2%	$41.46	1%
Rate 6	Medium Commercial	$27.85	2%	$116.52	2%	$606.36	111%	$750.73	5%
Rate 6	Large Commercial	$27.85	2%	$399.41	2%	$15.43	0%	$442.70	1%
Rate 11	Sample Dryer 1	$55.71	2%	$354.65	2%	($967.52)	-68%	($557.16)	-1%
Rate 11	Sample Dryer 2	$55.71	2%	$1,182.17	2%	($3,225.07)	-68%	($1,987.20)	-1%
Rate 16	Contracted Demand	$409.61	2%	$13,969.57	2%	$4,418.52	13%	$18,797.70	2%

Appendix A - 2026 Annual Incentive Rate Adjustment Model

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Distributor Information

Distributor Name	EPCOR Natural Gas Limited Partnership
OEB Application Number	EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

A1.1 Distributor Information

Current Distribution Tariff Sheet Rates

Rate Class		Fixed Monthly Base $/month	Delivery Charge Tier 1 ¢ / m3	Tier 2 ¢ / m3	Tier 3 ¢ / m3	Delivery Charge Contract Demand ¢ /contracted m3	Upstream Recovery Charge (A)	Transportation & Storage Charge ¢ / m3	Transportation Charge From Dawn ¢ /contracted m3	Transportation Charge From Kirkwall ¢ /contracted m3	Transportation Charge From Parkway ¢ /contracted m3
Rate 1	General Firm Service	28.00	29.9921	29.4012	28.5328		1.4740	2.6982			
Rate 6	Large Volume General Firm Service	114.17	27.6684	24.9017	23.6564		2.9200	5.6413			
Rate 11	Large Volume Seasonal Service	228.35	17.1868	17.1868	17.1868		0.0352	1.8166			
Rate 16	Contracted Firm Service	1,678.98				114.5223	14.2434		18.2999	11.8480	11.8480

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Billing Determinants

Rate Class		Fixed Monthly Base	Delivery Charge Tier 1	Delivery Charge Tier 2	Delivery Charge Tier 3	Delivery Charge Contract Demand
Rate 1	General Firm Service	5,572	5,233,469	3,538,635	95,604	
Rate 6	Large Volume General Firm Service	72	607,190	1,243,389	617,622	
Rate 11	Large Volume Seasonal Service	10			1,826,281	
Rate 16	Contracted Firm Service	3				95,824

Source: EB-2025-0140 Gas Supply Plan Load Forecast - 2026 Forecast

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Forecasted Revenue from Current Rates

Months / Year	12
	EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate Class		Fixed Monthly Base	Bill 32 Rate	Delivery Charge Tier 1	Delivery Charge Tier 2	Delivery Charge Tier 3	Delivery Charge Contract Demand	Upstream Recovery Charge	Transportation & Storage Charge (A)	Total
Rate 1	General Firm Service	1,872,024	0	1,569,626	1,040,402	27,278	0	121,909	223,158	6,416,610
Rate 6	Large Volume General Firm Service	98,645	0	168,000	309,625	146,107	0	65,062	125,697	1,334,006
Rate 11	Large Volume Seasonal Service	27,401	0	0	0	313,879	0	504	26,012	638,264
Rate 16	Contracted Firm Service	60,443	0	0	0	0	1,316,879	163,783	210,428	1,751,534
Total Revenue		2,058,514	0	1,737,626	1,350,027	487,264	1,316,879	351,258	585,295	10,140,413

(A) Transportation & Storage for Rates 1, 6, and 11. Transportation only for Rate 16.

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Current Rate Riders

Delay in Revenue Recovery Rate Rider

Rate 1 | General Firm Service	1.6330	Cents/m3
Rate 6 | Large Volume General Firm Service	0.9090	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.5524	Cents/m3
Rate 16 | Contracted Firm Service	0.0601	$/contracted demand m3

Energy Content Variance Account (ECVA)

Rate 1 | General Firm Service	0.2481	Cents/m3
Rate 6 | Large Volume General Firm Service	0.2815	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.1847	Cents/m3
Rate 16 | Contracted Firm Service	0.0000	Cents/contracted demand m3

Contribution in Aid of Construction Variance Account (CIACVA)

Rate 1 | General Firm Service	2.3088	Cents/m3
Rate 6 | Large Volume General Firm Service	3.0469	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.5789	Cents/m3
Rate 16 | Contracted Firm Service	4.7092	Cents/contracted demand m3

Municipal Tax Variance Account (MTVA)

Rate 1 | General Firm Service	0.5052	Cents/m3
Rate 6 | Large Volume General Firm Service	0.8651	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.1648	Cents/m3
Rate 16 | Contracted Firm Service	1.2397	Cents/contracted demand m3

Other Revenue Deferral Account (ORDA)

Rate 1 | General Firm Service	(0.2738)	Cents/m3
Rate 6 | Large Volume General Firm Service	(0.2291)	Cents/m3
Rate 11 | Large Volume Seasonal Service	(0.0870)	Cents/m3
Rate 16 | Contracted Firm Service	(0.1547)	Cents/contracted demand m3/month

Customer Volume Variance Account (CVVA)

Rate 1 | General Firm Service	5.3700	$/Month
Rate 6 | Large Volume General Firm Service	-43.4600	$/Month

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

2026 OEB Inflation Factor **3.70%**

Incentive Rate Adjustment (IR) = [(1.0 – 0.314) x 0.0127] + [0.314 x Inflation (I)]

1.00	-0.314	0.0127	+	0.3140
	0.69	0.0127		0.0116
		0.0087		0.0116

2026 PCA Used in Application **2.03%**

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 1 Incentive Rate Adjustment
D1.1 Rate 1 Adjustment

Incentive Rate Adjustment	2.03%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	28.00	2.03%	28.57	5,572	1,910,082
Tier 1	cents / m3	29.9921	2.03%	30.6018	5,233,469	1,601,537
Tier 2	cents / m3	29.4012	2.03%	29.9990	3,538,635	1,061,553
Tier 3	cents / m3	28.5328	2.03%	29.1129	95,604	27,833
Upstream Recovery Charge	cents / m3	1.4740	0.00%	1.4740	8,270,620	121,909
Transportation & Storage Charge	cents / m3	2.6982	0.00%	2.6982	8,270,620	223,158
						6,575,149

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 6 Incentive Rate Adjustment

D1.2 Rate 6 Adjustment

Incentive Rate Adjustment	2.03%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	114.17	2.03%	116.49	72	100,651
Tier 1	cents / m3	27.6684	2.03%	28.2309	607,190	171,415
Tier 2	cents / m3	24.9017	2.03%	25.4079	1,243,389	315,919
Tier 3	cents / m3	23.6564	2.03%	24.1373	617,622	149,077
Upstream Recovery Charge	cents / m3	2.9200	0.00%	2.9200	2,228,157	65,062
Transportation & Storage Charge	cents / m3	5.6413	0.00%	5.6413	2,228,157	125,697
						1,349,556

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 11 Incentive Rate Adjustment

D1.3 Rate 11 Adjustment

Incentive Rate Adjustment	2.03%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	228.35	2.03%	232.99	10	27,958
Tier 1	cents / m3	17.1868	2.03%	17.5362	0	0
Tier 2	cents / m3	17.1868	2.03%	17.5362	0	0
Tier 3	cents / m3	17.1868	2.03%	17.5362	1,826,281	320,260
Upstream Recovery Charge	cents / m3	0.0352	0.00%	0.0352	1,431,902	504
Transportation & Storage Charge	cents / m3	1.8166	0.00%	1.8166	1,431,902	26,012
						645,322

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 16 Incentive Rate Adjustment

D1.4 Rate 16 Adjustment

Incentive Rate Adjustment	2.03%
Months / Year	12

	Unit	Current Rate	Price Cap	Adjusted Rates	Billing Determinants	Revenue
Monthly Base	$/month	1,678.98	2.03%	1,713.12	3	61,672
Tier 1	cents / m3	0.0000	2.03%	0.0000	0	0
Tier 2	cents / m3	0.0000	2.03%	0.0000	0	0
Tier 3	cents / m3	0.0000	2.03%	0.0000	0	0
Contract Demand	Cents/contracted demand m3	114.5223	2.03%	116.8506	95,824	1,343,651
Upstream Recovery Charge	Cents/contracted demand m3	14.2434	0.00%	14.2434	95,824	163,783
Transportation Charge From Dawn	Cents/contracted demand m3	18.2999	0.00%	18.2999	95,824	210,428
						1,779,571

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Proposed Distribution Tariff Sheet Rates

E1.1 Proposed Dist Rates

Rate Class		Monthly Base $/month	Tier 1 ¢ / m3	Tier 2 ¢ / m3	Tier 3 ¢ / m3	Contract Demand ¢/contracted m3	Upstream Recovery Charge (A)	Transportation & Storage Charge ¢ / m3	Transportation Charge From Dawn ¢ /contracted m3	Transportation Charge From Kirkwall ¢ /contracted m3	Transportation Charge From Parkway ¢ /contracted m3
Rate 1	General Firm Service	28.57	30.6018	29.9990	29.1129		1.4740	2.6982			
Rate 6	Large Volume General Firm Service	116.49	28.2309	25.4079	24.1373		2.9200	5.6413			
Rate 11	Large Volume Seasonal Service	232.99	17.5362	17.5362	17.5362		0.0352	1.8166			
Rate 16	Contracted Firm Service	1,713.12				116.8506	14.2434		18.2999	11.8480	11.8480

(A) Rates 1, 6, and 11 all charged on cents / m3 basis. Rate 16 billed on cents / m3 of contracted demand basis

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Billing Determinants

E1.2 Billing Determinants

Rate Class	Description	Base cx's	Tier 1 m3	Tier 2 m3	Tier 3 m3	Firm Demand Contracted m3	Gas Supply m3
Rate 1	General Firm Service	5,572	5,233,469	3,538,635	95,604		8,270,620
Rate 6	Large Volume General Firm Service	72	607,190	1,243,389	617,622		2,228,157
Rate 11	Large Volume Seasonal Service	10			1,826,281		1,431,902
Rate 16	Contracted Firm Service	3				95,824	

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Proposed Revenue from Rates

Months / Year: 12

Rate Class		Monthly Base	Tier 1	Tier 2	Tier 3	Contracted Demand	Upstream Recovery Charge	Transportation & Storage Charge (A)	Total
Rate 1	General Firm Service	1,910,082	1,601,537	1,061,553	27,833	0	121,909	223,158	6,508,285
Rate 6	Large Volume General Firm Service	100,651	171,415	315,919	149,077	0	65,062	125,697	1,348,692
Rate 11	Large Volume Seasonal Service	27,958	0	0	320,260	0	504	26,012	645,202
Rate 16	Contracted Firm Service	61,672	0	0	0	1,343,651	163,783	210,428	1,779,535

(A) Transportation & Storage for Rates 1, 6, and 11. Transportation only (no seasonal storage) for Rate 16 from Dawn.

Proposed Revenue	10,281,714
Current Revenue	10,140,413
Change	141,301
% Change	1.39%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application
F1.3 Rate Riders

Delay in Revenue Recovery Rate Rider

Rate 1 | General Firm Service	1.6330	Cents/m3
Rate 6 | Large Volume General Firm Service	0.9090	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.5524	Cents/m3
Rate 16 | Contracted Firm Service	0.0601	Cents/contracted demand m3/month

Energy Content Variance Account (ECVA)

Rate 1 | General Firm Service	0.1794	Cents/m3
Rate 6 | Large Volume General Firm Service	0.1949	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.1031	Cents/m3
Rate 16 | Contracted Firm Service	0.0000	Cents/contracted demand m3

Contribution in Aid of Construction Variance Account (CIACVA)

Rate 1 | General Firm Service	2.0743	Cents/m3
Rate 6 | Large Volume General Firm Service	2.6496	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.4372	Cents/m3
Rate 16 | Contracted Firm Service	4.5364	Cents/contracted demand m3/month

Municipal Tax Variance Account (MTVA)

Rate 1 | General Firm Service	-0.4139	Cents/m3
Rate 6 | Large Volume General Firm Service	-0.6861	Cents/m3
Rate 11 | Large Volume Seasonal Service	-0.1135	Cents/m3
Rate 16 | Contracted Firm Service	-1.0891	Cents/contracted demand m3/month

Other Revenue Deferral Account (ORDA)

Rate 1 | General Firm Service	-0.2478	Cents/m3
Rate 6 | Large Volume General Firm Service	-0.2007	Cents/m3
Rate 11 | Large Volume Seasonal Service	-0.0662	Cents/m3
Rate 16 | Contracted Firm Service	-0.1501	Cents/contracted demand m3/month

Customer Volume Variance Account (CVVA)

Rate 1 | General Firm Service	8.53	$/Month
Rate 6 | Large Volume General Firm Service	26.03	$/Month

Unaccounted for Gas Variance Account (UFGVA)

Rate 1 | General Firm Service	-0.5865	Cents/m3
Rate 6 | Large Volume General Firm Service	-0.5848	Cents/m3
Rate 11 | Large Volume Seasonal Service	-0.9459	Cents/m3
Rate 16 | Contracted Firm Service	-0.6628	Cents/contracted demand m3/month

Transportation Variance Account (TVA)

Rate 1 | General Firm Service	0.0000	Cents/m3
Rate 6 | Large Volume General Firm Service	0.0000	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.0000	Cents/m3
Rate 16 | Contracted Firm Service	3.8962	Cents/contracted demand m3/month

Storage and Transportation Variance Account (S&TVA)

Rate 1 | General Firm Service	1.1454	Cents/m3
Rate 6 | Large Volume General Firm Service	1.5539	Cents/m3
Rate 11 | Large Volume Seasonal Service	0.4734	Cents/m3
Rate 16 | Contracted Firm Service	0.0000	Cents/contracted demand m3/month

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 1 Delivery Bill Impact

G1.1 Rate 1 Bill Impact

Rate 1

Rate 1 - Residential	Units	Current Rate	Proposed Rate
Customer	$/month	28.00	28.57
Bill 32 Rate	$/month	1.00	1.00
First 100 m3	¢/m3	29.9921	30.6018
Next 400 m3	¢/m3	29.4012	29.9990
GT 500m3	¢/m3	28.5328	29.1129
Gas Supply	¢/m3	18.8887	18.8887
Upstream Recovery Charge	$/m3	1.4740	1.4740
Transportation & Storage Charge	¢/m3	2.6982	2.6982
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	1.6330	1.6330
ECVA Rate Rider	¢/m3	0.2481	0.1794
CIACVA Rate Rider	¢/m3	2.3088	2.0743
MTVA Rate Rider	¢/m3	0.5052	- 0.4139
ORDA Rate Rider	¢/m3	- 0.2738	- 0.2478
CVVA Rate Rider	$/month	5.3700	8.5345
UFG Rate Rider	¢/m3	-	- 0.5865
TVA Rate Rider	¢/m3	-	-
S&TVA Rate Rider	¢/m3	-	1.1454

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	335.97	342.80	6.83	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 100 m3	837	251.00	256.11	5.10	2.03%
Next 400 m3	587	172.59	176.09	3.51	2.03%
GT 500m3	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	1,424	268.96	268.96	0.00	0.00%
Upstream Recovery Charge	1,424	20.99	20.99	0.00	0.00%
Transportation & Storage Charge	1,424	38.42	38.42	0.00	0.00%
Total Delivery		1,099.92	1,115.36	15.44	1.40%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	1,424	23.25	23.25	0.00	0.00%
ECVA Rate Rider	1,424	3.53	2.55	-0.98	-27.69%
CIACVA Rate Rider	1,424	32.88	29.54	-3.34	-10.16%
MTVA Rate Rider	1,424	7.19	-5.89	-13.09	-181.94%
ORDA Rate Rider	1,424	-3.90	-3.53	0.37	-9.48%
CVVA Rate Rider	12	64.44	102.41	37.97	58.93%
UFG Rate Rider	1,424	0.00	-8.35	-8.35	#DIV/0!
TVA Rate Rider	1,424	0.00	0.00	0.00	#DIV/0!
S&TVA Rate Rider	1,424	0.00	16.31	16.31	#DIV/0!
Total Rate Riders		127.39	156.29	28.90	22.68%
Total Bill Impact		1,227.32	1,271.66	44.34	3.6%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 1 Delivery Bill Impact

Rate 1 - Small Commercial	Units	Current Rate	Proposed Rate
Customer	$/month	28.00	28.57
Bill 32 Rate	$/month	1.00	1.00
First 100 m3	¢/m3	29.9921	30.6018
Next 400 m3	¢/m3	29.4012	29.9990
GT 500m3	¢/m3	28.5328	29.1129
Gas Supply	¢/m3	18.8887	18.8887
Upstream Recovery Charge	¢/m3	1.4740	1.4740
Transportation & Storage Charge	¢/m3	2.6982	2.6982
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	1.6330	1.6330
ECVA Rate Rider	¢/m3	0.2481	0.1794
CIACVA Rate Rider	¢/m3	2.3088	2.0743
MTVA Rate Rider	¢/m3	0.5052	-0.4139
ORDA Rate Rider	¢/m3	-0.2738	-0.2478
CVVA Rate Rider	$/month	5.3700	8.5345
UFG Rate Rider	¢/m3	0.0000	-0.5865
TVA Rate Rider	¢/m3	0.0000	0.0000
S&TVA Rate Rider	¢/m3	0.0000	1.1454

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	335.97	342.80	6.83	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 100 m3	1,151	345.21	352.23	7.02	2.03%
Next 400 m3	2,250	661.50	674.95	13.45	2.03%
GT 500m3	784	223.81	228.36	4.55	2.03%
Gas Supply	4,185.30	790.55	790.55	0.00	0.00%
Upstream Recovery Charge	4,185.30	61.69	61.69	0.00	0.00%
Transportation & Storage Charge	4,185.30	112.93	112.93	0.00	0.00%
Total Delivery		2,543.66	2,575.50	31.85	1.25%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	4,185.30	68.35	68.35	0.00	0.00%
ECVA Rate Rider	4,185.30	10.38	7.51	-2.88	-27.69%
CIACVA Rate Rider	4,185.30	96.63	86.82	-9.81	-10.16%
MTVA Rate Rider	4,185.30	21.14	-17.32	-38.47	-181.94%
ORDA Rate Rider	4,185.30	-11.46	-10.37	1.09	-9.48%
CVVA Rate Rider	12.00	64.44	102.41	37.97	58.93%
UFG Rate Rider	4,185.30	0.00	-24.55	-24.55	#DIV/0!
TVA Rate Rider	4,185.30	0.00	0.00	0.00	#DIV/0!
S&TVA Rate Rider	4,185.30	0.00	47.94	47.94	#DIV/0!
Total Rate Riders		249.48	260.78	11.30	4.53%
Total Bill Impact		2,793.14	2,836.28	43.14	1.5%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 1 Delivery Bill Impact

Rate 1 - Small Agricultural	Units	Current Rate	Proposed Rate
Customer	$/month	28.00	28.57
Bill 32 Rate	$/month	1.00	1.00
First 100 m3	¢/m3	29.9921	30.6018
Next 400 m3	¢/m3	29.4012	29.9990
GT 500m3	¢/m3	28.5328	29.1129
Gas Supply	¢/m3	18.8887	18.8887
Upstream Recovery Charge	¢/m3	1.4740	1.4740
Transportation & Storage Charge	¢/m3	2.6982	2.6982
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	1.6330	1.6330
ECVA Rate Rider	¢/m3	0.2481	0.1794
CIACVA Rate Rider	¢/m3	2.3088	2.0743
MTVA Rate Rider	¢/m3	0.5052	-0.4139
ORDA Rate Rider	¢/m3	-0.2738	-0.2478
CVVA Rate Rider	$/month	5.3700	8.5345
UFG Rate Rider	¢/m3	0.0000	-0.5865
TVA Rate Rider	¢/m3	0.0000	0.0000
S&TVA Rate Rider	¢/m3	0.0000	1.1454

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	335.97	342.80	6.83	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 100 m3	1,200	359.90	367.22	7.32	2.03%
Next 400 m3	3,368	990.12	1,010.24	20.13	2.03%
GT 500m3	2,925	834.70	851.67	16.97	2.03%
Commodity	7,493.00	1,415.33	1,415.33	0.00	0.00%
Upstream Recovery Charge	7,493.00	110.45	110.45	0.00	0.00%
Transportation & Storage Charge	7,493.00	202.18	202.18	0.00	0.00%
Total Delivery		4,260.64	4,311.89	51.25	1.20%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	7,493.00	122.36	122.36	0.00	0.00%
ECVA Rate Rider	7,493.00	18.59	13.44	-5.15	-27.69%
CIACVA Rate Rider	7,493.00	173.00	155.43	-17.57	-10.16%
MTVA Rate Rider	7,493.00	37.85	-31.02	-68.87	-181.94%
ORDA Rate Rider	7,493.00	-20.52	-18.57	1.94	-9.48%
CVVA Rate Rider	12.00	64.44	102.41	37.97	58.93%
UFG Rate Rider	7,493.00	0.00	-43.95	-43.95	#DIV/0!
TVA Rate Rider	7,493.00	0.00	0.00	0.00	#DIV/0!
S&TVA Rate Rider	7,493.00	0.00	85.83	85.83	#DIV/0!
Total Rate Riders		395.73	385.94	(9.79)	-2.47%
Total Bill Impact		4,656.37	4,697.82	41.46	0.9%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 6 Delivery Bill Impact

G1.2 Rate 6 Bill Impact

Rate 6 - Medium Commercial	Units	Current Rate	Proposed Rate
Customer	$/month	114.17	116.49
Bill 32 Rate	$/month	1.00	1.00
First 1000 m3	¢/m3	27.6684	28.2309
Next 6000 m3	¢/m3	24.9017	25.4079
GT 7000m3	¢/m3	23.6564	24.1373
Contracted Demand	¢ / contracted m3	-	-
Gas Supply	¢/m3	18.8887	18.8887
Upstream Recovery Charge	¢/m3	2.9200	2.9200
Transportation & Storage Charge	¢/m3	5.6413	5.6413
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.9090	0.9090
ECVA Rate Rider	¢/m3	0.2815	0.1949
CIACVA Rate Rider	¢/m3	3.0469	2.6496
MTVA Rate Rider	¢/m3	0.8651	- 0.6861
ORDA Rate Rider	¢/m3	- 0.2291	- 0.2007
CVVA Rate Rider	$/month	- 43.4600	26.0283
UFG Rate Rider	¢/m3	-	- 0.5848
TVA Rate Rider	¢/m3	-	-
S&TVA Rate Rider	¢/m3	-	1.5539

