ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B);

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, 2025 to serve Aylmer and surrounding areas within its service territory.

EB-2024-0130

EPCOR NATURAL GAS LIMITED PARTNERSHIP

SETTLEMENT PROPOSAL

November 20, 2024

APPENDIXES

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ACCOMPANYING EXCEL MODELS

ENGLP_EB-2024-0130_Supporting Appendices_Settlement 20241120

ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

ENGLP_EB-2024-0130_DVA Continuity Schedule_Settlement_20241120

ENGLP_EB-2024-0130_Rate Model_Settlement_20241120

ENGLP_EB-2024-0130_Cost Allocation_Settlement_20241120

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A. BACKGROUND

EPCOR Natural Gas Limited Partnership ("ENGLP") filed a Cost of Service application with the Ontario Energy Board ("OEB") on July 18, 2024 under section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the "Act"), seeking approval for changes to the rates that ENGLP charges for natural gas distribution and other charges, to be effective January 1, 2025 (OEB Docket Number EB-2024-0130) (the "Application").

The OEB issued and published a Notice of Hearing dated August 15, 2024, and issued Procedural Order No. 1 on September 5, 2024, the latter of which, among other things, required the parties to the proceeding to develop a proposed issues list and schedule a Settlement Conference on October 28-29, 2024.

On September 9, 2024, pursuant to Procedural Order No. 1, OEB staff submitted a proposed issues list and on September 10, 2024, the OEB approved the issues list for the purposes of this proceeding (the "Approved Issues List").

ENGLP filed Interrogatory Responses and certain evidentiary updates with the OEB on October 17, 2024. Two of ENGLP's Interrogatory Responses (to interrogatories from Pollution Probe ("PP") (defined below)) were initially filed confidentially. On October 22, 2024, ENGLP filed updated redacted versions of these two Interrogatory Responses as agreed with PP. Pre-settlement clarification questions from CCC (defined below) and OEB Staff were received by ENGLP on October 21 and October 24, 2024, respectively. ENGLP responded to both sets of pre-settlement clarification questions on October 25, 2024.

A Settlement Conference was convened from October 28-29, 2024 in accordance with the OEB's *Rules of Practice and Procedure* (the "Rules") and the OEB's *Practice Direction on Settlement Conferences* (the "Practice Direction").

Karen Wianecki, Director of Practice, Planning Solutions Inc. acted as facilitator for the Settlement Conference that lasted for two days.

ENGLP and the following intervenors participated in the Settlement Conference:

- Pollution Probe (PP); and
- Consumers Council of Canada (CCC).

ENGLP and the intervenors are collectively referred to as the "Parties".

OEB staff also participated in the Settlement Conference. The role adopted by OEB staff is set out in the Practice Direction. Although OEB staff is not a party to this Settlement Proposal, as noted in the Practice Direction, the OEB staff participating in the Settlement

Conference are bound by the same confidentiality requirements that apply to the Parties in the proceeding.

B. SETTLEMENT PROPOSAL PREAMBLE

This document comprises the Settlement Proposal and is presented jointly to the OEB by the Parties. This document is called a "Settlement Proposal" because it is a proposal by the Parties to the OEB to settle certain issues in this proceeding, identified as settled in this Settlement Proposal. However, as between the Parties, and subject only to the OEB's approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this Settlement Proposal is subject to a condition subsequent, that if it is not accepted by the OEB in its entirety, then unless amended by the Parties, it is null and void and of no further effect. In entering into this Settlement Proposal, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that the Settlement Conference, including any settlement information related thereto, is privileged and confidential in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings and the rules of that latter document do not apply. Instead, in the Settlement Conference, and in this Settlement Proposal, the Parties have interpreted "confidential" to mean that the documents and other information provided during the course of the Settlement Conference, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement of each issue during the Settlement Conference and during the preparation of this Settlement Proposal are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the Parties agree that "attendees" is deemed to include, in this context, persons who were not in attendance via video conference at the Settlement Conference but were a) any persons or entities that the Parties engage to assist them with the Settlement Conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions as the Parties.

This Settlement Proposal is organized in accordance with the Approved Issues List. This Settlement Proposal provides a brief description of each of the settled issues, together with references to the evidence submitted on the record in this proceeding. The Parties agree that references to the "evidence" in this Settlement Proposal shall, unless the context otherwise requires, include, in addition to the Application, the written responses to interrogatories and other components of the record up to and including the date hereof, (a) additional information included by the Parties in this Settlement Proposal; (b) the Appendices to this document; and (c) the evidence filed concurrently with this Settlement Proposal titled "Responses to Pre-Settlement Clarification Questions" (Clarification Responses).

The supporting Parties for each settled issue agree that the evidence in respect of each settled issue is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal.

There are Appendices to this Settlement Proposal, which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by ENGLP. While the Intervenors have reviewed the Appendices, the Intervenors are relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties following the Settlement Conference. The Parties are pleased to advise the OEB that they have reached a complete agreement with respect to the settlement of all of the issues in this proceeding. Specifically:

"Complete Settlement" means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, none of the Parties (including Parties who take no position on that issue) will adduce any evidence or argument during an oral hearing, if applicable, in respect of the specific issue.		# issues settled: **ALL**
"Partial Settlement" means an issue for which there is partial settlement, as ENGLP and the Intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties (including Parties who take no position on the Partial Settlement) will only adduce evidence and argument during an oral hearing on the portions of the issue for which no agreement has been reached.		# issues partially settled: **0**

"No Settlement" means an issue for which no settlement was reached. ENGLP and the Intervenors who take a position on the issue will adduce evidence and/or argument at an oral hearing on the issue.		# issues not settled: **0**

The Parties explicitly request that the OEB consider and accept this Settlement Proposal as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this Settlement Proposal. If the OEB does not accept this Settlement Proposal in its entirety, then there is no agreement, unless the Parties agree, in writing, that the balance of this Settlement Proposal may continue as a valid settlement subject to any revisions that may be agreed upon by the Parties.

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue, or decide to take no position on the issue, prior to its resubmission to the OEB for its review and consideration as a basis for making a decision.

Unless otherwise expressly stated in this Settlement Proposal, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not ENGLP is a party to such proceeding.

In this Settlement Proposal, where any of the Parties "accept" the evidence of ENGLP, or "agree" to a revised term or condition, including a revised budget or forecast, then, unless the Settlement Proposal expressly states to the contrary, the words "for the purpose of settlement of the issues herein" shall be deemed to qualify that acceptance or agreement.

Summary of Settlement Proposal:

In reaching this complete settlement, the Parties have been guided by the Filing Requirements for Natural Gas Applications, dated February 16, 2017, the Approved Issues List, dated September 25, 2024 and the Natural Gas Facilities Handbook, dated March 31, 2022.

The Parties have reached a complete settlement on all aspects of the Approved Issues List as summarized below in Table A.

Table A – Issues List Summary and Settlement Status		
ISSUE		**STATUS**
1.1	**Administration**	
	1.1 Has ENGLP complied with the OEB directives from and since the utility's last cost of service proceeding (EB-2018-0336 and EB-2019-0276)?	**Complete Settlement**
	1.2 Are the proposed changes to ENGLP's Conditions of Service appropriate?	**Complete Settlement**
	1.3 Is the proposed effective date appropriate?	**Complete Settlement**
2.0	**Rate Base**	
	2.1 Are the proposed rate base amounts appropriate?	**Complete Settlement**
	2.2 Is the level of planned capital expenditures, and related in-service additions, appropriate, and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to: • customer feedback and preferences; • productivity; • benchmarking of costs; • reliability and service quality; • impact on distribution rates; • trade-offs with OM&A spending; • government-mandated obligations; • the objectives of ENGLP and its customers; • the utility system plan; and • the business plan.	**Complete Settlement**
	2.3 Is the working capital allowance for the 2025 Test Year appropriate?	**Complete Settlement**
3.0	**Operating Revenue**	
	3.1 Are the customer addition forecasts for the 2024 Bridge Year and 2025 Test Year appropriate?	**Complete Settlement**
	3.2 Are the volume throughput and revenue forecasts for the 2024 Bridge Year and 2025 Test Year appropriate?	**Complete Settlement**

	3.3 Are the proposed Other Revenues for the 2025 Test Year appropriate?	**Complete Settlement**
4.0	**Operating Costs**	
	4.1 Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to: • customer feedback and preferences; • productivity; • benchmarking of costs; • reliability and service quality; • impact on distribution rates; • trade-offs with capital spending; • government-mandated obligations; • the objectives of ENGLP and its customers; • the utility system plan; • the business plan; • affiliate shared services; and, • corporate shared services and the corporate structure/status.	**Complete Settlement**
	4.2 Are the depreciation costs for the 2025 Test Year appropriate?	**Complete Settlement**
	4.3 Is the proposed shared services cost allocation methodology and the quantum appropriate?	**Complete Settlement**
	4.4 Is the gas transportation cost forecast for the 2025 Test Year appropriate?	**Complete Settlement**
5.0	**Deferral and Variance Accounts**	
	5.1 Is ENGLP's proposal for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts and the continuation or closure of existing accounts, appropriate?	**Complete Settlement**
6.0	**Cost of Capital, Taxes and Revenue Requirement**	
	6.1 Is the proposed cost of capital (interest on debt, return on equity) and capital structure appropriate?	**Complete Settlement**
	6.2 Are the proposed tax amounts appropriate?	**Complete Settlement**
	6.3 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the ratemaking treatment of each of these impacts appropriate?	**Complete Settlement**

	6.4 Is the proposed calculation of the Revenue Requirement appropriate?	**Complete Settlement**
7.0	**Cost Allocation and Rate Design**	
	7.1 Are the proposed changes to cost allocation, rate design and revenue-to-cost ratios appropriate?	**Complete Settlement**
	7.2 Are the proposed rates appropriate?	**Complete Settlement**
	7.3 Are ENGLP's Schedule of Service Charges appropriate?	**Complete Settlement**
8.0	**Incentive Rate-Setting Plan**	
	8.1 *Is ENGLP's proposed Incentive Rate-setting Plan for the period 2026 to 2029 appropriate?*	**Complete Settlement**
9.0	**Score Card**	
	9.1 Is ENGLP's Score Care appropriate?	**Complete Settlement**
10.0	**Other**	
	10.1 Should ENGLP establish a DSM Program?	**Complete Settlement**

This Settlement Proposal, including all Appendices, represents the evidence and the settlement between the Parties at the time of filing the Settlement Proposal.