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	1,370.07	1,397.92	27.85	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 1000 m3	9,818	2,716.60	2,771.83	55.23	2.03%
Next 6000 m3	12,106	3,014.57	3,075.86	61.29	2.03%
GT 7000m3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	21,924.30	4,141.22	4,141.22	0.00	0.00%
Upstream Recovery Charge	21,924.30	640.19	640.19	0.00	0.00%
Transportation & Storage Charge	21,924.30	1,236.82	1,236.82	0.00	0.00%
Total Delivery		13,131.46	13,275.83	144.37	1.10%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	21,924.30	199.29	199.29	0.00	0.00%
ECVA Rate Rider	21,924.30	61.72	42.73	-18.99	-30.76%
CIACVA Rate Rider	21,924.30	668.01	580.91	-87.10	-13.04%
MTVA Rate Rider	21,924.30	189.67	-150.43	-340.10	-179.31%
ORDA Rate Rider	21,924.30	-50.23	-44.01	6.22	-12.38%
CVVA Rate Rider	12.00	-521.52	312.34	833.86	-159.89%
UFG Rate Rider	21,924.30	0.00	-128.21	-128.21	#DIV/0!
TVA Rate Rider	21,924.30	0.00	0.00	0.00	#DIV/0!
S&TVA Rate Rider	21,924.30	0.00	340.68	340.68	#DIV/0!
Total Rate Riders		546.94	1,153.30	606.36	110.86%
Total Bill Impact		13,678.40	14,429.13	750.73	5.49%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 6 Delivery Bill Impact

Rate 6 - Large Commercial	Units	Current Rate	Proposed Rate
Customer	$/month	114.17	116.49
Bill 32 Rate	$/month	1.00	1.00
First 1000 m3	¢/m3	27.6684	28.2309
Next 6000 m3	¢/m3	24.9017	25.4079
GT 7000m3	¢/m3	23.6564	24.1373
Contracted Demand	¢ / contracted m3	0.0000	0.0000
Gas Supply	¢/m3	18.8887	18.8887
Upstream Recovery Charge	¢/m3	2.9200	2.9200
Transportation & Storage Charge	¢/m3	5.6413	5.6413
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.9090	0.9090
ECVA Rate Rider	¢/m3	0.2815	0.1949
CIACVA Rate Rider	¢/m3	3.0469	2.6496
MTVA Rate Rider	¢/m3	0.8651	-0.6861
ORDA Rate Rider	¢/m3	-0.2291	-0.2007
CVVA Rate Rider	$/month	-43.4600	26.0283
UFG Rate Rider	¢/m3	0.0000	-0.5848
TVA Rate Rider	¢/m3	0.0000	0.0000
S&TVA Rate Rider	¢/m3	0.0000	1.5539

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	1,370.07	1,397.92	27.85	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
First 1000 m3	11,745	3,249.77	3,315.84	66.07	2.03%
Next 6000 m3	41,500	10,334.17	10,544.27	210.10	2.03%
GT 7000m3	25,627	6,062.37	6,185.62	123.25	2.03%
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	78,872.10	14,897.91	14,897.91	0.00	0.00%
Upstream Recovery Charge	78,872.10	2,303.07	2,303.07	0.00	0.00%
Transportation & Storage Charge	78,872.10	4,449.41	4,449.41	0.00	0.00%
Total Delivery		42,678.77	43,106.04	427.27	1.00%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	78,872.10	716.95	716.95	0.00	0.00%
ECVA Rate Rider	78,872.10	222.02	153.72	-68.30	-30.76%
CIACVA Rate Rider	78,872.10	2,403.15	2,089.81	-313.34	-13.04%
MTVA Rate Rider	78,872.10	682.33	-541.16	-1,223.49	-179.31%
ORDA Rate Rider	78,872.10	-180.70	-158.33	22.37	-12.38%
CVVA Rate Rider	12.00	-521.52	312.34	833.86	-159.89%
UFG Rate Rider	78,872.10	0.00	-461.24	-461.24	#DIV/0!
TVA Rate Rider	78,872.10	0.00	0.00	0.00	#DIV/0!
S&TVA Rate Rider	78,872.10	0.00	1,225.58	1,225.58	#DIV/0!
Total Rate Riders		3,322.24	3,337.67	15.43	0.46%
Total Bill Impact		46,001.01	46,443.71	442.70	0.96%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 11 Delivery Bill Impact

G1.3 Rate 11 Bill Impact

Rate 11 - Large Seasonal Service Sample Dryer 1	Units	Current Rate	Proposed Rate
Customer	$/month	228.35	232.99
Bill 32 Rate	$/month	1.00	1.00
All Volumes	¢/m3	17.1868	17.5362
Tier 2	¢/m3	17.1868	17.5362
Tier 3	¢/m3	17.1868	17.5362
Contracted Demand	¢ / contracted m3	-	-
Gas Supply	¢/m3	18.8887	18.8887
Upstream Recovery Charge	¢/m3	0.0352	0.0352
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.5524	0.5524
ECVA Rate Rider	¢/m3	0.1847	0.1031
CIACVA Rate Rider	¢/m3	0.5789	0.4372
MTVA Rate Rider	¢/m3	0.1648	- 0.1135
ORDA Rate Rider	¢/m3	- 0.0870	- 0.0662
CVVA Rate Rider	$/month	-	-
UFG Rate Rider	¢/m3	-	- 0.9459
TVA Rate Rider	¢/m3	-	-
S&TVA Rate Rider	¢/m3	-	0.4734

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	2,740.14	2,795.85	55.71	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
All Volumes	101,499	17,444.47	17,799.12	354.65	2.03%
Tier 2	-	0.00	0.00	0.00	#DIV/0!
Tier 3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	101,499.49	19,171.93	19,171.93	0.00	0.00%
Upstream Recovery Charge	101,499.49	35.73	35.73	0.00	0.00%
Transportation & Storage Charge	101,499.49	1,843.84	1,843.84	0.00	0.00%
Total Delivery		41,248.11	41,658.47	410.36	0.99%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	101,499.49	560.68	560.68	0.00	0.00%
ECVA Rate Rider	101,499.49	187.47	104.65	-82.82	-44.18%
CIACVA Rate Rider	101,499.49	587.58	443.79	-143.79	-24.47%
MTVA Rate Rider	101,499.49	167.26	-115.21	-282.47	-168.88%
ORDA Rate Rider	101,499.49	-88.30	-67.19	21.11	-23.91%
CVVA Rate Rider	12.00	0.00	0.00	0.00	#DIV/0!
UFG Rate Rider	101,499.49	0.00	-960.06	-960.06	#DIV/0!
TVA Rate Rider	101,499.49	0.00	0.00	0.00	#DIV/0!
S&TVA Rate Rider	101,499.49	0.00	480.51	480.51	#DIV/0!
Total Rate Riders		1,414.69	447.17	- 967.52	-68.39%
Total Bill Impact		42,662.80	42,105.64	- 557.16	-1.31%

Rate 11 - Large Seasonal Service Sample Dryer 2	Units	Current Rate	Proposed Rate
Customer	$/month	228.35	232.99
Bill 32 Rate	$/month	1.00	1.00
All Volumes	¢/m3	17.1868	17.5362
Tier 2	¢/m3	17.1868	17.5362
Tier 3	¢/m3	17.1868	17.5362
Contracted Demand	¢ / contracted m3	0.0000	0.0000
Gas Supply	¢/m3	18.8887	18.8887
Upstream Recovery Charge	¢/m3	0.0352	0.0352
Transportation & Storage Charge	¢/m3	1.8166	1.8166
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢/m3	0.5524	0.5524
ECVA Rate Rider	¢/m3	0.1847	0.1031
CIACVA Rate Rider	¢/m3	0.5789	0.4372
MTVA Rate Rider	¢/m3	0.1648	-0.1135
ORDA Rate Rider	¢/m3	-0.0870	-0.0662
CVVA Rate Rider	$/month	0.0000	0.0000
UFG Rate Rider	¢/m3	0.0000	-0.9459
TVA Rate Rider	¢/m3	0.0000	0.0000
S&TVA Rate Rider	¢/m3	0.0000	0.4734

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	2,740.14	2,795.85	55.71	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
All Volumes	338,332	58,148.24	59,330.40	1,182.17	2.03%
Tier 2	-	0.00	0.00	0.00	#DIV/0!
Tier 3	-	0.00	0.00	0.00	#DIV/0!
Contracted Demand	-	0.00	0.00	0.00	#DIV/0!
Gas Supply	338,331.62	63,906.44	63,906.44	0.00	0.00%
Upstream Recovery Charge	338,331.62	119.09	119.09	0.00	0.00%
Transportation & Storage Charge	338,331.62	6,146.13	6,146.13	0.00	0.00%
Total Delivery		172,991.34	174,229.21	1,237.87	0.72%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	338,331.62	1,868.94	1,868.94	0.00	0.00%
ECVA Rate Rider	338,331.62	624.90	348.82	-276.08	-44.18%
CIACVA Rate Rider	338,331.62	1,958.60	1,479.31	-479.29	-24.47%
MTVA Rate Rider	338,331.62	557.54	-384.04	-941.58	-168.88%
ORDA Rate Rider	338,331.62	-294.35	-223.97	70.37	-23.91%
CVVA Rate Rider	12.00	0.00	0.00	0.00	#DIV/0!
UFG Rate Rider	338,331.62	0.00	-3,200.18	-3,200.18	#DIV/0!
TVA Rate Rider	338,331.62	0.00	0.00	0.00	#DIV/0!
S&TVA Rate Rider	338,331.62	0.00	1,601.69	1,601.69	#DIV/0!
Total Rate Riders		4,715.63	1,490.56	- 3,225.07	-68.39%
Total Bill Impact		177,706.97	175,719.77	- 1,987.20	-1.12%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Rate 16 Delivery Bill Impact

G1.4 Rate 16 Bill Impact

Rate 16 - Contracted Demand	Units	Current Rate	Proposed Rate
Customer	$/month	1,678.98	1,713.12
Bill 32 Rate	$/month	1.00	1.00
Contracted Demand	¢ / contracted m3	114.5223	116.8506
Gas Supply	¢/m3	0.0000	0.0000
Upstream Recovery Charge	¢ / contracted m3	14.2434	14.2434
Transportation Charge From Dawn	¢ / contracted m3	18.2999	18.2999
Transportation Charge From Kirkwall	¢ / contracted m3	11.8480	11.8480
Transportation Charge From Parkway	¢ / contracted m3	11.8480	11.8480
Rate Riders			
Delay in Revenue Recovery Rate Rider	¢ / contracted m3	0.0601	0.0601
ECVA Rate Rider	¢ / contracted m3	-	-
CIACVA Rate Rider	¢ / contracted m3	4.7092	4.5364
MTVA Rate Rider	¢ / contracted m3	1.2397	- 1.0891
ORDA Rate Rider	¢ / contracted m3	- 0.1547	- 0.1501
CVVA Rate Rider	$/month	-	-
UFG Rate Rider	¢ / contracted m3	-	- 0.6628
TVA Rate Rider	¢ / contracted m3	-	3.8962
S&TVA Rate Rider	¢ / contracted m3	-	-

Delivery	Metric	Current Rate	Proposed Rate	Change $	Change %
Customer	12	20,147.79	20,557.40	409.61	2.03%
Bill 32 Rate	12	12.00	12.00	0.00	0.00%
Contracted Demand	50,000	687,134.08	701,103.65	13,969.57	2.03%
Gas Supply	0.00	0.00	0.00	0.00	#DIV/0!
Upstream Recovery Charge	50,000.00	85,460.40	85,460.40	0.00	0.00%
Transportation Charge From Dawn	50,000.00	109,799.40	109,799.40	0.00	0.00%
Total Delivery		902,553.67	916,932.85	14,379.18	1.59%

Rate Riders	Metric	Current Rate	Proposed Rate	Change $	Change %
Delay in Revenue Recovery Rate Rider	12.00	360.60	360.60	0.00	0.00%
ECVA Rate Rider	12.00	0.00	0.00	0.00	#DIV/0!
CIACVA Rate Rider	12.00	28,255.20	27,218.40	-1,036.80	-3.67%
MTVA Rate Rider	12.00	7,438.08	-6,534.60	-13,972.68	-187.85%
ORDA Rate Rider	12.00	-928.20	-900.60	27.60	-2.97%
CVVA Rate Rider	12.00	0.00	0.00	0.00	#DIV/0!
UFG Rate Rider	12.00	0.00	-3,976.80	-3,976.80	#DIV/0!
TVA Rate Rider	12.00	0.00	23,377.20	23,377.20	#DIV/0!
S&TVA Rate Rider	12.00	0.00	0.00	0.00	#DIV/0!
Total Rate Riders		35,125.68 #	39,544.20 #	4,418.52	12.58%
Total Bill Impact		937,679.35	956,477.05	18,797.70	2.00%

EPCOR Natural Gas Limited Partnership
OEB Application Number: EB-2025-0178 Exhibit A - 2026 Custom Incentive Application

Summary of Bill Impacts

G1.7 Summary of Bill Impacts

Rate Class		Fixed Charge ($/year)	Fixed Charge (%)	Volumetric Charge ($/year)	Volumetric Charge (%)	Rate Riders ($/year)	Rate Riders (%)	Total ($/year)	Total (%)
Rate 1	Residential	$6.83	2%	$8.61	2%	$28.90	23%	$44.34	4%
Rate 1	Small Commercial	$6.83	2%	$25.02	2%	$11.30	5%	$43.14	2%
Rate 1	Small Agricultural	$6.83	2%	$44.42	2%	($9.79)	-2%	$41.46	1%
Rate 6	Medium Commercial	$27.85	2%	$116.52	2%	$606.36	111%	$750.73	5%
Rate 6	Large Commercial	$27.85	2%	$399.41	2%	$15.43	0%	$442.70	1%
Rate 11	Sample Dryer 1	$55.71	2%	$354.65	2%	($967.52)	-68%	($557.16)	-1%
Rate 11	Sample Dryer 2	$55.71	2%	$1,182.17	2%	($3,225.07)	-68%	($1,987.20)	-1%
Rate 16	Contracted Demand	$409.61	2%	$13,969.57	2%	$4,418.52	13%	$18,797.70	2%

Overrun Charges

Rate 11	Current	Updated
Authorized Overrun Charge	17.5581	17.9151
Unauthorized Overrun Charge	420.4559	429.0039

Rate 16	Current	Updated
Authorized Overrun Charge	5.4867	5.5982
Unauthorized Overrun Charge	420.5640	429.1142

Appendix B - Proposed Draft Rate Schedules

EB-2025-0178

Effective: January 1, 2026

RATE 1 - General Firm Service

Applicability

Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are equal to or less than 10,000 m^3 per year.

Rate

Rates per m3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge [(1)]	$29.57	
Delivery Charge		
First 100 m^3 per month	30.6018	¢ per m^3
Next 400 m^3 per month	29.9990	¢ per m^3
Over 500 m^3 per month	29.1129	¢ per m^3
Upstream Charges		
Upstream Recovery charge	1.4740	¢ per m^3
Transportation and Storage charge	2.6982	¢ per m^3
Rate Rider for Delay in Revenue Recovery - effective for 10 years ending December 31, 2028	1.6330	¢ per m^3
ECVA Rate Rider - effective for 12 months ending December 31, 2026	0.1794	¢ per m^3
CIACVA Rate Rider - effective for 12 months ending December 31, 2026	2.0743	¢ per m^3
MTVA Rate Rider - effective for 12 months ending December 31, 2026	(0.4139)	¢ per m^3
ORDA Rate Rider - effective for 12 months ending December 31, 2026	(0.2478)	¢ per m^3
CVVA Rate Rider - effective for 12 months ending December 31, 2026	$8.53	Per month
UFGVA Rate Rider - effective for 12 months ending December 31, 2026	(0.5865)	¢ per m^3
S&TVA Rate Rider - effective for 12 months ending December 31, 2026	1.1454	¢ per m^3
Gas Supply Charge	18.8887	¢ per m^3

[1]Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the supplier must qualify as a "gas marketer" under the *Ontario Energy Board Act, 1998*, and must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2026
Implementation: All bills rendered on or after January 1, 2026
EB-2025-0178

RATE 6 – Large Volume General Firm Service

Applicability

Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose total gas requirements are greater than 10,000 m^3 per year.

Rate

Rates per m^3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge (1)	$117.49	
Delivery Charge		
First 1000 m^3 per month	28.2309	¢ per m^3
Next 6000 m^3 per month	25.4079	¢ per m^3
Over 7000 m^3 per month	24.1373	¢ per m^3
Upstream Charges		
Upstream Recovery charge	2.9200	¢ per m^3
Transportation and Storage charge	5.6413	¢ per m^3
Rate Rider for Delay in Revenue Recovery - effective for 10 years ending December 31, 2028	0.9090	¢ per m^3
ECVA Rate Rider - effective for 12 months ending December 31, 2026	0.1949	¢ per m^3
CIACVA Rate Rider - effective for 12 months ending December 31, 2026	2.6496	¢ per m^3
MTVA Rate Rider - effective for 12 months ending December 31, 2026	(0.6861)	¢ per m^3
ORDA Rate Rider - effective for 12 months ending December 31, 2026	(0.2007)	¢ per m^3
CVVA Rate Rider - effective for 12 months ending December 31, 2026	$26.03	Per month
UFGVA Rate Rider - effective for 12 months ending December 31, 2026	(0.5848)	¢ per m^3
S&TVA Rate Rider - effective for 12 months ending December 31, 2026	1.5539	¢ per m^3

Gas Supply Charge	18.8887 ¢ per m^3

(1)Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

Direct Purchase Delivery

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2026
Implementation: All bills rendered on or after January 1, 2026
EB-2025-0178

RATE 11 - Large Volume Seasonal Service

Applicability

Any customer in EPCOR's Southern Bruce Natural Gas System who is an end user and whose gas requirements are only during the period of May 1 through Dec 15 inclusive and are greater than 10,000 m^3.

Rate

Rates per m3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge (1)	$233.99	
Delivery Charge		
All volumes delivered	17.5362	¢ per m^3
Upstream Charges		
Upstream Recovery charge	0.0352	¢ per m^3
Transportation and Storage charge	1.8166	¢ per m^3
Rate Rider for Delay in Revenue Recovery	0.5524	¢ per m^3
- effective for 10 years ending December 31, 2028		
ECVA Rate Rider	0.1031	¢ per m^3
- effective for 12 months ending December 31, 2026		
CIACVA Rate Rider	0.4372	¢ per m^3
- effective for 12 months ending December 31, 2026		
MTVA Rate Rider	(0.4372)	¢ per m^3
- effective for 12 months ending December 31, 2026		
ORDA Rate Rider	(0.0662)	¢ per m^3
- effective for 12 months ending December 31, 2026		
UFGVA Rate Rider	(0.9459)	¢ per m^3
- effective for 12 months ending December 31, 2026		
S&TVA Rate Rider	0.4734	¢ per m^3
- effective for 12 months ending December 31, 2026		
Gas Supply Charge	18.8887	¢ per m^3

(1) Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

Unaccounted for Gas (UFG):

Forecasted UFG is applied to all volumes of gas delivered to the customer.

Forecasted Unaccounted for Gas Percentage	0.00	%

Overrun Charges:

Any volume of gas taken during the period of December 16 through April 30 inclusive shall constitute “Overrun Gas” and must be authorized in advance by EPCOR. Delivery of these volumes is available at the Authorized Overrun Charge in addition to applicable Upstream Charges and Gas Supply Charges. EPCOR will not unreasonably withhold authorization.

Authorized Overrun Charge	17.9151	¢ per m^3

Any volume of gas taken during the period of December 16 through April 30 inclusive without EPCOR’s approval in advance shall constitute “Unauthorized Overrun Gas”. Delivery of these volumes will be paid for at the Unauthorized Overrun Charge in addition to applicable Upstream Charges and Gas Supply Charges.

Unauthorized Overrun Charge	429.0039	¢ per m^3

For any volume of Unauthorized Overrun Gas taken, the customer shall, in addition, indemnify EPCOR in respect of any penalties or additional costs imposed on EPCOR by its suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

Nominations:

Union Gas Limited will be the “Upstream Service Provider” to facilitate delivery and balancing of gas supplies to the EPCOR Southern Bruce Natural Gas System. For service under this Rate Schedule, the customer shall nominate for transportation of gas volumes for ultimate delivery to the customer. The customer agrees to nominate its daily gas volumetric requirement to EPCOR, or its designated agent, consistent with industry nomination standards including those nomination requirements of the Upstream Service Provider.

The customer shall nominate gas delivery daily based on its daily gas requirements plus the Forecasted UFG rate as set out in this Rate Schedule.

The nomination calculation shall equal:

[(Daily volume of gas to be delivered) * (1 + Forecasted UFG)]

Customers may change daily nominations based on the nomination windows within a day as defined by EPCOR’s agreement with the Upstream Service Provider.

In the event nominations under this Rate Schedule do not match upstream nominations, the nomination will be confirmed at the upstream value.

Customers with multiple connections under this Rate Schedule may combine nominations at the sole discretion of EPCOR. For combined nominations the customer shall specify the quantity of gas to each meter installation ("Terminal Location") and the order in which the gas is to be delivered to each Terminal Location.

Load Balancing:

Daily nominations provided by the customer shall be used for the purposes of day-to-day balancing as required under EPCOR's arrangement with the Upstream Service Provider.

When a customer's metered consumption on any day is different than the gas nominated for consumption by the customer on any day, this constitutes a "Daily Load Imbalance". A "Cumulative Load Imbalance" occurs when the ongoing absolute value of Daily Load Imbalances are greater than zero.

To the extent that EPCOR incurs daily or cumulative load balancing charges, the customer will be responsible for its proportionate share of such charges. Charges related to these imbalances are as defined in EPCOR's agreement with the Upstream Service Provider.

Direct Purchase Delivery:

Where a customer elects under this Rate Schedule to directly purchase its gas from a supplier other than EPCOR, the customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). T-Service Receipt Contract rates are described in Rate Schedule T1. Transportation and Storage charges may vary depending on the Ontario Delivery Point. Gas Supply Charges in this Rate Schedule are not applicable for Rate T1 customers.

Terms and Conditions of Service

1. In any year, during the period of May 1 through December 15 inclusive, the customers shall receive continuous ("**Firm**") service from EPCOR, except where impacted by events as specified in EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service including force majeure. During the period of December 16 through April 30 inclusive, any authorized overrun service shall be interruptible at the sole discretion of EPCOR. All service during the period December 16 through April 30 inclusive shall be subject to EPCOR's prior authorization under the daily nomination procedures outlined in this Rate Schedule and shall constitute Overrun Gas.

2. To the extent that EPCOR's Upstream Service Provider provides any seasonal or day-to-day balancing rights for EPCOR, the customer shall be entitled to a reasonable proportion of such balancing rights as determined by EPCOR from time to time. If the customer utilizes any of EPCOR's seasonal or day-to-day balancing services or any other services available from the Upstream Service Provider, the customer agrees to comply with all balancing requirements imposed by the Upstream Service Provider. The customer also agrees to be liable for its share of any such usage limitations or restrictions, fees, costs or penalties associated with the usage of such services, including but not limited to any associated

storage fees, daily or cumulative balancing fees or penalties, and gas commodity costs as determined by EPCOR, acting reasonably.

3. EPCOR receives upstream services under the Union Gas Limited M17 Rate Schedule. Details of this upstream arrangement and associated nomination standards and Load Balancing Arrangement are available at www.uniongas.com.
4. The provisions in the "EPCOR Natural Gas Limited Partnership Southern Bruce Natural Gas Operations Conditions of Service" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2026
Implementation: All bills rendered on or after January 1, 2026
EB-2025-0178

RATE 16 – Contracted Firm Service

Applicability

Any customer connected directly to EPCOR's Southern Bruce Natural Gas High Pressure Steel System and who enters into a contract with EPCOR for firm contract daily demand of at least 2,739m^3.

Rate

Rates per m^3 assume an energy content of 38.89MJ/m^3

Bills will be rendered monthly and shall be the total of:

Monthly Fixed Charge (1)	$1,713.12	
Delivery Charge		
Per m^3 of Contract Demand	116.8506	¢ per m^3
Upstream Charges		
Upstream Recovery charge per m^3 of Contract Demand	14.2434	¢ per m^3
Transportation charge per m^3 of Contract Demand		
Transportation from Dawn	18.2999	¢ per m^3
Transportation from Kirkwall	11.8480	¢ per m^3
Transportation from Parkway	11.8480	¢ per m^3
Rate Rider for Delay in Revenue Recovery	0.0601	¢ per m^3
- effective for 10 years ending December 31, 2028		
CIACVA Rate Rider	4.5364	Per m^3 of Contract Demand per month
- effective for 12 months ending December 31, 2026		
MTVA Rate Rider	(1.0891)	Per m^3 of Contract Demand per month
- effective for 12 months ending December 31, 2026		
ORDA Rate Rider	(0.1501)	Per m^3 of Contract Demand per month
- effective for 12 months ending December 31, 2026		
UFGVA Rate Rider	(0.6628)	Per m^3 of Contract Demand per month
- effective for 12 months ending December 31, 2026		
TVA Rate Rider	3.8962	Per m^3 of Contract Demand per month
- effective for 12 months ending December 31, 2026		

(1)Aggregated within Monthly Fixed Charge is the amount of one dollar per month in accordance with Bill 32 and Ontario Regulation 24/19.

Unaccounted for Gas:

Forecasted Unaccounted for Gas (UFG) is applied to all volumes of gas delivered to the customer.

Forecasted Unaccounted for Gas Percentage	0.00	%

Overrun Charges:

Any volume of gas taken in excess of the daily Contract Demand or Peak Hourly Volume EPCOR is obligated to transport as per the contract with the customer shall constitute “Overrun Gas” and must be authorized in advance by EPCOR. Delivery of these volumes is available at the Authorized Overrun Charge in addition to applicable Upstream Charges. EPCOR will not unreasonably withhold authorization.

Authorized Overrun Charge	5.5982	¢ per m^3

Any volume of gas taken in excess of the daily Contract Demand or Peak Hourly Volume EPCOR is obligated to transport as per the contract with the customer without EPCOR’s approval in advance shall constitute “Unauthorized Overrun Gas”. Delivery of these volumes will be paid for at the Unauthorized Overrun Charge in addition to applicable Upstream Charges.

Unauthorized Overrun Charge	429.1142	¢ per m^3

For any volume of Unauthorized Overrun Gas taken, the customer shall, in addition, indemnify EPCOR in respect of any penalties or additional costs imposed on EPCOR by its suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

Nominations:

Union Gas Limited will be the “Upstream Service Provider” to facilitate delivery and balancing of gas supplies to the EPCOR Southern Bruce Natural Gas System. For service under this Rate Schedule, the customer shall nominate for transportation of gas volumes for ultimate delivery to the customer. The customer agrees to nominate its daily gas volumetric requirement to EPCOR, or its designated agent, consistent with industry nomination standards including those nomination requirements of the Upstream Service Provider.

The customer shall nominate gas delivery daily based on its daily gas requirements plus the Forecasted UFG rate and Fuel Ratio. The Forecasted UFG rate is as set out in this Rate Schedule. The Fuel Ratio is the Shipper Supplied Fuel rates applicable to the receipt point of gas defined in the “Gas Supply” section of this Rate Schedule.

The nomination calculation shall equal:

[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Customers may change daily nominations based on the nomination windows within a day as

defined by EPCOR's agreement with the Upstream Service Provider.
In the event nominations under this Rate Schedule do not match upstream nominations, the nomination will be confirmed at the upstream value.

Customers with multiple connections under this Rate Schedule may combine nominations at the sole discretion of EPCOR. For combined nominations the customer shall specify the quantity of gas to each meter installation ("Terminal Location") and the order in which the gas is to be delivered to each Terminal Location.

Load Balancing:

Daily nominations provided by the customer shall be used for the purposes of day-to-day balancing as required under EPCOR's arrangement with the Upstream Service Provider.

When a customer's metered consumption on any day is different than the gas nominated for consumption by the customer on any day, this constitutes a "Daily Load Imbalance". A "Cumulative Load Imbalance" occurs when the ongoing absolute value of Daily Load Imbalances are greater than zero.

To the extent that EPCOR incurs daily or cumulative load balancing charges, the customer will be responsible for its proportionate share of such charges. Charges related to these imbalances are as defined in EPCOR's agreement with the Upstream Service Provider.

Gas Supply:

Unless otherwise authorized by EPCOR, customers under this Rate Schedule must deliver firm gas at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**"). The customer or their agent must enter into a T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. T-Service Receipt Contract rates are described in Rate Schedule T1.

The customer must deliver to EPCOR on a daily basis the volume of gas to be delivered to the customer's Terminal Location plus the Forecasted UFG rate and Fuel Ratio. Transportation charges vary depending on the Ontario Delivery Point at the rates provided in this Rate Schedule. The Forecasted UFG rate is as set out in this Rate Schedule, and the Fuel Ratio is the Shipper Supplied Fuel rates of the Ontario Delivery Point related to necessary compressor or other fuel requirements of the Upstream Service Provider.

The Gas Supply calculation shall equal:

[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Terms and Conditions of Service

1. EPCOR receives upstream services under the Union Gas Limited M17 Rate Schedule. Details of this upstream arrangement and associated nomination standards, applicable Fuel Ratio, and Load Balancing Arrangement are available at www.uniongas.com.
2. The provisions in the "EPCOR Natural Gas Limited Partnership General Terms and Conditions for Rate 16 Customers" apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2026
Implementation: All bills rendered on or after January 1, 2026
EB-2025-0178

RATE T1 – Direct Purchase Contract Rate

Availability

Rate T1 is available to all customers or their agent who enter into a T-Service Receipt Contract for delivery of gas to EPCOR. The availability of this option is subject to EPCOR obtaining a satisfactory agreement or arrangement with EPCOR's Upstream Service Provider for direct purchase volume.

Eligibility

All customers who must, or elect to, purchase gas directly from a supplier other than EPCOR. These customers must enter into a T-Service Receipt Contract with EPCOR either directly or through their agent, for delivery of gas to EPCOR at a receipt point listed on the upstream transportation contract that EPCOR has with the Upstream Service Provider ("**Ontario Delivery Point**").

Rate

All charges in the customer's appropriate Rate Schedule excluding Gas Supply Charge shall apply. Applicable Transportation and Storage charges are determined based on the Ontario Delivery Point.

In addition, administration fees apply to customers who elect to enter into a T-Service Receipt Contract with EPCOR and are detailed in the Direct Purchase Contract with the customer or its agent.

For gas delivered to EPCOR at any point other than the Ontario Delivery Point, EPCOR will charge the customer or their agent all approved tolls and charges incurred by EPCOR to transport the gas to the Ontario Delivery Point.

Unaccounted for Gas:

Forecasted Unaccounted for Gas (UFG) is applied to all volumes of gas supplied:

Forecasted Unaccounted for Gas Percentage	0.00	%

Gas Supply:

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must deliver firm gas at a daily volume acceptable to EPCOR, to an Ontario Delivery Point, and, where applicable, must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

The customer or its agent must deliver to EPCOR on a daily basis, at the Ontario Delivery Point, the volume of gas to be delivered to the customer's Terminal Location plus the Forecasted UFG rate and Fuel Ratio. Where the Forecasted UFG rate is as set out in this Rate Schedule, and the Fuel Ratio is the Shipper Supplied Fuel rates of the Ontario Delivery Point related to necessary compressor or other fuel requirements of the Upstream Service Provider.

The Gas Supply calculation shall equal:

[(Daily volume of gas to be delivered) * (1 + Forecasted UFG) * (1 + Fuel Ratio)]

Terms and Conditions of Service

The provisions in the “T-Service Receipt Contract General Terms and Conditions” apply, as contemplated therein, to service under this Rate Schedule.

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2025-0178

EPCOR NATURAL GAS LIMITED PARTNERSHIP

Schedule of Miscellaneous and Service Charges

	A Service	B Fee
1	Service Work	
2	During normal working hours	
3	Minimum charge (up to 60 minutes)	$100.00
4	Each additional hour (or part thereof)	$100.00
5	Outside normal working hours	
6	Minimum charge (up to 60 minutes)	$130.00
7	Each additional hour (or part thereof)	$105.00
8		
9	Miscellaneous Charges	
10	Returned Cheque / Payment	$20.00
11	Replies to a request for account information	$25.00
12	Bill Reprint / Statement Print Requests	$20.00
13	Consumption Summary Requests	$20.00
14	Customer Transfer / Connection Charge	$35.00
15		
16	Reconnection Charge	$85.00
17		
18	Inactive Account Charge	ENGLP's cost to install service
19		
20	Late Payment Charge	1.5% / month, 19.56% / year (effective rate of 0.04896% compounded daily)
21		
22		
23	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs
24	Installation of Service Lateral [1]	No charge for the first 30 meters

Note: Applicable taxes will be added to the above charges

[1] No Charge for initial connection

Appendix C - Proposed Customer Notice

IMPORTANT INFORMATION ABOUT YOUR NATURAL GAS BILL

On **XXX**, 2025, the OEB approved EPCOR's gas distribution rates effective January 1, 2026.

For a typical residential customer who consumes about 1,400 cubic meters of gas annually, the rate change will increase the bill by $3.69 per month. Commercial, industrial and seasonal rate customers will also be impacted by the change. Please refer to epcor.com or visit OEB.ca for information on the current approved rates.

The approved rates are reflected in the following line items on your EPCOR natural gas bill:

1. **"Monthly Charge"** – This is an administration charge covering the costs of maintaining gas services and providing billing and customer service. Included in this charge, is the $1 per month required to be billed to all customers as part of the *Access to Natural Gas Act* (Bill 32), which helps to facilitate the expansion of natural gas into more Ontario communities.
2. **"Delivery and Upstream Charges"** – These charges reflect the costs associated with the distribution, transportation and storage of natural gas from the source to you. This includes all charges EPCOR pays to its upstream service provider in association with transportation and storage of the gas before it is delivered to EPCOR's system. Included in this charge is a rate rider to recover revenue the utility was not able to collect as a result of delays in connecting customers to the system.
3. **"Gas Supply Charge"** – These are gas commodity costs calculated using the cost of gas you use during the period between meter readings (or based on an estimate of the gas used during that period). The commodity rate you are charged on your EPCOR bill depends upon the commodity purchase choice you have made. If you have not signed a contract with an energy retailer you are automatically billed at EPCOR's OEB approved gas commodity rate. If you have signed a contract with an energy retailer you are billed at your contracted energy retailer rate.

When applicable, miscellaneous and/or service charges as set out in EPCOR's Rate Schedules, may appear on your bill in addition to the above charges. Please see the EPCOR's Conditions of Services for more detail on these charges.

Your natural gas bill includes information on the amount of natural gas you consumed in the billing period. Your consumption information is broken out to include length of the billing period, the date of your last meter reading and whether your consumption calculation was based on actual or estimated meter reading or a combination of both.

If you have any questions about the rates or any other items on your bill, please call our office at 1-888-765-2256 or email at gas@epcor.com.

Appendix D - Accounting Orders

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

Accounting Order

Contribution in Aid of Construction Variance Account (“CIACVA”)

The Contribution in Aid of Construction Variance Account (“CIACVA”) is to record the revenue requirement impact of any differences between the actual capital contributions that EPCOR Southern Bruce pays to Enbridge Gas/Union Gas related to Enbridge’s Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the capital contribution included for these projects for the purposes of determining EPCOR’s approved rates. Enbridge Gas provided EPCOR with a forecasted contribution value of $2.363 million for the Owen Sound Transmission Reinforcement and $2.935 million for the Dornoch Meter and Regulator Station. These values have been included in EPCOR’s capital budget and form part of the utility’s rate base. The costs associated with this capital are recovered through the Upstream Recovery Charge included in the proposed rates and changes to the contribution values will have a direct impact on the amount of capital EPCOR proposes to recover through the Upstream Recovery Charge. The effective date of this account is January 1, 2019.

The balance of this account would be calculated as the revenue requirement impact resulting from the difference between the forecasted capital contribution values provided by Enbridge Gas/Union Gas and the actual capital contributions paid. No balance will be recorded in this account until such time as the actual capital contribution amounts EPCOR is required to pay to Enbridge Gas/Union Gas are finalized. Once the actual capital contributions are finalized the cumulative revenue requirement impact to date will be calculated and recorded in this account, after which the balance will be recorded annually. In its cost of service application for rates commencing 2029 EPCOR will propose to adjust its rate base to record the depreciated difference in capital contribution so as to appropriately reflect the finalized capital contribution paid in its rate base and revenue requirement commencing 2029.

The balance in this account, together with carrying charges, will brought forward for disposition on an annual basis at which time EPCOR will propose a methodology and timing for disposition of the balance that aligns with customers’ use of the capacity and EPCOR’s rate smoothing objectives.

Simple interest is to be calculated monthly on the opening balance in this account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the revenue requirement impact resulting from the difference between the forecasted capital contribution values provided by Enbridge Gas/Union Gas and the actual capital contributions paid:

   Debit/Credit Account No. 179.74 Contribution in Aid of Construction Variance Account (CIACVA)

   Credit/Debit Account No. 300 Operating Revenue

ii. To record simple interest on the opening monthly balance of the CIACVA :

   Debit/Credit Account No.179.75 Interest on Contribution in Aid of Construction Variance Account

   Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

Accounting Order

Energy Content Variance Account ("ECVA")

The Energy Content Variance Account ("ECVA") is to record differences in variable revenues resulting from differences in the energy content of the gas actually delivered and the assumed energy content of 38.89MJ/M3 used in determining EPCOR Southern Bruce's revenue requirement and delivery rates as approved in EB-2018-0264. Differences in the energy content of the gas delivered from the assumed energy content would impact the actual volumes delivered thereby impacting the amount of revenue collected over EPCOR's 10-year rate stability period. The effective date of this account is January 1, 2019.

This account will capture the impact of energy content changes on variable revenue by applying the energy content change to the revenue earned from Delivery Charges for all customers in Rates 1, 6 and 11. Rate 16, contract demand customers, are excluded from the calculation of the balances in this account as the revenue from these customers is not impacted by the energy content given that these customers contract for a specified volume.

On an annual basis the amount to be recorded in this account will be calculated by taking the difference between the actual energy content (heat value conversion factor) for the year as provided by the gas provider and the assumed energy content of 38.89 MJ/M3 and applying this to the revenue approved in EB-2016-0137/0138/0139 for Delivery Charges for Rates 1, 6 and 11 for the year as modified by EB-2018- 0264 ("CIP Revenue Rates 1, 6 and 11"). The calculation will be as follows:

$$\frac{\text{Actual Energy Content} - 38.89\ \text{MJ/M3}}{\text{Actual Energy Content}} \times \text{CIP Revenue Rates 1, 6 and 11} = \text{Amount to record in ECVA}$$

In cases where the actual energy content is lower than the assumed energy content this will result in credit booked to the ECVA and actual energy content that is higher than the assumed energy content will result in a debit amount recorded in the ECVA.

The audited balance in this account, together with carrying charges, will brought forward for approval for disposition on an annual basis. The balance in this account will be apportioned to Rates 1, 6 and 11 based on forecasted volumes underpinning CIP revenues for each rate class. Other details on the manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Simple interest is to be calculated monthly on the opening balance in the ECVA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the difference in revenues resulting from differences in the energy content of the gas actually delivered and the assumed energy content of 38.89MJ/M3:

Debit/Credit Account No. 179.17 Energy Content Variance Account (ECVA)

Credit/Debit Account No. 300 Operating Revenue

ii. To record simple interest on the opening monthly balance of the ECVA :

Debit/Credit Account No.179.18 Interest on Energy Content Variance Account

Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

Accounting Order

Municipal Tax Variance Account ("MTVA")

The Municipal Tax Variance Account (”MTVA”) is to record the difference between the actual annual municipal taxes paid, net of municipal contributions related to municipal taxes, and the net municipal taxes billed to customers by ENGLP. The effective date of this account is January 1, 2019.

Net municipal taxes billed to customers by ENGLP is calculated by multiplying the annual distribution revenues billed to customers and accrued for the year by the proportion of annual municipal taxes included in the annual revenue requirement for EPCOR's Southern Bruce operations as approved in EB-2018-0264 for each year of the rate stability period.

CIP Municipal Taxes as a Percentage of CIP Revenue Requirement ($000's)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
CIP Revenue Requirement (1)	589	3,050	4,621	5,818	6,646	7,190	7,455	7,594	7,727	7,846	58,535
CIP Municipal Taxes	(214)	(377)	(547)	(565)	(582)	(590)	(624)	(626)	(629)	(630)	(5,383)
% of Revenue Requirement	36%	12%	12%	10%	9%	8%	8%	8%	8%	8%	9%

(1) EB-2018-0264 Decision and Order November 28, 2019, pg. 6

For example, if in 2021 ENGLP bills $1,950 of distribution revenues to customers and pays $339 in municipal taxes, the net municipal taxes billed to customer would be calculated as:

$$Net\ municipal\ taxes\ billed\ to\ customers = \ Billed\ Distribution\ Revenues\ \frac{CIP\ Municipal\ Taxes}{CIP\ Revenue\ Requirement}$$

$$Net\ municipal\ taxes\ billed\ to\ customers = \$1{,}950 * \frac{\$547}{\$4{,}621} = \$231$$

The amount recorded in the MTVA for 2021 would be the variance between the calculated net municipal taxes of $231 and the actual municipal taxes paid of $339, for an amount owing to EPCOR of $108.

The audited balance in this account, together with carrying charges, will brought forward for approval for disposition on an annual basis. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Simple interest is to be calculated monthly on the opening balance of this account in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the difference between actual annual net municipal taxes paid and net municipal taxes billed to customers by ENGLP:

Debit/Credit Account No. 179.15 Municipal Tax Variance Account ("MTVA")
Credit/Debit Account No. 305 Municipal Tax

ii. To record simple interest on the opening monthly balance of the MTVA:

Debit/Credit Account No.179.16 Interest on Municipal Tax Variance Account
Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

Accounting Order

Other Revenues Deferral Account ("ORDA")

The ORDA is to record customer service charge revenue amounts (as per the schedule of Miscellaneous and Service Charges on the Distributors approved rate order). As part of its 10-year rate stability period, EPCOR was approved to collect specific service charges as part of the Settlement Proposal. The OEB approved $0 in Other Revenues for ratemaking purposes for the periods of 2019-2021 and the establishment of a deferral account to track actual other revenues for the remaining years of the rate stability period.

The effective date of this account is January 1, 2022 and is expected to be in effect until the effective date of EPCOR's first rate filing for rates after the 10-year stability period (currently scheduled to be January 1, 2029).

Simple interest is to be calculated monthly on the opening balance in the ORDA in accordance with the methodology approved by the Board in EB-2006-0117.

The audited balance of this account, together with carrying charges, will be brought forward for approval for disposition an annual basis, unless otherwise directed by the Board. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Accounting Entries

i. To record EPCOR's customer service charge revenues billed to customers:

Debit/Credit ORDA (Account 179.94)

Credit/Debit: Late Payment Penalties/Miscellaneous Operating Revenue (Account 560/579)

ii. To record simple interest on the opening monthly balance of the ORDA:

Debit/Credit: Interest on ORDA (Account 179.95)

Credit/Debit: Interest expense (Account 323)

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

Accounting Order

Customer Volume Variance Account ("CVVA")

The Customer Volume Variance Account is to record the variance in revenue by rate class resulting from the difference between customer volume forecast based on common assumptions and the Actual Normalized Average Customer Volume ("NACV") as defined below. This account will record such resulting variances in revenue for Rate 1 and Rate 6 since a common assumption related to customer usage volume was used for these rate classes in the development of the Common Infrastructure Plan as submitted by EPCOR in EB-2016-0137 / EB-2016-0138 / EB-2016-0139.

The effective date of this account is January 1, 2023 and this account will record such variances for amounts consumed until December 31, 2028.

The common assumption volumes per customer by rate class to be used in determining the balances to be recorded in this account are as follows:

Rate Class	Segment / Sub-segment		Average Annual Consumption (M^3/year)
Rate 1	Residential	Pre-existing Homes	2,149
		Future Construction	2,066
	Commercial	Small (0-15,000 m^3/year)[27]	4,693
Rate 6		Medium (15,001- 50,000 m^3/year)	26,933
		Large (>50,000 m^3/year)	75,685
	Agricultural	Cash Crop Farm (excl. large grain dryers)	4,720
		Other Agri-Business	4,720

In order that EPCOR retain the risk related to customer connection counts, for the purposes of calculating amounts to be recorded in the CVVA the common assumption volumes per customer outlined in the table above will be applied to the actual customer connections for each corresponding customer segment and rate class to determine the "Common Assumptions Customer Volume".

The NACV shall be calculated as the actual average monthly consumption per customer, adjusting it to remove the impact of the Energy Content Variance Account (ECVA), and applying the weather normalization methodology.