C. SUMMARY

As a result of this Settlement Proposal, ENGLP has calculated changes to the Revenue Requirement as presented below:

Revenue Requirement Comparison – Applied vs. Settlement

Driver	2025T - Applied	2025T - Settlement	*Variance ($)*	*Variance (%)*
OM&A	$4,321,958	$4,141,958	($180,000)	-4.2%
Depreciation	$1,320,799	$1,302,707	($18,092)	-1.4%
Property Taxes	$705,564	$705,564	$0	0.0%
Income Taxes	$74,989	$11,366	($63,623)	-84.8%
Cost of Debt	$643,825	$613,545	($30,279)	-4.7%
Return on Equity	$980,922	$957,596	($23,326)	-2.4%
Service Revenue Requirement	**$8,048,058**	**$7,732,737**	**($315,321)**	**-3.9%**
Revenue Offsets	*($108,388)*	*($108,388)*	*$0*	*0%*
Distribution Revenue Requirement	**$7,939,670**	**$7,624,349**	**($315,321)**	**-4%**

Rate Base (Mid-Year)	$26,626,558	$25,880,979	($745,578)	-2.8%
Weighted Average Cost of Capital	6.10%	6.07%	-0.03%	
Debt	*2.42%*	*2.37%*	*-0.05%*	
Return on Equity	*3.68%*	*3.70%*	*0.02%*	

This has also resulted in adjustments to average annual customer bill impacts:

	Application		**Settlement**	
Rate Class	**Change in Total Bill ($ / year / customer)**	**Change in Total Bill (%)**	**Change in Total Bill ($ / year / customer)**	**Change in Total Bill (%)**
R1 - Residential	$78	6%	$51	4%
R1- General Service	$326	6%	$232	4%
R2 - Seasonal - Annual	$515	7%	$391	5%
R3 - Large Volume Contract	$8,782	3%	$5,716	2%
R4 - Peaking - Annual	$1,479	6%	$1,088	5%
R5 - Interruptible Peaking	$3,364	5%	$2,736	4%
R6 - IGPC	$63,942	8%	$28,438	3%

D. SETTLEMENT BY ISSUE

The subsections below summarize the key components of this partial settlement reached by the Parties, including details on how each of the issues in the Approved Issues List has been addressed either through the Application or through the modifications to ENGLP's proposals, which have been agreed upon in this Settlement Proposal.

1.0 ADMINISTRATION

1.1 *Has ENGLP complied with the OEB directives from and since the utility's last cost of service proceeding (EB-2018-0336 and EB-2019-0276)?*

Complete Settlement: The Parties agree that ENGLP has complied with the OEB directives since its last cost of service proceeding.

Evidence:

- ***Application***: Exhibits 1.3.14 & 1.3.15
- ***IRRs***: Staff-7

Support: All Parties

1.2 *Are the proposed changes to ENGLP's Conditions of Service appropriate?*

Complete Settlement: The Parties agree that the proposed changes to ENGLP's Conditions of Service are appropriate.

Evidence:

- ***Application***: Exhibits 1.3.16 & 1.3.17
- ***IRRs***: Staff-8, Staff-13

Support: All Parties

1.3 *Is the proposed effective date appropriate?*

Complete Settlement: The Parties agree that the proposed effective date of January 1, 2025 is appropriate.

Evidence:

- ***Application***: Exhibit 1.3.12
- ***IRRs***: None

Support: All Parties

2.0 RATE BASE

2.1 *Are the proposed rate base amounts appropriate?*

Complete Settlement: For settlement purposes, the Parties agree that: (a) ENGLP will reduce the opening rate base by $700,000 to reflect the fact that approximately $700,000 of Bridge Year planned capital expenditures will not come into service until early 2025; and (b) the proposed rate base amounts are otherwise appropriate.

Evidence:

- ***Application***: Exhibit 1.5.3, Exhibit 2.1, Exhibit 2.4

- ***IRRs***: Staff-19, Staff-25 through Staff 34, Staff-41, Staff-77, Staff-78, 2-PP-7, 2-PP-10, 2-PP-11, 2-CCC-1, 2-CCC-3, 2-CCC-4-2-CCC-7, 3-CCC-13

- ***Appendixes to this Settlement Proposal***
  Appendix A – Rate Base

- ***Settlement Models:***
  ENGLP_EB-2024-0130_Supporting Appendixes_Settlement 20241120
    - *2C_Fixed Asset Continuity*
    - *2E_Depreciation Expense*

  ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

2.2 *Is the level of planned capital expenditures, and related in-service additions, appropriate, and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to: customer feedback and preferences; productivity; benchmarking of costs; reliability and service quality; impact on distribution rates; trade-offs with OM&A spending; government-mandated obligations; the objectives of ENGLP and its customers; the utility system plan; and the business plan.*

Complete Settlement: For the purposes of settlement, the Parties agree that: (a) the $700,000 in Bridge Year capital expenditures noted in Issue 2.1 above will be included in the Test Year capital additions; and (b) ENGLP will apply an $800,000 reduction in 2025 capital expenditures. The Parties otherwise agree that the capital expenditures and related in-service additions as stated in ENGLP's Application are appropriate.

In addition, ENGLP will assess options for implementation of an integrated resource plan (IRP) and present those options in its next rebasing proceeding. This obligation does not restrict ENGLP from coming forward earlier if IRP opportunities become apparent prior to ENGLP's next rebasing. The IRP opportunity assessment will be filed with ENGLP's next rebasing application, and will include incentives to operationalize IRP alternatives as part of its utility operations including responding to the needs of customers while mitigating stranded assets and capital costs where more cost-effective options exist.

Evidence:

- ***Application***: Exhibit 1.5.3, Exhibit 2.5, Exhibit 2.6, Exhibit 2 – Utility System Plan & Asset Management Plan

- ***IRRs***: 2-PP-12, 2-PP-13, 2-PP-20, 2-CCC-2, 2-CCC-5, 2-CCC-8 through 3-CCC-13

- ***Appendixes to this Settlement Proposal***
  Appendix B – 2025-2029 Planned CAPEX

- ***Settlement Models:***
  ENGLP_EB-2024-0130_Supporting Appendices_Settlement 20241120
    - *2A_Capital Projects*
    - *2B_Capital Expenditures*
    - *2C_Fixed Asset Continuity*
    - *2E_Depreciation Expense*

  ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

2.3 *Is the working capital allowance for the 2025 Test Year appropriate?*

Complete Settlement: The Parties agree that the working capital allowance (as recalculated for adjustments made herein) for the 2025 Test Year is appropriate.

Evidence:

- ***Application***: Exhibit 1.5.3, Exhibit 2.3

- ***IRRs***: 2-PP-7, Staff-18, Staff-36

- ***Settlement Models:***

ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

3.0 OPERATING REVENUE

3.1 *Are the customer addition forecasts for the 2024 Bridge Year and 2025 Test Year appropriate?*

Complete Settlement: The Parties agree that the customer addition forecasts for the 2024 Bridge Year and 2025 Test Year are appropriate.

Evidence:

- ***Application***: Exhibit 1.5.2, Exhibit 3.1, Exhibit 3, Appendix A – Power Advisory Report, ENGLP_EB-2024-0130_Load Forecast

- ***IRRs***: Staff-65, Staff-68

Support: All Parties

3.2 *Are the volume throughput and revenue forecasts for the 2024 Bridge Year and 2025 Test Year appropriate?*

Complete Settlement: The Parties agree that the volume throughput and revenue forecasts for the 2024 Bridge Year and 2025 Test Year are appropriate.

Evidence:

- ***Application***: Exhibit 1.5.2, Exhibit 3.1, Exhibit 3.2, Exhibit 3, Appendix A – Power Advisory Report, ENGLP_EB-2024-0130_Load Forecast

- ***IRRs***: Staff-60, Staff-65 through Staff-68, 3-CCC-13, 3-CCC-13_2

Support: All Parties

3.3 *Are the proposed Other Revenues for the 2025 Test Year appropriate?*

Complete Settlement: The Parties agree that the proposed Other Revenues for the 2025 Test Year are appropriate.

Evidence:

- ***Application***: Exhibit 1.5.1, Exhibit 3.4, ENGLP_EB-2024-0130_Revenue Requirement, Exhibit 8-Appendix B – Proposed Rate Schedules

- ***IRRs***: Staff-24

Support: All Parties

4.0 OPERATING COSTS

4.1 *Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to: customer feedback and preferences; productivity; benchmarking of costs; reliability and service quality; impact on distribution rates; trade-offs with capital spending; government-mandated obligations; the objectives of ENGLP and its customers; the utility system plan; the business plan; affiliate shared services; and, corporate shared services and the corporate structure/status.*

Complete Settlement: The Parties agree that ENGLP will reduce its proposed OM&A expenditures in the Test Year by $180,000, and that the total planned OM&A expenditure of $4,141,958 in the Test Year is appropriate. The Parties also agree that ENGLP will be permitted to manage its OM&A budget as it sees fit and specific adjustments to ENGLP's OM&A plans have not been finalized and may change. ENGLP has applied the reduction in the tables throughout this settlement document and the live Excel models as an envelope adjustment.

Evidence:

- ***Application***: Exhibit 1.5.4, Exhibit 4.3
- ***IRRs***: Staff-69 through Staff-76 4-PP-21, 2-CCC-11, 2-CCC-12, 4-CCC-14-4-CCC-16
- ***Settlement Models:***
  ENGLP_EB-2024-0130_Supporting Appendixes_Settlement 20241120
  - *4A_Total O&M Summary*
  - *4B_OM&A Detail*

  ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

4.2 *Are the depreciation costs for the 2025 Test Year appropriate?*

Complete Settlement: The Parties agree that the depreciation methodology and useful lives are appropriate. The Parties agree that the depreciation costs for the 2025 Test Year are appropriate (as recalculated as an outcome of Settlement).

Evidence:

- ***Application***: Exhibit 1.5.1, Exhibit 4.4
- ***IRRs***: Staff-41, Staff-71, 4-CCC-16

- ***Appendixes to this Settlement Proposal***
  Appendix C – 2025 Depreciation

- ***Settlement Models:***
  ENGLP_EB-2024-0130_Supporting Appendixes_Settlement 20241120
    - *2E_Depreciation Expense*
  ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

4.3 *Is the proposed shared services cost allocation methodology and the quantum appropriate?*

Complete Settlement: The Parties have agreed to settle this issue as part of the overall settlement on OM&A expenditures in the Test Year (Issue 4.1 above).

Evidence:

- ***Application***: Exhibit 1.5.4, Exhibit 4.3.3.2

- ***IRRs***: Staff-71, Staff-72, Staff-73, 4-PP-21, 4-CCC-15

Support: All Parties

4.4 *Is the gas transportation cost forecast for the 2025 Test Year appropriate?*

Complete Settlement: The Parties agree that the gas transportation cost forecast for the 2025 Test Year is appropriate.