Differences are to be shared on a 50/50 basis between EPCOR and its customers. Accordingly, the monthly balance to be recorded in this account will be calculated as 50% of the variance in revenue resulting in the difference between the Common Assumptions Customer Volume and the NACV, both determined in the applicable manner described above for Rate 1 and Rate 6 customers. The

[27] Small commercial customers with a volume greater than 10,000m3/year will be billed as a Rate 6 customer.

revenue difference shall be calculated by applying approved rate schedules (including volumetric charges, monthly fixed charges and the delay in revenue rate rider) to the calculated difference between the Common Assumptions Customer Volume and the NACV. EPCOR shall only be eligible for the recovery of the annual net balance in the CVVA from its customers until such point that EPCOR's actual Return on Equity (ROE) reach 300 basis points below 8.78%, consistent with the ROE in the 10-year revenue requirement.

The revenue variances for each of Rate Class 1 and Rate Class 6 shall be calculated separately and tracked in subaccounts to enable allocation and disposition options when the balances in both accounts are disposed.

The variance account will apply only to the Southern Bruce distribution system.

Simple interest is to be calculated monthly on the opening balance in the CVVA in accordance with the methodology approved by the Board in EB-2006-0117.

The audited balance of this account, together with carrying charges, will be brought forward for approval for disposition an annual basis, unless otherwise directed by the Board. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Accounting Entries

i. Subaccount to record 50% of the revenue impact of the difference between Common Assumptions Customer Volume and the NAC for Rate Class 1:

   Debit / Credit Account No. 179.96 Customer Volume Variance Account – Rate 1 (CVVA)
   Credit / Debit Account No. 300 Operating Revenue

ii. To record simple interest on the opening balance of the CVVA for Rate Class 1:

   Debit / Credit Account No. 179.97 Interest on Customer Volume Variance Account – Rate 1
   Credit / Debit Account No. 323 Other Interest Expense

iii. Subaccount to record 50% of the revenue impact of the difference between Common Assumptions Customer Volume and the NAC for Rate Class 6:

   Debit / Credit Account No. 179.98 Customer Volume Variance Account – Rate 6 (CVVA)

Credit / Debit Account No. 300 Operating Revenue

iv. To record simple interest on the opening balance of the CVVA for Rate Class 6:

Debit / Credit Account No. 179.99 Interest on Customer Volume Variance Account - Rate 6

Credit / Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

ACCOUNTING ORDER

Unaccounted For Gas Variance Account (“UFGVA”)

The Unaccounted for Gas Variance Account (“UFGVA”) is to record the cost of gas for EPCOR Southern Bruce that is associated with volumetric variances between the actual volume of Unaccounted for Gas (“UFG”) and the Board approved UFG volumetric forecast included in the determination of rates. The effective date of this account is January 1, 2019.

The gas costs associated with the UFG variance will be calculated at the end of each calendar year based on the estimated volumetric variance between the applicable Board approved level of UFG and the estimate of the actual UFG. The UFG annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGCVA reference price. If required, an adjustment will be made in the subsequent year to record any differences between the estimated UFG and actual UFG. Where there are recoveries of gas loss amounts invoiced as part of third party damages, the gas loss amounts will be removed from the gas cost associated with UFG for the purposes of determining and recording a UFGVA balance.

The audited balances in this account, together with any carrying charges, will be brought forward for approval for disposition on an annual basis. The manner in which the account will be disposed of will be proposed at the time the account is brought forward for disposition.

Simple interest is to be calculated monthly on the opening balance in the UFGVA in accordance with the methodology approved by the Board in EB-2006-0117.

Accounting Entries

i. To record the costs associated with unaccounted for gas based on the estimated volumetric variance between the actual UAG and the Board approved level:

Debit/Credit Account No.179.13 Unaccounted for Gas Variance Account (UFGVA)
Credit/Debit Account No. 623 Cost of Gas

ii. To record the recovery of gas loss amounts invoiced to third parties:

Debit Account No. 140 Sundry Accounts Receivable
Credit Account No. 179.13 Unaccounted For Gas Variance Account (UFGVA)

iii. To record simple interest on the opening monthly balance of the UFGVA:

Debit/Credit Account No. 179.14 Interest on Unaccounted For Gas Variance Account
Credit/Debit Account No. 323 Other Interest Expense

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

Accounting Order

Storage and Transportation Variance Account for Rates 1, 6 & 11 ("S&TVA Rates 1, 6 & 11")

The Storage and Transportation Variance Account for Rates 1, 6 & 11 ("S&TVA Rates 1, 6 & 11") is to record the difference between actual total upstream costs, including all Transportation and Storage Costs and Upstream Recovery Costs, incurred for all customers in Rates 1, 6 and 11 and the Upstream Charges (including all Upstream Recovery Charges and Transportation and Storage Charges) recovered from these customers. The S&TVA Rates 1, 6 & 11 records the difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow-through to customers. The effective date of this account is January 1, 2019.

The S&TVA Rates 1, 6 & 11 will record: (a) the variance between the forecast storage and transportation demand levels and the actual storage and transportation demand levels; (b) amounts credited or invoiced from storage and transportation suppliers related to the disposition of the suppliers' deferral/variance accounts; (c) the variance between the forecasted commodity cost for fuel and the updated reference price set through the Quarterly Rate Adjustment Mechanism (QRAM) process; and (d) the variance between the forecast and actual administrative costs for storage and transportation including costs associated with daily nominations, load balancing, and storage procurement.

EPCOR has set its Upstream Recovery Charges so as to defer the recovery of a portion of the Upstream Recovery Costs related to the CIAC paid to Enbridge Gas/Union Gas for the Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the additional capacity EPCOR was required to contract with Enbridge Gas/Union Gas initially in order to provide service to its customer base in future years. Accordingly, this under recovery will accrue in the S&TVA Rates 1, 6 & 11 account and EPCOR estimates that this balance will reach its maximum in 2024.

EPCOR proposes to bring forward the balance in this account, together with any carrying charges for disposition after the maximum balance has been reached. The balance in this account together with any carrying charges will be collected over the remaining life of the 30-year upstream transportation contract with Enbridge Gas/Union Gas. When the balance in this account is brought forward for disposition EPCOR will also bring forward a proposal for the treatment of the variances related to upstream costs for these customers in subsequent years. This proposal will recognize that variances related to upstream costs in subsequent years should no longer be materially impacted by the deferred recovery of the Upstream Recovery Costs and therefore would more appropriately be brought forward for disposition on an annual basis and recovered over a shorter term.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved interest rate for long term debt. EPCOR is proposing to use the Board approved interest rate for long term debt as the balance of this deferral account will be financed over a long term period (i.e. remaining life of 30-year upstream transportation contract.

Accounting Entries

i. To record the difference between total upstream costs, including all Transportation and Storage Costs and Upstream Recovery Costs, incurred for all customers in Rates 1, 6 and 11 and the Upstream Charges recovered from these customers:

Debit/Credit Account No. 179.11 Storage and Transportation Variance Account Rates 1, 6 & 11 (S&TVA Rates 1, 6 & 11)

Credit/Debit Account No. 624 Gas Supply

ii. To record simple interest on the opening monthly balance of the S&TVA Rates 1, 6 & 11:

Debit/Credit Account No. 179.12 Interest on Storage and Transportation Variance Account Rates 1, 6 &11

Credit/Debit Account No. 323 Interest

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Southern Bruce

Accounting Order

Transportation Variance Account for Rate 16 ("TVA Rate 16")

The Transportation Variance Account for Rate 16 ("TVA Rate 16") is to record the difference between actual total upstream costs, including all Transportation Costs and Upstream Recovery Costs, incurred for all customers in Rate 16 and the Upstream Charges (including all Upstream Recovery Charges and Transportation Charges) recovered from these customers. The TVA Rate 16 records difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow- through to customers. The effective date of this account is January 1, 2019.

The TVA Rate 16 will record, as applicable: (a) the variance between the forecast transportation demand levels and the actual transportation demand levels; (b) amounts credited or invoiced from transportation suppliers related to the disposition of the suppliers' deferral/variance accounts; (c) the variance between the forecasted commodity cost for fuel and the updated reference price set through the Quarterly Rate Adjustment Mechanism (QRAM) process; and (d) the variance between the forecast and actual administrative gas supply costs including costs associated with daily nominations and load balancing.

EPCOR has set its Upstream Recovery Charges so as to defer the recovery of a portion of the Upstream Recovery Costs related to the CIAC paid to Enbridge Gas/Union Gas for the Owen Sound Transmission Reinforcement and the Dornoch Meter and Regulator Station, and the additional capacity EPCOR was required to contract with Enbridge Gas/Union Gas initially in order to provide service to its customer base in future years. Accordingly, this under recovery will accrue in the TVA Rate 16 account and EPCOR estimates that this balance will reach its maximum in 2024.

EPCOR proposes to bring forward the balance in this account, together with any carrying charges for disposition after the maximum balance has been reached. The balance in this account together with any carrying charges will be collected over the remaining life of the 30-year upstream transportation contract with Enbridge Gas/Union Gas. When the balance in this account is brought forward for disposition EPCOR will also bring forward a proposal for the treatment of the variances related to upstream costs for these customers in subsequent years. This proposal will recognize that variances related to upstream costs in subsequent years should no longer be materially impacted by the deferred recovery of the Upstream Recovery Costs and therefore would more appropriately be brought forward for disposition on an annual basis and recovered over a shorter term.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved interest rate for long term debt. EPCOR is proposing to use the Board approved interest rate for long term debt as the balance of this deferral account will be financed over a long term period (i.e. remaining life of 30-year upstream transportation contract.

Accounting Entries

i. To record the difference between total Upstream Costs, including all Transportation Costs and Upstream Recovery Costs, incurred for all customers in Rate 16 and the Upstream Charges recovered from these customers:

Debit/Credit Account No. 179.19 Transportation Variance Account Rate 16 (TVA Rate 16)
Credit/Debit Account No. 624 Gas Supply

ii. To record simple interest on the opening monthly balance of the TVA Rate 16:

Debit/Credit Account No. 179.20 Interest on Transportation Variance Account Rate 16
Credit/Debit Account No. 323 Interest Expense

Appendix E - Auditor’s Report

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BDO Canada LLP
300 Lakeshore Drive, Suite 300
Barrie, ON, Canada, L4N 0B4

Agreed-Upon Procedures Report

To the Management of EPCOR Natural Gas Limited Partnership:

Purpose of this Agreed-Upon Procedures Report

Our report is solely for the purpose of assisting EPCOR Natural Gas Limited Partnership (the “Entity”) in assessing the deferral accounts of the Southern Bruce operations in the S&TVA, UFGVA, MTVA, ECVA, TVA, CIACVA, ORDA and CVVA Schedules to comply with the requirements of the Ontario Energy Board (OEB) for the period from January 1, 2024 to December 31, 2024, and may not be suitable for another purpose.

Management’s Responsibilities

Management has acknowledged that the agreed-upon procedures are appropriate for the purpose of the engagement. Management is responsible for the subject matter on which the agreed-upon procedures are performed.

Practitioner's Responsibilities

We have conducted the agreed-upon procedures engagement in accordance with the Canadian Standard on Related Services (CSRS) 4400, Agreed-Upon Procedures Engagements. An agreed-upon procedures engagement involves our performing the procedures that have been agreed with the Entity, and reporting the findings, which are the factual results of the agreed-upon procedures performed. We make no representation regarding the appropriateness of the agreed-upon procedures.

This agreed-upon procedures engagement is not an assurance engagement. Accordingly, we do not express an opinion or an assurance conclusion.

Had we performed additional procedures, other matters might have come to our attention that would have been reported.

Professional Ethics

We have complied with the relevant ethical and independence requirements set out in rules of professional conduct / code of ethics in Canada.

Procedures and Findings

We have performed the procedures described below, on the deferral accounts as at December 31, 2024, which were agreed upon with the Entity.

Procedures	Findings
Obtain and recalculate the schedule of deferral activity for S&TVA from January 1, 2024 to December 31, 2024.	We obtained the schedule of deferral activity for the year and recalculated the schedules for accuracy. No differences were noted.
For the S&TVA schedules from January 1, 2024 to December 31, 2024, selected three months to vouch	We selected January, May and September 2024 and vouched the storage, transportation and ECNG costs

storage, transportation and ECNG costs. Also obtained backup spreadsheet for gas supply allocation and CIAC revenue requirement for upstream recovery calculation. Vouched total billed rates 1, 6 and 11 transportation and upstream recovery amounts for the year.	to supporting invoices. We obtained the calculation of gas supply payroll allocation costs and vouched for accuracy. We obtained the upstream recovery calculation and the upstream support journal entries and vouched to the schedules for accuracy. No differences were noted.
Obtain and recalculate the schedule of deferral activity for UFGVA from January 1, 2024 to December 31, 2024.	We obtained the schedule of deferral activity for the year and recalculated the schedules for accuracy. No differences were noted.
For the UFGVA schedules from January 1, 2024 to December 31, 2024, selected three months to vouch the Limited Balance Agreement amounts for selected months and compared to gas consumption amounts for rates 1, 6, 11 and 16 to re-calculate unaccounted for gas totals.	We selected February, May and October 2024 and obtained the limited balance agreement for these months as well as the meter read totals for these months. Re-calculated the unaccounted for gas totals for accuracy. No differences were noted.
Obtain and recalculate the schedule of deferral activity for MTVA from January 1, 2024 to December 31, 2024.	We obtained the schedule of deferral activity for the year and recalculated the schedules for accuracy. No differences were noted.
For the MTVA schedules from January 1, 2024 to December 31, 2024, selected three months to vouch billed distribution revenue and property taxes paid.	We selected February, July and August 2024 and vouched property taxes paid. We also selected December 2024 and vouched billed distribution revenue, distribution revenue per CIP and municipal taxes per CIP. No differences were noted.
Obtain and recalculate the schedule of deferral activity for ECVA from January 1, 2024 to December 31, 2024.	We obtained the schedule of deferral activity for the year and recalculated the schedules for accuracy. No differences were noted.
For the ECVA schedules from January 1, 2024 to December 31, 2024, vouch Actual Energy Content and annual delivery charges for the year.	We vouched the Actual Energy Content to the unit of measure information effective July 1, 2024 for South Bruce and the Benchmark Energy Content to Ontario Energy Board's Exhibit 9 Contents. We also vouched the delivery charges for 2024 to the financial model supporting the EB 2018-0264 application (EPCOR 2019 Financial Model Protected_20190412) and the sum of total delivery charges to the cumulative 10 year data from the rate application (EB 2018-0264). No differences were noted.
Obtain and recalculate the schedule of deferral activity for TVA from January 1, 2024 to December 31, 2024.	We obtained the schedule of deferral activity for the year and recalculated the schedules for accuracy. No differences were noted.
For the TVA schedules from January 1, 2024 to December 31, 2024, selected three months to vouch transportation and ECNG costs. Also obtained backup spreadsheet for CIAC revenue requirement for upstream recovery calculation and vouched billed rate 16 transportation and upstream recovery amounts for the year.	We selected April, July and December 2024 and vouched the transportation and ECNG costs to supporting invoices. We obtained the upstream recovery calculation and the upstream support journal entries and vouched to the schedules for accuracy. No differences were noted.
Obtain and recalculate the schedule of deferral activity for CIACVA from January 1, 2024 to December 31, 2024.	We obtained the schedule of deferral activity for the year and recalculated the schedules for accuracy. No differences were noted.
For the CIACVA schedules from January 1, 2024 to December 31, 2024, obtain back up spreadsheets for CIAC revenue requirement based on amount paid and CIAC revenue requirement per filing for the 2024 opening and ending balance and vouch capital expenditures.	We obtained the spreadsheet and vouched both figures as well as reviewed capital expenditure activity. No differences were noted, no capital expenditures observed.
Obtain and recalculate the schedule of deferral	We obtained the schedule of deferral activity for the

activity for ORDA from January 1, 2024 to December 31, 2024.	year and recalculated the schedules for accuracy. No differences were noted.
For the ORDA schedules from January 1, 2024 to December 31, 2024, selected three months to vouch samples for other revenues and agreed all late payment charges.	We selected March, July and October 2024 and vouched one sample within late payment charge, miscellaneous revenue and connection fees, respectively. Also vouched all other late payment charges. No differences were noted.
Obtain and recalculate the schedule of deferral activity for CVVA from January 1, 2024 to December 31, 2024.	We obtained the schedule of deferral activity for the year and recalculated the schedules for accuracy. No differences were noted.
For the CVVA schedules from January 1, 2024 to December 31, 2024, selected three months to vouch monthly differences between NAC and CIP revenue.	We selected March, July and September 2024 and vouched the differences with no discrepancies noted.
From deferral schedules, verify the reference price to specific OEB filings and the monthly interest rate on deferred charges to OEB prescribed interest rates.	We obtained OEB rate orders for each quarter and vouched interest rates to deferral schedules. No differences were noted.

BDO Canada LLP

Barrie, Canada
July 22, 2025

Chartered Professional Accountants
Licensed Public Accountants

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Contribution In Aid of Construction variance account

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2025 Year
CIAC revenue requirement based on amount paid	-	-	-	-	-	-	-	-	-	-	-	679,259	-
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	379,234	-
Difference	-	-	-	-	-	-	-	-	-	-	-	300,025	-
Cumulative	-	-	-	-	-	-	-	-	-	-	-	300,025	300,025
Opening Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-	9,466
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-	9,466
OEB Prescribed Interest Rate	5.49%	5.49%	5.49%	5.49%	5.49%	5.49%	5.20%	5.20%	5.20%	4.40%	4.40%	4.40%	3.16%

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year	
CIAC revenue requirement based on amount paid	-	-	-	-	-	-	-	-	-	-	-	690,967	-	
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	385,984	-	
Difference	-	-	-	-	-	-	-	-	-	-	-	304,983	-	
Cumulative	-	-	-	-	-	-	-	-	-	-	-	304,983	304,983	(4)
Opening Interest														
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-	16,301	(4)
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-	16,301	
OEB Prescribed Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	5.49%	5.49%	5.49%	5.35%	

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2023 Year	
CIAC revenue requirement based on amount paid	-	-	-	-	-	-	-	-	-	-	-	702,675	-	
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	392,735	-	
Difference	-	-	-	-	-	-	-	-	-	-	-	309,940	-	
Cumulative	-	-	-	-	-	-	-	-	-	-	-	309,940	309,940	(3)
Opening Interest														
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-	15,241	(3)
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-	15,241	
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	1.02%	1.02%	1.02%	2.20%	2.20%	2.20%	3.87%	3.87%	3.87%	4.92%	

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2022 Year	
CIAC revenue requirement based on amount paid	-	-	-	-	-	-	-	-	-	-	-	704,053	-	
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	399,485	-	
Difference	-	-	-	-	-	-	-	-	-	-	-	304,568	-	
Cumulative	-	-	-	-	-	-	-	-	-	-	-	304,568	304,568	(2)
Opening Interest														
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-	4,561	(2)
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-	4,561	
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	1.02%	1.02%	1.02%	2.20%	2.20%	2.20%	3.87%	3.87%	3.87%	1.50%	

	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2021 Year
CIAC revenue requirement based on amount paid												511,168	-
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	406,235	-
Difference	-	-	-	-	-	-	-	-	-	-	-	104,933	-
Cumulative	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	(43,424)	61,509	61,509 (1)
Opening Interest	-	-	(79)	(158)	(237)	(316)	(394)	(415)	(436)	(456)	(477)	(498)	(518)
Interest calculation on disposal balance	-	(79)	(79)	(79)	(79)	(79)	(21)	(21)	(21)	(21)	(21)	(21)	351
Closing Interest	-	(79)	(158)	(237)	(316)	(394)	(415)	(436)	(456)	(477)	(498)	(518)	(168) (1)
OEB Prescribed Interest Rate	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%

	2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
CIAC revenue requirement based on amount paid	-	-	-	-	-	-	-	-	-	-	-	161,381
CIAC revenue requirement per filing	-	-	-	-	-	-	-	-	-	-	-	204,805
Difference	-	-	-	-	-	-	-	-	-	-	-	(43,424)
Cumulative	-	-	-	-	-	-	-	-	-	-	-	(43,424)
Opening Interest												
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate	2.45%	2.45%	2.45%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%

(1) - Variance balances approved for disposition in EB-2020-0234
(2) - Variance balances approved for disposition in EB-2022-0184
(3) - Variance balances approved for disposition in EB-2023-0161
(4) - Variance balances approved for disposition in EB-2024-0238

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Energy Content variance account

Annual CIP Rev R1, 6, 11 (K)	######### ##	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2025	
Actual Energy Content (L)	39.09	January	February	March	April	May	June	July	August	September	October	November	December	Year	
Benchmark Energy Content (M)	38.89														
Difference (K * ((L - M)/L))		-	-	-	-	-	-	-	-	-	-	-	21,913	-	
Cumulative		-	-	-	-	-	-	-	-	-	-	-	21,913	21,913	
Opening Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	
Interest calculation on disposal balance		-	-	-	-	-	-	-	-	-	-	-	-	691	
Closing Interest		-	-	-	-	-	-	-	-	-	-	-	-	691	
OEB Prescribed Interest Rate		5.49%	5.49%	5.49%	5.49%	5.49%	5.49%	5.20%	5.20%	5.20%	4.40%	4.40%	4.40%	3.16%	

Annual CIP Rev R1, 6, 11 (K)	######### ##	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2024	
Actual Energy Content (L)	39.17	January	February	March	April	May	June	July	August	September	October	November	December	Year	
Benchmark Energy Content (M)	38.89														
Difference (K * ((L - M)/L))		-	-	-	-	-	-	-	-	-	-	-	27,940	-	
Cumulative		-	-	-	-	-	-	-	-	-	-	-	27,940	27,940	(4)
Opening Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	
Interest calculation on disposal balance		-	-	-	-	-	-	-	-	-	-	-	-	1,493	
Closing Interest		-	-	-	-	-	-	-	-	-	-	-	-	1,493	(4)
OEB Prescribed Interest Rate		4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	5.49%	5.49%	5.49%	5.35%	

Annual CIP Rev R1, 6, 11 (K)	######### ##	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2023	
Actual Energy Content (L)	39.12	January	February	March	April	May	June	July	August	September	October	November	December	Year	
Benchmark Energy Content (M)	38.89														
Difference (K * ((L - M)/L))		-	-	-	-	-	-	-	-	-	-	-	19,512	-	
Cumulative		-	-	-	-	-	-	-	-	-	-	-	19,512	19,512	(3)
Opening Interest		-	-	-	-	-	-	-	-	-	-	-	-		
Interest calculation on disposal balance		-	-	-	-	-	-	-	-	-	-	-	-	960	
Closing Interest		-	-	-	-	-	-	-	-	-	-	-	-	960	(3)
OEB Prescribed Interest Rate		0.57%	0.57%	0.57%	1.02%	1.02%	1.02%	2.20%	2.20%	2.20%	3.87%	3.87%	3.87%	4.92%	

Annual CIP Rev R1, 6, 11 (H)	######### ##	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2022	
Actual Energy Content (I)	39.32	January	February	March	April	May	June	July	August	September	October	November	December	Year	
Benchmark Energy Content (J)	38.89														
Difference (H * ((I - J)/I))		-	-	-	-	-	-	-	-	-	-	-	26,734	-	
Cumulative		-	-	-	-	-	-	-	-	-	-	-	26,734	26,734	(2)
Opening Interest		-	-	-	-	-	-	-	-	-	-	-	-		
Interest calculation on disposal balance		-	-	-	-	-	-	-	-	-	-	-	-	400	
Closing Interest		-	-	-	-	-	-	-	-	-	-	-	-	400	(2)
OEB Prescribed Interest Rate		0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	1.50%	

Annual CIP Rev R1, 6, 11 (E)	1,333,805	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2021 Year	
Actual Energy Content (F)	39.28														
Benchmark Energy Content (G)	38.89														
Difference (E * ((F - G)/F))		-	-	-	-	-	-	-	-	-	-	-	13,243	-	
Cumulative		864	864	864	864	864	864	864	864	864	864	864	14,107	14,107	(1)
Opening Interest		-	2	3	5	6	8	9	10	10	11	11	11	12	
Interest calculation on disposal balance		2	2	2	2	2	2	0	0	0	0	0	0	80	
Closing Interest		2	3	5	6	8	9	10	10	11	11	11	12	92	(1)
OEB Prescribed Interest Rate		2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	

Annual CIP Rev R1, 6, 11 (A)	374,194	2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
Actual Energy Content (B)	38.98												
Benchmark Energy Content (C)	38.89												
Difference (A * ((B - C)/B))		-	-	-	-	-	-	-	-	-	-	-	864
Cumulative		-	-	-	-	-	-	-	-	-	-	-	864
Opening Interest		-	-	-	-	-	-	-	-	-	-	-	-
Interest calculation on disposal balance		-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest		-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate		2.45%	2.45%	2.45%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%

(1) - Variance balances approved for disposition in EB-2020-0234
(2) - Variance balances approved for disposition in EB-2022-0184
(3) - Variance balances approved for disposition in EB-2023-0161
(4) - Variance balances approved for disposition in EB-2024-0238

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Municipal Tax variance account

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2025 Year
Billed Distribution revenue												6,315,610	
Distribution Revenue per CIP												7,189,662	
Municipal taxes per CIP												590,055	
Ratio												8.2%	
Property taxes collected through revenues												518,322	
Other													
Property taxes paid	-	128,635			7,852	3,132	163,061	324,899			(188,241)		
Difference	-	128,635	-	-	7,852	3,132	163,061	324,899	-	-	(188,241)	(518,322)	-
Cumulative	-	128,635	128,635	128,635	136,487	139,618	302,680	627,579	627,579	627,579	439,338	(78,984)	(78,984)
Opening Interest	-	-	-	589	1,177	1,766	2,390	2,995	4,307	7,026	9,327	11,628	13,239
Interest calculation on disposal balance	-	-	589	589	589	624	605	1,312	2,720	2,301	2,301	1,611	(2,492)
Closing Interest	-	-	589	1,177	1,766	2,390	2,995	4,307	7,026	9,327	11,628	13,239	10,747
OEB Prescribed Interest Rate	5.49%	5.49%	5.49%	5.49%	5.49%	5.49%	5.20%	5.20%	5.20%	4.40%	4.40%	4.40%	3.16%

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year
Billed Distribution revenue												5,034,240	
Distribution Revenue per CIP												6,645,722	
Municipal taxes per CIP												581,587	
Ratio												8.8%	
Property taxes collected through revenues												440,561	
Other													
Property taxes paid	118	293			202,644	43,027	209	256,669	50				
Difference	118	293	-	-	202,644	43,027	209	256,669	50	-	-	(440,561)	-
Cumulative	118	411	411	411	203,055	246,082	246,292	502,961	503,011	503,011	503,011	62,450	62,450 (3)
Opening Interest	-	-	0	2	4	6	848	1,869	2,892	4,979	7,280	9,581	11,883
Interest calculation on disposal balance	-	0	2	2	2	843	1,021	1,022	2,087	2,301	2,301	2,301	3,338
Closing Interest	-	0	2	4	6	848	1,869	2,892	4,979	7,280	9,581	11,883	15,221 (3)
OEB Prescribed Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	5.49%	5.49%	5.49%	5.35%

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2023 Year
Billed Distribution revenue												3,469,603	
Distribution Revenue per CIP												5,818,265	
Municipal taxes per CIP												565,324	
Ratio												9.7%	
Property taxes collected through revenues												337,120	
Property taxes paid	-	106	260	-	-	-	-	439	30	-	-	-	
Difference	-	106	260	-	-	-	-	439	30	-	-	(337,120)	-
Cumulative	-	106	366	366	366	366	366	805	835	835	835	(336,285)	(336,285) (2)
Opening Interest	-	-	-	0	0	1	1	2	2	4	6	9	12
Interest calculation on disposal balance	-	-	0	0	0	0	1	1	1	3	3	3	(16,537)
Closing Interest	-	-	0	0	1	1	2	2	4	6	9	12	(16,525) (2)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	1.02%	1.02%	1.02%	2.20%	2.20%	2.20%	3.87%	3.87%	3.87%	4.92%

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2022 Year
Billed Distribution revenue												1,897,887	
Distribution Revenue per CIP												4,620,572	
Municipal taxes per CIP												546,701	
Ratio												11.8%	
Property taxes collected through revenues												224,556	
Property taxes paid								525					
Difference	-	-	-	-	-	-	-	525	-	-	-	(224,556)	-
Cumulative	(56,915)	(56,915)	(56,915)	(56,915)	(56,915)	(56,915)	(56,915)	(56,390)	(56,390)	(56,390)	(56,390)	(280,946)	(280,946) (1)
Opening Interest	-	(27)	(54)	(81)	(108)	(135)	(162)	(189)	(216)	(243)	(270)	(297)	(323)
Interest calculation on disposal balance	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(27)	(4,207)
Closing Interest	(27)	(54)	(81)	(108)	(135)	(162)	(189)	(216)	(243)	(270)	(297)	(323)	(4,531) (1)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	1.50%

	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December
Billed Distribution revenue												460,454
Distribution Revenue per CIP												3,049,735
Municipal taxes per CIP												376,964
Ratio	-	-	-	-	-	-	-	-	-	-	-	12.4%
Property taxes collected through revenues												56,915
Property taxes paid												0.0%
Difference	-	-	-	-	-	-	-	-	-	-	-	(56,915)
Cumulative	-	-	-	-	-	-	-	-	-	-	-	(56,915)
Opening Interest	-	-	-	-	-	-	-	-	-	-	-	-
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%

	2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
Billed Distribution revenue												0
Distribution Revenue per CIP												589,357
Municipal taxes per CIP												213,867
Ratio	-	-	-	-	-	-	-	-	-	-	-	36.3%
Property taxes collected through revenues	-	-	-	-	-	-	-	-	-	-	-	-
Property taxes paid	-	-	-	-	-	-	-	-	-	-	-	-
Difference	-	-	-	-	-	-	-	-	-	-	-	-
Cumulative	-	-	-	-	-	-	-	-	-	-	-	-
Opening Interest	-	-	-	-	-	-	-	-	-	-	-	-
Interest calculation on disposal balance	-	-	-	-	-	-	-	-	-	-	-	-
Closing Interest	-	-	-	-	-	-	-	-	-	-	-	-
OEB Prescribed Interest Rate	2.45%	2.45%	2.45%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%	2.18%

(1) - Variance balances approved for disposition in EB-2022-0184
(2) - Variance balances approved for disposition in EB-2023-0161
(3) - Variance balances approved for disposition in EB-2024-0238

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Other Revenues Deferral Account

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2025 Year
4505 - Late Payment Charge	-	(1,231)	(1,853)	(1,618)	(1,742)	-	(1,350)	(1,349)	(1,071)	(1,121)	(1,050)	-	
4506 - Penalty Fees	-	-	-	-	-	-	-	-	-	-	-	-	
4511 - Collection & NSF Fees	(60)	(80)	(180)	(80)	(300)	(140)	-	(100)	(60)	(100)	-	(60)	
4515 - Connection Fees	(630)	(560)	(385)	(735)	(910)	(770)	(945)	(980)	(140)	(1,670)	(980)	(1,050)	
4592 - Miscellaneous Revenue	105	-	-	-	(159)	-	(4,302)	(1,430)	-	728	-	-	
Total	(585)	(1,871)	(2,418)	(2,433)	(3,111)	(910)	(6,597)	(3,859)	(1,271)	(2,163)	(2,030)	(1,110)	
Cumulative	(585)	(2,456)	(4,874)	(7,307)	(10,418)	(11,328)	(17,925)	(21,784)	(23,055)	(25,218)	(27,248)	(28,358)	(28,358)
Opening Interest	-	-	(3)	(14)	(36)	(70)	(117)	(166)	(244)	(338)	(423)	(515)	(615)
Interest calculation on disposal balance	-	(3)	(11)	(22)	(33)	(48)	(49)	(78)	(94)	(85)	(92)	(100)	(895)
Closing Interest	-	(3)	(14)	(36)	(70)	(117)	(166)	(244)	(338)	(423)	(515)	(615)	(1,510)
OEB Prescribed Interest Rate	5.49%	5.49%	5.49%	5.49%	5.49%	5.49%	5.20%	5.20%	5.20%	4.40%	4.40%	4.40%	3.16%

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year
4505 - Late Payment Charge	(666)	16	(1,774)	(2,703)	(1,791)	(1,388)	(902)	(706)	(684)	(1,362)	(18)	12	
4506 - Penalty Fees	-	-	-	-	-	-	-	-	-	-	-	-	
4511 - Collection & NSF Fees	(60)	(80)	(40)	(60)	(80)	(60)	(140)	(120)	(20)	(40)	(220)	(40)	
4515 - Connection Fees	(350)	(315)	(350)	(420)	(875)	(595)	(1,120)	(910)	(770)	(835)	(820)	(840)	
4592 - Miscellaneous Revenue	(6,406)	-	-	(41)	(20)	-	(660)	-	-	(20)	-	(145)	
Total	(7,482)	(379)	(2,164)	(3,224)	(2,766)	(2,043)	(2,822)	(1,736)	(1,474)	(2,257)	(1,058)	(1,013)	
Cumulative	(7,482)	(7,860)	(10,024)	(13,248)	(16,014)	(18,057)	(20,879)	(22,615)	(24,089)	(26,346)	(27,404)	(28,417)	(28,417) (2)
Opening Interest		-	(29)	(60)	(102)	(157)	(224)	(298)	(385)	(479)	(589)	(710)	(835)
Interest calculation on disposal balance	-	(29)	(31)	(42)	(55)	(66)	(75)	(87)	(94)	(110)	(121)	(125)	(1,519)
Closing Interest	-	(29)	(60)	(102)	(157)	(224)	(298)	(385)	(479)	(589)	(710)	(835)	(2,354) (2)
OEB Prescribed Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	5.49%	5.49%	5.49%	5.35%

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2023 Year
4505 - Late Payment Charge	-	-	-	-	-	-	-	(1,036)	1	(473)	(247)	(1,048)	
4506 - Penalty Fees	(217)	-	-	-	-	-	-	-	-	-	-	-	
4511 - Collection & NSF Fees	(48)	-	(192)	48	(96)	(48)	(96)	(60)	(60)	(60)	(20)	(40)	
4515 - Connection Fees	(140)	(245)	(210)	(210)	(315)	(490)	(315)	-	(280)	(35)	(770)	-	
4592 - Miscellaneous Revenue	-	-	-	-	-	-	(963)	(245)	(35,747)	(455)	(49,075)	84,165	
Total	(405)	(245)	(402)	(162)	(411)	(538)	(1,374)	(1,341)	(36,086)	(1,023)	(50,112)	83,077	
Cumulative	(405)	(650)	(1,052)	(1,214)	(1,625)	(2,163)	(3,537)	(4,878)	(40,964)	(41,986)	(92,098)	(9,021)	(9,021) (1)
Opening Interest		-	(0)	(1)	(1)	(2)	(4)	(8)	(14)	(23)	(155)	(291)	(588)
Interest calculation on disposal balance	-	(0)	(0)	(1)	(1)	(1)	(4)	(6)	(9)	(132)	(135)	(297)	(444)
Closing Interest	-	(0)	(1)	(1)	(2)	(4)	(8)	(14)	(23)	(155)	(291)	(588)	(1,031) (1)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	1.02%	1.02%	1.02%	2.20%	2.20%	2.20%	3.87%	3.87%	3.87%	4.92%

(1) - Variance balances approved for disposition in EB-2023-0161
(2) - Variance balances approved for disposition in EB-2024-0238

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Customer Volume Variance Account

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2025 Year
Monthly NACS/CIP Difference	66,198	109,482	93,815	43,180	44,493	25,213	17,995	17,657	20,332	32,922	12,971	68,345	
Closing CVVA Balance	66,198	175,680	269,495	312,675	357,168	382,382	400,376	418,034	438,366	471,288	484,259	552,604	552,604
Opening Interest	-	-	303	1,107	2,340	3,770	5,404	7,061	8,796	10,607	12,215	13,943	15,719
Interest calculation on disposal balance	-	303	804	1,233	1,430	1,634	1,657	1,735	1,811	1,607	1,728	1,776	17,435
Closing Interest	-	303	1,107	2,340	3,770	5,404	7,061	8,796	10,607	12,215	13,943	15,719	33,153
OEB Prescribed Interest Rate	5.49%	5.49%	5.49%	5.49%	5.49%	5.49%	5.20%	5.20%	5.20%	4.40%	4.40%	4.40%	3.16%

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year
Monthly NACS/CIP Difference	43,572	66,581	56,169	17,948	11,589	12,375	11,621	11,760	12,294	14,729	(6,814)	50,410	
Closing CVVA Balance	43,572	110,153	166,322	184,270	195,859	208,234	219,855	231,615	243,909	258,639	251,824	302,235	302,235 (1)
Opening Interest		-	172	606	1,296	2,061	2,874	3,738	4,650	5,611	6,727	7,911	9,063
Interest calculation on disposal balance	-	172	434	690	765	813	864	912	961	1,116	1,183	1,152	16,154
Closing Interest	-	172	606	1,296	2,061	2,874	3,738	4,650	5,611	6,727	7,911	9,063	25,217 (1)
OEB Prescribed Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	5.49%	5.49%	5.49%	5.35%

(1) - Variance balances approved for disposition in EB-2024-0238

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Unaccounted For Gas

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2025 Year
Opening Balance	(46,484.69)												
Unaccounted for Gas	(9,889.71)	5,763.06	(14,671.57)	782.96	(5,311.89)	(3,906.68)	(1,079.36)	(3,729.17)	230.58	(5,713.77)	(235.29)	4,332.58	
Closing UFG Balance	(56,374)	(50,611)	(65,283)	(64,500)	(69,812)	(73,719)	(74,798)	(78,527)	(78,296)	(84,010)	(84,246)	(79,913)	(79,913)
Opening Interest	(5,405)	(5,618)	(5,876)	(6,107)	(6,406)	(6,701)	(7,020)	(7,340)	(7,664)	(8,004)	(8,291)	(8,599)	(8,908)
Interest calculation on disposal balance	(213)	(258)	(232)	(299)	(295)	(319)	(319)	(324)	(340)	(287)	(308)	(309)	(2,521)
Closing Interest	(5,618)	(5,876)	(6,107)	(6,406)	(6,701)	(7,020)	(7,340)	(7,664)	(8,004)	(8,291)	(8,599)	(8,908)	(11,430)
OEB Prescribed Interest Rate	5.49%	5.49%	5.49%	5.49%	5.49%	5.49%	5.20%	5.20%	5.20%	4.40%	4.40%	4.40%	3.16%

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year
Opening Balance	(122,598.86)												
Unaccounted for Gas	48,810.26	13,185.99	3,008.28	5,247.85	(8,878.73)	(5,497.15)	1,367.71	(2,550.00)	(2,194.12)	(16,375.28)	35035.02	4,954.34	
Closing UFG Balance	(73,789)	(60,603)	(57,594)	(52,346)	(61,225)	(66,722)	(65,355)	(67,905)	(70,099)	(86,474)	(51,439)	(46,485)	(46,485)
Opening Interest	(1,900)	(2,384)	(2,674)	(2,913)	(3,152)	(3,369)	(3,624)	(3,900)	(4,172)	(4,453)	(4,774)	(5,170)	
Interest calculation on disposal balance	(483)	(291)	(239)	(239)	(217)	(254)	(277)	(271)	(282)	(321)	(396)	(235)	
Closing Interest	(2,384)	(2,674)	(2,913)	(3,152)	(3,369)	(3,624)	(3,900)	(4,172)	(4,453)	(4,774)	(5,170)	(5,405)	(5,405)
OEB Prescribed Interest Rate	4.73%	4.73%	4.73%	4.98%	4.98%	4.98%	4.98%	4.98%	4.98%	5.49%	5.49%	5.49%	

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2023 Year
Opening Balance	(32,506.95)												
Unaccounted for Gas	17,698.61	4,282.21	(25,936.85)	(7,667.77)	(23,387.49)	(38,080.83)	(4,710.09)	(21,104.69)	(9,571.85)	32,897.47	57,965.03	(72,475.66)	
Closing UFG Balance	(14,808)	(10,526)	(36,463)	(44,131)	(67,518)	(105,599)	(110,309)	(131,414)	(140,986)	(108,088)	(50,123)	(122,599)	(122,599)
Opening Interest	(145)	(161)	(168)	(173)	(204)	(241)	(299)	(492)	(694)	(935)	(1,390)	(1,739)	
Interest calculation on disposal balance	(15)	(7)	(5)	(31)	(38)	(57)	(194)	(202)	(241)	(455)	(349)	(162)	
Closing Interest	(161)	(168)	(173)	(204)	(241)	(299)	(492)	(694)	(935)	(1,390)	(1,739)	(1,900)	(1,900)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	1.02%	1.02%	1.02%	2.20%	2.20%	2.20%	3.87%	3.87%	3.87%	

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2022 Year
Opening Balance	(35,300.53)												
Unaccounted for Gas	24,434.82	732.23	(1,962.41)	(4,658.26)	(3,667.45)	(5,029.58)	(3,402.56)	(2,582.37)	(1,484.94)	(287.03)	3,429.76	(2,728.63)	
Closing UFG Balance	(10,866)	(10,133)	(12,096)	(16,754)	(20,422)	(25,451)	(28,854)	(31,436)	(32,921)	(33,208)	(29,778)	(32,507)	(32,507)
Opening Interest	(9)	(26)	(31)	(36)	(41)	(49)	(59)	(71)	(85)	(100)	(115)	(131)	
Interest calculation on disposal balance	(17)	(5)	(5)	(6)	(8)	(10)	(12)	(14)	(15)	(16)	(16)	(14)	
Closing Interest	(26)	(31)	(36)	(41)	(49)	(59)	(71)	(85)	(100)	(115)	(131)	(145)	(145)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	

	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2021 Year
Opening Balance													
Unaccounted for Gas	-	-	-	-	-	-	-	(4,724.94)	(1,241.14)	(2,087.90)	8,274.90	(35,521.45)	
Closing UFG Balance	-	-	-	-	-	-	-	(4,725)	(5,966)	(8,054)	221	(35,301)	(35,301)
Opening Interest								-	-	(2)	(5)	(9)	
Interest calculation on disposal balance								-	(2)	(3)	(4)	0	
Closing Interest	-	-	-	-	-	-	-	-	(2)	(5)	(9)	(9)	(9)
OEB Prescribed Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Transportation Variance Account