Evidence:

- ***Application***: Exhibit 1.5.1, Exhibit 4.1

- ***IRRs***: Staff-18

Support: All Parties

5.0 DEFERRAL AND VARIANCE ACCOUNTS

5.1 *Is ENGLP's proposal for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for new accounts and the continuation or closure of existing accounts, appropriate?*

Complete Settlement: ENGLP proposed disposition of two deferral and variance accounts as part of this application:

- **Purchased Gas Transportation Variance Account (PGTVA):** The Parties agree with the disposition of the PGTVA as applied for by ENGLP.

- **Unaccounted for Gas Volume Deferral Account (UFGVA)**: For the purposes of settlement, the Parties agree that ENGLP will remove the carrying charges from the UFGVA disposition.

  The Parties further agree that ENGLP will assess the origin of its unaccounted for gas and consider opportunities to mitigate such unaccounted for gas, and provide an update at ENGLP's next rebasing proceeding.

  The revised UFGVA balance has been included on ENGLP_EB-2024-0130_DVA Continuity Schedule_Settlement workbook and the resulting rate rider has been used in rate generation in the ENGLP_EB-2024-0130_Rate Model_Settlement workbook. The final result appears in the proposed rate order.

The Parties agree with the continuance of the following deferral and variance accounts (as applied) with the following exceptions:

- **Earnings Sharing Mechanism Deferral Account** (**ESMDA**): The Parties agree to revise the wording of the accounting order included in the application to change the calculation methodology from a cumulative calculation (over the rate-setting period) to an annual calculation. A copy of the revised accounting order has been included as Appendix D.

- **Regulatory Expense Deferral Account (REDA):** The Parties agree on the continuance of the REDA based on the revised accounting order included in this document (Appendix D).

- **Transportation Service Charge Deferral Account (TSCDA):** The Parties agree on the continuance of the TSCDA based on the revised accounting order included in this document (Appendix D).

- **Getting Ontario Connected Deferral Account**: ENGLP will discontinue the Getting Ontario Connected Deferral Account.

- **Accelerated CCA Deferral Account:** ENGLP will discontinue the Accelerated CCA Deferral Account.

A summary is included below:

Account	Short Name	Status	Accounting Order Revised During Settlement?
Current Accounts			
Unaccounted For Gas Variance Account	UFGVA	Continuance	No
Regulatory Expense Deferral Account	REDA	Continuance	Yes
Purchased Gas Transportation Variance Account Rates 1-5	PGTVA	Continuance	No
Approved Deferral/Variance Disposal Account	ADVADA	Continuance	No
Earnings Share Mechanism Deferral Account	ESMDA	Continuance	Yes
Transportation Service Charge Deferral Account	TSCDA	Continuance	Yes
LEAP EFA Funding Deferral Account	LEAPDA	Continuance	No
Cloud Computing DVA	CLOUDVA	Continuance	No
Accounts to be Closed			
Loss on Disposal of Meters Deferral Account	LDMDA	Closed	
2016-2017 System Integrity Capital Projects Deferral Account	SICDA	Closed	
Getting Ontario Connected Act Variance Account	LOCATEVA	Closed	
Accelerated CCA Income Taxes Variance Account	ACITVA	Closed	
Excluded From This Application			
Customer Carbon Charge Variance Account	CCCVA	Continuance	
Facility Carbon Charge Variance Account	FCCVA	Continuance	
Greenhouse Gas Emissions Administration Deferral Account:	GGEADA	Continuance	
Purchased Gas Commodity Variance Account	PGCVA	Continuance	
Gas Purchase Rebalancing Account	GPRA	Continuance	

Evidence:

- ***Application***: Exhibit 1.5.9, Exhibit 9.0, Exhibit 9.1, Exhibit 9.2

- ***IRRs***: Staff-82, 5-PP-24, 10-CCC-23

- ***Appendixes to this Settlement Proposal***
  Appendix D – Accounting Orders

- ***Settlement Models:***

ENGLP_EB-2024-0130_DVA Continuity Schedule_Settlement_20241120
ENGLP_EB-2024-0130_Rate Model_Settlement_20241120

Support: All Parties

6.0 COST OF CAPITAL, TAXES AND REVENUE REQUIREMENT

6.1 *Is the proposed cost of capital (interest on debt, return on equity) and capital structure appropriate?*

Complete Settlement: The Parties agree that the proposed cost of capital parameters (i.e., deemed short-term debt rate of 5.04%, long-term debt rate of 3.87%, and return on equity of 9.25%) and capital structure are appropriate. These parameters align or incorporate the OEB's 2025 cost of capital parameters issued on October 31, 2024, on an interim basis.

These cost of capital parameters will be implemented in accordance with the direction set out in the OEB's Letter and Accounting Order issued on July 26, 2024, as well as the OEB's Letter and Accounting Orders issued on October 31, 2024.

This is subject to the Parties agreeing that, for the 2025-2029 capital structure and cost of capital parameters, ENGLP will implement whatever outcomes are decided by the OEB in the Generic Cost of Capital Proceeding (EB-2024-0063), including what the OEB decides with respect to implementation. For clarity, no Party will be restricted from taking any position, or making any submission in the Generic Cost of Capital proceeding as a result of this settlement.

Evidence:

- ***Application***: Exhibit 1.5.5 & Exhibit 5
- ***IRRs***: Staff-79, Staff-80, Staff-81, Staff-83, Staff-84, 5-CCC-17
- ***Appendixes to this Settlement Proposal***
  Appendix E – Weighted Average Cost of Capital
- ***Settlement Models:***
  ENGLP_EB-2024-0130_Supporting Appendices_Settlement 20241120
    - *5B_Capital Structure*
    - *5C_Debt Instruments*

  ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

6.2 *Are the proposed tax amounts appropriate?*

Complete Settlement: Subject to ENGLP claiming accelerated capital cost allowance (CCA) and reflecting the same in its 2025 Test Year, the Parties agree that the proposed tax amounts are appropriate. ENGLP also agrees to discontinue the related Accelerated CCA Deferral Account.

ENGLP has included this change in calculation in the revised revenue requirement calculation and work form.

Evidence:

- ***Application***: Exhibit 4.5
- ***IRRs***: None
- ***Appendixes to this Settlement Proposal***
  Appendix F – Accelerated Capital Cost Allowance
- ***Settlement Models:***
  ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

6.3 *Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the ratemaking treatment of each of these impacts appropriate?*

Complete Settlement: The Parties agree that ENGLP has identified and recorded all impacts of changes in accounting standards, policies, estimates and adjustments, and that the ratemaking treatment of these impacts are appropriate.

Evidence:

- ***Application***: None
- ***IRRs***: None

Support: All Parties

6.4 *Is the proposed calculation of the Revenue Requirement appropriate?*

Complete Settlement: Subject to a recalculation resulting from other changes noted within this Settlement Proposal, the Parties agree that the proposed calculation of the Revenue Requirement is appropriate.

Evidence:

- ***Application***: Exhibit 1.5.1, Exhibit 6
- ***IRRs***: None
- ***Settlement Models:***
  ENGLP_EB-2024-0130_Revenue Requirement_Settlement_20241120

Support: All Parties

7.0 COST ALLOCATION AND RATE DESIGN

7.1 *Are the proposed changes to cost allocation, rate design and revenue-to-cost ratios appropriate?*

Complete Settlement: The Parties agree that the proposed changes to cost allocation, rate design and revenue-to-cost ratios are appropriate. The Parties further agree that settlement of this issue does not reflect an acceptance by the intervenors of the appropriateness of a move to fully fixed residential rates by gas distributors generally, and is without prejudice to any Party taking any position with respect to the appropriateness of a move to fully fixed residential rates for natural gas distributors in other proceedings.

Regarding the R1-General Service customer class, the Parties agree that the move towards an increased fixed revenue percentage is without prejudice to the position of any party, including ENGLP, on a fixed/variable split going forward.

The following tables show the allocated distribution revenue per rate class and revenue to cost ratios:

Rate Class	Current Rates	Application	Settlement
R1 - Residential	$4,757,827	$5,124,352	$4,920,840
R1 - General Service	$1,093,159	$1,177,373	$1,130,615
R2 - Seasonal	$95,440	$103,189	$99,172
R3 - Large Volume Contract	$271,134	$292,022	$280,424
R4 - Peaking	$273,470	$301,742	$288,462
R5 - Interruptible Peaking	$50,704	$47,004	$46,352
R6 - IGPC	$830,046	$893,989	$858,484
Total Revenue	**$7,371,780**	**$7,939,671**	**$7,624,349**

Rate Class	EB-2018-0334	Application	Settlement
R1 - Residential	0.98	1.02	1.02
R1 - General Service	1.09	1.06	1.06
R2 - Seasonal	1.01	0.80	0.80
R3 - Large Volume Contract	0.97	0.93	0.94
R4 - Peaking	0.93	0.80	0.80
R5 - Interruptible Peaking	0.64	1.02	1.06
R6 - IGPC	1.06	0.96	0.96

Evidence:

- ***Application***: Exhibit 1.5.6, Exhibit 7
- ***IRRs***: Staff-6, Staff-11, Staff-21, 2-PP-8, 8-PP-25, 7-CCC-18 7-CCC-19, 7-CCC-20, 8-CCC-21 10-CCC-22
- ***Settlement Models:***
  ENGLP_EB-2024-0130_Cost Allocation_Settlement_20241120

Support: All Parties

7.2 *Are the proposed rates appropriate?*

Complete Settlement: The Parties agree that the proposed rates are appropriate as recalculated as an outcome of Settlement.

Evidence:

- ***Application***: Exhibit 1.5.8, Exhibit 8
- ***IRRs***: Staff-21, 8-CCC-21, 8-PP-25
- ***Appendixes to this Settlement Proposal***
  Appendix G – Draft Rate Order
- ***Settlement Models:***
  ENGLP_EB-2024-0130_Rate Model_Settlement_20241120

Support: All Parties

7.3 *Are ENGLP's Schedule of Service Charges appropriate?*

Complete Settlement: The Parties agree that ENGLP's Schedule of Service Charges is appropriate.

Evidence:

- ***Application***: Exhibit 1.5.1, Exhibit 3.4, ENGLP_EB-2024-0130_Revenue Requirement, Exhibit 8-Appendix B – Proposed Rate Schedules

- ***IRRs***: Staff-24

- ***Appendixes to this Settlement Proposal***
  Appendix G – Draft Rate Order

Support: All Parties

8.0 INCENTIVE RATE-SETTING PLAN

8.1 *Is ENGLP's proposed Incentive Rate-setting Plan for the period 2026 to 2029 appropriate?*

Complete Settlement: The Parties agree that ENGLP's Incentive Rate-setting Plan is appropriate. For clarity, ENGLP will: (a) escalate the fixed monthly charge for the R1-Residential and R1-General Service by 15% (after inflation); and (b) make a corresponding adjustment to the volumetric charges to achieve a total projected revenue for the Price Cap IR year equivalent to the prior year OEB approved revenue for each Rate Class 1 (increased by the Price Cap Adjustment).