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2025 Year
Storage	-	-	-	-	-	-	-	-	-	-	-	-	
Transportation	19,285.87	19,224.20	19,313.14	28,585.63	20,404.09	20,428.10	20,363.48	20,401.95	20,384.59	19,697.82	19,776.44	19,673.21	
ECNG	3,201.43	2,602.01	2,668.56	2,490.68	2,690.56	1,881.29	2,234.58	2,297.49	2,216.87	2,632.95	2,607.75	3,009.16	
Gas Supply													
CNG													
CIAC Revenue Requirement	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	12,439.77	
Total Cost	34,927	34,266	34,421	43,516	35,534	34,749	35,038	35,139	35,041	34,771	34,824	35,122	
Billed R16 Transportation	17,536	17,536	17,536	17,536	17,536	17,536	17,536	17,536	17,536	17,536	17,536	17,536	
R16 Upstream Recovery	13,649	13,649	13,649	13,649	13,649	13,649	13,649	13,649	13,649	13,649	13,649	13,649	
Opening Balance	328,815	332,558	335,639	338,877	351,208	355,558	359,123	362,977	366,932	370,789	374,375	378,015	
Monthly Variance	3,743	3,082	3,237	12,332	4,350	3,565	3,854	3,955	3,857	3,586	3,640	3,938	
Cumulative Variance	332,558	335,639	338,877	351,208	355,558	359,123	362,977	366,932	370,789	374,375	378,015	381,952	381,952
Opening Interest	34,930	35,950	36,981	38,021	39,072	40,160	41,263	42,376	43,501	44,639	45,788	46,949	48,121
Interest calculation on disposal balance	1,019	1,031	1,040	1,051	1,089	1,102	1,113	1,125	1,137	1,149	1,161	1,172	14,209
Closing Interest	35,950	36,981	38,021	39,072	40,160	41,263	42,376	43,501	44,639	45,788	46,949	48,121	62,329
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year
Storage	-	-	-	-	-	-	-	-	-	-	-	-	
Transportation	22,765.85	19,365.80	19,450.92	19,702.57	19,771.45	19,920.18	20,004.36	19,835.33	19,887.91	19,566.92	18,977.74	19,257.64	
ECNG	2,948.78	2,720.02	2,993.79	2,767.46	2,348.28	1,990.50	2,206.71	2,296.23	2,146.72	2,561.66	2,783.79	2,975.77	
Gas Supply	-	-	-	-	-	-	-	-	-	-	-	-	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	12,661.20	
Total Cost	38,376	34,747	35,106	35,131	34,781	34,572	34,872	34,793	34,696	34,790	34,423	34,895	
Billed R16 Transportation	19,182	15,889	17,536	17,536	17,545	19,190	17,536	17,536	17,536	17,536	17,536	17,536	
R16 Upstream Recovery	14,930	12,367	13,649	13,649	13,649	14,930	13,649	13,649	13,649	13,649	13,649	13,649	
Opening Balance	284,792	289,055	295,546	299,468	303,414	307,002	307,453	311,141	314,749	318,261	321,866	325,105	
Monthly Variance	4,264	6,491	3,922	3,947	3,588	451	3,687	3,608	3,512	3,605	3,238	3,710	
Cumulative Variance	289,055	295,546	299,468	303,414	307,002	307,453	311,141	314,749	318,261	321,866	325,105	328,815	328,815
Opening Interest	23,529	24,412	25,308	26,224	27,153	28,093	29,045	29,998	30,963	31,938	32,925	33,923	
Interest calculation on disposal balance	883	896	916	928	941	952	953	965	976	987	998	1,008	
Closing Interest	24,412	25,308	26,224	27,153	28,093	29,045	29,998	30,963	31,938	32,925	33,923	34,930	34,930
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2023 Year
Storage	-	-	-	-	-	-	-	-	-	-	-	-	
Transportation	19,058.54	19,030.45	19,097.11	19,220.43	19,322.40	19,331.84	19,364.05	19,249.30	19,241.04	18,852.00	18,754.84	18,773.44	
ECNG	3,638.74	3,110.04	3,267.76	2,965.31	2,819.43	2,048.84	2,031.21	2,120.17	1,903.93	2,561.48	2,772.57	2,957.91	
Gas Supply	-	-	-	-	-	-	-	-	-	-	-	-	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	12,882.63	
Total Cost	35,580	35,023	35,247	35,068	35,024	34,263	34,278	34,252	34,028	34,296	34,410	34,614	
Billed R16 Transportation	15,889	15,889	15,889	15,889	15,889	15,889	15,889	15,889	17,536	17,536	17,536	40,969	
R16 Upstream Recovery	12,367	12,367	12,367	12,367	12,367	12,367	12,367	12,367	13,656	13,661	13,684	31,963	
Opening Balance	261,298	268,622	275,388	282,380	289,191	295,960	301,967	307,988	313,984	316,820	319,919	323,110	
Monthly Variance	7,324	6,767	6,991	6,812	6,768	6,007	6,021	5,996	2,836	3,099	3,191	(38,318)	
Cumulative Variance	268,622	275,388	282,380	289,191	295,960	301,967	307,988	313,984	316,820	319,919	323,110	284,792	284,792
Opening Interest	12,504	13,314	14,146	15,000	15,875	16,772	17,689	18,625	19,580	20,554	21,536	22,527	
Interest calculation on disposal balance	810	833	854	875	896	917	936	955	973	982	992	1,002	
Closing Interest	13,314	14,146	15,000	15,875	16,772	17,689	18,625	19,580	20,554	21,536	22,527	23,529	23,529
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2022 Year
Storage	-	-	-	-	-	-	-	-	-	-	-	-	
Transportation	17,528.81	17,421.02	17,400.53	17,629.36	17,615.86	17,557.89	17,573.59	17,546.95	17,484.54	17,441.26	17,254.03	18,010.30	
ECNG	3,076.94	2,942.54	3,119.70	2,857.00	2,624.07	1,928.90	2,096.86	1,997.23	1,735.97	2,690.79	2,955.70	3,219.27	
Gas Supply	-	-	-	-	-	-	-	-	-	-	-	-	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	13,104.06	
Total Cost	33,710	33,468	33,624	33,590	33,344	32,591	32,774	32,648	32,325	33,236	33,314	34,334	
Billed R16 Transportation	15,889	15,889	15,889	15,889	15,889	15,889	15,889	15,889	15,889	15,889	15,889	15,889	
R16 Upstream Recovery	12,367	12,367	12,367	12,367	12,367	12,367	12,367	12,367	12,367	12,367	12,367	12,367	
Opening Balance	201,417	206,870	212,082	217,449	222,784	227,871	232,206	236,724	241,116	245,184	250,163	255,221	
Monthly Variance	5,453	5,211	5,368	5,334	5,088	4,334	4,518	4,392	4,068	4,980	5,057	6,077	
Cumulative Variance	206,870	212,082	217,449	222,784	227,871	232,206	236,724	241,116	245,184	250,163	255,221	261,298	261,298
Opening Interest	3,981	4,606	5,247	5,905	6,579	7,269	7,976	8,696	9,429	10,177	10,937	11,712	
Interest calculation on disposal balance	624	641	657	674	691	706	720	734	747	760	776	791	
Closing Interest	4,606	5,247	5,905	6,579	7,269	7,976	8,696	9,429	10,177	10,937	11,712	12,504	12,504
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2021 Year
Storage	-	-	-	-	-	-	-	-	-	-	-	-	
Transportation	-	-	-	-	-	-	-	7,355.29	7,736.27	7,777.62	11,442.73	17,257.70	
ECNG	-	-	-	-	-	-	-	1,369.53	1,856.03	2,734.96	2,712.45	2,945.35	
Gas Supply	-	-	-	-	-	-	-	-	-	-	-	-	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	20,044	20,044	20,044	20,044	20,044	20,044	20,044	20,044	20,044	20,044	20,044	20,044	
Total Cost	20,044	20,044	20,044	20,044	20,044	20,044	20,044	28,768	29,636	30,556	34,199	40,247	
Billed R16 Transportation	-	-	-	-	-	-	-	-	9,877	15,883	15,873	15,889	
R16 Upstream Recovery	-	-	-	-	-	-	-	-	7,688	12,362	12,355	12,367	
Opening Balance	-	20,044	40,087	60,131	80,174	100,218	120,262	140,305	169,074	181,144	183,456	189,427	
Monthly Variance	20,044	20,044	20,044	20,044	20,044	20,044	20,044	28,768	12,071	2,311	5,971	11,990	
Cumulative Variance	20,044	40,087	60,131	80,174	100,218	120,262	140,305	169,074	181,144	183,456	189,427	201,417	201,417
Opening Interest	-	-	62	186	373	621	932	1,305	1,740	2,264	2,825	3,394	
Interest calculation on disposal balance	-	62	124	186	249	311	373	435	524	562	569	587	
Closing Interest	-	62	186	373	621	932	1,305	1,740	2,264	2,825	3,394	3,981	3,981
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

EPCOR Natural Gas Limited Partnership
Southern Bruce Deferral
Storage & Transportation Variance Account

	2024 January	2024 February	2024 March	2024 April	2024 May	2024 June	2024 July	2024 August	2024 September	2024 October	2024 November	2024 December	2025 Year
Storage	7,177.07	7,183.88	7,186.96	7,184.94	7,211.49	7,136.97	7,123.09	7,155.92	7,155.51	7,083.33	7,112.13	7,197.33	
Transportation	25,381.14	25,361.39	30,372.70	39,962.65	25,196.03	25,057.43	25,176.83	25,139.52	25,150.18	26,058.57	25,943.48	26,185.94	
ECNG	5,927.41	5,485.95	5,216.92	4,471.48	3,830.44	3,622.63	3,698.62	3,775.53	3,798.87	5,603.23	5,335.67	6,189.50	
Gas Supply	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	15,750.25	
CNG	-	-	-	-	-	-	-	-	-	13,603.79	77,424.14	36,305.25	
CIAC Revenue Requirement	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	19,163.05	
Total Cost	73,399	72,945	77,690	86,532	71,151	70,730	70,912	70,984	71,018	87,262	150,729	110,791	
Billed R1/R6/R11 Transportation	41,233	54,349	43,007	41,547	22,558	10,908	5,653	6,090	5,917	5,475	32,389	36,154	
R1/R6/R11 Upstream Recovery	19,114	29,035	23,034	22,268	12,085	5,831	3,032	2,755	3,063	2,796	8,708	17,583	
Opening Balance	2,712,190	2,725,242	2,714,802	2,726,451	2,749,169	2,785,677	2,839,667	2,901,893	2,964,032	3,026,070	3,105,061	3,214,693	
Monthly Variance	13,052	(10,439)	11,649	22,717	36,508	53,990	62,226	62,139	62,038	78,991	109,631	57,054	
Cumulative Variance	2,725,242	2,714,802	2,726,451	2,749,169	2,785,677	2,839,667	2,901,893	2,964,032	3,026,070	3,105,061	3,214,693	3,271,747	3,271,747
Opening Interest	201,622	210,030	218,478	226,894	235,346	243,869	252,504	261,307	270,303	279,492	288,872	298,498	308,464
Interest calculation on disposal balance	8,408	8,448	8,416	8,452	8,522	8,636	8,803	8,996	9,189	9,381	9,626	9,966	121,709
Closing Interest	210,030	218,478	226,894	235,346	243,869	252,504	261,307	270,303	279,492	288,872	298,498	308,464	430,173
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2023 January	2023 February	2023 March	2023 April	2023 May	2023 June	2023 July	2023 August	2023 September	2023 October	2023 November	2023 December	2024 Year
Storage	7,190.27	7,223.48	7,193.88	7,143.41	7,192.08	7,191.89	7,158.08	7,176.33	7,157.90	7,098.68	7,161.82	7,126.90	
Transportation	35,198.12	25,158.18	25,099.73	24,747.68	24,614.51	24,384.06	24,321.06	24,523.86	24,445.48	24,873.23	25,758.15	25,369.71	
ECNG	4,824.85	4,799.65	4,751.08	4,017.37	3,705.67	3,364.97	3,355.52	3,729.65	3,598.68	4,427.86	6,998.17	5,714.99	
Gas Supply	20,849.92	20,849.92	20,849.92	20,849.92	20,849.92	20,849.92	20,849.92	20,849.92	20,849.92	21,431.16	21,431.16	21,431.16	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	19,504.15	
Total Cost	87,567	77,535	77,399	76,263	75,866	75,295	75,189	75,784	75,556	77,335	80,853	79,147	
Billed R1/R6/R11 Transportation	33,897	28,215	29,709	30,027	19,076	11,537	4,431	3,009	5,984	4,526	19,901	49,149	
R1/R6/R11 Upstream Recovery	16,259	15,189	16,043	16,213	10,116	6,262	2,387	1,617	2,272	2,400	6,732	15,503	
Opening Balance	2,128,856	2,166,267	2,200,398	2,232,045	2,262,067	2,308,742	2,366,237	2,434,608	2,505,765	2,573,065	2,643,475	2,697,695	
Monthly Variance	37,411	34,132	31,646	30,023	46,675	57,495	68,370	71,157	67,300	70,409	54,220	14,495	
Cumulative Variance	2,166,267	2,200,398	2,232,045	2,262,067	2,308,742	2,366,237	2,434,608	2,505,765	2,573,065	2,643,475	2,697,695	2,712,190	2,712,190
Opening Interest	113,213	119,812	126,528	133,349	140,268	147,281	154,438	161,773	169,320	177,088	185,065	193,260	
Interest calculation on disposal balance	6,599	6,715	6,821	6,919	7,012	7,157	7,335	7,547	7,768	7,977	8,195	8,363	
Closing Interest	119,812	126,528	133,349	140,268	147,281	154,438	161,773	169,320	177,088	185,065	193,260	201,622	201,622
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December	2023 Year
Storage	7,226.73	7,201.23	7,182.03	7,200.70	7,308.44	7,200.15	7,166.84	7,165.35	7,163.39	7,083.33	7,123.54	7,202.09	
Transportation	23,854.99	23,830.68	23,765.37	23,679.61	23,538.29	23,422.85	23,401.20	23,532.60	23,518.97	24,064.17	24,224.45	24,238.52	
ECNG	4,210.46	4,025.96	3,917.68	3,592.09	3,248.05	3,159.36	3,201.55	3,310.50	3,336.18	4,261.71	4,560.82	4,754.96	
Gas Supply	16,622.92	16,622.92	16,622.92	16,622.92	16,622.92	16,622.92	16,622.92	16,622.92	16,622.92	35,332.25	35,332.25	35,332.25	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	19,845.25	
Total Cost	71,760	71,526	71,333	70,941	70,563	70,251	70,238	70,477	70,487	90,587	91,086	91,373	
Billed R1/R6/R11 Transportation	15,978	19,404	18,862	18,316	12,393	12,296	5,059	20,294	3,123	4,554	22,672	18,893	
R1/R6/R11 Upstream Recovery	8,632	10,936	10,652	10,318	7,131	6,886	3,120	3,557	1,027	1,671	4,449	8,566	
Opening Balance	1,467,023	1,514,174	1,555,359	1,597,178	1,639,485	1,690,524	1,741,593	1,803,652	1,850,278	1,916,615	2,000,977	2,064,942	
Monthly Variance	47,151	41,185	41,819	42,307	51,039	51,069	62,059	46,626	66,337	84,362	63,965	63,914	
Cumulative Variance	1,514,174	1,555,359	1,597,178	1,639,485	1,690,524	1,741,593	1,803,652	1,850,278	1,916,615	2,000,977	2,064,942	2,128,856	2,128,856
Opening Interest	48,603	53,151	57,845	62,667	67,618	72,700	77,941	83,340	88,931	94,667	100,608	106,811	
Interest calculation on disposal balance	4,548	4,694	4,822	4,951	5,082	5,241	5,399	5,591	5,736	5,942	6,203	6,401	
Closing Interest	53,151	57,845	62,667	67,618	72,700	77,941	83,340	88,931	94,667	100,608	106,811	113,213	113,213
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2021	2022
	January	February	March	April	May	June	July	August	September	October	November	December	Year
Storage	7,089.22	7,207.81	7,122.92	7,083.33	7,164.24	7,169.55	7,083.33	7,086.34	7,101.33	7,083.33	7,135.53	7,168.98	
Transportation	24,596.10	24,800.78	24,738.48	24,553.02	24,553.02	24,553.02	24,553.02	24,574.57	24,620.10	24,749.88	24,988.58	24,257.53	
ECNG	3,132.66	3,235.82	3,209.22	3,150.44	3,116.69	3,057.46	3,077.14	3,096.33	3,133.39	3,308.65	3,723.26	3,800.49	
Gas Supply	18,210.58	18,210.58	18,210.58	18,210.58	18,210.58	18,210.58	18,210.58	18,210.58	18,210.58	18,210.58	18,210.58	(841.42)	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	20,186.36	
Total Cost	73,215	73,641	73,468	73,184	73,231	73,177	73,110	73,154	73,252	73,539	74,244	54,572	
Billed R1/R6/R11 Transportation	661	1,475	3,071	3,427	2,827	2,076	1,200	1,257	1,108	1,415	4,434	11,082	
R1/R6/R11 Upstream Recovery	364	809	1,671	1,848	1,524	1,099	642	550	573	749	1,697	4,841	
Opening Balance	655,636	727,826	799,183	867,909	935,818	1,004,697	1,074,699	1,145,968	1,217,315	1,288,885	1,360,259	1,428,373	
Monthly Variance	72,190	71,357	68,726	67,909	68,879	70,002	71,268	71,347	71,570	71,374	68,114	38,650	
Cumulative Variance	727,826	799,183	867,909	935,818	1,004,697	1,074,699	1,145,968	1,217,315	1,288,885	1,360,259	1,428,373	1,467,023	1,467,023
Opening Interest	9,833	11,865	14,122	16,599	19,290	22,191	25,305	28,637	32,189	35,963	39,958	44,175	
Interest calculation on disposal balance	2,032	2,256	2,477	2,691	2,901	3,115	3,332	3,553	3,774	3,996	4,217	4,428	
Closing Interest	11,865	14,122	16,599	19,290	22,191	25,305	28,637	32,189	35,963	39,958	44,175	48,603	48,603
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	2021
	January	February	March	April	May	June	July	August	September	October	November	December	Year
Storage	-	-	-	-	3,613.29	7,218.33	7,222.83	7,588.08	7,173.33	7,083.33	7,094.53	7,083.33	
Transportation	-	-	-	-	(0.00)	14,998.79	16,665.32	9,393.95	9,022.76	9,022.76	15,208.70	24,159.74	
ECNG	-	-	-	-	-	-	-	3,313.03	3,060.21	3,148.60	3,142.87	3,075.81	
Gas Supply	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	9,898.75	
CNG	-	-	-	-	-	-	-	-	-	-	-	-	
CIAC Revenue Requirement	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	30,876.47	
Total Cost	40,775	40,775	40,775	40,775	44,389	62,992	64,663	61,070	60,032	60,030	66,221	75,094	
Billed R1/R6/R11 Transportation	-	-	-	-	-	-	-	-	90	(357)	1,166	1,230	
R1/R6/R11 Upstream Recovery	-	-	-	-	-	-	-	-	2	(266)	23	69	
Opening Balance	-	40,775	81,550	122,326	163,101	207,489	270,482	335,145	396,215	456,156	516,809	581,841	
Monthly Variance	40,775	40,775	40,775	40,775	44,389	62,992	64,663	61,070	59,940	60,653	65,032	73,795	
Cumulative Variance	40,775	81,550	122,326	163,101	207,489	270,482	335,145	396,215	456,156	516,809	581,841	655,636	655,636
Opening Interest	-	-	126	379	758	1,264	1,907	2,746	3,785	5,013	6,427	8,029	
Interest calculation on disposal balance	-	126	253	379	506	643	838	1,039	1,228	1,414	1,602	1,804	
Closing Interest	-	126	379	758	1,264	1,907	2,746	3,785	5,013	6,427	8,029	9,833	9,833
Rate	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%	3.72%

Appendix F - CNG Analysis

EPCOR

Memorandum

Introduction

The information contained herein is intended to supplement EPCOR Natural Gas Limited Partnership's ("ENGLP") Southern Bruce 2026 IRM and is provided as response to the OEB Staff Report to the Ontario Energy Board (EB-2024-0139), Section 3.6 Compressed Natural Gas (CNG) – Southern Bruce. Section 3.6 of the OEB Staff Report noted that OEB staff, "*recommends that EPCOR prepare a thorough analysis and cost comparison on CNG and other viable options with a proposal to implement the most appropriate option as part of Southern Bruce's 2026 IRM*." The analysis was performed from April to June 2025, lead by EPCOR Process Engineer, Elizabeth Magnussen, and with support from Southern Bruce Operations and Management team members.

Results of the analysis and cost comparison of options indicate that CNG continues to be the most cost effective solution to address the seasonally-driven low-pressure challenges within Southern Bruce. Should financial assumptions change within the future, ENGLP reserves the right to reassess other options detailed within this report.

Background

During the Fall drying season of 2023, the southern-most sections of ENGLP's natural gas supply system experienced low pressure, causing high-volume, seasonal grain drying customers to experience periods of reduced gas supply. Immediate action was taken by Operations to limit the impact to customers; this included modifications to two high-volume grain drying customer's pressure regulating stations to add secondary regulator runs. The also team evaluated the option to replace several customer regulator stations with regulators which have a lower pressure drop across the device. These regulators were individually priced at over $20,000 each, a price point which is comparatively 5x more costly than other devices currently selected for the application. Although this option could suffice if the low pressure impacts were marginal, due to the signficant gas demand on the system, the option to replace select customer regulators was found to be insufficient to address the low pressure challenges within Southern Bruce.

The efforts taken by Operations improved downstream supply pressures in 2023, however, this would prove insufficient to address forecasted 2024 conditions. As hydraulic modelling indicated, with increased growth of system gas (residential, commercial) connections as well as the addition of another large grain dryer at the end of the Ripley line, the southern part of the South Bruce system was poised to see unacceptably low pressures in 2024 (see Figure 1). The 2024 growth is considered to be within the filed Common Infrastructrue Plan ("CIP"), and low pressures are experienced during a Fall typical case (dryers running at their average rates). Table 1 provides the breakdown of total gas flow through Kincardine Station for the Fall worst case scenario (all agricultural customers demanding gas, plus typical residential and customer gas demand). From Table 1, 4,337.5 m^3/hr is the current maximum demanded gas flow through the system used within all subsequent hydraulic analyses.

In 2024, to address the near-term low pressure challenges within the Southern Bruce natural gas supply system, ENGLP turned to a third party compressed natural gas (CNG) supplier, Certarus, to provide temporary injection of CNG into its southern-most distribution line. The solution proved successful as no agricultural customers experienced low gas supply pressure during Fall 2024. The total cost incurred for this temporary initiative in 2024 was $130,864.

As ENGLP looks towards the Fall 2025 drying season, the intent of this report is to evaluate all options previously considered to alleviate the low-pressure challenge within the Southern Bruce natural gas system, and to provide a detailed technical and cost analysis for each. As taken from the August 15, 2024 "*Review of 2024 Annual Update to Gas Supply Plan of EPCOR Natural Gas Limited Partnership - Responses to OEB Staff Questions (EB-2024-0139)*", Pages 22-23, the following options were considered:

A. Dryer customer participation: seek mutual support from Dryer customers requesting them to stagger their loading, thus reducing the overall system impacted demand;
B. Increased pressure at Kincardine Station from 80 psig outlet pressure (current) to 95 psig (design maximum);
C. Install a compressor station on the 6" MDPE line in the south;
D. Install a secondary gas line to loop Kincardine and Ripley;
E. Aquire a Local Gas Supply System ("LGSS") and tie-into ENGLP piping at Lucknow; and
F. Inject compressed natural gas (CNG) on a 2.5 month basis during the Fall term through rental and supply agreement with Certarus.