For the purposes of settlement, the Parties agree that to amend the Incentive Rate-setting Plan as applied to include the following:

- ENGLP will apply a 0.45% stretch factor for its annual IRM filings.
- ENGLP will maintain its Earning Sharing Mechanism and deferral account as revised in issue 5.1.
- ENGLP will maintain a new Y-factor that would track revenue requirement impacts from any OEB generic proceeding on determining an appropriate revenue horizon (for general service and other customers) and/or customer attachments. The details of this Y-factor would be determined after an OEB decision in the generic proceeding.
- ENGLP will propose rate mitigation if bill impacts are greater than 10% for the lowest 10^{th} percentile volume customer in any given year of the term, for R1 Residential or R1 General Service customers.

Evidence:

- ***Application***: Exhibit 1.5.10, Exhibit 10
- ***IRRs***: Staff-6, 10-CCC-22

Support: All Parties

9.0 SCORE CARD

5.1 *Is ENGLP's proposed Score Card appropriate?*

Complete Settlement: The Parties agree that ENGLP's proposed Score Card is appropriate.

Evidence:

- ***Application***: Exhibit 1.7
- ***IRRs***: Staff-22, 9-PP-26
- ***Appendixes to this Settlement Proposal***
  Appendix H – Scorecard

Support: All Parties

10.0 OTHER

Complete Settlement: It was agreed by Parties that Demand Side Management was relevant to certain issues in this proceeding, including Issues 4 (Operating Expenses) and Issue 5 (Deferral Accounts) and that it would not be excluded from the Issues List for purposes of the proceeding. For simplicity it has been added to this Settlement Proposal as an "Other" category.

ENGLP will file a plan for the delivery of a cost-effective Demand Side Management (DSM) program (including any relevant ratemaking mechanisms) by the 2027 annual filing (forecasted to be filed in 2026) for the OEB's consideration and approval and provide a copy to all Parties to this proceeding. In developing its DSM proposal: (a) ENGLP will consult with relevant stakeholders, which may include OEB Staff, IESO, municipal representatives, Ministry of Energy and Electrification staff, and Pollution Probe; and (b) the DSM proposal may leverage cost-effective partnerships with IESO and/or Enbridge.

Parties are free to take any position on the filed DSM proposal.

Evidence:

- ***Application***: None
- ***IRRs***: 2-PP-13 through 2-PP-18

Support: All Parties

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Appendix A – Rate Base

EB-2024-0130 Rate Base

Rate Base ($000's)

							Applied		**Settlement**		**Variance vs. Applied**
		A	C	D	E	F	G	H	I	J	K
	Category	**2020 OEB Approved**	**2020A**	**2021A**	**2022A**	**2023A**	**2024B**	**2025T**	**2024B**	**2025T**	**2025T**
1	**Gross Asset Value**										
2	Opening Balance	$33,017	$31,711	$34,574	$36,315	$38,243	$41,156	$46,201	$41,156	$45,501	-$700
3	Addition	$1,340	$2,863	$1,741	$1,928	$2,913	$5,045	$4,064	$4,345	$3,964	-$100
4	Disposal	-$1,194	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Closing Balance	$33,162	$34,574	$36,315	$38,243	$41,156	$46,201	$50,265	$45,501	$49,465	-$800
6	**Accumulated Depreciation**										
7	Opening Balance	-$16,975	-$17,013	-$17,994	-$18,894	-$19,831	-$20,860	-$22,019	-$20,860	-$22,010	$9
8	Depreciation	-$877	-$981	-$901	-$936	-$1,029	-$1,159	-$1,321	-$1,151	-$1,303	$18
9	Disposal	$966	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Closing Balance	-$16,886	-$17,994	-$18,894	-$19,831	-$20,860	-$22,019	-$23,340	-$22,010	-$23,313	$27
11	**Mid-year Net Asset Value**	**$16,160**	**$15,639**	**$17,000**	**$17,916**	**$19,354**	**$22,239**	**$25,553**	**$21,893**	**$24,821**	**-$732**
12	Closing Net Asset Value	$16,277	$16,580	$17,420	$18,412	$20,296	$24,181	$26,925	$23,490	$26,152	-$773
13	**Working Capital Allowance**										
14	Cost of Gas (Non-Distribution)	$0	$6,102	$7,291	$11,004	$12,293	$9,759	$9,992	$9,759	$9,992	$0
15	OM&A	$3,359	$3,264	$3,316	$3,820	$3,680	$4,162	$4,322	$4,162	$4,142	-$180
16	Rate	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%	0.0%	7.5%	0.0%
17	**Total WCA**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,074**	**$0**	**$1,060**	**-$14**
18											
19	**Total Rate Base**	**$16,160**	**$15,639**	**$17,000**	**$17,916**	**$19,354**	**$22,239**	**$26,627**	**$21,893**	**$25,881**	**-$746**
20	*YOY Variance ($)*		*-$520*	*$1,361*	*$916*	*$1,438*	*$2,885*	*$4,388*	*$2,539*	*$3,988*	
21	*YOY Variance (%)*		*-3%*	*9%*	*5%*	*8%*	*15%*	*20%*	*13%*	*18%*	

		A	C	D	E	F	G	H	I	J	K
	Working Capital Allowance		**2020A**	**2021A**	**2022A**	**2023A**	**2024B**	**2025T**	**2024B**	**2025T**	**2025T**
1	Cost of Gas (Non-Distribution)		$6,102	$7,291	$11,004	$12,293	$9,759	$9,992	$9,759	$9,992	$0
2	OM&A		$3,264	$3,316	$3,820	$3,680	$4,162	$4,322	$4,162	$4,142	-$180
3	Rate		7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
4	**Total**		**$702**	**$795**	**$1,112**	**$1,198**	**$1,044**	**$1,074**	**$1,044**	**$1,060**	**-$14**

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Appendix B – 2025-2029 Planned CAPEX

Applied:

CATEGORY	Forecast Period (planned)				
	2025	2026	2027	2028	2029
	$ '000				
System Access	1,954	2,731	1,665	1,750	1,830
System Renewal	1,460	1,567	912	930	567
System Service	450	40	405	409	50
General Plant	272	152	160	164	168
TOTAL EXPENDITURE	4,136	4,490	3,142	3,253	2,615
Capital Contributions	72	477	75	79	83
NET CAPITAL EXPENDITURES	**4,064**	**4,013**	**3,066**	**3,174**	**2,532**

Settlement:

CATEGORY	Forecast Period (planned)				
	2025	2026	2027	2028	2029
	$ '000				
System Access	1,254	2,731	1,665	1,750	1,830
System Renewal	1,410	1,567	912	930	567
System Service	450	40	405	409	50
General Plant	222	152	160	164	168
TOTAL EXPENDITURE	3,336	4,490	3,142	3,253	2,615
Capital Contributions	72	477	75	79	83
NET CAPITAL EXPENDITURES	**3,264**	**4,013**	**3,066**	**3,174**	**2,532**

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EPCOR NATURAL GAS LIMITED PARTNERSHIP

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Appendix C – 2025 Depreciation

2025 Test Year Depreciation – Settlement ($)

OEB Account	Description	2024 Opening PPE Balance	2024 Additions	2025 Additions	Depreciation Rate	Depreciation on Existing Rate Base	Depreciation on 2024 Additions	Depreciation on 2025 Additions	Total Depreciation
		a	b	c	d	e	b*d=f	c*d*0.5= g (half year rule)	e+f+g=h
488	Communication Equipment	313,003	12,530	17,525	6.67%	10,857	836	584	12,278
490	Computer Equipment	581,101	27,530	57,525	25.00%	18,555	6,883	7,191	32,628
499	Contributions - Mains - Metallic (IGPC)	(376,288)	-	-	1.98%	(8,331)	-	-	(8,331)
499	Contributions - Mains Plastic	(292,496)	(25,000)	(25,000)	2.31%	(7,265)	(578)	(289)	(8,131)
499	Contributions - Services Metal	(13,208)	-	-	2.83%	(361)	-	-	(361)
499	Contributions - Services Plastic	(457,030)	(47,250)	(47,250)	2.51%	(10,254)	(1,186)	(593)	(12,033)
401	Franchise & Consents	842,667	-	-	4.80%	35,232	-	-	35,232
483	Furnishing / Office Equipment	200,720	-	-	6.67%	7,774	-	-	7,774
480	Land	82,653	-	-	0.00%	-	-	-	-
475	Mains - Metallic	-	-	-	2.83%	-	-	-	-
475	Mains - Metallic (IGPC)	6,230,974	300,000	250,000	1.98%	80,174	5,940	2,475	88,589
475	Mains - Plastic	16,153,236	1,607,550	1,404,350	2.31%	306,935	37,134	16,220	360,289
477	Measuring & Regulating Equip	2,098,729	260,430	179,940	3.66%	42,200	9,532	3,293	55,025
477	Measuring & Regulating Equip (IGPC)	576,367	-	-	3.66%	21,087	-	-	21,087
478	Meters - Commercial	1,926,249	150,000	167,000	5.00%	78,072	7,500	4,175	89,747
478	Meters - IGPC	14,139	-	-	16.67%	-	-	-	-
478	Meters - Residential	2,623,113	824,640	820,860	10.00%	170,186	82,464	41,043	293,693
474	Regulators	807,746	300,750	260,740	5.00%	21,857	15,038	6,519	43,413
473	Services - Plastic	6,614,832	801,560	696,160	2.51%	92,158	20,119	8,737	121,014
491	Software - Acquired	748,287	6,400	10,000	10.00%	41,924	640	500	43,064
482	Structures & Improvements	782,562	-	73,530	1.92%	12,333	-	706	13,038
486	Tools and Work Equipment	894,279	23,400	23,030	6.67%	24,714	1,561	768	27,043
485	Vehicle - Heavy Work Equip	33,033	-	-	6.92%	2,335	-	-	2,335
484	Vehicles - Transportation Equip	771,093	102,400	75,520	16.60%	62,062	16,998	6,268	85,328
Total		**41,155,761**	**4,344,940**	**3,963,930**		**1,002,241**	**202,881**	**97,597**	**1,302,719**

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Appendix D – Revised Accounting Orders

*Note, the following accounting orders have been revised during settlement. All other accounting orders to be continued (consistent with section 5.1) are agreed upon as per the Application.