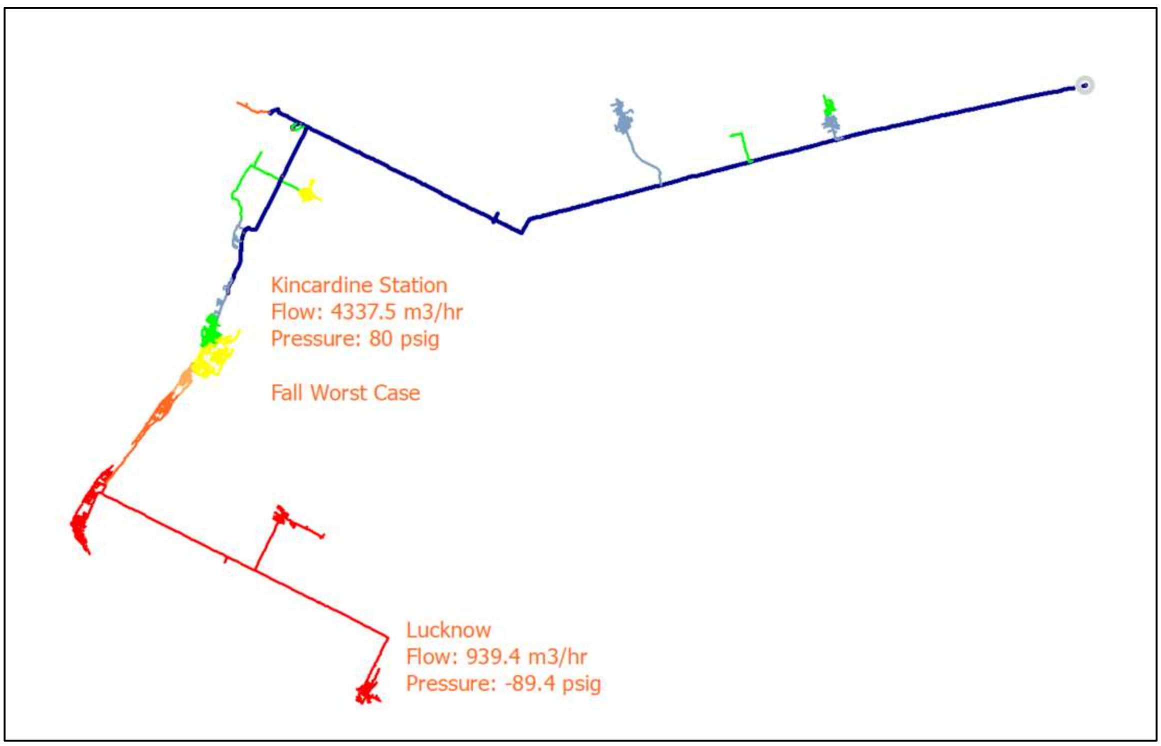

Figure 1: Hydraulic modelling results for Fall worst case scenario indicates insufficient pressure (red line) within system south of Lurgan Beach

Table 1 – 2024 Fall Worst Case Flow Demand

Agricultural Drying Customers	Peak Day Flowrate (m^3/h)
Snobelen Ripley	984
Snobelen Lucknow	726
Smith Dryer	286
McLarty	184
Schlegel	426
Schwoba	145
Sam Snobelen	129
Beishuizen	92
Residential & Commercial Customers*	1,365
Total Fall Worst Case	4,337

*Taken as the total demand from Kincardine Station from all residential and commercial customers for Fall typical case

Options Analysis

The following options were evaluated first in 2024 and again more recently as part of the April to June 2025 assessment.

A. Dryer Customer Participation. This option involved meeting with the dryer customers to explain the issue and seek their input into staggering their loading. While this may assist in managing low pressure issues in an emergency, it is not seen as a viable option on its own. Dryer customers expect to be able to consume at peak demand as per their applied-for loading. There is also not much flexibility for dryer customers to manage their gas usage per the existing contracted rates. The crop type and weather determine the timing of drying, and this is not within the customer's direct control. In consideration of forecasted growth and the unpredictable nature of seasonality impacts, this solution alone cannot provide adequate confidence to fully address the low-pressure supply challenges within Southern Bruce.

B. Increased Pressure at Kincardine Station. This option considered raising the pressure at the upstream Kincardine station from 80 psig (current regulator set pressure) to its designed maximum allowable operating pressure of 95 psig. Kincardine Station is located at the terminal point of the 6-inch steel pipeline in ENGLP's Southern Bruce distribution network and provides pressure regulation from 300 psig (maximum inlet pressure) to 80 psig. After Kincardine Station, the piping network transitions to 6-inch MDPE piping, for which pressures must be maintained below 99 psig.

   Kincardine Station is designed to allow a throughput of 5,417 m^3/hr at minimum design inlet pressure conditions of 110 psig and discharge pressure of 95 psig. The throughput available increases as the supply pressure increases. At present, the supply pressure has consistently been above 200 psig, therefore it would stand to reason that there is ample capacity through Kincardine Station to support the current maximum demand conditions of 4,337.5 m^3/hr.

   In evaluating the option further, a hydraulic analysis was performed with Kincardine Station outlet pressure adjusted to 95 psig; however, as can be seen in Figure 2, the pressure loss along the existing piping network is too significant to be overcome with a pressure adjustment at the station alone. As indicated by Figure 2, at the southern-most region of Southern Bruce, the system experiences a negative pressure, thus eliminating this option as a viable solution.

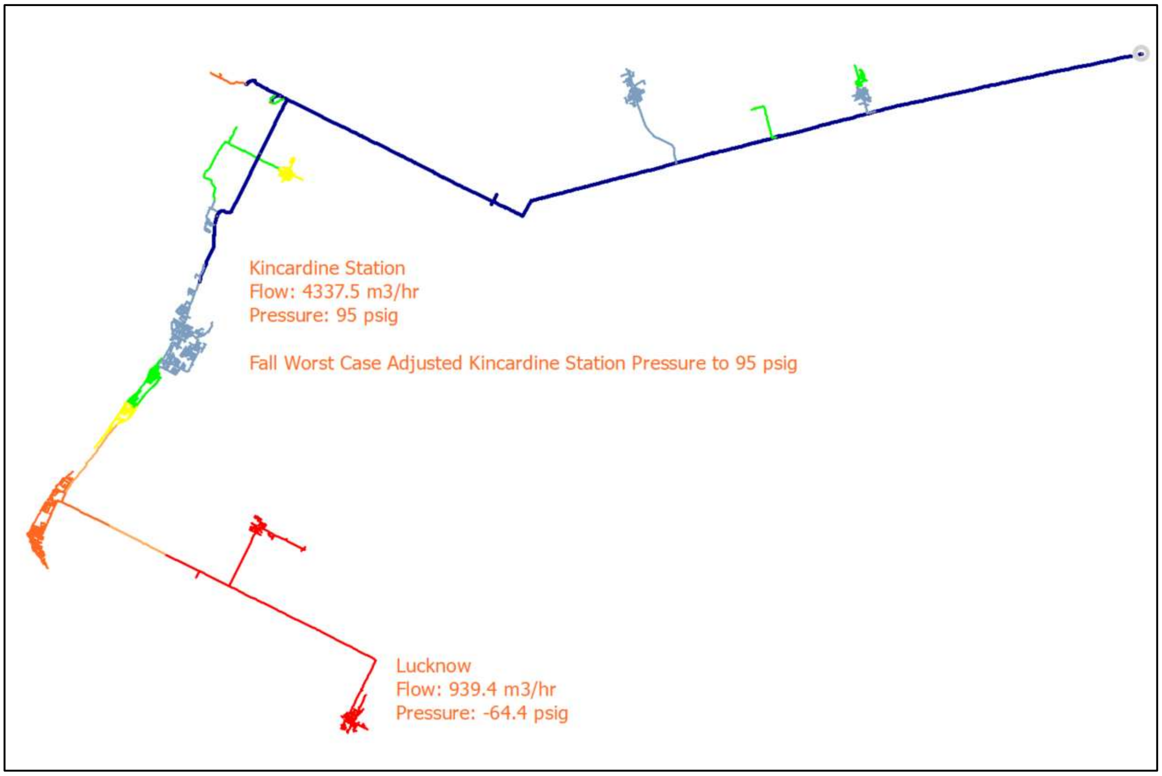

Figure 2: Hydraulic modelling results for Fall worst case when Kincardine Station set pressure is adjusted to 95 psig.

C. Installation of a Compressor Station. This option considered addition of a compressor station at the location indicated in Figure 3, just north of Lurgan Beach, where the inlet pressure of the system during the Fall worst case scenario is anticipated to be 18 psig. The compressor selected would increase the system pressure on the discharge side to 80 psig, which is found through hydraulic analysis to be sufficient to resolve the low-pressure challenges observed within the southern-most region of the pipeline network. This option is therefore considered viable, and has the ability to increase the overall system capacity by an additional 50 m^3/hr.

While this option is shown to be viable, Operations has expressed concerns over the additional maintenance effort that will be required to ensure the safe operation and continued reliability of the proposed compressor station. High-level cost estimates for compressor stations can be determined by calculating the power requirement of the equipment and applying cost factors for the purchase and installation. According to Towler and Sinnott, the formula:

$C_e = a + b*S^n$ can be used to estimate the cost of a compressor, where:
C_e = purchased equipment cost (Jan 2010)
a = 580,000 (centrifugal compressor)
b = 20,000 (centrifugal compressor)
n = 0.6 (centrifugal compressor))
S = size parameter, for compressor (kW)

The total power requirement for the compressor station was calculated to be 164 kW based on a two-stage, adiabatic centrifugal compressor with efficiency of 88% and intercooling between the stages[1]. The ratio of specific heats (C_p/C_v) was taken as 1.31. Based on the cost estimation formula above and in consideration of 2% inflation, the approximate equipment cost is $1.8M, not inclusive of installation. EPCOR's process engineer has attempted to validate the cost figure above, however, at the time of this report, vendor specification documentation and pricing quotes have not been received. To complete the financial analysis, a 200% factor is applied to estimate the installation cost, including forecasted LTC costs; therefore, the total value of the compression option is $3.5M, not including ongoing operations and maintenance (O&M) spend.

To approximate the O&M costs, the energy demand of the compressor station is used and a $0.14/kWh rate is applied. Assuming 30-day peak loading, the electrical consumption is determined to cost $16,300. Labor and specialty maintenance services would be required during the 2.5 months of Fall worst case; the value of this cost was provided a placeholder value of $10,000. Thus, the total O&M value used within financial modelling was $26,300 to account for 30 days of peak operating time; it should be noted that a fullsome validation of all assumptions for the compressor would be required if pursuing this option.

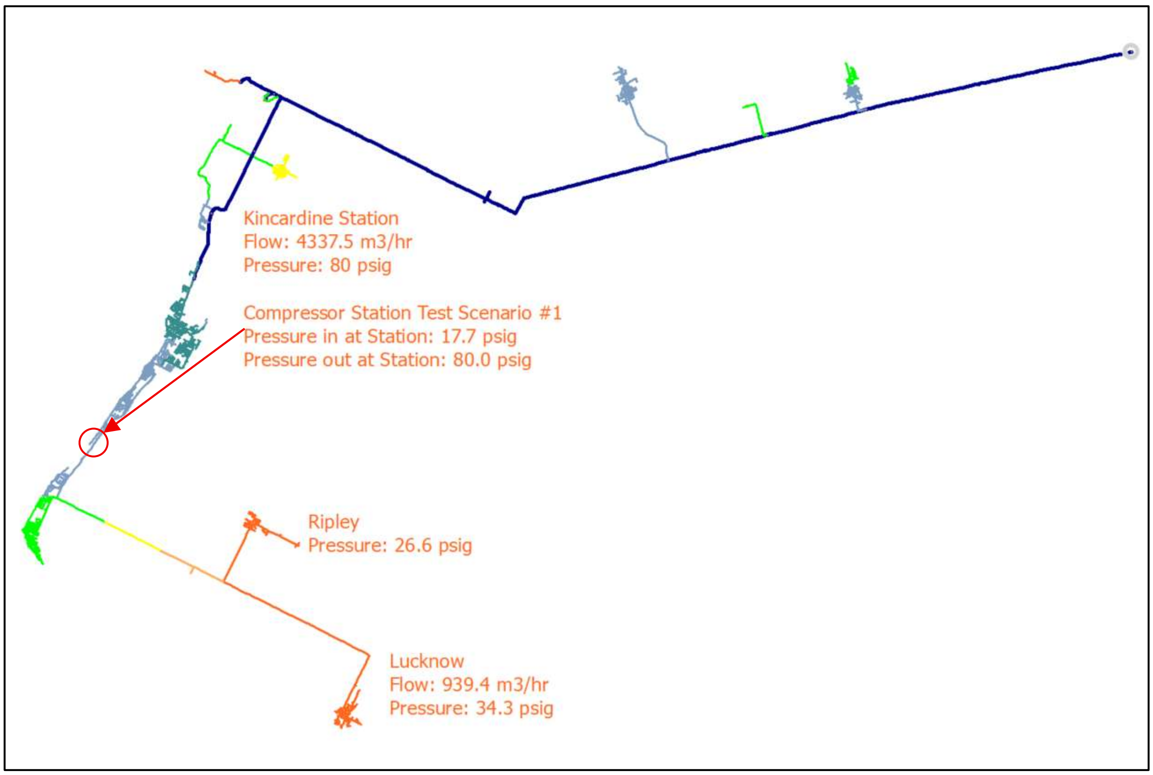

Figure 3: Hydraulic modelling results for compressor station option (location indicated by arrow). Model indicates sufficient pressure at south of system after compression.

[1] Calculation of compressor total power demand taken from Fluid Mechanics for Chemical Engineers, McGraw-Hill (3rd Edition). 2005. See dimensional formula 8.31a, power equation for adiabatic compressor:

$$P_B = \frac{0.371 T_a \gamma q_o}{(\gamma - 1)\eta}\left[\left(\frac{p_b}{p_a}\right)^{1-1/\gamma} - 1\right]$$

Where, P_B = power, kW, q_0 = volume gas (m^3/s), T_a = inlet temp (K), γ = compressibility ratio (C_p/C_v), η = efficiency, $p_b/p_a = [(80+14.7)/(17.7+14.7)]^{1/2} = 1.71$ absolute pressure ratio for each stage, where two stages are assumed

D. Install a secondary gas line to loop Kincardine and Ripley. This option was evaluated at two tie-in locations for the Kincardine supply side, (1) at Kincardine Station where the supply pressure is at its highest (80 psig), and (2) further north of Kincardine station at an off-take from the 8-inch steel line, identified as “Valve Site 2”. In the case of Option 2, a pressure regulation station would reduce the gas supply from the steel mainline to 80 psig prior to transitioning to 6-inch MDPE piping. The technical details for both options are described in Table 2, below.

Table 2 – Bypass option key data by location tie-in

	Option 1	Option 2
Supply Pressure (psig)	80.0	268.0**
Minimum Pressure Observed in Lucknow (psig)	22.7	24.7
Secondary Line Length (km)	21.0	30.0
Additional Capacity Available (m^3/h)	925	800
Total Flow through Kincardine Station (m^3/h)	5,260	3,276
Estimated Capital Cost to Install*	$9.2M	$12.9M

*For full detailed cost breakdown, see Addendum

**Option 2 supply pressure is further reduced to 80 psig within the hydraulic model prior to transitioning to MDPE

Figure 4 provides the hydraulic modelling results for Option 1. As is shown in Figure 4, this option provides a solution to the low gas pressure observed within the southern most region of South Bruce, while also allowing the system to grow its revenue base with the added capacity of up to 925 m^3/hr which would be available under this scenario. Figure 5 provides the hydraulic modelling results for Option 2, which was also found to be a viable solution.

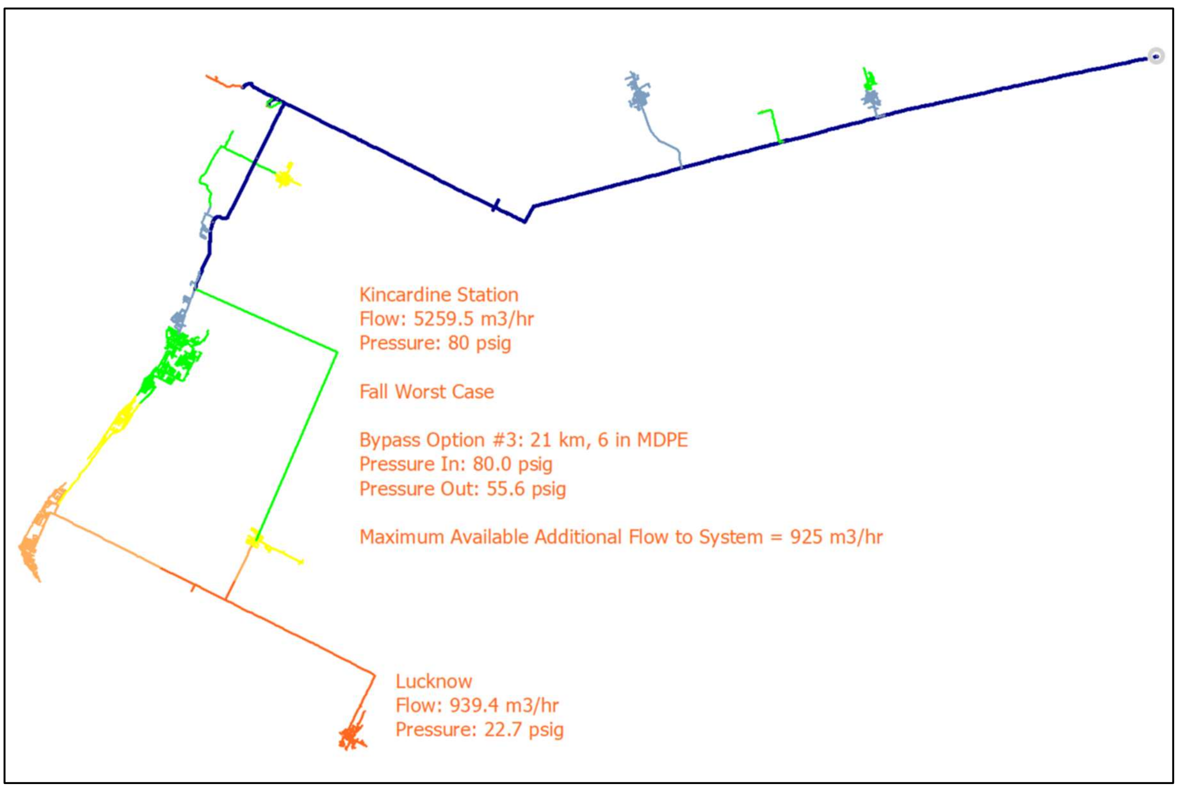

Figure 4: Hydraulic modelling results of Bypass Option #1 routing with additional capacity added of 925 m^3/hr

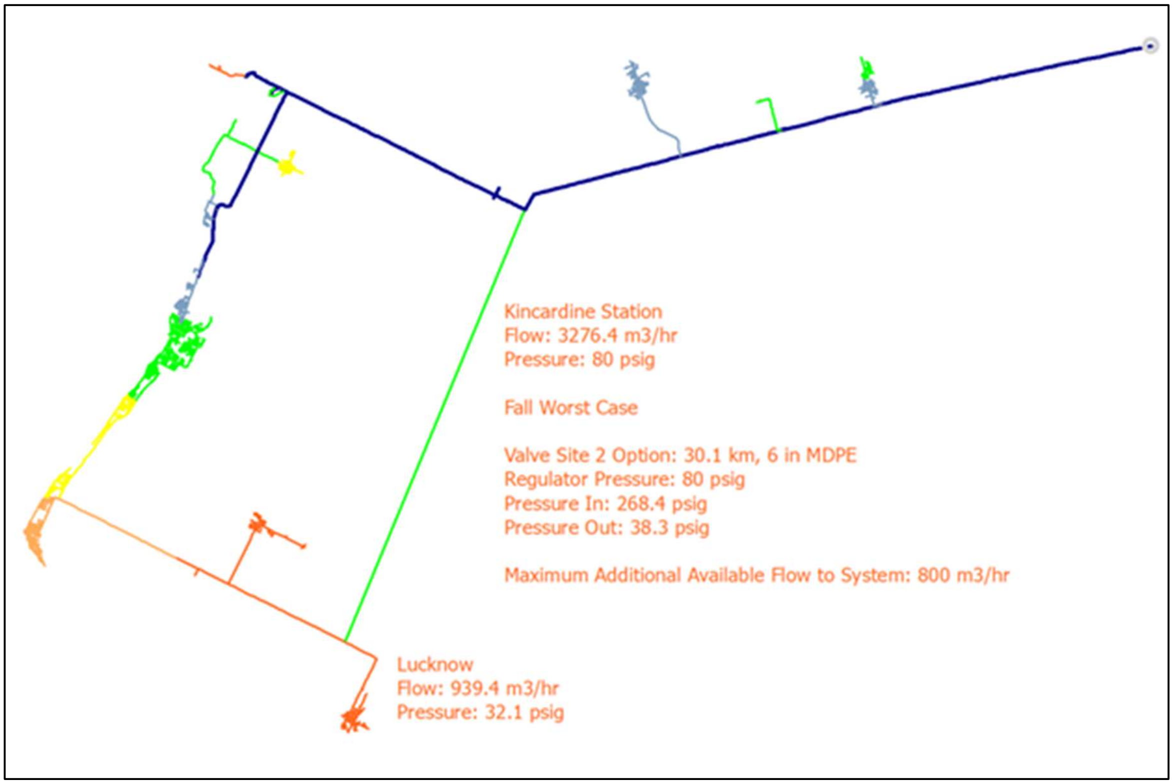

Figure 5 Hydraulic modelling results of Bypass Option #2 routing with additional capacity added of 800 m^3/hr

E. Aquire local gas supply system ("LGSS") and tie-into ENGLP piping at Lucknow. This option involves constructing a 7.5 km pipeline from the south end of the ENGLP system in Lucknow to connect to the existing LGSS pipeline. The LGSS pipeline is currently connected to well gas and to the Enbridge system south of Wingham. The LGSS line is constructed of a combination of 6-inch MDPE, 4-inch MDPE, and 3-inch aluminum piping and serves a large agricultural drying customer ("Drying Customer") at the terminal point of this line with an assumed 850 m^3/hr of gas. During the Fall drying months, the Drying Customer uses gas from the Enbridge supply system as well as some gas from the local produced well gas supply.

   ENGLP has performed hydraulic modelling for the option to acquire LGSS' pipeline and tie-in to the system with approximately 7.5 km of 6 inch MDPE piping (Figure 6). The LGSS regulating station located at Enbridge's supply interconnect would be regulated to 95 psig to maximize the system throughput. A second regulating station would be required prior to further injecting gas at Lucknow, to reduce gas pressure below 80 psig and to restrict the gas such that adeqate flow is maintained to the Drying Customer. As is indicated in Figure 6, the option presented does resolve the Fall worst case low-pressure challenges within the southern region of South Bruce; however, due to the required continued supply of gas to the Drying Customer at an assumed 850 m^3/hr gas while maintaining adequate supply pressure to this customer, it was determined that the LGSS option only provided marginal gains in capacity to the southern region of Lucknow, estimated at up to 100 m^3/hr. It was also found that by supplying the southern region of Lucknow by the LGSS connection, the gas flowing through Kincardine Station was significantly reduced, thus showing the competitive nature of fluid dynamics on the system as a result of the bi-directional flow of gas (Kincardine Station supplying from the north, LGSS supplying from the South).