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

Earnings Sharing Mechanism Deferral Account

The Earnings Share Mechanism Deferral Account ("ESMDA") is to record the annual earnings sharing mechanism (ESM) impact over the Price Cap IR Term as implemented as part of EPCOR Natural Gas Limited Partnership's ("ENGLP") 2025-2029 distribution rate application EB-2024-0130. In the event that the utility's annual ROE from 2025 to 2029 exceeds the Board- approved ROE in EB-2024-0130 by more than 150 basis points, the utility is required to share with ratepayers 50% of the earnings that are in excess of the 150 basis points threshold.

For clarity, the ROE will be calculated annually as the sum of actual regulated net income taking into account any necessary adjustments, divided by the sum of the actual regulated equity balances for the same term (i.e. considers rate base growth).

An entry will be made annually to record the balance of the ESMDA that is equal to the annual earnings to be shared, as if the balance were to be settled on the date it was recorded. The balance in this account will be reflective of the ratepayers' share of utility earnings (i.e. recorded at 50% of earnings eligible to be shared). As the ESM is asymmetrical the ESMDA balance will be either a credit balance or zero.

The audited balance in this account will be brought forward annually for approval for disposition once earnings over the have been assessed and the actual ESM amount has been determined.

As any balance in this account is not owing until earnings are assessed as over-earned under the ESM, interest will not be computed on the balance in the ESMDA.

Accounting Entries[1]

To record the annual change in the cumulative ESM:

Debit/Credit Account No. 300 Operating Revenue
Credit/Debit Account No. 179.76 Earnings Share Mechanism Deferral Account

[1] Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the *Ontario Energy Board Act*.

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

Regulatory Expense Deferral Account

<u>Accounting Entries for Regulatory Expense Deferral Account ("REDA")</u>[2]

To record monthly as a debit (credit) in Deferral Account No. 179-21 (REDA) the external costs for participating in generic proceedings and Enbridge Gas proceedings, including a main rates case, which are not already recovered in base rates.

Debit/Credit Account No. 179-21 Regulatory Expense Deferral Account (REDA)

Credit/Debit - Account No. 251 Accounts Payable

To record, as a debit (credit) in Deferral Account No. 179-22, interest on the balance in Deferral Account

Debit/Credit - Account No.179-22 Regulatory Expense Deferral Account (REDA)

Credit/Debit - Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

[2] Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the *Ontario Energy Board Act*.

EPCOR NATURAL GAS LIMITED PARTNERSHIP - Aylmer

Accounting Order

Deferral Account to Record Revenues Through the Transportation Service Charges

As indicated in its Decision dated December 6, 2010, the Board authorized NRG to establish a deferral account to record the revenues recovered through the Board authorized Transportation service Charges.

Accounting Entries[3]

Deferral Account No. 179 Other Deferred Revenues - Transportation Service Charge Revenues

To record, as a debit (credit) in Deferral Account No. 179-39 the actual revenues recovered through the operation of the Board authorized Transportation Service Charge and the Transportation Service Administration Fee.

> Debit/Credit - Account No. 179-39 Other Deferred Revenues- Transportation Service Revenues

> Credit/Debit - Account No. 579 Miscellaneous Operating Revenues

To record, as a debit (credit) in Deferral Account No. 179-40, interest on the balance in Deferral Account

> Debit/Credit - Account No.179-40 Other Deferred Revenues- Transportation Service Revenues

> Credit/Debit - Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

[3] Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the *Ontario Energy Board Act*.

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EPCOR NATURAL GAS LIMITED PARTNERSHIP

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Appendix E – Weighted Average Cost of Capital

Application	**Rate Base:**	**$26,626,558**		
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$14,910,872	3.87%	$577,471
Short-term Debt	4.00%	$1,065,062	6.23%	$66,353
Total Debt	60.00%	$15,975,935	4.03%	$643,825
Equity				
Common Equity	40.00%	$10,650,623	9.21%	$980,922
Preferred Shares	0.00%	$ -		$ -
Total Equity	40.00%	$10,650,623	9.21%	$980,922
Total	100.00%	$26,626,558	6.10%	$1,624,747

Settlement	**Rate Base:**	**$25,880,979**		
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$14,493,349	3.87%	$561,369
Short-term Debt	4.00%	$1,035,239	5.04%	$52,176
Total Debt	60.00%	$15,528,588	3.95%	$613,545
Equity				
Common Equity	40.00%	$10,352,392	9.25%	$957,596
Preferred Shares	0.00%	$ -		$ -
Total Equity	40.00%	$10,352,392	9.25%	$957,596
Total	100.00%	$25,880,979	6.07%	$1,571,141

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EPCOR NATURAL GAS LIMITED PARTNERSHIP

SETTLEMENT PROPOSAL

Appendix F – Accelerated Capital Cost Allowance

Application:

	A	B	C	D	E	F	G	H	I	J
	CCA Class	**CCA Class Description**	**CCA Rate**	**2023 Closing UCC/ 2024B Opening UCC**	**2024B Additions**	**CCA Claimed**	**2024B Closing UCC/ 2025T Opening UCC**	**2025T Additions**	**CCA Claimed**	**2025T Closing UCC**
1	Land	Land	0%	$52,763	$0	$0	$52,763	$0	$0	$52,763
2	Class 1	Building	4%	$384,725	$0	($15,389)	$369,336	$123,530	($17,244)	$494,721
3	Class 8	Furniture	20%	$761,677	$671,580	($219,493)	$1,213,764	$376,710	($280,424)	$1,651,404
4	Class 10	Vehicles/Computer Hardware	30%	$255,550	$102,400	($92,025)	$265,925	$75,520	($91,105)	$340,525
5	Class 12	Software	100%	$54,878	$6,400	($58,078)	$3,200	$10,000	($8,200)	($36,678)
6	Class 14.1	Goodwill	5%	$2,875,423	$0	($143,771)	$2,731,652	$0	($136,583)	$2,724,463
7	Class 50	Hardware	55%	$68,974	$40,060	($48,952)	$60,082	$75,050	($53,684)	$139,863
8	Class 51	Mains	6%	$20,541,376	$4,224,500	($1,359,218)	$23,406,659	$3,403,120	($1,506,493)	$26,957,054
9			**Total**	**$24,995,366**	**$5,044,940**	**($1,936,926)**	**$28,103,380**	**$4,063,930**	**($2,093,733)**	**$32,324,117**

Settlement:

	A	B	C	D	E	F	G	H	I	J
	CCA Class	**CCA Class Description**	**CCA Rate**	**2023 Closing UCC/ 2024B Opening UCC**	**2024B Additions**	**CCA Claimed**	**2024B Closing UCC/ 2025T Opening UCC**	**2025T Additions**	**CCA Claimed**	**2025T Closing UCC**
1	Land	Land	0%	$52,763	$0	$0	$52,763	$0	$0	$52,763
2	Class 1	Building	4%	$384,725	$0	($15,389)	$369,336	$73,530	($17,715)	$425,152
3	Class 8	Furniture	20%	$761,677	$584,580	($210,793)	$1,135,464	$463,710	($319,835)	$1,279,339
4	Class 10	Vehicles/Computer Hardware	30%	$255,550	$102,400	($92,025)	$265,925	$75,520	($102,433)	$239,011
5	Class 12	Software	100%	$54,878	$6,400	($58,078)	$3,200	$10,000	($13,200)	$0
6	Class 14.1	Goodwill	5%	$2,875,423	$0	($143,771)	$2,731,652	$0	($136,583)	$2,595,069
7	Class 50	Hardware	55%	$68,974	$40,060	($48,952)	$60,082	$75,050	($74,322)	$60,809
8	Class 51	Mains	6%	$20,541,376	$3,611,500	($1,340,828)	$22,812,049	$3,266,120	($1,564,690)	$24,513,479
9			**Total**	**$24,995,366**	**$4,344,940**	**($1,909,836)**	**$27,430,470**	**$3,963,930**	**($2,228,778)**	**$29,165,622**

EB-2024-0130

EPCOR NATURAL GAS LIMITED PARTNERSHIP

SETTLEMENT PROPOSAL

Appendix G – Draft Rate Order

EPCOR Natural Gas Limited Partnership

RATE 1 - Residential Rate

Rate Availability

The entire service area of the Company.

Eligibility

A customer that requires delivery of natural gas to any residential building served through one meter and containing no more than three dwelling units.

Rate

a)	Monthly Fixed Charge[1]	$25.00
b)	Delivery Charge	
c)	All volumes per month	10.9330 cents per m^3
	Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2025	0.6291 cents per m^3
	Rate Rider for UFGVA recovery – effective for 12 months ending December 31, 2025	1.3165 cents per m^3
d)	Transportation Charge	2.9161 cents per m^3
e)	Carbon Charges [2]	
	Federal Carbon Charge (if applicable)	15.2500 cents per m^3
	Facility Carbon Charge	0.0035 cents per m^3
f)	Gas Supply Charge (if applicable)	Schedule A

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

[2] The Federal Carbon Charge is only “applicable” to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled 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 Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

RATE 1 – General Service Rate

Rate Availability

The entire service area of the Company.

Eligibility

A customer who has not entered into a contract with EPCOR with the company for the purchase or transportation of gas and does not meet the eligibility of the Rate 1 – Residential rate class.

Rate

a)	Monthly Fixed Charge[1]	$24.50
b)	Delivery Charge	
	First 1,000 m^3 per month	12.0582 cents per m^3
	All over 1,000 m^3 per month	9.6276 cents per m^3
	Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2025	0.6291 cents per m^3
	Rate Rider for UFGVA recovery – effective for 12 months ending December 31, 2025	1.3165 cents per m^3
c)	Transportation Charge	2.9161 cents per m^3
d)	Carbon Charges [2]	
	Federal Carbon Charge (if applicable)	15.2500 cents per m^3
	Facility Carbon Charge	0.0035 cents per m^3
e)	Gas Supply Charge (if applicable)	Schedule A

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

(2) The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled 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 Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
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EPCOR Natural Gas Limited Partnership

RATE 2 - Seasonal Service

Rate Availability

The entire service area of the company.

Eligibility

All customers.

Rate

For all gas consumed from:		April 1 - Oct 31	Nov 1 - Mar 31
a)	Monthly Fixed Charge[1]	\$24.48	\$24.48
b)	Delivery Charge		
	First 1,000 m^3 per month	17.0039 cents per m^3	22.0752 cents per m^3
	Next 24,000 m^3 per month	7.6087 cents per m^3	14.2095 cents per m^3
	All over 25,000 m^3 per month	5.5016 cents per m^3	15.4831 cents per m^3
	Rate Rider for PGTVA Recovery – effective for 12 months ending December 31, 2025	0.7158 cents per m^3	0.7158 cents per m^3
	Rate Rider for UFGVA Recovery – effective for 12 months ending December 31, 2025	1.4575 cents per m^3	1.4575 cents per m^3
c)	Transportation Charge	2.9161 cents per m^3	2.9161 cents per m^3
d)	Carbon Charges [2]		
	Federal Carbon Charge (if applicable)	15.2500 cents per m^3	15.2500 cents per m^3
	Facility Carbon Charge	0.0035 cents per m^3	0.0035 cents per m^3
e)	Gas Supply Charge (if applicable)		Schedule A

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

[2] The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled 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 Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

RATE 3 - Special Large Volume Contract Rate

Rate Availability

The entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 113,000 m^3.

Rate

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

a) A Monthly Customer Charge[(1)]:

A Monthly Customer Charge of $234.68 for firm or interruptible customers; or
A Monthly Customer Charge of $260.42 for combined (firm and interruptible) customers.

b) A Monthly Demand Charge:

A Monthly Demand Charge of 33.9977 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 1.7539 cents per m^3,
(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 9.8284 cents per m^3 and not to be less than 6.4445 per m^3.

Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2025	0.2336	cents per m^3
Rate Rider for UFGVA recovery – effective for 12 months ending December 31, 2025	0.5277	cents per m^3

d) Transportation Charge 2.9161 cents per m^3

e) Carbon Charges [(2)]

Federal Carbon Charge (if applicable)	15.2500 cents per m^3
Facility Carbon Charge	0.0035 cents per m^3

f) Gas Supply Charge (if applicable) Schedule A

g) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 3 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

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

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;
b) The load factor of the customer's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions; and
d) Competition.
e)

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if

available and not accepted by the customer, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.5159 cents per m^3 for firm gas and 6.0676 cents per m^3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the customer during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 6.1707 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

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

(2) The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Bundled 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 Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

RATE 4 - General Service Peaking

Rate Availability

The entire service area of the company.

Eligibility

All customers whose operations, in the judgment of EPCOR NATURAL GAS LIMITED PARTNERSHIP, can readily accept interruption and restoration of gas service with 24 hours' notice.

Rate

For all gas consumed from:		April 1 - Dec 31	Jan 1 - Mar 31
a)	Monthly Fixed Charge [1]	\$24.83	\$24.83
b)	Delivery Charge		
	First 1,000 m^3 per month	19.2608 cents per m^3	25.2614 cents per m^3
	All over 1,000 m^3 per month	10.8506 cents per m^3	18.9517 cents per m^3
	Rate Rider for PGTVA Recovery – effective for 12 months ending December 31, 2025	0.6539 cents per m^3	0.6539 cents per m^3
	Rate Rider for UFGVA Recovery – effective for 12 months ending December 31, 2025	1.1178 cents per m^3	1.1178 cents per m^3
c)	Transportation Charge	2.9161 cents per m3	2.9161 cents per m3
d)	Carbon Charges [2]		
	Federal Carbon Charge (if applicable)	15.2500 cents per m^3	15.2500 cents per m^3
	Facility Carbon Charge	0.0035 cents per m^3	0.0035 cents per m^3
e)	Gas Supply Charge	Schedule A	

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

[2] The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducingtheir effective Federal Carbon Charge rate.

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled 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 Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

RATE 5 - Interruptible Peaking Contract Rate

Rate Availability

The entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a daily contracted demand for interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 50,000 m^3.

Rate

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

a)	Monthly Fixed Charge[(1)]	$197.22
b)	A Monthly Delivery Charge:	
	A Monthly Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 7.3996 cents per m^3 and not to be less than 4.0069 per m^3.	
	Rate Rider for PGTVA recovery – effective for 12 months ending December 31, 2025	1.0374 cents per m^3
	Rate Rider for UFGVA recovery – effective for 12 months ending December 31, 2025	1.5934 cents per m^3
c)	Transportation Charge	2.9161 cents per m^3
d)	Carbon Charges [(2)]	
	Federal Carbon Charge (if applicable)	15.2500 cents per m^3
	Facility Carbon Charge	0.0035 cents per m^3
e)	Gas Supply Charge and System Gas Refund Rate Rider (if applicable)	Schedule A

f) Overrun Gas Charge:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or
(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any applicable Gas Supply Charge.

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

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(b) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;
b) The load factor of the customer's anticipated gas consumption and the pattern of annual use and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions; and
d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas of 50,000 m^3. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this annual minimum shall be 5.8239 cents per m^3 for interruptible gas.

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

(2) The Federal Carbon Charge is only "applicable" to 20% of the natural gas volumes used by eligible greenhouses, reducing their effective Federal Carbon Charge rate.

Bundled 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 Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by EPCOR, customers who are delivering gas to EPCOR under direct purchase arrangements must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

RATE 6 – Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility

Rate Availability

Rate 6 is available to the Integrated Grain Processors Co-Operative, Aylmer Ethanol Production Facility only.

Eligibility

Integrated Grain Processors Co-Operative's ("IGPC") ethanol production facility located in the Town of Aylmer

Rate

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

   a) Fixed Monthly Charge(1) for firm services $71,541.35

   b) Carbon Charges
      - Facility Carbon Charge 0.0035 cents 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.

Purchased Gas Transportation Charges

In addition to the Rates and Charges outlined above, IGPC is responsible for all costs, charges and fees incurred by EPCOR related to gas supplied by Enbridge Gas Inc. to EPCOR's system for IGPC. All actual charges billed to ENGLP by Enbridge Gas Inc. under former Union Gas contract ID SA008936 and SA008937, as amended or replaced from time to time, shall be billed to IGPC by EPCOR when and as billed to EPCOR by Enbridge Gas Inc.

Bundled Direct Purchase Delivery

Where IGPC elects under this rate schedule to directly purchase its gas from a supplier other than EPCOR, IGPC or its agent must enter into a Bundled T-Service Receipt Contract with EPCOR for delivery of gas to EPCOR. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to IGPC if it elects said Bundled T transportation service.

Unless otherwise authorized by EPCOR, IGPC, when delivering gas to EPCOR under direct purchase arrangements, must obligate to deliver said gas at a point acceptable to EPCOR, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

SCHEDULE A – Gas Supply Charges

Rate Availability

The entire service area of the company.

Eligibility

All customers served under Rates 1, 2, 3, 4, 5 and 6.

Rate

The Gas Supply Charge applicable to all sales customers shall be made up of the following charges:

PGCVA Reference Price	(EB-2024-XXXX)	13.0514 cents per m^3
GPRA Recovery Rate	(EB-2024-XXXX)	2.4643 cents per m^3
Total Gas Supply Charge		15.5157 cents per m^3

Note:

PGCVA means Purchased Gas Commodity Variance Account
GPRA means Gas Purchase Rebalancing Account

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

RATE BT1 – Bundled Direct Purchase Contract Rate

Rate Availability

Rate BT1 is available to all customers or their agent who enter into a Receipt Contract for delivery of gas to EPCOR. The availability of this option is subject to EPCOR obtaining a satisfactory agreement or arrangement with Enbridge Gas Inc. and EPCOR's gas supplier for direct purchase volume and DCQ offsets.

Eligibility

All customers electing to purchase gas directly from a supplier other than EPCOR must enter into a Bundled T- Service Receipt Contract with EPCOR either directly or through their agent, for delivery of gas to EPCOR at a mutually acceptable delivery point.

Rate

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

Note:

Ontario Point of Delivery means Dawn or Parkway on the Enbridge Gas Inc. (Union South) System as agreed to by EPCOR and EPCOR's customer or their agent.

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Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

EPCOR Natural Gas Limited Partnership

Transmission Service

Availability

Transmission Service charges shall be applied to all natural gas producers that sell gas into Enbridge Gas' Union South system via ENGLP's distribution system.

Eligibility

All natural gas producers, transporting gas through ENGLP's system for sale into Enbridge Gas' Union South system shall be charged the Transmission Service Rate and associated Administrative Charge. Rates and Charges will be applied only in those months that a natural gas producer delivers gas to a delivery point on ENGLP's system for sale into Enbridge Gas' Union South system.

Rate

Administrative Charge	$250/month
Transmission Service Rate	$0.95/mcf

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Implementation: All bills rendered on or after January 1, 2025
EB-2024-0130

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	Meter Tested at Customer Request Found to be Accurate	Charge based on actual costs
22	Installation of Service Lateral	$100 for the first 20 meters for residential customers. Additional if pipe length exceeds 20 meters.

Note: Applicable taxes will be added to the above charges

Effective: January 1, 2025
Implementation: All bills rendered on or after January 1, 2025
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EPCOR NATURAL GAS LIMITED PARTNERSHIP

SETTLEMENT PROPOSAL

Appendix H – Scorecard

Performance Categories	Measures	Description
Service Quality	Reconnection response time (# of days to reconnect a customer) Scheduled appointments met on time (appointments met within designated time period) Telephone calls answered on time (call answering service level)	*# of reconnections completed within 2 business days/# of reconnections completed* *# of appointments met within 4hrs of the scheduled date / # of appointments scheduled in the month* *# of calls answered within 30 seconds / # of calls received*
Customer Satisfaction	Customer Complaint Written Response (# of days to provide a written response) Billing accuracy Abandon Rate (# of calls abandon rate) Time to reschedule missed appointments	*# of complaints requiring response within 10 days / # of complaints requiring a written response* *Number of manual checks done as per quality assurance program, for excessively high or low usage.* *# of calls abandoned while waiting for a live agent / # of calls requesting to speak to a live agent* *% of rescheduled work within 2 hours of the end of the original appointment time*
Safety, system reliability and asset management	Meter Reading Performance % of Emergency Calls Responded within One Hour Damages	*# of meters with no read for 4 consecutive months / # of active meters to be read* *# of emergency calls responded within 60 minutes / # of emergency calls* *Third party line breaks per 1,000 locate requests*
Extending natural gas distribution to new communities	New communities that have access to natural gas distribution system $/m3 cost to deliver natural gas Customer years Cumulative volume	*(# of communities serviced by system)* *Actual average $/m3* *Average customer years* *Actual cumulative volume*
Financial Ratios	Current Ratio Debt Ratio Debt to Equity Ratio Interest Coverage Financial Statement Return on Assets Financial Statement Return on Equity Total Cost per Customer per year Total Cost per km of distribution pipe per year	

EB-2024-0130

EPCOR NATURAL GAS LIMITED PARTNERSHIP

SETTLEMENT PROPOSAL

Appendix I – Pre-Settlement Clarification Questions

EPCOR Aylmer Rebasing (EB-2024-0130)
Responses to OEB Staff Pre-Filed Questions for Settlement Conference

IR-Staff-61

Preamble:

A threshold of 0.8 is only relevant if a utility has adopted a Rolling Project Portfolio approach (rather than stand-alone project-by-project economic assessment). The IR response requires an expanded explanation. For example, Section 2.1.1 of the OEB's EBO 188 states:

> *The Board believes that utilities are in the best position to plan their distribution systems and, therefore, they should have flexibility in choosing the optimal system design for their distribution system expansions. The Board also believes that if the utilities are allowed to assess the financial viability of all potential customers as a group [using a portfolio approach] more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.*

Follow-up question:

Why has ENGLP decided not to use the flexibility of the Rolling Project Portfolio approach to expand its distribution system, which could allow for a greater number of customer attachments to be completed?