The total estimated cost for this option was evaluated to be $7.2 M*

*Due to the commercial sensitivity of the proposed LGSS acquisition and tie-in option, details surrounding the cost breakdown are not provided within this report.

Although this option does resolve the low-pressure challenges within the Fall drying season, there are several reasons why it is not a preferred long-term solution. The rationale used to eliminate this option as a contender for long-term low-pressure mitigation are as follows:

- Lower comparative gain in incremental system capacity,
- Uncertainties surrounding the cost for Enbridge Reinforcement, and,
- Unconfirmed condition of existing LGSS assets.

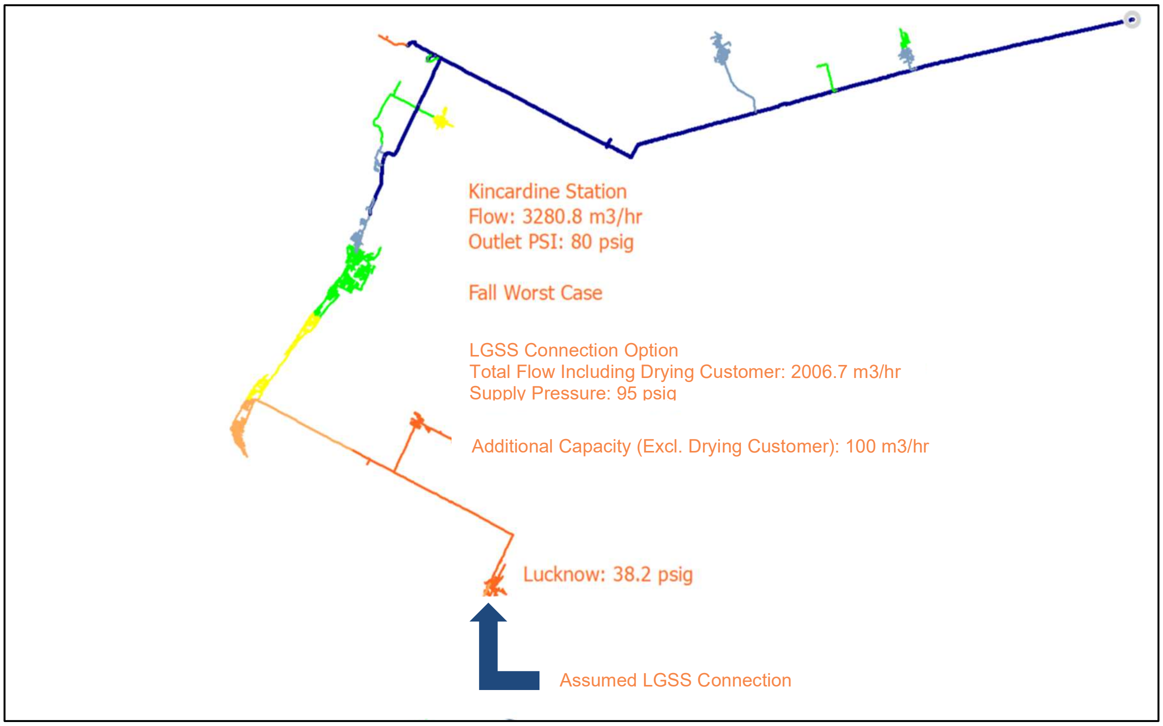

Figure 6: Hydraulic modelling results of LGSS connection; 100 m^3/hr additional capacity available (in addition to Existing Dryer). Pressure regulation at connector line set to 45 psig was determined through iteration to provide the best flow to Lucknow and southern system customers.

F. <u>Inject compressed natural gas ("CNG") on a 2.5 month basis during the Fall term through rental and supply agreement with Certarus</u>. This option involves injecting CNG in the south part of ENGLP's system near Ripley, Ontario. CNG was first injected into ENGLP's natural gas distribution network in 2024 as a method to counter the low-pressure challenges observed in 2023 and in anticipation that the challenge would be further impacted by increased gas demand by residential, commercial, and agricultural drying customers.

Certarus is an energy-as-a-service supplier of CNG across North America. In 2024, Certarus provided two (2) CNG trailers and two (2) pressure reduction stations at the injection point located at 2375 Concession 4, Ripley, Ontario. The equipment functions to inject gas once a pre-determined set pressure is sensed at the interconnecting line. As one trailer is depleted, the second trailer automatically takes over, and the first trailer is swapped by Certarus for a fully supplied one. Certarus' CNG refill station is located in Mount Forest, approximately 80 km from Ripley.

Certarus' business model is that of a transportation and storage company. ENGLP is responsible for the in-year cost of transportation and rental of the CNG trailers and equipment, and the fixed midstream cost/m^3 of gas usage. The intended regulatory treatment of these costs would be to recover them through the Storage & Transportation variance deferral account. The gas commodity costs would be a flow through to system customers and blended into the gas supply plan from Enbridge at Dornoch.

CNG was initially set to be injected into the system once the system pressure dropped to 40 psig; however, system monitoring found that low pressures continued to be observed elsewhere along the piping network which posed a risk to agricultural drying customers. As such, Certarus was requested to increase the set pressure at which injection would begin; this value was increased to 55 psig at which point CNG began to flow into the southern pipeline network and there was observed to be no further challenges with inability to meet system pressure requirements.

Throughout the duration of CNG injection, which occurred from October 12 to November 8, 2024, Operations monitored the system and injected natural gas predominantly during the early morning hours between 6 AM to 10 AM. There were many days where gas injection was not required during this time period. The total gas supplied by CNG amounted to 28,586 m^3 while the total cost incurred for equipment rentals, service call outs, TSSA application and variable cost of gas, amounted to $130,863.52. It should be noted that only 10% of the costs incurred were from the variable cost of gas, and the bulk of the total cost was due to equipment rentals.

Hydraulic modelling was performed to estimate the system shortfall that would be required to be replaced with CNG, caused by significant pressure losses throughout the system from Kincardine Station during the Fall drying season. Through this analysis, it was determined that 1,117 m^3/hr was required to supplement the ENGLP gas network through CNG injection at the southern-most area of the pipeline during these periods of high gas demand. Assuming 4 hours per day of CNG injection and 45 days of peak drying time, it is estimated that a total of 201,060 m^3 of CNG could be required to supplement the low-pressure challenges within the south. Using the 2024 pricing model from Certarus, this would account for $257,411. A second cost scenario was calculated whereby only 30 days of peak drying time was observed, this totalled to a CNG demand of 134,040 m^3 or $227,608 total cost.

In comparing the extent of the 2023 grain drying season (which continued until early December) and the 2024 grain drying season (which was completed by early November), it is challenging to predict the extent of drying time year-over-year to formulate a fair assumption on anticipated cost of CNG. Historical climate data was reviewed for Goderich, Ontario, which is the closest weather station to the surrounding area where ENGLP's pipeline is located (see Table 3) and is compared against the climate data observed from September to December 2024 (see Table 4).

From this data, it is clear that ENGLP experienced drier-than-average conditions with approximately one-third of the typical precipitation, thus suggesting that the 28,586 m^3 of CNG injected is well-below what could be observed in future years. As such, ENGLP has determined to use the 30-day peak flow scenario when comparing other options from an economic perspective.

Initial cost estimates from 2024 based on 3-month rental fee are compared against actuals in Table 5, below.

Table 3 – Historical Climate Data, Goderich Station

Goderich Station Historical Average (1991-2024)[2]	Average Temp. (°C)	Average Relative Humidity (%)	Total Precipitation Amount (mm)
September	17.8	73	112
October	11.2	74	123
November	5.0	76	125
December	-0.2	77	113

Table 4 – 2024 Climate Data. Goderich Station

Goderich Station (2024)[3]	Average Temp. (°C)	Average Relative Humidity (%)	Total Precipitation Amount (mm)
September	18.2	76	47.1
October	12.2	69	33.5
November	6.7	77	37.3
December	-0.3	82	104.4

Table 5 – CNG Cost Analysis

	Budget 2024	Actuals 2024	% Difference
Equipment Rental	$162,500	$105,583	42%
Mob/Demob	$5,060	$7,150	34%
TSSA Fee	$0	$2,120	200%
Service Callouts	$0	$3,300	200%
Commodity Charge	$0.56/$m^3$	$0.45/$m^3$	22%
Total Cost of CNG	$191,008	$130,863	37%

[2] Taken from ClimateData.org, see table "Weather by Month // Weather Averages Goderich." Accessed June 12, 2025. Goderich climate: Weather Goderich & temperature by month

[3] Taken from Government of Canada website, Historical Data "Daily Data Report for [*Month*] 2024." Data pulled for each month and consolidated. Goderich, Ontario weather station. Accessed on June 12, 2025. Daily Data Report for December 2024 - Climate - Environment and Climate Change Canada

Financial Analysis

Having performed hydraulic feasibility verifications in the previous section, the following four (4) options were found to be viable and were subsequently compared with a Net Present Value (NPV) analysis:

C. Installation of a Compressor Station
D. Install a secondary gas line to loop Kincardine and Ripley
  D.1. Option 1 – Bypass Located at Kincardine Station
  D.2. Option 2 – Bypass Located at Valve Site 2
E. Aquire local gas supply system ("LGSS") and tie-into ENGLP piping at Lucknow
F. Inject compressed natural gas ("CNG") on a 2.5 month basis during the Fall term through rental and supply agreement with Certarus.

Financial assumptions applied across all examples are as indicated in Table 6, while Table 7 provides the summary of NPV results. As shown in Table 7, Option F – Injection of CNG on a 2.5-month basis results in the lowest NPV of $4.9M over a 40-year period. CNG remains the preferred option for ENGLP for the short term.

Long term, ENGLP may find it prudent to revisit the other options considered here, especially if able to quantify to a greater certainty the capital and O&M cost estimates applied. Detailed cost analyses of Options D and E also found several opportunities whereby, should regulatory frameworks change in the future, such as modification of the limit where LTC fees apply, these may warrant further investigation. Lastly, the revenue that could be gained from sales of excess gas provided in Options D.1 & D.2 likely warrants further analysis to evaluate this opportunity. Although at present, there is not perceived to be a demand for this gas, should that change in the future, Options D.1 and D.2. would be worthwhile revisiting.

See the attached Addendum for detailed capital cost assessment for Options D.1 and D.2. All other financial data for Options C and F is provided within the body of this report.

Table 6: Financial assumptions used in NPV analysis

Discount Rate Determination	OEB Cost of Capital	Capital Structure
Short term debt	1.76%	4%
Long term debt	3.72%	60%
Equity	8.78%	36%
Weighted Average Cost of Capital (WACC)	5.46%	
Other Calculation Inputs	**Value**	
Inflation	2%	
Asset Life	20 years (Compressor Option C) * 40 years (Pipeline Options D-F)	

*Option C is modelled at full replacement cost in year 20 to ensure fair comparison between options for full 40-year asset life

Table 7: NPV Analysis of Options Considered

	Options Description	Capital Cost ($Million)	O&M Cost ($/yr)	NPV ($Millions)
C	Installation of a Compressor Station	3.5	26,300	5.9
D.1.	Secondary Gas Line – Kincardine Station	9.2	*	9.2
D.2.	Secondary Gas Line – Valve Site 2	12.9	*	12.9
E	LGSS Acquisition and Tie-in at Lucknow	7.2	-	7.2
F	CNG Injection – 2.5-month term	-	225,000	4.9

*Although there is excess gas capacity within these options, the perceived revenue from this gas was not included within the NPV analysis, nor has the capital cost been adjusted to accommodate adding of services. Internal discussions believe that the cost of service is in excess of the revenue potential, thus this opportunity was not developed further.

Cost Recovery – CNG

As provided within the Financial Analysis, CNG is the preferred option to address the seasonal low-pressure challenges caused by excess gas demand on the system from agricultural drying customers.

The commodity cost is expected to be treated as a flow through to the customer and submitted as part of the regulatory QRAM schedules.

An option for recovery is through the use of the existing Storage & Transportation variance account (S&TVA). ENGLP does not have certainty to recover the costs of the trailer equipment rental, pressure reduction system and transportation of this equipment through this account until it files for it with the OEB in subsequent years. The following is an excerpt from the S&TVA accounting order. Grain dryers are rate 11 customers.

> *The Storage and Transportation Variance Account for Rates 1, 6 & 11 ("S&TVA Rates 1, 6 & 11") is to record the difference between actual total upstream costs, including all Transportation and Storage Costs and Upstream Recovery Costs, incurred for all customers in Rates 1, 6 and 11 and the Upstream Charges (including all Upstream Recovery Charges and Transportation and Storage Charges) recovered from these customers. The S&TVA Rates 1, 6 & 11 records the difference between upstream costs and Upstream Charges collected to ensure that upstream costs are treated as a flow-through to customers. The effective date of this account is January 1, 2019.*
>
> *The S&TVA Rates 1, 6 & 11 will record: (a) the variance between the forecast storage and transportation demand levels and the actual storage and transportation demand levels; (b) amounts credited or invoiced from storage and transportation suppliers related to the disposition of the suppliers' deferral/variance accounts; (c) the variance between the forecasted commodity cost for fuel and the updated reference price set through the Quarterly Rate Adjustment Mechanism (QRAM) process; and (d) the variance between the forecast and actual administrative costs for storage and transportation including costs associated with daily nominations, load balancing, and storage procurement.*

ENGLP expects to request disposition of this deferral account for the first time as part of its 2025 custom IR annual update, for recovery in 2026. ENGLP will need to accept the risk that the OEB may not approve the inclusion of these costs, and they may be incurred at the shareholder expense.

Conclusion and Recommendation

As indicated within the financial analysis, ENGLP should continue to use CNG to address the seasonally driven low-pressure challenges within its southern system as Option F provides the lowest value NPV of $4.9M when evaluated over a 40-year period. In 2024, ENGLP paid a total of $130,863 to Certarus to provide CNG to its system. Climate data indicated Fall 2024 was a drier-than-average season, and it is believed that CNG pricing is more likely to cost $225,000 in the foreseeable future, especially if precipitation were to follow historical averages. ENGLP should continue to monitor CNG as with each year, more data will continue to justify this option, or point to a need to revisit other, longer-term capital investments as indicated within this report.

Bypass Option D.1

			Qty	Rate	Total
AECON	NPS4 Install		0.00	$ 163.60	$ -
	NPS2 Install		0.00	$ 133.50	$ -
	NPS 3 Install		0.00	$ 143.00	$ -
	NPS 6 Install - New Build		0.00	$ 174.21	$ -
	NPS 6 Install - Built Up		21000.00	$ 239.47	$ 5,028,870.00
	Meter Install		0.00	$ 100.00	$ -
	Distribution disc 2"		0.00	$ 121.36	$ -
	Dist disc 4"		0.00	$ 148.73	$ -
	Service Install - short		0.00	$ 2,760.16	$ -
	Service install - long		0.00	$ 5,214.12	$ -
	residential per meter		0.00	$ 50.20	$ -
	Service - comm short		0.00	$ 3,829.72	$ -
	service - comm long		0.00	$ 6,283.67	$ -
	com per meter		0.00	$ 50.20	$ -
	mainline taps		0.00	$ 50,000.00	$ -
	private locates (services)		0.00	$ 540.00	$ -
	HDD rock		0.00	$ 525.00	$ -
	mech rock		0.00	$ 800.00	$ -
	small reg station supply and install		0.00	$ 150,000.00	$ -
	mainline Locates		21000.00	$ -	$ -
	mainline sewer / septic		21000.00	$ -	$ -
ENGINEERING	Aecon - pre-design	per meter	21000.00	$ 10.80	$ 226,800.00
	Aecon - Design	per meter	21000.00	$ 14.40	$ 302,400.00
	Seer Innovation - AC mit+ CP	lump sum	0	$ 50,000.00	$ -
	Stantec - Pre-LTC (Environmental)	lump sum	1	$ 200,000.00	$ 200,000.00
	Stantec - Enviro Monitoring	per meter	21000.00	$ 10.00	$ 210,000.00
	Stantec - Post report (Environmental)	lump sum	1	$ 50,000.00	$ 50,000.00
	Stantec - Excess solis legislation		1	$ 100,000.00	$ 100,000.00
MATERIAL	Material - NPS 6	per meter	21630	$ 59.44	$ 1,285,687.20
	Tracer Wire	per meter	21630	$ 0.50	$ 10,815.00
	1/2 inch reels - Residential Service	per meter	0	$ 1.50	$ -
	2" fittings	placeholder	0	$ 50,000.00	$ -
	Meters / sets / regs - Residential	each	0.00	$ 650.00	$ -
	Risers - Residential (3/4'' riser and valve and bracket)	each	0.00	$ 102.30	$ -
	Tee Kits - Residential (EF tee, EFV, EF coupling)	each	0.00	$ 126.72	$ -
	Fittings - Residential	placeholder	0.00	$ 50,000.00	$ -
	Meters / sets / regs - Commercial	each	0.00	$ 2,500.00	$ -
	Risers - Commercial (2")	each	0.00	$ 305.80	$ -
	Tee Kits - Commercial (2")	each	0.00	$ 167.20	$ -
	Fittings - Commercial	placeholder	0.00	$ 50,000.00	$ -
	Pipeline markers	placeholder	70	$ 46.60	$ 3,262.00
EPCOR COST	Internal QA/QC Inspections / Gas Tech	months	6	$ 11,250.00	$ 67,500.00
	IDC				
	OH's	Placeholder	1	$ 75,000.00	$ 75,000.00
	land purchases / TLUs	Placeholder	1	$ 50,000.00	$ 50,000.00
	Land solution	Placeholder	1	$ 50,000.00	$ 50,000.00
	Legal	Placeholder	1	$ 50,000.00	$ 50,000.00
	SCADA	Placeholder	0	$ 25,000.00	$ -
	meter protection	Placeholder	1	$ -	$ -
	P&GA / marketing	Placeholder	1	$ 50,000.00	$ 50,000.00
	FN meetings	Placeholder	1	$ 50,000.00	$ 50,000.00
	Enbride contribution (Not Required)				
	Modelling	Placeholder	0	$ 10,000.00	$ -
	Ops spares, etc.		1		$ -
	other ops costs?				
	Gas	Placeholder	1	$ 2,000.00	$ 2,000.00
	CONTINGENCY (15%)				$ 1,171,850.13
	Project Sub Total				$ 8,984,184.33
	Project Management (3.0%)				$ 269,525.53
	Project Total				$ 9,253,709.86

Bypass Option D.2

			Qty	Rate	Total
AECON	NPS4 Install		0.00	$ 163.60	$ -
	NPS2 Install		0.00	$ 133.50	$ -
	NPS 3 Install		0.00	$ 143.00	$ -
	NPS 6 Install - New Build		0.00	$ 174.21	$ -
	NPS 6 Install - Built Up		30100.00	$ 239.47	$ 7,208,047.00
	Meter Install		0.00	$ 100.00	$ -
	Distribution disc 2"		0.00	$ 121.36	$ -
	Dist disc 4"		0.00	$ 148.73	$ -
	Service Install - short		0.00	$ 2,760.16	$ -
	Service install - long		0.00	$ 5,214.12	$ -
	residential per meter		0.00	$ 50.20	$ -
	Service - comm short		0.00	$ 3,829.72	$ -
	service - comm long		0.00	$ 6,283.67	$ -
	com per meter		0.00	$ 50.20	$ -
	mainline taps		0.00	$ 50,000.00	$ -
	private locates (services)		0.00	$ 540.00	$ -
	HDD rock		0.00	$ 525.00	$ -
	mech rock		0.00	$ 800.00	$ -
	small reg station supply and install		0.00	$ 150,000.00	$ -
	mainline Locates		30100.00	$ -	$ -
	mainline sewer / septic		30100.00	$ -	$ -
ENGINEERING	Aecon - pre-design	per meter	30100.00	$ 10.80	$ 325,080.00
	Aecon - Design	per meter	30100.00	$ 14.40	$ 433,440.00
	Seer Innovation - AC mit+ CP	lump sum	0	$ 50,000.00	$ -
	Stantec - Pre-LTC (Environmental)	lump sum	1	$ 200,000.00	$ 200,000.00
	Stantec - Enviro Monitoring	per meter	30100.00	$ 10.00	$ 301,000.00
	Stantec - Post report (Environmental)	lump sum	1	$ 50,000.00	$ 50,000.00
	Stantec - Excess solis legislation		1	$ 100,000.00	$ 100,000.00
MATERIAL	Material - NPS 6	per meter	31003	$ 59.44	$ 1,842,818.32
	Tracer Wire	per meter	31003	$ 0.50	$ 15,501.50
	1/2 inch reels - Residential Service	per meter	0	$ 1.50	$ -
	2" fittings	placeholder	0	$ 50,000.00	$ -
	Meters / sets / regs - Residential	each	0.00	$ 650.00	$ -
	Risers - Residential (3/4'' riser and valve and bracket)	each	0.00	$ 102.30	$ -
	Tee Kits - Residential (EF tee, EFV, EF coupling)	each	0.00	$ 126.72	$ -
	Fittings - Residential	placeholder	0.00	$ 50,000.00	$ -
	Meters / sets / regs - Commercial	each	0.00	$ 2,500.00	$ -
	Risers - Commercial (2")	each	0.00	$ 305.80	$ -
	Tee Kits - Commercial (2")	each	0.00	$ 167.20	$ -
	Fittings - Commercial	placeholder	0.00	$ 50,000.00	$ -
	Pipeline markers	placeholder	100	$ 46.60	$ 4,675.53
EPCOR COST	Internal QA/QC Inspections / Gas Tech	months	6	$ 11,250.00	$ 67,500.00
	IDC				
	OH's	Placeholder	1	$ 75,000.00	$ 75,000.00
	land purchases / TLUs	Placeholder	1	$ 50,000.00	$ 50,000.00
	Land solution	Placeholder	1	$ 50,000.00	$ 50,000.00
	Legal	Placeholder	1	$ 50,000.00	$ 50,000.00
	SCADA	Placeholder	0	$ 25,000.00	$ -
	meter protection	Placeholder	1	$ -	$ -
	P&GA / marketing	Placeholder	1	$ 50,000.00	$ 50,000.00
	FN meetings	Placeholder	1	$ 50,000.00	$ 50,000.00
	Enbride contribution (Not Required)				
	Modelling	Placeholder	0	$ 10,000.00	$ -
	Ops spares, etc.		1		$ -
	other ops costs?				
	Gas	Placeholder	1	$ 2,000.00	$ 2,000.00
	CONTINGENCY (15%)				$ 1,631,259.35
	Project Sub Total				$ 12,506,321.71
	Project Management (3.0%)				$ 375,189.65
	Project Total				$ 12,881,511.36