ENGLP Response: ENGLP does not currently have the ability to calculate and maintain a portfolio view of expansion projects. As a result projects are reviewed on an individual basis to ensure they meet a PI of 1.0.

IR-Staff-62

Preamble:

ENGLP provides a copy of its proposed New Connections Policy. The policy defines a Large Volume Customer as any customer that has 1,000,000 British Thermal Unit (BTUs) or more of equipment per service. The IR response provides that for the purposes of customer classification during the initial intake, ENGLP would use the Canada Energy Regulator energy conversion tables as follows:

1 MMBtu = 1,000,000 Btu = 1.0551 GJ

1 MMBtu = 1,000,000 Btu = 28.3278 m3

Follow-up question:

Please provide the contract demand and monthly and/or annual usage, in cubic meters, for the customer to be classified as a Large Volume Customer?

ENGLP Response: Contract demand and usage amounts are not captured during the initial classification as are they directly relevant to the intake process. The classification of a new Customer as a Large Volume Customer is intended to determine the complexity of the service lateral installation. The classification does not directly impact the rate class that a Customer may ultimately end up in.

IR-Staff-52 and IR-2-CCC-1 c

Preamble:

ENGLP stated that a meter's life begins when it is places on the shelf in inventory as defined by Measurement Canada.

Follow-up questions:

1. What is the turnaround time for meters from inventory to being placed into operation in the field? Please delineate between the different meter sizes.

ENGLP Response:

The majority of meter sizes in inventory are placed into service within the seal data year. Few of the larger meter sizes will get placed into service within a two year period of seal date year. In very rare instances, meters are placed into service after two year period of seal date year. The table below delineates between the different meter sizes:

Meter Size AC 250	Placed into service within 1 year of seal date
Meter Size AC 425	Placed into service within 1 year of seal date
Meter Size AC 630	Placed into service within 1 year of seal date
Meter Size AL 750	Placed into service within 1 year of seal date
Meter Size AL 800	Placed into service within 1 year of seal date
Meter Size AL 1,000	Placed into service within 1 year of seal date
Meter Size 3M175	Placed into service within 1 year of seal date
Meter Size 5M175	Placed into service within 1 year of seal date
Meter Size 7M175	Placed into service within 2 year of seal date
Meter Size 11M175	Placed into service within 2 year of seal date
Meter Size 16M175	Placed into service within 2 year of seal date

2. What are the lead times to get meters? Please delineate between the different meter sizes.

ENGLP Response:

Meter Size AC 250	Larger order - Average 12 month lead time
Meter Size AC 425	Larger order - Average 12 month lead time
Meter Size AC 630	Larger order - Average 12 month lead time

Meter Size AL 750	Larger order - Average 12 month lead time
Meter Size AL 800	Larger order - Average 12 month lead time
Meter Size AL 1,000	Larger order - Average 12 month lead time
Meter Size 3M175	Specific smaller order – Average 6 month lead time
Meter Size 5M175	Specific smaller order – Average 6 month lead time
Meter Size 7M175	Specific smaller order – Average 6 month lead time
Meter Size 11M175	Specific smaller order – Average 6 month lead time
Meter Size 16M175	Specific smaller order – Average 6 month lead time

3. What are the consequences of expired meters or meter not being compliant with Measurement Canada?

ENGLP Response: Please refer to this link for an overview of Measurement Canada's compliance and enforcement details:

https://ised-isde.canada.ca/site/measurement-canada/en/authorized-service-providers/measurement-canada-compliance-and-enforcement-fact-sheet

Further, please refer to the below link for the Electricity and Gas Inspection Act Offences and Punishment details:

https://laws-lois.justice.gc.ca/eng/acts/E-4/page-4.html#h-214925

IR- Staff-53 and IR-2-CCC-9 -

Preamble:

For the Port Burwell Low Pressure Reinforcement, ENGLP stated they had considered alternatives including:

1. Using CNG. (Exh 2, USP, pg 152)
2. Conduct an engineering assessment to accept an increase of current pipeline MOP of 30psig, to an upgraded MOP of 80psig. (Response to 2-CCC-9)

Follow-up question:

1. Please provide the cost for the 2 alternatives and timelines.

ENGLP Response: The alternatives of CNG along with the acceptance of the MOP increase to 80psig from 30psig on the current pipeline were both discussed internally in 2023 but detailed costing was not completed for both options.

The age of the current pipeline, as well as its assessed condition determined it was not feasible to increase the MOP. The best path forward is to abandon the existing 2-inch PE pipe and install a new 4-inch PE pipe, which will be rated for the higher pressure (80psi).

From our recent experience in the South Bruce, two CNG trailers for three months of winter would cost approximately $200K in rental fees/annum. This continuous annual expense compares to the depreciation plus the weighted average cost of capital of a $450K capital upgrade to 4-inch PE. Given the life of this asset, it would significantly less than CNG in the long run.

IR-Staff-54

Preamble:

The following table was provided for Customer 1 in South Belmont:

Customer 1: South Belmont	
Year	**Total Annual Consumption (m^3)**
2020	68,298
2021	75,723
2022	66,027
2023	143,545
2024 Year to Date	7,149

For the South Belmont Pipe Addition, ENGLP stated they had considered an alternative involving additional piping segments on Yorke Line close to Belmont South will need to be updated to 4-inch.

Follow-up questions:

1. Please provide a discussion as to why the customer doubled its consumption in 2023.
    a. Is this trend expected to continue for the next 5 years, or will it plateau to 2023 consumptions?

    ENGLP Response: The customer expanded is operational footprint in 2022 from 6 MMBtu/hr capacity to 24 MMBtu/hr. Further, 2023 was a wet year for corn drying which is why there was increased consumption compared to 2022. The consumption trend is expected to plateau between 2022- 2023 annual consumption numbers over the next 5 years.

2. Please provide the cost of the alternative and timelines.

ENGLP Response: The alternative estimated cost of upgrading the existing Yorke Line main close to the Belmont South Station (approx. 3.7kms) is $549,950. Estimated timeline for completion is 2027. Modeling simulation results suggested that the installation of the 4inch main along Wilson Road and north on Belmont Road not only resolved the South Belmont area low pressure issue but also improves pressure distribution at Aylmer and eastern central districts.

EPCOR Aylmer Rebasing (EB-2024-0130)
Responses to CCC Pre-Filed Questions for Settlement Conference

SC-CCC-1

a) Please provide all of the assumptions used for the PI calculation provided in response to Staff-50(e). Please provide the analysis in a working excel spreadsheet.

ENGLP Response: Refer to attachment SC-CCC-1_PreSettlement_PI Calculation. Refer to the tab 'Cost Assumptions' for a summary of the assumptions used in the workbook.

b) Please confirm that $1.87M is the expected final cost of the Phase 1 Agricultural Connection Project.

ENGLP Response: The final cost of the first part of Phase 1 is $890,949. The estimated cost to complete the second part of Phase 1 is $980,820 and is based on time and materials spend. Overall, the $1.87M is the estimated final cost to complete Phase 1 of the Agricultural Connection Project.

c) Please confirm that the second part of Phase 1 is already in service. If not, when is it expected to go into service.

ENGLP Response: The second part of Phase 1 is currently expected to go into service by Mid-November 2024.

d) Please confirm that the $500k placeholder for Phase 2 of the Agricultural Connection Project in 2025 is no longer needed based on the updated information from the customer. Is this amount currently reflected in the proposed 2025 rate base in the application?
ENGLP Response: The $500k placeholder is currently reflected in the proposed 2025 rate base in the application. The Agricultural Customer has communicated that there continues to be plans in place for future expansion although specific timing at this stage remains unknown.

SC-CCC-2

a) Based on the response to 2-CCC-1(d) and the additions set out in the rate base figure provided at Table 2.1-1 (PDF p. 3 of Exhibit 2), it appears that CAPEX figures are equivalent to in-service additions, is that correct? Also, please confirm that EPCOR applies the half-year rule to convert in-service additions to rate base.

ENGLP Response: Generally, for the purposes of applied for capital, CAPEX figures would be equivalent to in-service additions. Table 2.1-1 would show actual in-service additions in the year that they occurred. In 2-CCC-1(d), the year to date CAPEX would represent the amount of capital spent (construction work in progress) in 2024. Generally, the majority of capital expenditures incurred in a given year would be added to rate base in that year but there are scenarios where construction work in progress could span multiple years if the asset being constructed is not completed before year end.

Confirmed, when ENGLP moves expenditures from construction work in progress to rate base (addition) the half year rule is applied.

SC-CCC-3

In EB-2018-0264 at Exhibit 4, Tab 1, Schedule 1, there is salary transfer line in Table 4-5 paid by Southern Bruce that appears to include costs related to general support from Aylmer staff.

a) Please describe, more specifically, what is included in the salary transfer line.

ENGLP Response: In EB-2018-0264 at Exhibit 4, Tab 1, Schedule 1, the salary transfer line in Table 4-5 represents both Aylmer staff transfers and Ontario Affiliate Shared Services transfers.

As explained in detail in paragraphs 29 & 30 in EB-2018-0264[4], the positions being partially transferred from Aylmer would be the General Manager and Administrative Manager positions. Whereas the positions being transferred from other EUI entities (equivalent to Ontario Affiliate Shared Services as defined in Exhibit 4 of EB-2024-0130) would include: Capital planning and management, operational support, health safety and environment and financial planning & management.

As such, only the General Manager and Administrative Manager positions would have been approved in Southern Bruce rates as previously noted in ENGLP's interrogatories response.

[4] EB-2018-0264 (Updated 2019-04-11), Exhibit 4, Tab 1, Schedule 1, Page 15-16

SC-CCC-4

a) Please provide a calculation of earnings for the purposes of sharing for each year 2020 to 2023 using each of the following approaches:

i. Inclusion of the language in the ESMDA accounting order regarding the Affiliate and Corporate shared service costs (as previously approved)

	2020	2021	2022	2023	Notes / Reference
Regulatory Net Income	$347,694	$488,387	$567,337	$746,798	
Actual:					
Ontario Affiliate Shared Services	$696,813	$640,942	$739,357	$894,767	Table 4.3.2-2, Line 5
Corporate Shared Services	$340,753	$369,511	$531,347	$529,218	Table 4.3.2-2, Line 19
Operations Engineering	($51,938)	($50,913)	($42,801)	($41,724)	A - Table 4.3.3.2-3, Line 10
Gas Procurement Support	($35,636)	($49,869)	($63,901)	($62,775)	B - Table 4.3.3.2-3, Line 6
	$949,922	$909,671	$1,164,002	$1,319,486	
Test Year shared services:					
Shared Services in 2020 test year	$892,722	$892,722	$908,791	$935,146	
Inflation	1.000	1.018	1.029	1.033	
	$892,722	$908,791	$935,146	$966,006	
Adjustment	$57,200	$880	$228,856	$353,480	
ESM Regulatory Net Income	**$404,894**	**$489,267**	**$796,193**	**$1,100,278**	
Regulated Equity					
Opening Ratebase	$14,697,874	$16,580,487	$17,420,192	$18,411,602	
Closing Ratebase	$16,580,487	$17,420,192	$18,411,602	$20,295,945	
Mid-Year Ratebase	15,639,181	17,000,340	17,915,897	19,353,774	
Equity Component	40.00%	40.00%	40.00%	40.00%	
	6,255,672	6,800,136	7,166,359	7,741,509	
Actual ROE	6.47%	7.19%	11.11%	14.21%	
Deemed ROE	8.98%	8.98%	8.98%	8.98%	
Variance	-2.51%	-1.79%	2.13%	5.23%	

Notes:

A. In EB-2018-0336 engineering support was forecast to be completed by an embedded ENGLP position (Senior Advisor)[5]. In the 2020, the operations engineering support function was established in Ontario Affiliate Shared Services to allow this resource to provide the same support across all of Ontario affiliates. As the service was originally forecast as embedded but moved to Ontario Affiliate Shared Services, ENGLP normalized for these expenditures as part of the ESM calculation.

[5] EB-2018-0336, Exhibit 4, Tab 1, Schedule 1, Page 21, Paragraph 44

B. In EB-2018-0336 gas procurement support was forecast as part of the system gas fee[6]. In this application this system gas fee was removed from the proposed rates and replaced with this Ontario Affiliate Shared Service functionality. As the service was originally forecast as system gas fees but then moved to Ontario Affiliate Shared Services, ENGLP normalized for these expenditures as part of the ESM calculation.

ii. Exclusion of the language regarding the Affiliate and Corporate shared service costs (as proposed).

ENGLP Response: See below. Note this is the same table as previously provided in 10-CCC-23.

	2020	**2021**	**2022**	**2023**
Regulatory Net Income	$347,694	$488,387	$567,337	$746,798
Regulated Equity				
Opening Ratebase	14,697,874	16,580,487	17,420,192	18,411,602
Closing Ratebase	16,580,487	17,420,192	18,411,602	20,295,945
Mid-Year Ratebase	15,639,181	17,000,340	17,915,897	19,353,774
Equity Component	40%	40%	40%	40%
	6,255,672	6,800,136	7,166,359	7,741,509
Actual ROE	5.56%	7.18%	7.92%	9.65%
Deemed ROE	8.98%	8.98%	8.98%	8.98%
Variance	-3.42%	-1.80%	-1.06%	0.67%

[6] EB-2018-0336, Exhibit 8, Tab 1, Schedule 1, Page 1, Table 8.0-1, Line 9

b) Based on the response to 10-CCC-22(d), please confirm that the REDA is only applicable to EPCOR's participation in generic hearings or policy consultations. Please also explain what types of costs the account covers (e.g., only external costs, both internal and external costs, etc.).

ENGLP Response: As per the accounting order, the REDA is used to record the cost for participating in generic proceedings and Union Gas proceedings, including a main rates case. Historical approvals have included Ontario Energy Board costs along with external legal costs. Examples of relevant hearings include:

- EB-2015-0245 (DSM Evaluation Process of Program Results)
- EB-2017-0108 (Overlapping CPCN)
- EB-2020-0049 (EGI - Harmonized SES)

The REDA would only include external costs. This could also potentially include consultant/expert witness costs if appropriate. In those cases, ENGLP would register as a participant in the hearing and instead of submitting cost claims (as it is not eligible), would receive cost recovery via the REDA account.

c) For the following DVAs that EPCOR has sought to continue into the next rate term, please explain why they should be continued:

i. Transportation Service Charge Deferral Account

ENGLP Response: ENGLP has proposed the same charge for 2025 as ENGLP is not in a position to determine or justify a different rate for this service. ENGLP does not have a comparable reference price to use to establish a new market-based rate nor is ENGLP able to justify a cost-based rate for these services given that these services have not been provided for a number of years. ENGLP is not expecting any gas producers to use its distribution system to transport gas into Enbridge Gas' Union South system. The continuance of this transportation rate and corresponding deferral account provides ENGLP and customers flexibility when procuring local supply options along with other initiatives (such as RNG) without filing a stand-alone rate application for transportation services.

ii. Accelerated CCA Income Tax Variance Account

ENGLP Response: The Accelerated CCA Income Taxes Variance Account (“ACITVA”) is intended for ENGLP to record the income tax impact from the difference between the capital cost allowance (“CCA”) rates used in the income taxes payable calculation included in the 2025 revenue requirement and the accelerated CCA rates as enacted under Bill C-97, should ENGLP claim accelerated CCA for its Aylmer operations during the Price Cap IR Term.

In the calculation of income taxes payable included in the 2025 revenue requirement, ENGLP has not claimed the accelerated CCA on eligible capital property. Therefore, this account is required to record the impact associated with changes to income taxes payable should ENGLP claim accelerated CCA during the Price Cap IR Term.

This deferral account was agreed up on the EB-2018-0336 settlement and ENGLP believes it is appropriate to continue, as it is in the best interest of customers.

iii. LEAP EFA Funding Deferral Account

ENGLP Response: The LEAP EFA deferral account is used for the purpose of recording incremental contributions that are beyond the amounts currently embedded in distribution rates.

This generic deferral account was approved for all electricity LDCs and gas distributors, which allows them to provide LEAP to any eligible customers without a cap. While ENGLP currently has a LEAP carryforward, this deferral account will ensure that LEAP funding remains an option for eligible customers.

iv. Cloud Computing Deferral Account

ENGLP Response: The Cloud Computing technology space continues to evolve rapidly and ENGLP would benefit from the flexibility that all other LDC’s have when considering technology solutions in the next rate term.

v. Getting Ontario Connected Act Variance Account

ENGLP Response: ENGLP has included provisions in its test-year forecast to address additional locate legislative requirements but can not fully anticipate costs of the next 5 years. Should amounts in this application not be sufficient, ENGLP would need to rely on this deferral account to ensure compliance with legislation

SC-CCC-5

a) With respect to the Unaccounted for Gas Variance Account, please advise:

i. Whether this account was previously disposed during the 2020-2024 IRM term?

ENGLP Response: The UFGVA not disposed of during the rate term.

ii. Why EPCOR waited until the current rebasing application to dispose of the UFGVA?

ENGLP Response: ENGLP was monitoring the activity of the UFG in an effort to identify a trend in activity and in an effort to smooth out any disposition related to the 2022 balance accumulation. As the 2023 balance was more consistent with prior year trending and ENGLP was filing this application, it believes it is appropriate to request disposition at this time.

iii. EPCOR's view on the $25,000 threshold set out in the accounting order and how it is properly applied?

ENGLP Response: As per the accounting order[7]:

"The materiality threshold for this account is $25,000. Accordingly, the annual gas costs associated with the UFG as calculated in the manner described above which are equal to or greater than $25,000 (debit or credit) will be recorded in the UFGVA."

and additional in the EB-2018-0336 settlement proposal[8]:

With respect to the Unaccounted For Gas Variance Account ("UFGVA"), the Parties agree that this account shall apply to Rates 1-5 and an annual materiality threshold of $25,000 shall apply to this account.

The threshold has been applied annually and if an annual balance is above or below $25,000 the adjustments to the UFGVA are excluded from the request for disposition. This occurred in 2021. As noted on the ENGLP_EB-2024-0130_DVA Continuity Schedule_20240718 – Tab UFGVA – Cells N22:Y22, the changes in balances related

[7] ENGLP_REV_Settlement Proposal_20190605 – page 35
[8] ENGLP_REV_Settlement Proposal_20190605 – page 18.

to 2021 have been excluded as the 2021 balance was a credit of $14,284 (Cells N19:Y19) .

SC-CCC-6

a) CCC asks that EPCOR be prepared to further discuss the response to 7-CCC-20 regarding the allocation of the costs related to Agricultural customer load project at the outset of the settlement conference. We are interested in understanding why only $87k of the 2025 project-specific RR is allocated to the customer. In addition, we want to understand why EPCOR did not elect to directly assign the project costs to the customer (or customer class). A written response would also be acceptable. –

ENGLP Response: ENGLP does acknowledge that this is a large project and did contemplate treatment in the cost allocation/rate design process. The most direct answer to this question is that this investment was treated consistently with the rest of the capital investments allocation and rate setting process to avoid subjectivity. Only Rate 6 (IGPC) has a specific direct allocation as there is only one customer included in this rate class. ENGLP has included below some additional commentary which contributed to this approach.

The profitability index/customer contribution calculation completed for the Rate 3 customer indicates the NPV of forecast revenues exceed the NBV of costs (including both capital directly attributable to the customer and incremental OM&A), and therefore no contribution is required. On a 10-year NPV basis, revenues from the customer exceed the costs caused by the customer.

The revenue requirement impact of this customer may exceed the revenue from the customer in the Test Year because the new assets are mostly undepreciated and gross asset costs are higher than historic assets due to inflation. This will not be the case in the long run as those assets depreciate and newer assets decrease the extent that the dedicated assets are relatively higher cost.

This allocation is consistent with the allocation of other costs attributable to a customer, such as services and meters. For example, a new R1 Residential customer in 2024 will have a new meter that, due to inflation, will cost more than the average Residential meter in-service. This meter will have only a half-year of accumulated depreciation so its net book value will be higher than that of other Residential meters. Each Residential customer will pay the same fixed charge despite differences in the revenue requirement impacts of different vintages of meters.

An alternative methodology that directly allocates these costs to the Rate 3 class may increase the costs allocated to that class in the Test Year, but it would decrease the costs allocated to the Rate 3 class in the future. It would be inappropriate to change the direct allocation of these costs to rate classes in future rate applications so the change may put upward pressure on the rates of other rate classes in the future. Additionally, directly allocating the costs of one customer to a rate class with multiple customers would not be appropriate and ENGLP is not proposing to create a new rate class for this customer.

Finally, ENGLP notes that revenue-to-cost ratio of the R3 rate class is sufficiently above the 80% lower bound that the revenue requirement increase of the class following any adjustments would have to be in excess of 16% for there to be a change in the proposed revenues to be collected from the class. While this is more of an outcome based validation rather than a principled approach, it does support the reasonableness of the approach.